STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-130

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Winter 2021/2022 Cost of Gas
Summer 2022 Cost of Gas

UPDATED DIRECT TESTIMONY

OF

DAVID B. SIMEK

AND

CATHERINE A. MCNAMARA

October 19, 2021

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I. INTRODUCTION

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. ("LUSC"), which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("EnergyNorth" or "the Company").

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

A. (DS) (CM) Please see our Direct Testimony, filed September 15, 2021, for our educational backgrounds and business and professional experience.

Q. Mr. Simek and Ms. McNamara, have you previously testified in regulatory proceedings before the New Hampshire Public Utilities Commission (the "Commission")?

A. Yes, we have.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to explain the Company's updated proposed firm sales cost of gas rates for the 2021/2022 Winter (Peak) Period and the Company's proposed 2021/2022 Local Delivery Adjustment Clause, both effective November 1, 2021. Our testimony also explains the Company's updated proposed firm sales cost of gas rates for the 2022 Summer (Off-Peak) Period.

II. WINTER 2021/2022 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 \$1.1339 per therm for residential customers, \$1.1341per therm for commercial/industrial high winter use customers, and \$1.1324 per therm for commercial/industrial low winter use customers as shown on Proposed Second Revised Page 95 (Bates 056). The Company proposes a firm transportation cost of gas rate of \$0.0002 per therm as shown on Proposed Second Revised Page 98 (Bates 058).

Q. Please explain tariff page Proposed Second Revised Page 95 (Bates 056).

A. Proposed Second Revised Page 95 contains the calculation of the 2021/2022 Winter Period Cost of Gas Rate and summarize the Company's forecast of firm gas costs and firm gas sales. As shown on Page 95, the proposed 2021/2022 Average Cost of Gas of \$1.1339 per therm is derived by adding the Direct Cost of Gas Rate of \$1.0843 per therm to the Indirect Cost of Gas Rate of \$0.0496 per therm. The estimated total Anticipated Direct Cost of Gas, derived on Proposed Second Revised Page 95, is \$94,810,891. The estimated Indirect Cost of Gas, also derived on Page 95, is \$4,338,002. The Direct Cost of Gas Rate of $1.0843 and the Indirect Cost of Gas Rate of $0.0496 are determined by dividing each of these total cost figures by the projected winter period firm sales volumes of 87,443,741 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 Proposed Second Revised Page 96 (Bates 057), total $161,141. These adjustments are added to the Unadjusted Anticipated Cost of Gas of $94,649,751 to determine the Total Anticipated Direct Cost of Gas of $94,810,891(slightly off due to rounding).

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

A. The Unadjusted Anticipated Cost of Gas shown on Proposed Second Page 96 (Bates 057) consists of the following components:

1.	Purchased Gas Demand Costs	$12,887,000
2.	Purchased Gas Commodity Costs	72,351,034
3.	Storage Demand and Capacity Costs	981,898
4.	Storage Commodity Costs	6,130,435
5.	Produced Gas Cost	2,299,384
	Total	$94,649,751

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

A. The allowable adjustments to gas costs, listed on Proposed Second Page 96 (Bates 057), are as follows:

1.	Deferred Gas Cost Prior Period Under Collection	$1,431,639
2.	Interest	44,085

3.	Fuel Inventory Revenue Requirement	335,667
4.	Broker Revenues	(3,600)
5.	Transportation COG Revenue	(6,938)
6.	Capacity Release Margin	(1,676,512)
7.	Fixed Price Administrative Cost	36,800
	Total Adjustments	$161,141

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 20-141 for the 2020/2021 winter period?

A. The average cost of gas rate proposed in this filing of $1.1339 per therm is $0.5768 per therm more than the initial rate of $0.5571 per therm approved by the Commission in Order No. 26,419 (October 30, 2020) in Docket No. DG 20-141. The $0.5768 per therm increase in the rate is primarily due to a $48,513,696 increase in the Total Unadjusted Direct 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 2020/2021 winter period?

A. The proposed firm transportation winter cost of gas rate is $0.0002 per therm. The rate approved in Docket No. DG 20-141 was $0.0001 per therm. There is a $0.0001 increase in the firm transportation rate.

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. The pressure support purposes rate of 8.7% stayed the same based on the marginal cost study used for the rate design approved in Docket No. DG 20-105.

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

A. Yes. The calculation is provided on Schedule 26 (Bates 207). The Company is proposing to collect $335,667 in fuel inventory revenue requirement consistent with the approved rate of return in Order No. 26,505 (July 30, 2021) in Docket No. DG 20-105. The impact of this amount to the overall Cost of Gas rate is $0.0038 per therm, which is determined by dividing the $335,667 by the estimated November 2021 through October 2022 COG sales volumes of 87,443,741 therms.

Q. How was the statutory tax rate of 27.08% on Schedule 26 calculated?

A. The statutory rate of 27.08% was calculated by using a 21% federal tax rate and a 7.7% tax rate for the State of New Hampshire (0.21 + 0.077 – (0.21 x 0.077) = 0.27083).

Q. How was the common equity pre-tax rate of 6.640% on Schedule 26 calculated?

A. The common equity pre-tax rate of 6.640% was calculated by dividing the 9.30% rate of return on common equity, approved in Docket No. DG 20-105, by 0.72917 (1 – 0.27083) [statutory tax rate – see previous question] and multiplied by 52.00% (equity component of the capital structure approved in DG 20-105) [0.093 / 0.72917 x 0.5200 = 0.06664].

Q. Has the bad debt percentage in this filing of 0.700% changed from the bad debt percentage calculated in the Winter 2020/2021 Cost of Gas Reconciliation?

A. Yes. The bad debt percentage of 0.70% used in this filing is the calculated rate for the period of May 2020–April 2021. The bad debt percentage that was calculated in the Winter 2020/2021 Cost of Gas Reconciliations for the period of May 2019–April 2020 was 1.1%.

Q. What was the actual weighted average firm sales cost of gas rate for the 2020/2021 winter period?

A. The weighted average cost of gas rate was $0.5100 per therm (Bates 104, line 54). This was calculated by applying the actual monthly cost of gas rates for November 2020 through April 2021 to the monthly therm usage of an average residential heating customer using 667 therms for the six winter period months.

Q. What is the current percentage used to calculate the maximum increase to the Cost of Gas rate?

A. The current percentage used to calculate the maximum allowed increase to the Cost of Gas rate is 25% for both Winter and Summer period Cost of Gas rates.

Q. Is the Company requesting an increase to the percentage used to calculate the maximum allowed Cost of Gas Rate?

A. Yes, the Company is requesting that the percentage used to calculate the maximum allowed cost of Gas rate be increased for the Summer period of May through October.

The Company is not requesting a change to the maximum allowed percentage increase applicable to the Winter period.

Q. Why is the Company asking that the percentage used to calculate the maximum allowed cost of Gas rate be increased for the summer period of May through October?

A. In the past eighteen summer months (i.e., the last three Summer periods) the Company has been at the maximum allowed rate for twelve of those months. In the summer of 2021, the Company has been at the maximum allowed rate for all six months. The under collected balance has grown to approximately $4.5M. That under collection is the beginning balance for the summer portion of this filing. In the summer of 2020, the Company's calculated Cost of Gas rate was at the maximum allowed rate for three out of the six months and the under collected balance grew to $3.5M but was primarily offset by an out of period accounting adjustment. Given these circumstances, the Company believes the 25% used to calculate the maximum allowed Cost of Gas rate is insufficient. While the 25% maximum increase was appropriate in prior years when there was a separate filing for the Summer Cost of Gas rate, once the Winter and Summer periods were combined into one filing, the amount of time between the filing and the effective date for the Summer Cost of Gas rate increased by six months, thus increasing the likelihood of the forecasted Summer Cost of Gas rate differing significantly from the market conditions during the applicable summer period. One of the reasons for having a "trigger" adjustment to the Cost of Gas rate it to try to reduce potential under collections at the end of the rate period. As shown by the size of the under collections during the recent summer periods, the 25% limit has been insufficient to serve that purpose.

Q. What percentage used to calculate the maximum allowed Summer Cost of Gas Rate is the Company asking for approval of?

A. The Company is asking for the percentage used to calculate the maximum allowed Summer Cost of Gas rate to be increased from 25% to 40%.

Q. How did the Company determine that an increase of the maximum allowed Summer Cost of Gas from 25% to 40% was appropriate?

A. The Company did an analysis of the past four years. We started with the original summer cost of gas monthly adjustment filings, removed out of period adjustments and then calculated what the four-year average increase would have been if we were able to increase the rates beyond 25%. The average increase was 47.2%. We then rounded down to 40%.

Q. Why should the Commission increase the percentage used to calculate the maximum allowed Cost of Gas rate for the Summer period?

A. When the Company reaches the maximum allowed rate, the under collected balance continues to grow. In the summer of 2021, the projected under collected balance is $4,472,186. Based on the 2022 estimated summer therms of 27,125,444, the rate for next summer will be starting with an increase of $0.1649 per therm just to recover that under collection. The Commission should approve the increased percentage used to calculate the maximum allowed Summer Cost of Gas because the only other option is the

Company would be forced to file for additional rate increase approvals which would defeat the purpose of having a single annual Cost of Gas filing

Q. Why doesn't the Company make an interim filing when the maximum allowed Cost of Gas is reached?

A. An additional filing would be an administrative burden for all parties. The primary reason for combining the winter and summer filing into one, was to reduce this administrative burden.

Q. Is the 25% used to calculate the maximum allowed Cost of Gas sufficient for the Winter period?

A. Yes, the 25% used to calculate the maximum allowed Cost of Gas increase, in the winter period, is sufficient. The volume of therms sold is approximately 40% higher than the amount of therms sold during the summer months. The same $4.5M under collection referenced above would cause an automatic increase of only $0.0519 per therm during the winter. Also, rates for the Winter Cost of Gas are calculated using more near-term market information than those for the future Summer period.

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

Q. Please explain the prior period under collection of $1,431,639.

A. The prior period under-collection is detailed in the 2020/2021 winter period reconciliation that was filed with the Commission on July 29, 2021. The $1,431,639 under-collection is the sum of the deferred gas cost, bad debt, and working capital over- and under-collection balances as of April 30, 2021. 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.

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 Second Revised Page 94 (Bates 055) contains the FPO rate for the 2021/2022 winter period, which is $0.9256per therm for residential customers. This compares to the FPO rate approved for the 2020/2021 winter period of $0.5771 per therm for residential customers. This represents a $0.3485 per therm or 60.4% increase in the residential FPO rate. The total bill impact on the winter period bills for an average FPO heating customer using 667 therms is an increase of approximately $232.45 or 60.4% compared to last winter's approved FPO rate. The estimated winter period bill for an average residential heating customer opting for the FPO would be approximately $138.94(or 22.5%) lower 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 204) 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 Second Revised Page 101 (Bates 061), the Company is submitting for approval an LDAC of $0.1444 per therm for the residential non-heating class and residential heating class, and $0.0878 per therm for the commercial/industrial bundled sales classes, effective November 1, 2021. The surcharges proposed to be billed under the LDAC are the Energy Efficiency Charge, the Revenue Decoupling Adjustment Factor, the Environmental Surcharge for Manufactured Gas Plant ("MGP") remediation, the Residential Gas Assistance Program charge, and the rate case expense reconciliation surcharge from Docket No. DG 20-105.

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, 2021, through October 31, 2022, forecasted Keene therm sales of 1,405,237 are added to the EnergyNorth therm sales forecast of 181,424,635 for a total therm sales forecast of 182,829,872.

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 the November 2021 through October 2022 period. In the calculation of the Energy Efficiency Charge, the Company has also included the projected prior period under-recovery of the Company's residential and commercial energy efficiency programs as of October 2021. As shown on Schedule 19 Energy Efficiency (Bates 132–134), the proposed Energy Efficiency charge is $0.0861 per therm for residential customers and $0.0408 per therm for commercial and industrial customers.

Q. Please explain the Revenue Decoupling Adjustment Factor ("RDAF").

A. The purpose of the RDAF is to recover or refund, on an annual basis, the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer. Schedule 19 RDAF Page 3 (Bates 130) shows the prior period difference (September 2020 through August 2021) between the proposed Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer calculation of a total under-collection of $2,426,364. Schedule 19 RDAF Page 2 (Bates 129) also includes a reconciliation of the amount of prior refunds (accumulated through October 2020 and refunded November 2020 through August 2021) of $969,938 remaining to be refunded.

Q. Did the Company's original filing on September 1, 2021, filing include a schedule showing the calculation of the reconciliation of allowed and actual revenues related to what was formerly known as the Residential Low Income Assistance Program ("RLIAP")?

A. Yes. In that original filing, the Company included Schedule RDAF Page 4 which provided a calculation of a total amount of $4,024,830 which, due to a lack of clarity in the tariff which resulted in a mismatch between allowed and actual revenues associated with the R-4 rate class, had been inappropriately refunded to customers over the prior two decoupling years. Specifically, the amounts for each year were $1,932,224 for the 2019/2020 year and $2,092,605 for the 2020/2021 year. The Company's original filing had initially sought to recover the $4,024,830 over a two-year period beginning November 1, 2021. However, as discussed in various pleadings in this docket, it is clear that the issue warrants further investigation and discussion among the parties. Thus, the

Company is requesting that the issue remain in this proceeding but on a different schedule to allow for that further examination and a later hearing. Liberty notes that this request is similar to an alternative set forth by the Department of Energy in its October 14, 2021, motion in this proceeding. Consistent with the preceding discussion, the Company has retained Schedule RDAF Page 4 in this updated filing but has removed its request for recovery to begin on November 1 and the associated rate impacts from the associated rate schedules. The Company maintains its request to recover this amount, but does not object to a later effective date to allow for further review and investigation.

Q. Does the mismatch described above impact the current reconciliation period related to revenues associated with the Gas Assistance Program ("GAP")?

A. No. As a result of changes to the tariff that were approved in Docket No. DG 20-105, revenue per customer used in the allowed revenue calculations are no longer different from residential customers not categorized as GAP and, thus, the allowed and actual revenues for the R-4 customer class are in alignment.

Q. What is the proposed Gas Assistance Program charge?

A. As shown on Schedule 19 Gas Assistance (Bates 135–136), the proposed GAP charge is $0.0156 per therm. This charge is designed to recover administrative costs, revenue shortfall resulting from the GAP discount, and the prior period reconciliation adjustment relating to this program. For the 2021/2022 winter period, the Company is providing a 45% base rate and cost of gas discount, consistent with the settlement agreement approved by the Commission in Order No. 26,397 (August 27, 2020) in Docket No. DG 20-013. The proposed Residential Gas Assistance charge is designed to recover

$2,849,123, of which $2,640,884 is for the revenue shortfall resulting from 5,320 customers receiving a 45% discount off their base and cost of gas rates, and $208,239 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 205) the short-term debt limit for fuel and non-fuel purposes for the 2021/2022 winter period. As shown, the short-term debt limit for fuel inventory financing for the period November 1, 2021, through October 31, 2022, is calculated to be $29,744,668 and the limit for non-fuel purposes is calculated to be $115,471,436.

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 138) 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 2020/2021 costs are provided in Schedule 20 of this filing. 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, 2021, and ending October 31, 2022, is $0.0155 per therm. Consistent with filings made over the past few years, this surcharge will recover a total of $2,832,222 in amortized remediation costs. The amortized actual to forecast true-up recovery costs through June 2019 of $341,389 (total amount is $1,024,167 which is amortized over three years). The $1,024,167 is the amount approved by Order No. 26,419 in Docket No. DG 20-141. Also, the actual to forecast true-up recovery cost for the period July 2020 through June 2021 is $139,028. 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 126–127), the Company is proposing to collect $2,214,505 in uncollected rate case and recoupment expense consistent with Order No. 26,505 (July 30, 2021) in Docket No. DG 20-105. The RCE rate of $0.0121 per therm is determined by dividing the $2,214,505 by the estimated November 2021 through October 2022 sales volumes of 182,829,872182,829,875 therms.

Q. Has the Company also updated its Company Allowance percentage for the period November 2021 through October 2022 in accordance with Section 8 of the Company's Delivery Terms and Condition?

A. Yes, in Schedule 25 (Bates 206) the Company has recalculated its Company Allowance for the period November 2021 through October 2022. The Company calculated the Company Allowance of 1.22% based on sendout and throughput data for the twelve-month period ending June 2021. The Company proposes to apply this recalculated Company Allowance to all supplier deliveries beginning in November 2021.

VI. <u>CUSTOMER BILL IMPACTS</u>

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 104) of this filing. These bill impacts reflect the implementation of the increases approved in Docket No. DG 20-105 effective August 1, 2021, relating to the EnergyNorth distribution rate case. The total bill impact over the winter period for an average residential heating customer is an increase of approximately $469.43 or 55.15%. The total bill impact over the winter period for an average commercial/industrial G-41 customer is an increase of approximately $1,293.37 or 60.32% (Bates 105). 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 Second Revised Page 153 (Bates 062) relating to Supplier Balancing and Peaking Demand Charges and Proposed Second Revised Page 154 (Bates 063) relating to Capacity Allocation.

Q. Please describe the changes to tariff Page 153.

A. In Proposed Second Revised Page 153 (Bates 062), the Company is updating the Peaking Demand Charge from $17.32 per MMBtu of Peak MDQ to $54.72 per MMBtu of Peak MDQ. This calculation is also presented in Schedule 21 (Bates 187–197).

Q. Please describe the changes to tariff Page 154.

A. Proposed Second Revised Page 154 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 198–203) contains the six-page worksheet that backs up the calculations for the updated allocators.

VIII. SUMMER 2021 COST OF GAS FACTOR

Q. What are the proposed 2022 summer firm sales cost of gas rates?

A. The Company proposes a firm sales cost of gas rate of $0.5587 per therm for residential customers, $0.5593 per therm for commercial/industrial high winter use customers, and $0.5580 per therm for commercial/industrial low winter use customers as shown on Proposed Third Revised Page 92 (Bates 211).

Q. Please explain tariff pages Proposed Third Revised Page 91 and Proposed Third Revised Page 92.

A. Proposed Third Revised Page 91 (Bates 210) and Proposed Third Revised Page 92 (Bates 211) contain the calculation of the 2022 Summer Period Cost of Gas Rate and summarize the Company's forecast of firm gas sales, firm gas sendout, and gas costs. On Proposed Third Revised Page 92 (Bates 211), the 2022 Average Cost of Gas of $0.5587 per therm is derived by adding the Direct Cost of Gas Rate of $0.5539 per therm to the Indirect Cost of Gas Rate of $0.0048 per therm. The estimated total Anticipated Direct Cost of gas is $15,025,844 and the estimated Indirect Cost of Gas is $132,141. 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 27,125,444 therms. Proposed Third Revised Page 92 further shows that the Residential Cost of Gas Rate of $0.5587 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 $0.5593 per therm and the Commercial/Industrial Low Winter Use Cost of Gas Rate of $0.5580 per therm.

The calculation of the Anticipated Direct Cost of Gas is shown on Proposed Third Revised Page 91 (Bates 210). To derive the total Anticipated Direct Cost of Gas of $15,025,844, the Company starts with the Unadjusted Anticipated Cost of Gas of $10,330,821 and adds the Net Adjustment totaling $4,695,023.

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	$3,276,842
2. Purchased Gas Supply Costs	7,053,979
3. Produced Gas Costs	4,695,023
Total Unadjusted Anticipated Cost of Gas	$15,025,844

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

A. The adjustments to gas costs, listed on Proposed Third Revised Page 91 (Bates 210), are as follows:

1. Prior Period (Over)/Under Collection	$4,472,186
2. Interest	222,837
Total Adjustments	$4,695,023

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 2021 Summer Period?

A. The cost of gas rate proposed in this filing is $0.2439 per therm higher than the initial rate approved by the Commission for the 2020 Summer Period ($0.3148 vs. $0.5587) (Schedule 8, Bates 233). This increase is due to a projected increase in supply costs and an under collection from the prior summer of $4,472,186.

Q. Does this conclude your testimony?

A. Yes, it does.

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STATE OF NEW HAMPSHIRE
BEFORE THE
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Docket No. DG 21-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Winter 2021/2022 Cost of Gas
Summer 2022 Cost of Gas

DIRECT TESTIMONY

OF

DEBORAH M. GILBERTSON

September 1, 2021

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Q. Please state your name, position, and business address.

A. My name is Deborah M. Gilbertson. I am Senior Manager, Energy Procurement for Liberty Utilities Service Corp. ("LUSC"), which provides services to Liberty Utilities (EnergyNorth Natural Gas) Corp. ("Liberty" or "the Company"). My business address is 15 Buttrick Road, Londonderry, New Hampshire.

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

A. I graduated from Bentley College in Waltham, Massachusetts, in 1996 with a Bachelor of Science in Management. In 1997, I was hired by Texas Ohio Gas where I was employed as a Transportation Analyst. In 1999, I joined Reliant Energy, located in Burlington, Massachusetts, as an Operations Analyst. From 2000 to 2003, I was employed by Smart Energy as a Sr. Energy Analyst. In 2004, I joined Keyspan Energy Trading as a Sr. Resource Management Analyst and from 2008 to 2011, I was employed by National Grid as a Lead Analyst in the Project Management Office. In 2011, I was hired by LUSC as a Natural Gas Scheduler and was promoted to Manager of Retail Choice in 2012. In 2016, I was promoted to Sr. Manager of Energy Procurement. In this capacity, I provide gas procurement services to Liberty.

Q. Have you previously testified in regulatory proceedings?

A. Yes, I have testified before the New Hampshire Public Utilities Commission ("Commission") on prior occasions.

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

A. The purpose of this testimony is to summarize the gas supply and firm transportation portfolio and the forecasted sendout requirements for Liberty for the 2021/22 peak and off-peak seasons. This information is provided in significantly more detail in the schedules that the Company is including with this filing.

Q. Please describe the firm transportation contract portfolio that the Company now holds.

A. The Company currently holds firm transportation contracts on Tennessee Gas Pipeline ("Tennessee") (106,833 MMBtu/day) and Portland Natural Gas Transmission System ("PNGTS") (1,000 MMBtu/day) to provide a daily deliverability of 107,833 MMBtu/day to its citygate stations. For this upcoming plan year, and subject to Commission approval for subsequent years, the Company has contracted for an additional 40,000 MMbtu/day of upstream Tennessee capacity which increases the Company's daily deliverability to 147,833 MMBtu/day. In addition to these citygate delivery contracts, the Company also holds other transportation contracts further upstream on other pipelines that feed into the citygate delivery transportation contracts. Schedule 12, page 1, in the Company's filing is a schematic diagram of the transportation contracts, and Schedule 12, page 2, is a table listing these contracts. The transportation contracts provide delivery of natural gas from three sources as described below.

First, the Company holds firm transportation contracts to allow for delivery of up to 13,122 MMBtu/day of Canadian supply. These consist of the following:

- The Company can receive up to 4,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Enbridge Inc. (formally Union Gas Limited), ("Enbridge"), TC Energy Corporation (formally TransCanada Pipelines Limited) ("TC Energy"), Iroquois Gas Transmission System ("Iroquois"), and Tennessee.
- The Company can receive up to 5,000 MMBtu/day of firm Canadian supply from Dawn, Ontario. This supply is delivered to the Company on Company-held firm transportation contracts on Enbridge, TC Energy, PNGTS, and Tennessee.
- The Company can receive up to 3,122 MMBtu/day of firm Canadian supply from the Canadian/New York border at Niagara Falls, NY. This supply is delivered to the Company on Company-held firm transportation contracts on Tennessee.
- The Company can receive up to 1,000 MMBtu/day of firm Canadian supply from a Company-held firm transportation contract PNGTS for delivery to its Berlin service territory.

Second, the Company holds the following firm transportation contracts to allow for delivery of up to 106,596 MMBtu/day of domestic supply from the producing and market areas within the United States.

- The Company can receive up to 21,596 MMBtu/day of firm domestic supplies from Texas and Louisiana production areas. These supplies are delivered to the Company on firm transportation contracts on Tennessee.

- The Company can receive up to 85,000[1] MMBtu/day of firm supply from Tennessee's Dracut receipt point located in Dracut, Massachusetts. This supply is delivered to the Company on three firm transportation contracts on Tennessee.

Third, the Company holds the following firm transportation contracts to allow for delivery of up to 28,115 MMBtu/day of domestic supply from underground storage fields in the New York/Pennsylvania area or the purchase of flowing supply in or downstream of Tennessee Zones 4 and 5.

- The Company can receive up to 19,076 MMBtu/day of firm domestic supplies from its Tennessee FS-MA storage contract. This contract allows for a storage inventory capacity of 1,560,391 MMBtu. These supplies are delivered to the Company on firm transportation contracts on Tennessee.
- The Company can receive up to 9,039 MMBtu/day of firm domestic supplies from its storage contracts with National Fuel Gas Supply Corporation, Honeoye Storage Corporation, and Dominion Transmission, Inc. In aggregate, these contracts allow for a storage inventory capacity of 1,019,740 MMBtu. These supplies are delivered to the Company on a firm transportation contract on Tennessee.

1 An additional 5,000 MMBtu/day of Dracut capacity is used to transport the previously described 5,000 MMBtu/day of firm Canadian supply from Dawn, Ontario via Enbridge, TC Energy, and PNGTS.

Q. Have there been any changes in the portfolio of firm transportation contracts that the Company now holds since the Company submitted its Winter 2020/2021 Cost of Gas Filing?

A. Yes, the Company has contracted for 40,000 MMbtu/day of capacity from Tennessee's Dracut receipt point. This contract has been filed with the Commission for approval in Docket to DG 21-008. Further detail and rationale for the contract is currently under review in that docket.

Q. Would you describe the source of gas supplies used with the firm transportation contracts described previously?

A. The firm transportation contracts that interconnect at the Canadian border may source firm gas supplies from both Eastern and Western Canada. The Company's domestic long-haul firm transportation contracts source firm gas supplies primarily from the U.S. Gulf Coast during the winter period and provide access to natural gas supplies in the Marcellus Shale. Supplies purchased at the Dracut receipt point, on the other hand, may originate from any number of locations including Western and Eastern Canada and liquefied natural gas ("LNG") from the Canaport LNG import terminal in New Brunswick, Canada.

Q. Will there be any changes in the portfolio of supply contracts held by the Company as compared to the portfolio of contracts that existed when the Company submitted its Winter 2020/2021 Cost of Gas Filing?

A. Yes. Typically, the Company negotiates a number of different supply contracts for delivery during the peak period. Since its 2020/2021 COG filing, the Company has issued five requests for proposals ("RFP") for supply for the upcoming winter period. The first is for a baseload Tennessee Zone 6 citygate or Dracut supply; the second is for its Canadian firm transportation capacity interconnecting with Iroquois; the third is for its Tennessee long-haul capacity from the Gulf Coast and the Zone 4 market areas; the fourth is for a Tennessee Zone 6 citygate or Dracut swing supply with a call option; and the last is for a second Tennessee Zone 6 citygate or Dracut swing supply with a call option. Each of these five RFPs for the 2021/22 peak period supply are consistent with the RFPs issued for the 2020/21 peak period with the addition of the second call option to coincide with the incremental 40,000 MMbtu/day of capacity mentioned above.

Q. Could you describe the RFP process in more detail?

A. Yes. The Company issued an RFP for a baseload Tennessee Zone 6 citygate supply priced at NYMEX plus a fixed basis as a hedge against basis price spikes. This RFP was issued in accordance with the Company's revised hedging plan, which was approved by the Commission in Order No. 25,691 in Docket No. DG 14-133. The Company received proposals for a delivered citygate supply and has selected a winning bidder.

The Company also issued an RFP for supply originating from Dawn, Ontario. The Company entered into an Asset Management Agreement ("AMA") transaction that will provide a firm baseload supply during the peak period with index-based pricing. The Company has selected a winning bidder.

For the Tennessee long-haul firm transportation from the U.S. Gulf Coast, the Company issued an RFP for an AMA transaction coupled with a delivered service during the peak period. The Company has selected a winning bidder.

Lastly, the Company issued two RFPs for a Tennessee Zone 6 citygate or Dracut supply with an option for the Company to call on the supply as needed to meet day-to-day increases in demand. The RFPs requested a six-month Dracut or delivered citygate supply with swing nomination provisions whereby it intends to release its Dracut capacity to the winning bidder as needed. The price for this supply is market area index based. The Company has selected a winning bidder.

Q. Could you provide the status of the Company's storage refill plan?

A. Yes. During the 2021 off-peak period, the Company has been injecting supplies into its underground storage fields. The Company plans to have all storage fields, with the exception of its Tennessee FS-MA storage, full by November 1, 2021; the Tennessee FS-MA field is targeted to be approximately 95 percent full by November 1, 2021. The approximate five percent unfilled portion of FS-MA storage provides a buffer which allows the Company operational flexibility to inject some of its supply into storage if needed due to weather fluctuations during the month of November. By December 1, 2021, it is the Company's plan to have all of its storage fields full.

Q. Would you describe the additional sources of gas supply available to the Company that do not require pipeline transportation capacity?

A. The Company has three additional sources of gas supply available. First, as described in the 2020/21 COG filing, the Company contracted with Constellation LNG, LLC for a combination liquid/vapor service that can be used to either refill its LNG storage tanks during the peak period and/or deliver incremental supply to its citygate for up to 7,000 MMBtu per day in total. This flexibility will allow the Company to either call on citygate delivered supply or use the liquid option to refill its LNG inventory. Although this contract will continue through the upcoming peak period, it will expire on March 31, 2022. In addition to the combination liquid/vapor service, the Company has contracted for dedicated LNG trucking in order to refill its LNG storage inventory. Since the Company's LNG storage capability is limited, having dedicated LNG trucks allows the Company to replenish inventory as it is used, provides supply security for its customers, and enables the Company to adhere to its seven-day storage inventory requirement established by Puc 506.03.

Second, the Company refilled its propane inventory including approximately 390,000 gallons of inventory at its Amherst storage facility.

Third, the Company has solicited bids for an LNG supply contract to be used as winter liquid refill only. This incremental liquid refill contract must also provide trucking of the

LNG for storage refill. By using the Constellation LNG vapor option along with a separate refill supply contract, the Company will be positioned to meet the demands of the seven-day storage inventory requirement. The Company has selected the winning bidders.

Q. Please describe the supplemental gas supply facilities available to the Company.

A. The Company owns three LNG vaporization facilities in Concord, Manchester, and Tilton that have a combined design vaporization rate of approximately 22,800 MMBtu/day, but are limited operationally by the combined workable storage capacity of approximately 12,600 MMBtu. As described previously, the Company solicited bids for additional LNG refill and associated trucking in order to utilize more vaporization capacity from its LNG facilities. The Company's LNG facilities will be refilled with liquid natural gas from the previously mentioned Constellation combination liquid/vapor service and/or the incremental LNG refill supply.

Additionally, the Company owns four propane facilities in Amherst, Manchester, Nashua, and Tilton that have historically been designated a combined design vaporization capacity of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 122,590 MMBtu. (For more information on the propane facilities, please refer to Attachment DMG-1, which is a copy of the Company's response to CLF 1-20 in Docket No. DG 21-008 which discusses a propane study being performed by the Company to analyze and update the actual operational vaporization capacity of these facilities.)

The Company has allocated approximately 12,000 MMBtu of the Amherst propane storage capacity to its Keene Division, leaving approximately 110,700 MMBtu of combined workable storage capacity for Liberty. The Company's propane facilities were refilled during the summer of 2021 and they are ready for the 2021/22 peak period. The Company will seek to have arrangements in place for its propane trucking needs for the upcoming peak period.

Together, these LNG and propane facilities provide the Company and its customers with necessary system pressure support during peak days as well as a critical gas supply source to meet design day requirements. These facilities contribute to the Company's reliable, flexible, and least-cost resource portfolio.

Q. Ms. Gilbertson, what was the source of the projected sendout requirements and costs used in this filing?

A. As in prior cost of gas filings, the Company used projected sendout requirements and costs from its internal budgets and forecasts.

Q. Would you please describe the forecasted sendout requirements for the peak period of 2021/22?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements for sales customers at 94,216,591 therms over the period November 1, 2021, to April 30, 2022, under normal weather conditions, which is up from last year's forecasted volume of 90,922,460 therms for the period November 1, 2020, to April 30, 2021. In comparison, the normalized actual sendout for firm sales customers for the

November 1, 2020, to April 30, 2021, period was 93,155,745 therms (Reconciliation Filing, Summary Page 5, 'Total Volume Weather Variance,' Column B).

Schedule 11B shows the Company's forecasted sendout requirements for sales customers of 104,530,752 therms over the period November 1, 2021, to April 30, 2022, under design weather conditions, which is up from last year's forecasted volume of 101,061,871 therms for the period November 1, 2020, to April 30, 2021. For the current peak period forecast, design weather requirements are approximately 10 percent greater than normal sendout requirements for weather that is 10 percent colder than normal.

In Schedule 11C, the Company summarizes the normal and design year sendout requirements, the seasonally available contract quantities (inclusive of assigned and Company Managed capacity), and the utilization rates of its pipeline firm transportation and storage contracts.

Schedule 11D shows the Company's forecasted design day sendout for sales customers for the upcoming 2021/22 winter period of 1,283,926 therms, which is up from last year's figure of 1,248,088 therms.

Q. Would you please describe the forecasted sendout requirements for the off-peak period of 2022?

A. Schedule 11A of the Company's filing shows the Company's forecasted sendout requirements of 22,950,820 therms over the period May 1 to October 31, 2022, under normal weather conditions, which is slightly higher than last year's forecasted volume of 22,065,798 therms over the period May 1 to October 31, 2021.

Schedule 11B shows the Company's forecasted sendout requirements of 22,928,033 therms over the period May 1 to October 31, 2022, under design weather conditions, which is higher than last year's forecasted volume of 22,175,995 therms over the period May 1 to October 31, 2021.

In Schedule 11C, the Company summarizes the normal and design off-peak sendout requirements, the seasonally available contract quantities (inclusive of assigned and Company Managed capacity), and the calculated utilization rates of its pipeline transportation and storage contracts based on the normal and design off-peak forecasts contained in Schedules 11A and 11B.

Q. Why did the Company contract for an additional 40,000 of Tennessee capacity?

A. Over the past several years the need for additional gas resources to meet the ever-increasing demand of Liberty's customers has continued to grow. The Company has presented various demand forecasts, resource requirement analyses, and waiver requests in many dockets over the years. This began with the request for approval of a Precedent Agreement ("PA") for 115,000 MMbtu/day of capacity on the proposed Northeast Energy Direct ("NED") project in 2014 which was to provide additional capacity to Liberty. The Company contracted for capacity on the NED Project to meet its projected demand growth, and the Commission approved the PA. *See* Order No. 25,822 (Oct. 2, 2015). However, Tennessee ultimately cancelled NED.

Since the cancellation of the NED project in 2016, the Company has conducted a rigorous search and analysis of capacity options to increase the deliverability of firm gas supplies and/or decrease the requirement of Puc 506.03, the On-Site Storage Requirement rules. As described above, beginning on November 1, 2017, the Company entered into an agreement with Engie/Constellation to supply 7,000 MMbtu/day of either firm vapor to the citygate or liquid natural gas to refill the Company's existing LNG facilities. That contract will expire on March 31, 2022. Although that additional capacity/supply was a much-needed supplement to the portfolio, from December 27, 2017 through January 2, 2018, the Company's service territory experienced a significant cold weather event which surpassed its historical consecutive seven-day cold snap. As a result, the Company needed to have more supplemental gas on hand to meet the increased demand attributable to the higher 7-day forecast as stipulated in Puc.506.03. In August 2019, the Company filed with the Commission a request to waive and modify the requirements of Puc 506.03. At that time, the Company knew it did not have (nor could have had) enough supplemental supply on hand for the upcoming peak season to meet the demands of the rule as written. The Commission approved the Company's request for a waiver and modifications of Puc 506.03 for three years. *See* January 5, 2018, secretarial letter in Docket No. DG 17-200. That waiver will expire in March of 2022.

With the expirations of both the Engie/Constellation agreement and the waiver of Puc 506.03, the Company is again faced with imminent concerns for capacity and supply shortfall. If approved, the contract for 40,000 MMbtu/day of incremental capacity with Tennessee will ensure that the Company will have sufficient resources on hand to meet near term design day requirements of its customers. (As mentioned above, please refer to Docket No. DG 21-008 for additional detail.)

Q. Will the Company need the entire 40,000 MMbtu/day in the first year?

A. No, the Company will release any excess capacity in the market consistent with its current cost mitigation strategy designed to reduce costs to customers.

Q. Can you comment on what is causing the dramatic increase in forward looking natural gas prices as compared to 2020/2021 peak period?

A. As with all local distribution companies across the United States, and the Northeast in particular, the Company's purchase prices for its natural gas supplies are impacted by regional, national, and global forces. According to the most recent data, NYMEX natural gas futures continue to trade at their highest summer levels in seven years. Compared to last year, for example, NYMEX on average is currently trading at approximately 30% higher than this time last year. This is largely related to fears regarding national storage levels for the coming winter. Hot summer temperatures across the nation have stymied consistent, larger injections relative to the five-year average, with last year being particularly impacted. Additionally, demand for U.S. LNG exports to international markets are robust, which reduces supply availability to U.S. markets. The consensus is that until storage across the country returns to normal levels and LNG exports level off, the higher domestic prices are likely to persist.

Q. Please provide the results of the Company's basis hedging program for the winter of 2020/21.

A. For the winter of 2020/21 the Company hedged the Tennessee Zone 6 basis through the purchase of physical supply for its baseload requirements from Dracut for the months of

December, January, and February as provided for in Docket No. DG 14-133 and approved in Order *Nisi* No. 25,691. The result of this basis hedging program showed a cost of approximately $1,500,000. Although the Company cannot predict whether the hedge program will result in a gain or loss each year, it does support the need for price stabilization against fluctuations in the market prices during peak period.

Q. Has the Company hedged the Tennessee Zone 6 basis for the winter 2021/22?

A. Yes, the Company conducted an RFP to solicit physical supply basis bids for the months of December, January, and February during the 2021/22 winter and has selected a supplier.

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

A. Yes, it does.

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

DG 21-008
Petition for Approval of a Firm Transportation Agreement with
Tennessee Gas Pipeline Company, LLC

Conservation Law Foundation Data Requests - Set 1

Date Request Received: 4/9/21 | Date of Response: 4/23/21
Request No. CLF 1-20 | Respondent: William R. Killeen

REQUEST:

Has the Company analyzed the costs and historic record of having propane facilities performing at their design or nameplate vaporization rates? Is there a record of them not performing as designed to help meet peak demands? Are there upgrades and investments in these facilities that can be made to help them perform to design and nameplate ratings? Have such upgrades been considered as options to help meet peak day demands? Please provide any workpapers and analyses with formulas intact.

RESPONSE:

The Company's three propane production facilities directly connected to its distribution system are located in Manchester, Nashua, and Tilton. In total, they have a design, or nameplate, vaporization capacity of approximately 34,600 MMBtu/day and a combined workable storage capacity of approximately 122,590 MMBtu. Historically, the facilities have never reached their nameplate vaporization capacity primarily due to the fact that there is not sufficient natural gas flowing by these propane facilities to provide a proper blending of a propane/air mix with natural gas. The historical peak sendout from the Nashua propane plant was 9,954 Dth which occurred on February 14, 2016. The historical peak sendout from the Manchester propane plant was 9,921 Dth which occurred on February 5, 2007. The historical peak sendout for the Tilton propane plant was 1,242 Dth (the Company does not have the date on which this occurred). While the combined total historical peak vaporization capacity of these facilities was 21,117 Dth, the peak vaporization capacity for each facility occurred on different days. The combined single day peak vaporization from these facilities was 18,869 Dth which occurred on February 5, 2007.

As to whether any upgrades or investments can be made to these propane facilities, the Company recently engaged with a process control engineer to analyze the current operating controls at Manchester and Nashua to see if upgrades would allow for increased vaporization capacity. The process control engineer will take into consideration the adverse impact that propane/air injection has on high efficiency equipment. As noted in prior dockets, the Company is very concerned with customer outages and complaints associated with propane production. Due to the low tolerance of high efficiency equipment to handle the particular characteristics of propane air, customer outages and complaints have been correlated directly to when the Company is utilizing its propane facilities. As recently as March 15, 2021, the Company received significant customer complaints when it had to utilize its propane facility in Manchester to meet increased demand due to much colder than forecast temperatures.

Given the increased installation of high efficiency equipment and the adverse impact that propane/air blending has on that equipment, it is highly unlikely that the operational capacity of the Company's existing propane facilities will reach, or exceed, historical levels. Rather, it is more likely that the operational capacity of the propane facilities will decrease over time as new high efficiency equipment is added by customers.

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 21-XXX

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Winter 2021/2022 Cost of Gas
Summer 2022 Cost of Gas

DIRECT TESTIMONY

OF

MARY E. CASEY

September 1, 2021

Liberty™

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I. INTRODUCTION

Q. Please state your name, job title, and job description.

A. My name is Mary E. Casey. I am the Senior Manager, Environment, for Liberty Utilities Service Corp. ("LUSC"). I am responsible for overseeing the management, investigation, and remediation of manufactured gas plant (MGP) sites for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or "the "Company"), as well as operational environmental compliance, including air and waste permitting, wetlands permitting, and protection and spill response.

Q. Please describe your educational and professional background.

A. I hold a Bachelor of Science in Chemical Engineering from Polytechnic Institute of New York, and a Master of Science in Civil/Environmental Engineering from Polytechnic University. I have been employed by LUSC since July 3, 2012, managing the investigation and remediation of Liberty's MGP sites. Prior to my employment by LUSC, I held the position of Principal Environmental Engineer for National Grid and KeySpan Energy, with responsibility for operational environmental compliance.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the status of Liberty's site investigation and remediation efforts at various MGP sites in New Hampshire, to briefly describe the MGP-related activities performed by the various contractors and consultants, to discuss the costs for which the Company is seeking rate recovery, and to describe the status of the Company's efforts to seek reimbursement for MGP-related liabilities from third parties. My testimony is intended to update the information provided by the Company in prior cost of gas proceedings. The costs associated with these investigations and remediation efforts and certain of the amounts recovered from third parties are included in the schedules and other data prepared by Mr. Simek and Ms. McNamara as part of the Local Distribution Adjustment Charge ("LDAC") portion of the Company's cost of gas filing.

II. STATUS OF INVESTIGATION AND REMEDIATION ACTIVITIES

Q. Please briefly describe the status of each of the Company's MGP sites.

A. Consistent with past practice, the description of the status of investigation and remediation efforts at each site, as well as the various efforts to recover the site investigation and remediation costs from third parties, are summarized in materials included in the Company's filing at Schedule 20.

Q. Please briefly describe the current status of the Company's remediation efforts at the Lower Liberty Hill site in Gilford and any significant events over the course of the past year at that site.

A. The project has been completed since December 2015. The site is stable, and the grass is mowed twice a year. The Notice of Activity and Use Restriction (AUR) was approved by New Hampshire Department of Environmental Services ("NHDES") and recorded at the Belknap Registry of Deeds in February 2017. The groundwater wells are monitored and sampled once a year per the Groundwater Management Permit that was obtained from NHDES in May 2017.

Q. Please briefly describe the current status of the Company's remediation work at the Manchester MGP.

A. On-site activities in the past year were minimal due to COVID-19 access limitations. Some costs were incurred relative to handling MGP-impacted media that resulted from the repair of a sink hole in within the LNG tank area. Groundwater monitoring is ongoing twice a year pursuant to the Groundwater Management Permit for this site.

Q. Please briefly describe the current status of the Company's remediation work at the Concord MGP.

A. The Company continues to move toward a remedy for the MGP-impacted "Concord Pond" site on the parcel known as Healy Park. In 2020, the City and the Company finalized an access agreement that gives Liberty access for the pre-design investigation field work, the construction of the remedy, and subsequent maintenance of the capped area after its completion. Pre-design field investigations commenced in 2021 to develop the final design of a wetland and subaqueous cap, per the Remedial Action Plan approved by NHDES. The construction of the remedy is planned to take place in late summer 2022.

In 2017, the Company received approval from NHDES on a near-bank sediment sampling program in the Merrimack River, or Monitored Natural Recovery (MNR). This program involves annual sediment sampling for contaminants and river bathymetry studies to monitor both the chemical and physical behavior of sediments that may have been impacted by coal tar wastes. There will be five annual samplings, the fourth of which was conducted in October 2020.

As for the Gas Holder site, the City and the Company jointly prepared a report in 2019 that details various use options for the Gas Holder site on the east side of the highway, including costs for various scenarios ranging from cleaning and fortifying the holder structure for public entry to demolition of the structure. In response to Liberty's communication that the gas holder needed to be demolished, as the condition of the structure raises significant safety concerns, the Concord City Council established a working group in 2020, comprised of representatives of the City Council, City Staff, Liberty, and the New Hampshire Preservation Alliance ("NHPA"), and charged with developing a plan and assigning responsibilities for stabilization and preservation of the holder house structure.

The working group discussions resulted in a plan for the NHPA to raise funds to stabilize the holder house and to manage the relevant construction, and for Liberty to seek Commission approval to contribute up to the estimated costs of demolition and remediation beneath the holder house, as the least cost option for customers. The City, the NHPA, and Liberty met with Commission Staff in February 2021 and obtained Staff's support for the plan, provided Liberty can demonstrate that the Company's contribution toward the stabilization of the holder house is less than the estimated costs of demolition and remediation that would otherwise have been incurred.

In April 2021, the City, the NHPA, and Liberty signed an MOU documenting the above understanding as the parties worked toward a formal agreement. As of the date of this testimony, the parties are near completion of a formal Emergency Stabilization License Agreement to govern the repairs to the holder house. The NHPA has substantially completed the engineering for the stabilization work and has obtained a contractor to complete the work before the end of 2021. Liberty has substantially completed the estimate to demolish the holder house and remedy any contamination, which estimate will serve as the cap of Liberty's contribution toward stabilization. Liberty is not prepared to seek recovery of the costs contributed to the stabilization of the holder house at this time because the work has not yet been performed and will likely not be complete by the time of a hearing in this docket. Liberty expects that it will seek recovery of those costs in next year's cost of gas/LDAC filing. Liberty will provide an update of this project at hearing.

Q. Please briefly describe the current status of the Company's remediation work at the Nashua MGP site.

A. In May 2019, the NHDES accepted details of a cap design for the central portion of the property, and construction was planned for 2020, in conjunction with a capital paving project for this property. However, this cap and pave project has been moved to the 2021 construction season due to the COVID-19 pandemic. The Company is presently working on obtaining State and Local permitting for this project, and construction is targeted for late summer 2021.

Q. What other MGP investigation and remediation activity has the Company undertaken in the last year?

A. No other MGP investigation and remediation activity has occurred in the last year.

III. <u>STATUS OF INSURANCE COVERAGE LITIGATION</u>

Q. Have there been any recent significant developments in the Company's efforts to seek contribution from its insurance carriers in the past year?

A. No. Insurance recovery efforts are complete with respect to all the Company's former MGP sites.

Q. What environmental remediation efforts do you anticipate for the remainder of 2021 and in 2022?

A. At the Manchester MGP site, the Company will continue remediation of localized areas of contamination on-site as well as working on the storm drain improvement for a deteriorated drainage pipe along the western boundary of the property. At the Concord MGP site, as described above, Liberty is working with other parties to stabilize the gas holder house to preserve its function as a cap over its footprint; Liberty will continue environmental site monitoring. For the Concord Pond site, the Company will continue to develop the final design of a wetland and subaqueous cap, with the construction of the remedy expected to occur in late summer 2022. The monitoring of near bank sediments will continue in October 2021 per the NHDES-approved Monitored Natural Recovery plan. At the Nashua MGP site, the Company is targeting later in 2021 for capping and paving to commence, now that approval of the cap design has been received. All sites are also now in the monitoring phase, so groundwater monitoring will occur at all of them under their respective Groundwater Management Permits.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective November 1, 2020 - April 30, 2021~~ Rates effective November 1, 2021 - April 30, 2022 Winter Period				~~Rates Effective May 1, 2021 - October 31, 2021~~ Rates Effective May 1, 2022 - October 31, 2022 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 95**	**LDAC Page 101**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 92**	**LDAC Page 101**	**Total Rate**
Residential Non Heating - R-1	~~$ 15.50~~			~~$ 15.50~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
All Therms	$ 0.3844	$ 1.1339	$ 0.1444	$ 1.6627	$ 0.3844	$ 0.5587	$ 0.1444	$ 1.0875
	~~$ 0.3860~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.0020~~	~~$ 0.3860~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.7597~~
Residential Heating - R-3	~~$ 15.50~~			~~$ 15.50~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
Size of the first block	all therms				all therms			
All Therms	$ 0.5632	$ 1.1339	$ 0.1444	$ 1.8415	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.5678~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1838~~	~~$ 0.5678~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.9415~~
Residential Heating - R-4	~~$ 8.52~~			~~$ 8.52~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 8.47			$ 8.47	$ 15.39			$ 15.39
Size of the first block	all therms				all therms			
All Therms	$ 0.3098	$ 0.6236	$ 0.1444	$ 1.0778	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.3123~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.6776~~	~~$ 0.5678~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.9415~~
Commercial/Industrial - G-41	~~$ 57.46~~			~~$ 57.46~~	~~$ 57.46~~			~~$ 57.46~~
Customer Charge per Month per Meter	$ 57.06			$ 57.06	$ 57.06			$ 57.06
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.4688	$ 1.1341	$ 0.0878	$ 1.6907	$ 0.4688	$ 0.5593	$ 0.0878	$ 1.1159
	~~$ 0.4711~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0818~~	~~$ 0.4711~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.8375~~
All therms over the first block per month at	$ 0.3149	$ 1.1341	$ 0.0878	$ 1.5368	$ 0.3149	$ 0.5593	$ 0.0878	$ 0.9620
	~~$ 0.3165~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9272~~	~~$ 0.3165~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.6829~~
Commercial/Industrial - G-42	~~$ 172.39~~			~~$ 172.39~~	~~$ 172.39~~			~~$ 172.39~~
Customer Charge per Month per Meter	$ 171.19			$ 171.19	$ 171.19			$ 171.19
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4261	$ 1.1341	$ 0.0878	$ 1.6480	$ 0.4261	$ 0.5593	$ 0.0878	$ 1.0732
	~~$ 0.4284~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0391~~	~~$ 0.4284~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7948~~
All therms over the first block per month at	$ 0.2839	$ 1.1341	$ 0.0878	$ 1.5058	$ 0.2839	$ 0.5593	$ 0.0878	$ 0.9310
	~~$ 0.2855~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.8962~~	~~$ 0.2855~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.6519~~
Commercial/Industrial - G-43	~~$ 739.83~~			~~$ 739.83~~	~~$ 739.83~~			~~$ 739.83~~
Customer Charge per Month per Meter	$ 734.69			$ 734.69	$ 734.69			$ 734.69
All therms over the first block per month at	$ 0.2620	$ 1.1341	$ 0.0878	$ 1.4839	$ 0.1198	$ 0.5593	$ 0.0878	$ 0.7669
	~~$ 0.2633~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.8740~~	~~$ 0.1204~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.4868~~
Commercial/Industrial - G-51	~~$ 57.46~~			~~$ 57.46~~	~~$ 57.46~~			~~$ 57.46~~
Customer Charge per Month per Meter	$ 57.06			$ 57.06	$ 57.06			$ 57.06
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2819	$ 1.1324	$ 0.0878	$ 1.5021	$ 0.2819	$ 0.5580	$ 0.0878	$ 0.9277
	~~$ 0.2839~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9054~~	~~$ 0.2839~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6593~~
All therms over the first block per month at	$ 0.1833	$ 1.1324	$ 0.0878	$ 1.4035	$ 0.1833	$ 0.5580	$ 0.0878	$ 0.8291
	~~$ 0.1846~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8061~~	~~$ 0.1846~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.5600~~
Commercial/Industrial - G-52	~~$ 172.39~~			~~$ 172.39~~	~~$ 172.39~~			~~$ 172.39~~
Customer Charge per Month per Meter	$ 171.19			$ 171.19	$ 171.19			$ 171.19
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2428	$ 1.1324	$ 0.0878	$ 1.4630	$ 0.1759	$ 0.5580	$ 0.0878	$ 0.8217
	~~$ 0.2439~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8654~~	~~$ 0.1767~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.5521~~
All therms over the first block per month at	$ 0.1617	$ 1.1324	$ 0.0878	$ 1.3819	$ 0.1000	$ 0.5580	$ 0.0878	$ 0.7458
	~~$ 0.1624~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7839~~	~~$ 0.1004~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4758~~
Commercial/Industrial - G-53	~~$ 761.39~~			~~$ 761.39~~	~~$ 761.39~~			~~$ 761.39~~
Customer Charge per Month per Meter	$ 756.10			$ 756.10	$ 756.10			$ 756.10
All therms over the first block per month at	$ 0.1697	$ 1.1324	$ 0.0878	$ 1.3899	$ 0.0814	$ 0.5580	$ 0.0878	$ 0.7272
	~~$ 0.1705~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7920~~	~~$ 0.0818~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4572~~
Commercial/Industrial - G-54	~~$ 761.39~~			~~$ 761.39~~	~~$ 761.39~~			~~$ 761.39~~
Customer Charge per Month per Meter	$ 756.10			$ 756.10	$ 756.10			$ 756.10
All therms over the first block per month at	$ 0.0648	$ 1.1324	$ 0.0878	$ 1.2850	$ 0.0352	$ 0.5580	$ 0.0878	$ 0.6810
	~~$ 0.0650~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.6865~~	~~$ 0.0353~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4107~~

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	~~Rates effective November 1, 2020 - April 30, 2021~~ Rates effective November 1, 2021 - April 30, 2022 Winter Period				~~Rates Effective May 1, 2021 - October 31, 2021~~ Rates Effective May 1, 2022 - October 31, 2022 Summer Period			
	Delivery Charge	**Cost of Gas Rate Page 95**	**LDAC Page 101**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 92**	**LDAC Page 101**	**Total Rate**
Residential Non Heating - R-5	~~$ 20.15~~			~~$ 20.15~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 20.01		~~$ -~~	$ 20.01	$ 20.01			$ 20.01
All Therms	$ 0.4997	$ 1.1339	$ 0.1444	$ 1.7780	$ 0.4997	$ 0.5587	$ 0.1444	$ 1.2028
	~~$ 0.5018~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1178~~	~~$ 0.5018~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.8755~~
Residential Heating - R-6	~~$ 20.15~~			~~$ 20.15~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
Size of the first block	All Therms		~~$ -~~					
Therms in the first block per month at	$ 0.7322	$ 1.1339	$ 0.1444	$ 2.0105	$ 0.7322	$ 0.5587	$ 0.1444	$ 1.4353
	~~$ 0.7381~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.3541~~	~~$ 0.7381~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 1.1118~~
Residential Heating - R-7	~~$ 11.08~~			~~$ 11.08~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 11.01			$ 11.01	$ 20.01			$ 20.01
Size of the first block	All Therms		~~$ -~~					
Therms in the first block per month at	$ 0.4027	$ 0.6236	$ 0.1444	$ 1.1708	$ 0.7322	$ 0.5587	$ 0.1444	$ 1.4353
	~~$ 0.4060~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.7713~~	~~$ 0.7381~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 1.1118~~
Commercial/Industrial - G-44	~~$ 74.69~~			~~$ 74.69~~	~~$ 74.69~~			~~$ 74.69~~
Customer Charge per Month per Meter	$ 74.18			$ 74.18	$ 74.18			$ 74.18
Size of the first block	100 therms		~~$ -~~		20 therms			
Therms in the first block per month at	$ 0.6094	$ 1.1341	$ 0.0878	$ 1.8313	$ 0.6094	$ 0.5593	$ 0.0878	$ 1.2565
	~~$ 0.6126~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.2233~~	~~$ 0.6126~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.9790~~
All therms over the first block per month at	$ 0.4094	$ 1.1341	$ 0.0878	$ 1.6313	$ 0.4094	$ 0.5593	$ 0.0878	$ 1.0565
	~~$ 0.4114~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0221~~	~~$ 0.4114~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7778~~
Commercial/Industrial - G-45	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
Customer Charge per Month per Meter	$ 222.55			$ 222.55	$ 222.55			$ 222.55
Size of the first block	1000 therms		~~$ -~~		400 therms			
Therms in the first block per month at	$ 0.5539	$ 1.1341	$ 0.0878	$ 1.7758	$ 0.5539	$ 0.5593	$ 0.0878	$ 1.2010
	~~$ 0.5569~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.1676~~	~~$ 0.5569~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.9233~~
All therms over the first block per month at	$ 0.3691	$ 1.1341	$ 0.0878	$ 1.5910	$ 0.3691	$ 0.5593	$ 0.0878	$ 1.0162
	~~$ 0.3711~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9818~~	~~$ 0.3711~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7375~~
			~~$ -~~					
Commercial/Industrial - G-46	~~$ 961.78~~			~~$ 961.78~~	~~$ 961.78~~			~~$ 961.78~~
Customer Charge per Month per Meter	$ 955.10		~~$ -~~	$ 955.10	$ 955.10			$ 955.10
All therms over the first block per month at	$ 0.3406	$ 1.1341	$ 0.0878	$ 1.5625	$ 0.1557	$ 0.5593	$ 0.0878	$ 0.8028
	~~$ 0.3423~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9530~~	~~$ 0.1565~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.5229~~
Commercial/Industrial - G-55	~~$ 74.69~~			~~$ 74.69~~	~~$ 74.69~~			~~$ 74.69~~
Customer Charge per Month per Meter	$ 74.18			$ 74.18	$ 74.18			$ 74.18
Size of the first block	100 therms		~~$ -~~		100 therms			
Therms in the first block per month at	$ 0.3665	$ 1.1324	$ 0.0878	$ 1.5867	$ 0.3665	$ 0.5580	$ 0.0878	$ 1.0123
	~~$ 0.3691~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9906~~	~~$ 0.3691~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.7445~~
All therms over the first block per month at	$ 0.2383	$ 1.1324	$ 0.0878	$ 1.4585	$ 0.2383	$ 0.5580	$ 0.0878	$ 0.8841
	~~$ 0.2400~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8615~~	~~$ 0.2400~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6154~~
Commercial/Industrial - G-56	~~$ 224.11~~		~~$ -~~	~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
Customer Charge per Month per Meter	$ 222.55			$ 222.55	$ 222.55			$ 222.55
Size of the first block	1000 therms		~~$ -~~		1000 therms			
Therms in the first block per month at	$ 0.3156	$ 1.1324	$ 0.0878	$ 1.5358	$ 0.2287	$ 0.5580	$ 0.0878	$ 0.8745
	~~$ 0.3171~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9386~~	~~$ 0.2297~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6051~~
All therms over the first block per month at	$ 0.2102	$ 1.1324	$ 0.0878	$ 1.4304	$ 0.1300	$ 0.5580	$ 0.0878	$ 0.7758
	~~$ 0.2111~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8326~~	~~$ 0.1304~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.5058~~
			~~$ -~~					
Commercial/Industrial - G-57	~~$ 989.80~~			~~$ 989.80~~	~~$ 989.80~~			~~$ 989.80~~
Customer Charge per Month per Meter	$ 982.93		~~$ -~~	$ 982.93	$ 982.93			$ 982.93
All therms over the first block per month at	$ 0.2207	$ 1.1324	$ 0.0878	$ 1.4409	$ 0.1059	$ 0.5580	$ 0.0878	$ 0.7517
	~~$ 0.2216~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8431~~	~~$ 0.1063~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4817~~
Commercial/Industrial - G-58	~~$ 989.80~~			~~$ 989.80~~	~~$ 989.80~~			~~$ 989.80~~
Customer Charge per Month per Meter	$ 982.93		~~$ -~~	$ 982.93	$ 982.93			$ 982.93
All therms over the first block per month at	$ 0.0842	$ 1.1324	$ 0.0878	$ 1.3044	$ 0.0457	$ 0.5580	$ 0.0878	$ 0.6915
	~~$ 0.0846~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7061~~	~~$ 0.0459~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4213~~

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NHPUC NO. 11 - GAS | **Proposed Second Revised Page 94**
LIBERTY UTILITIES | **Superseding Proposed First Revised Page 94**

II. RATE SCHEDULES
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021~~
(Refer to Text in Section 17(A) Fixed Price Option Program)

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 74,822,730		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Direct Cost of Gas Rate		~~$ 0.5345~~		$ 0.8557	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~$ 0.1471~~	$ 13,859,546	$ 0.1585	
Commodity Cost of Gas Rate	~~33,157,366~~	~~$ 0.3759~~	$ 60,820,831	$ 0.6955	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~$ 0.0115~~	$ 142,353	$ 0.0016	
Total Direct Cost of Gas Rate	~~$ 47,150,454~~	~~$ 0.5345~~	$ 74,822,730	$ 0.8557	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,360,293		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0499	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.5597~~**		**$ 0.9056**	
<u>Calculation of FPO</u>					
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.5597~~**		**$ 0.9056**	
FPO Risk Premium		~~$ 0.0200~~		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.5797~~**		**$ 0.9256**	
RESIDENTIAL COST OF GAS RATE - EXCLUDING GAP - ~~(11/01/2020)~~ (11/1/2021)	**/therm**	**~~$ 0.5797~~**	**/therm**	**$ 0.9256**	

(Col 1)	(Col 2)	(Col 3)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 74,822,730		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Direct Cost of Gas Rate		~~$ 0.5345~~		$ 0.8557	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~$ 0.1471~~	$ 13,859,546	$ 0.1585	
Commodity Cost of Gas Rate	~~33,157,366~~	~~$ 0.3759~~	$ 60,820,831	$ 0.6955	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~$ 0.0115~~	$ 142,353	$ 0.0016	
Total Direct Cost of Gas Rate	~~47,150,454~~	~~$ 0.5345~~	$ 74,822,730	$ 0.8557	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,360,293		
Projected Prorated Sales ~~(11/01/20 - 4/30/21)~~ (11/01/21 - 04/30/22)	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0499	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.5597~~**		**$ 0.9056**	
<u>Calculation of FPO</u>					
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.3078~~**		**$ 0.4981**	
FPO Risk Premium		$ 0.0110		$ 0.0110	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE ~~(11/01/20)~~ (11/01/21)		**~~$ 0.3188~~**		**$ 0.5091**	
RESIDENTIAL COST OF GAS RATE - GAP - ~~(11/01/2020)~~ (11/1/2021)	**/therm**	**~~$ 0.3188~~**	**/therm**	**$ 0.5091**	

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NHPUC NO. 11 - GAS **Proposed Second Revised Page 95**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 95**

CALCULATION OF FIRM SALES COST OF GAS RATE

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022

~~**PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021**~~

(Refer to Text in Section 17 Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 94,810,891		
Projected Prorated Sales (11/01/20 - 04/30/21)~~(11/01/19 - 04/30/20)~~	~~88,213,529~~		$ 87,443,741		
Direct Cost of Gas Rate		~~0.5345~~		$ 1.0843	per therm
Demand Cost of Gas Rate	~~$ 12,978,688~~	~~0.1471~~	$ 13,868,897	$ 0.1586	
Commodity Cost of Gas Rate	~~33,157,366~~	~~0.3759~~	$ 80,780,853	$ 0.9238	
Adjustment Cost of Gas Rate	~~1,014,399~~	~~0.0115~~	$ 161,141	$ 0.0018	
Total Direct Cost of Gas Rate	~~$ 47,150,454~~	~~0.5345~~	$ 94,810,891	$ 1.0843	
Total Anticipated Indirect Cost of Gas	~~$ 2,222,909~~		$ 4,338,002		
Projected Prorated Sales (11/01/20 - 04/30/21)~~(11/01/19 - 04/30/20)~~	~~88,213,529~~		87,443,741		
Indirect Cost of Gas		~~$ 0.0252~~		$ 0.0496	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/21				$ 1.1339	per Therm
~~**TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/19**~~		~~$ 0.5597~~			

RESIDENTIAL COST OF GAS RATE - 11/01/21		**COGwr**	**$ 1.1339**	**/therm**
~~**RESIDENTIAL COST OF GAS RATE - 11/01/20**~~		~~**COGwr**~~	~~**$ 0.5597**~~	~~**/therm**~~
	Maximum	(COG + 25%)	~~$ 0.7754~~	$ 1.4174
GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 & R-7 - 11/01/21			**$ 0.6236**	**/therm**
~~**GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 & R-7 - 11/01/2(**~~			~~**$ 0.3078**~~	~~**/therm**~~
	Maximum	(COG + 25%)	~~$ 0.3848~~	$ 0.7796
C&I LOW WINTER USE COST OF GAS RATE - 11/01/21		**COGwl**	**$ 1.1324**	**/therm**
~~**C&I LOW WINTER USE COST OF GAS RATE - 11/01/20**~~		~~**COGwl**~~	~~**$ 0.5686**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective ~~11/01/20~~ 11/01/21	~~$ 0.1471~~	$ 0.1586	Maximum	(COG + 25%)	~~$ 0.7107~~	$ 1.4155
Times: Low Winter Use Ratio (Winter)	~~1.0620~~	0.9910				
Times: Correction Factor	~~0.9984~~	1.0001				
Adjusted Demand Cost of Gas Rate	~~$ 0.1560~~	$ 0.1572				
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238				
Adjustment Cost of Gas Rate	~~0.0115~~	0.0018				
Indirect Cost of Gas Rate	~~0.0252~~	0.0496				
Adjusted C&I Low Winter Use Cost of Gas Rate	~~$ 0.5686~~	$ 1.1324				

C&I HIGH WINTER USE COST OF GAS RATE - 11/01/21		**COGwh**	**$ 1.1341**	**/therm**
~~**C&I HIGH WINTER USE COST OF GAS RATE - 11/01/20**~~		~~**COGwh**~~	~~**$ 0.6190**~~	~~**/therm**~~

Average Demand Cost of Gas Rate Effective ~~11/01/20~~ 11/01/21	~~$ 0.1471~~	$ 0.1586	Maximum	(COG + 25%)	~~$ 0.6973~~	$ 1.4176
Times: High Winter Use Ratio (Winter)	~~0.9890~~	1.0017				
Times: Correction Factor	~~0.9984~~	1.0001				
Adjusted Demand Cost of Gas Rate	~~$ 0.1452~~	$ 0.1589				
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238	Minimum			
Adjustment Cost of Gas Rate	~~0.0115~~	0.0018	Maximum			
Indirect Cost of Gas Rate	~~0.0252~~	0.0496				
Adjusted C&I High Winter Use Cost of Gas Rate	~~$ 0.5578~~	$ 1.1341				

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Anticipated Cost of Gas
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~**PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021**~~
(REFER TO TEXT ON IN SECTION 17 COST OF GAS CLAUSE)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 12,022,922~~		$ 12,887,000	
Supply Costs:	~~28,279,842~~		72,351,034	
Storage Gas:				
Demand, Capacity:	~~$ 955,766~~		$ 981,898	
Commodity Costs:	~~3,285,987~~		6,130,435	
Produced Gas:	~~1,591,538~~		2,299,384	
Hedged Contract (Saving)/Loss	~~-~~		-	
Hedge Underground Storage Contract (Saving)/Loss	~~-~~		-	
Unadjusted Anticipated Cost of Gas		~~$ 46,136,054~~		$ 94,649,751
Adjustments:				
Prior Period (Over)/Under Recovery (as of 05/01/21)	~~$ 2,227,421~~		$ 1,431,639	
Interest	~~74,791~~		44,085	
Fuel Inventory Revenue Requirement	~~441,037~~		335,667	
Broker Revenues	~~(32,725)~~		(3,600)	
Refunds from Suppliers	~~-~~		-	
Fuel Financing	~~-~~		-	
Transportation CGA Revenues	~~(4,543)~~		(6,938)	
Interruptible Sales Margin	~~-~~		-	
Capacity Release and Off System Sales Margins	~~(1,736,581)~~		(1,676,512)	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs	~~45,000~~		36,800	
Total Adjustments		~~1,014,399~~		161,141
Total Anticipated Direct Cost of Gas		~~$ 47,150,454~~		$ 94,810,891
Anticipated Indirect Cost of Gas				
Working Capital:				
Total Unadjusted Anticipated Cost of Gas 11/01/21 - 04/30/22	~~$ 46,136,054~~		$ 94,649,751	
Working Capital Rate: Lead Lag Days / 365	~~0.0391~~		0.0705	
Prime Rate	~~3.25%~~		3.25%	
Working Capital Percentage	~~0.127%~~		0.229%	
Working Capital	~~$ 58,634~~		$ 216,761	
Plus: Working Capital Reconciliation (Acct 142.20)	~~(66,837)~~		(14,859)	
Total Working Capital Allowance	-	~~(8,203)~~		201,902
Bad Debt:				
Total Unadjusted Anticipated Cost of Gas 11/01/21 - 04/30/22	~~$ 46,136,054~~		$ 94,649,751	
Less: Refunds			-	
Plus: Total Working Capital	~~(8,203)~~		201,902	
Plus: Prior Period (Over)/Under Recovery	~~2,227,421~~		1,431,639	
Subtotal	~~$ 48,355,272~~		$ 96,283,291	
Bad Debt Percentage	~~1.11%~~		0.70%	
Bad Debt Allowance	~~$ 536,744~~		$ 673,983	
Plus: Bad Debt Reconciliation (Acct 175.52)	~~(296,628)~~		(223,340)	
Total Bad Debt Allowance	-	~~$ 240,116~~		$ 450,643
Production and Storage Capacity		~~$ 1,980,428~~		$ 3,685,458
Miscellaneous Overhead 11/01/21 - 04/30/22	~~$ 13,170~~		$ -	
Times Winter Sales	~~89,365~~		91,677	
Divided by Total Sales	~~111,369~~		115,043	
Miscellaneous Overhead		~~10,568~~		-
Total Anticipated Indirect Cost of Gas		~~$ 2,222,909~~		$ 4,338,002
Total Cost of Gas		~~$ 49,373,363~~		$ 99,148,894

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NHPUC NO. 11 - GAS **Proposed Second Revised Page 98**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 98**

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2021 THROUGH APRIL 30, 2022
~~PRIOR PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2020 THROUGH APRIL 30, 2021~~
(Refer to text in Section16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	~~(Col 4)~~	(Col 2)	(Col 3)	(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:						
PROPANE	~~$ 568,511~~			$ 920,459		
LNG	~~$ 1,023,026~~			1,378,925		
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	~~1,591,538~~			2,299,384		
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	~~8.7%~~			8.7%		
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	~~$ 138,464~~			$ 200,046		
PROJECTED FIRM THROUGHPUT (THERMS):						
FIRM SALES	~~89,364,968~~	~~67.8%~~		91,676,680	68.3%	
FIRM TRANSPORTATION SUBJECT TO FTCG	~~42,456,275~~	~~32.2%~~		42,583,790	31.7%	
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	~~131,821,243~~	~~100.0%~~		134,260,470	100.0%	
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	~~32.2%~~ ~~x~~	~~138,464~~ =	~~$ 44,596~~	31.7% x	$ 200,046 =	$ 63,449
PRIOR (OVER) OR UNDER COLLECTION			(40,053)			(56,511)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS			~~$ 4,543~~			$ 6,938
PROJECTED FIRM TRANSPORTATION THROUGHPUT			~~42,456,275~~			42,583,790
FIRM TRANSPORTATION COST OF GAS			~~$ 0.0001~~			$ 0.0002

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NHPUC NO. 11 - GAS | **Proposed Second Revised Page 99**
LIBERTY UTILITIES | **Superseding Proposed First Revised Page 99**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Required Annual Environmental Increase	~~$ 2,864,179~~	$ 2,351,805	
Second one-third of prior period under recoveries (through June 2019)	~~$ 341,389~~	$ 341,389	
July 2020 - June 2021 recovery difference between actual and estimate	~~$ 338,564~~	$ 139,028	
Environmental Subtotal	~~$ 3,544,132~~	$ 2,832,222	
Overall Annual Net Increase to Rates			
Estimated weather normalized firm therms billed for the twelve months ended 10/31/2022 - sales and transportation	~~179,574,679~~	182,829,872	therms
Surcharge per therm	~~$ 0.0197~~	$0.0155	per therm
Total Environmental Surcharge	~~$ 0.0197~~	$0.0155	

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NHPUC NO. 11 - GAS **Proposed First Revised Page 100**
LIBERTY UTILITIES **Superseding Original Page 100**

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty
Local Distribution Adjustment Charge (LDAC) decrease due to Rate Case Expense and Recoupment
For LDAC effective November 1, 2021 - October 31, 2022
~~For LDAC effective November 1, 2020 - October 31, 2021~~

~~1~~	~~Rate Case Expense Remaining from Docket No. DG 17-048~~	~~$87,069~~
~~2~~	~~Recoupment Remaining from Docket No. DG 17-048~~	~~$0~~
~~3~~	~~July 1, 2020 Balance~~	~~$87,069~~
~~4~~	~~Plus Estimated Interest from July 2020 through October 2020~~	~~$745~~
~~5~~	~~Minus Estimated Recoveries from July 2020 through October 2020~~	~~($43,733)~~
~~6~~	~~Total Estimated Remaining Recovery As of November 1, 2020~~	~~$44,081~~
~~7~~	~~Estimated November 2019 - October 2020 Interest~~	~~$538~~
~~8~~	~~Total Remaining Recovery~~	~~$44,619~~
~~9~~	~~Estimated November 2020 - October 2021 Sales (therms)~~	~~179,574,679~~
~~10~~	~~RCE & Recoupment rate per therm November 2020 - October 2021~~	~~$0.0002~~

1	Rate Case Exepense	
2	Prior Period Balance	($11,949)
3	Expenses thru June 30, 2021	$785,177
4	Balance at June 30, 2021	$773,228
5	Less: Accrual Balance	($26,000)
6	Adjusted Rate Case Expense	$747,228
7		
8	Recoupment	
9	Distribution Recoupment from Docket No. DG 20-105	($568,780)
10	Indirect Costs Recoupment from Docket No. DG 20-105	$1,900,000
11	Total Recoupment	$1,331,220
12		
13	July 1, 2021 Balance	$2,078,448
14		
15	Estimated Remaining Expenses	$97,375
16		
17	Plus Estimated Interest from July 2021 through October 2021	$19,820
18		
19	Minus Estimated Recoveries from July 2021 through October 2021	($7,864)
20		
21	Total Estimated Remaining Recovery As of November 1, 2021	$2,187,779
22		
23	Estimated November 2021 - October 2022 Interest	$26,727
24		
25	Total Remaining Recovery	$2,214,505
26		
27	Estimated November 2021 - October 2022 Sales (therms)	$182,829,872
28		
29	RCE & Recoupment rate per therm November 2021 - October 2022	$0.0121

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NHPUC NO. 11 - GAS **Proposed Second Revised Page 101**
LIBERTY UTILITIES **Superseding Proposed First Revised Page 101**

Local Delivery Adjustment Clause Calculation

				Sales Customers		Transportation Customers		
Residential Non Heating Rates - R-1								
Energy Efficiency Charge	~~$ 0.0831~~		$ 0.0861					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0831~~		$ 0.0861				
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155				
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0562)~~		$ 0.0152				
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121				
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156				
LDAC		~~**$ 0.0589**~~		**$ 0.1444**				**per therm**

Residential Heating Rates - R-3, R-4, R-6, R-7								
Energy Efficiency Charge	~~$ 0.0831~~		$ 0.0861					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0831~~		$ 0.0861				
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155				
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0562)~~		$ 0.0152				
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121				
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156				
LDAC		~~**$ 0.0589**~~		**$ 0.1444**				**per therm**

Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

Commercial/Industrial Large Annual Use Rates - G-43, G-53, G-54, G-46, G-56, G-57, G-58								
Energy Efficiency Charge	~~$ 0.0441~~		$ 0.0408					
Demand Side Management Charge	~~$ -~~		$ -					
Conservation Charge (CCx)		~~$ 0.0441~~		$ 0.0408	~~$ 0.0426~~	$ 0.0408		
Relief Holder and pond at Gas Street, Concord, NH	~~$ -~~		$ -					
Manufactured Gas Plants	~~$ 0.0197~~		$ 0.0155					
Environmental Surcharge (ES)		~~$ 0.0197~~		$ 0.0155	~~$ 0.0153~~	$ 0.0155		
Revenue Decoupling Adjustment Factor (RDAF)		~~$ (0.0206)~~		$ 0.0039	~~$ (0.0241)~~	$ 0.0039	~~$ (0.0213)~~	
Energy Efficiency Resource Standard Lost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense Factor (RCEF)		~~$ 0.0002~~		$ 0.0121	~~$ 0.0017~~	$ 0.0121		
Gas Assistance Program (GAP)		~~$ 0.0121~~		$ 0.0156	~~$ 0.0123~~	$ 0.0156		
LDAC		~~**$ 0.0555**~~		**$ 0.0878**	~~**$ 0.0478**~~	**$ 0.0878**		**per therm**

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III DELIVERY TERMS AND CONDITIONS

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	~~$ 0.12~~	$ 0.18	
II.	Capacity Mitigation Fee	~~15%~~	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
III.	Peaking Demand Charge	~~$ 17.32~~	$ 54.72	
IV.	Company Allowance Calculation (per Schedule 25)			
		~~169,030,868~~	165,859,380	Total Sendout - Therms Jul -2020 - Jun-2021 ~~Total Sendout - Therms Jul-2019 - Jun-2020~~
		~~166,311,578~~	163,831,092	Total Throughput - Therms Jul-2020 - Jun-2021 ~~Total Throughput - Therms Jul-2019 - Jun-2020~~
		~~2,719,290~~	2,028,288	Variance (Sendout - Throughput)
Company Allowance Percentage	2021-22 ~~2020-21~~	~~1.6%~~	1.2%	Variance / Total Sendout

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III DELIVERY TERMS AND CONDITIONS

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-51	Low Annual /Low Winter Use	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-42	Medium Annual / High Winter	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-52	High Annual / Low Winter Use	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-43	High Annual / High Winter	~~46.1%~~ 69.1%	~~17.1%~~ 16.8%	~~36.8%~~ 14.1%	100.0%
G-53	High Annual / Load Factor < 90%	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%
G-54	High Annual / Load Factor > 90%	~~59.3%~~ 76.2%	~~12.9%~~ 12.9%	~~27.9%~~ 10.9%	100.0%

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing

Table of Contents

Ln	Description	Reference		PK 21-22 Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**			
2	**d/b/a Liberty**			
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**			
4	**Summary**			
5				PK 21-22
6		Reference		Nov - Apr
7	(a)	(b)		(c)
9	**Anticipated Direct Cost of Gas**			
10	Purchased Gas:			
11	Demand Costs:	Sch. 5A, col (k), ln 46	$	12,887,000
12	Supply Costs	Sch. 6, col (i), ln 47		72,351,034
14	Storage Gas:			
15	Demand, Capacity:	Sch. 5A, col (k), ln 61	$	981,898
16	Commodity Costs:	Sch. 6, col (i), ln 50		6,130,435
18	Produced Gas:	Sch. 6, col (i), ln 56	$	2,299,384
20	Hedge Contract (Savings)/Loss	Sch. 7, col (i), ln 34	$	-
21	Hedge Underground Storage Contract (Savings)/Loss	Sch. 16, col (e), ln 172	$	-
23	**Total Unadjusted Cost of Gas**		$	94,649,751
25	**Adjustments:**			
27	Prior Period (Over)/Under Recovery	Sch. 3, col (c) ln 28	$	1,431,639
28	Interest 05/01/20 - 4/30/21	Sch. 3, col (q) ln 189		44,085
29	Fuel Inventory Revenue Req	Sch. 26, col (b) ln 8		335,667
30	Refunds from Suppliers	Sch. 4, ln 26 col (c)		-
31	Broker Revenues	Sch. 4, ln 26 col (d)		(3,600)
32	Fuel Financing	Sch. 4, ln 26 col (e)		-
33	Transportation CGA Revenues	Sch. 4, ln 26 col (f)		(6,938)
34	Interruptible Sales Margin	Sch. 4, ln 26 col (g)		-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 26 col (h) + col (i)		(1,676,512)
36	Hedging Costs	Sch. 4, ln 26 col (j)		-
37	Fixed Price Option Administrative Costs	Sch. 4, ln 26 col (k)		36,800
39	**Total Adjustments**		$	161,141
41	**Total Anticipated Direct Costs**	lns 23 + 39	$	94,810,891
43	**Anticipated Indirect Cost of Gas**			
44	**Working Capital**			
45	Total Unadjusted Anticipated Cost of Gas	Ln 23	$	94,649,751
46	Lead Lag Days / 365	DG 20-105, 25.72/ 365		0.0705
47	Prime Rate			3.25%
48	Working Capital Percentage	per GTC 18(f), ln 47 * ln 48		0.229%
49	Working Capital	ln 45 * ln 48		216,761
50	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 94		(14,859)
52	**Total Working Capital Allowance**	lns 49 + 50	$	201,902
54	**Bad Debt**			
55	Total Unadjusted Anticipated Cost of Gas	ln 23	$	94,649,751
56	Less Refunds	ln 30		-
57	Plus Working Capital	ln 52		201,902
58	Plus Prior Period (Over) Under Recovery	ln 27		1,431,639
59	Subtotal		$	96,283,291
60	Bad Debt Percentage	per GTC 18(f)		0.70%
62	Bad Debt Allowance	ln 59 * ln 60	$	673,983
63	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 169		(223,340)
65	**Total Bad Debt Allowance**	lns 62 + 63	$	450,643
67	**Production and Storage Capacity**	per GTC18(f)	$	3,685,458
70	**Miscellaneous Overhead**	lns 69 * 72	$	-
72	**Total Anticipated Indirect Cost of Gas**	lns 52 + 65 + 67 + 70	$	4,338,002
74	**Total Cost of Gas**	lns 41 + 72	$	99,148,894
76	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52		87,443,741

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

Updated Schedule 1
Page 1 of 4

Ln				Peak Costs								Peak Period
5												
6				Peak Costs								Peak Period
7	For Month of:			May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
8		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**											
10											1,139,930	1.2%
11	**A.**	**Firm Demand Volumes**										
12		Firm Gas Sales	Sch. 10B, ln 23	-	3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741
13		Lost Gas (Unaccounted for)		-	131,257	200,043	232,437	192,597	165,642	95,906		1,017,882
14		Company Use		-	15,738	23,986	27,870	23,093	19,861	11,500		122,048
15		Unbilled Therms		-	8,836,890	549,888	492,921	107,722	220,489	(249,614)	(4,325,377)	5,632,919
16												
17	**Total Firm Volumes**		Sch. 6, ln 97	-	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211		94,216,591
18												
19	**B.**	**Supply Volumes (Therms)**										
20	Pipeline Gas:											
21		Dawn Supply	Sch. 6, ln 66	-	876,821	926,304	927,705	840,605	911,138	750,758		5,233,331
22		Niagara Supply	Sch. 6, ln 67	-	691,567	730,181	731,285	662,478	718,226	679,016		4,212,753
23		TGP Supply (Direct)	Sch. 6, ln 68	-	4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346		17,283,547
24		Dracut Supply 1 - Baseload	Sch. 6, ln 69	-	-	2,800,032	4,674,030	3,176,712	-	-		10,650,774
25		Dracut Supply 2 - Swing	Sch. 6, ln 70	-	1,775,785	5,569,137	771,324	-	969,754	79,714		9,165,713
26		Dracut Supply 3 - Swing	Sch. 6, ln 71		-	596,455	290,490	-	1,484	-		888,430
27		Constellation COMBO	Sch. 6, ln 72	-	89,306	231,576	1,424,042	1,188,519	1,411,967	-		4,345,410
28		LNG Truck	Sch. 6, ln 73	-	20,666	21,875	51,371	291,824	362,081	-		747,817
29		Propane Truck	Sch. 6, ln 74	-	-	-	-	695,072	-	-		695,072
30		PNGTS	Sch. 6, ln 75	-	219,205	231,576	231,926	209,962	227,785	193,487		1,313,941
31		Portland Natural Gas	Sch. 6, ln 76		1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355		6,284,969
32		TGP Supply (Z4)	Sch. 6, ln 77	-	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071		14,753,578
33		Subtotal Pipeline Volumes		-	11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749		75,575,334
34												
35	Storage Gas:											
36		TGP Storage	Sch. 6, ln 82	-	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085		19,999,699
37												
38	Produced Gas:											
39		LNG Vapor	Sch. 6, ln 85	-	21,404	421,875	547,315	694,098	273,045	21,015		1,978,752
40		Propane	Sch. 6, ln 86	-	-	-	244,014	574,010	-	-		818,023
41		Subtotal Produced Gas		-	21,404	421,875	791,328	1,268,108	273,045	21,015		2,796,775
42												
43	Less - Gas Refill:											
44		LNG Truck	Sch. 6, ln 91	-	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-		(747,817)
45		Propane	Sch. 6, ln 92	-	-	-	-	(695,072)	-	-		(695,072)
46		TGP Storage Refill	Sch. 6, ln 93	-	(1,750,690)	-	-	-	-	(961,638)		(2,712,328)
47		Subtotal Refills		-	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)		(4,155,217)
48												
49	Total Firm Sendout Volumes		lns 33 + 36 + 41 + 47	-	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211		94,216,591
50												

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

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51	**II. Gas Costs**											
52	**A.**	**Demand Costs**										
53												
54												
55				Peak Costs								Peak Period
56	For Month of:			May 21 - Oct 21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Nov - Apr
57		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
58	Supply											
59		Niagara Supply	Sch.5A, ln 12	[redacted]								
60		Subtotal Supply Demand										
61		Less Capacity Credit										
62		Net Pipeline Demand Costs										
63												
64	Pipeline:											
65		Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
66		Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17									
67		Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18									
68		Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19									
69		Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20									
70		Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21									
71		Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22									
72		Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	Sch.5A, ln 23									
73		Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 24									
74		Portland Natural Gas Trans Service	Sch.5A, ln 25									
75		Portland Natural Gas	Sch.5A, ln 26									
76		ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 27									
77		TransCanada via Union to Portland	Sch.5A, ln 28									
78		Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 29									
79		Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 30									
80		Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 31									
81		National Fuel FST 2358	Sch.5A, ln 32									
82		Subtotal Pipeline Demand		$ 3,900,053	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874		$ 13,559,298
83		Less Capacity Credit		(1,320,558)	(405,527)	(405,527)	(405,527)	(405,527)	(405,527)	(405,527)		(3,753,722)
84		Net Pipeline Demand Costs		$ 2,579,495	$ 1,204,347	$ 1,204,347	$ 1,204,347	$ 1,204,347	$ 1,204,347	$ 1,204,347		$ 9,805,576
85												
86	Peaking Supply:											
87		Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 37	[redacted]								
88		Demand FLS	Sch.5A, ln 38									
89		Constellation Demand	Sch.5A, ln 39									
90		Subtotal Peaking Demand										
91		Less Capacity Credit										
92		Net Peaking Supply Demand Costs		$ -	$ 616,285	$ 616,285	$ 616,285	$ 616,285	$ 616,285	$ -		$ 3,081,424
93												
94	Storage:											
95		Dominion - Demand	Sch.5A, ln 49	[redacted]								
96		Dominion - Storage	Sch.5A, ln 50									
97		Honeoye - Demand	Sch.5A, ln 51									
98		National Fuel - Demand	Sch.5A, ln 52									
99		National Fuel - Capacity	Sch.5A, ln 53									
100		Tenn Gas Pipeline - Demand	Sch.5A, ln 54									
101		Tenn Gas Pipeline - Capacity	Sch.5A, ln 55									
102		Subtotal Storage Demand		$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105		$ 1,393,257
103		Less Capacity Credit		(235,878)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)		(411,359)
104		Net Storage Demand Costs		$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858		$ 981,898
105												
106		Total Demand Charges	lns 60 + 82 + 90 + 102	$ 4,596,681	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 1,725,979		$ 19,071,554
107 v		Total Capacity Credit	lns 61 + 83 + 91 + 103	(1,556,436)	(642,289)	(642,289)	(642,289)	(642,289)	(642,289)	(434,774)		(5,202,657)
108		Net Demand Charges		$ 3,040,245	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,291,205		$ 13,868,897
109												
110						**THIS PAGE HAS BEEN REDACTED**						

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

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Ln		(a)	(b)	Peak Costs May 21 - Oct 21 (c)	Nov-21 (d)	Dec-21 (e)	Jan-22 (f)	Feb-22 (g)	Mar-22 (h)	Apr-22 (i)	May-22 (j)	Peak Period Nov - Apr (k)
111	**B.**	**Commodity Costs**										
112												
113												
114												
118	Pipeline:											
119		Dawn Supply	Sch. 6, ln 12	[redacted]								
120		Niagara Supply	Sch. 6, ln 13									
121		TGP Supply (Direct)	Sch. 6, ln 14									
122		Dracut Supply 1 - Baseload	Sch. 6, ln 15									
123		Dracut Supply 2 - Swing	Sch. 6, ln 16									
		Dracut Supply 3 - Swing	Sch. 6, ln 17									
124		Constellation COMBO	Sch. 6, ln 18									
125		LNG Truck	Sch. 6, ln 19									
126		Propane Truck	Sch. 6, ln 20									
127		PNGTS	Sch. 6, ln 21									
128		Portland Natural Gas	Sch. 6, ln 22									
129		TGP Supply (Z4)	Sch. 6, ln 23									
130		Subtotal Pipeline Commodity Costs		$ -	$ 6,488,894	$ 25,785,739	$ 19,058,558	$ 11,866,845	$ 7,408,521	$ 3,274,803		$ 73,883,360
131												
132	Storage:											
133		TGP Storage - Withdrawals	Sch. 6, ln 50	$ -	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423		$ 6,130,435
134												
135	Produced Gas Costs:											
136		LNG Vapor	Sch. 6, ln 53	[redacted]								
137		Propane	Sch. 6, ln 54									
138		Subtotal Produced Gas Costs		$ -	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685		$ 2,299,384
139												
140	Less Storage Refills:											
141		LNG Truck	Sch. 6, ln 40	[redacted]								
142		Propane	Sch. 6, ln 41									
143		TGP Storage Refill	Sch. 6, ln 42									
144		Storage Refill (Trans.)	Sch. 6, ln 43									
145		Subtotal Storage Refill		$ -	$ (1,077,566)	$ (15,566)	$ (37,152)	$ (1,041,646)	$ (244,164)	$ (434,450)		$ (2,850,544)
146												
147	Total Supply Commodity Costs			$ -	$ 6,264,728	$ 26,325,246	$ 21,341,673	$ 13,453,475	$ 8,805,052	$ 3,272,462		$ 79,462,636
148												
149	**C. Supply Volumetric Transportation Costs:**											
150		Dawn Supply	Sch. 6, ln 28	[redacted]								
151		Niagara Supply	Sch. 6, ln 29									
152		TGP Supply (Direct)	Sch. 6, ln 30									
153		Dracut Supply 1 - Baseload	Sch. 6, ln 31									
154		Dracut Supply 2 - Swing	Sch. 6, ln 32									
		Dracut Supply 3 - Swing	Sch. 6, ln 33									
155		Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 249,688	$ 204,758	$ 198,077	$ 171,484	$ 172,367	$ 41,655		$ 1,038,029
156												
157		TGP Storage - Withdrawals	Sch. 6, ln 35	$ -	$ 38,503	$ 11,890	$ 76,971	$ 68,398	$ 66,579	$ 17,849		$ 280,188
158												
159		Total Supply Volumetric Trans. Costs	lns 155 + 157	$ -	$ 288,190	$ 216,647	$ 275,048	$ 239,882	$ 238,945	$ 59,504		$ 1,318,217
160												
161	Total Commodity Gas & Trans. Costs		lns 147 + 159	$ -	$ 6,552,919	$ 26,541,893	$ 21,616,721	$ 13,693,357	$ 9,043,998	$ 3,331,966		$ 80,780,853
162												
163												

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
164 **D. Supply and Demand Costs by Source**

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Line			Peak Costs	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Peak Period Nov - Apr
170	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
171	Purchased Gas Demand Costs										
172	Pipeline Gas Demand Costs	lns 60 + 82	$ 3,900,053	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874		$ 13,559,298
173	Peaking Gas Demand Costs	ln 90	-	823,800	823,800	823,800	823,800	823,800	-		4,119,000
174	Subtotal Purchased Gas Demand Costs		$ 3,900,053	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 1,609,874		$ 17,678,298
175	Less Capacity Credit	lns 61 + 83 + 91	(1,320,558)	(613,043)	(613,043)	(613,043)	(613,043)	(613,043)	(405,527)		(4,791,298)
176	Net Purchased Gas Demand Costs		$ 2,579,495	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,204,347		$ 12,887,000
177											
178	Storage Gas Demand Costs										
179	Storage Demand	ln 102	$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105		$ 1,393,257
180	Less Capacity Credit	ln 103	(235,878)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)	(29,247)		(411,359)
181	Net Storage Demand Costs		$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858		$ 981,898
182											
183	**Total Demand Costs**	lns 176 + 181	$ 3,040,245	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,291,205		$ 13,868,897
184											
185	Purchased Gas Supply										
186	Commodity Costs	ln 130	[redacted]								
187	Less Storage Inj.(TGP Storage)	ln 143									
188	Less Storage Transportation	ln 144									
189	Less LNG Truck	ln 141									
190	Less Propane Truck	ln 142									
191	Plus Transportation Costs	ln 155									
192	Subtotal Purchased Gas Supply		$ -	$ 5,661,016	$ 25,974,930	$ 19,219,483	$ 10,996,684	$ 7,336,724	$ 2,882,009		$ 72,070,845
193											
194	Storage Commodity Costs										
195	Commodity Costs	ln 133	$ -	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423		$ 6,130,435
196	Transportation Costs	ln 157	-	38,503	11,890	76,971	68,398	66,579	17,849		280,188
197	Subtotal Storage Commodity Costs		$ -	$ 876,979	$ 270,810	$ 1,753,181	$ 1,557,903	$ 1,516,478	$ 435,272		$ 6,410,624
198											
199	Produced Gas Commodity Costs	ln 138	$ -	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685		$ 2,299,384
200											
201	**Subtotal Commodity Costs**	lns 192 + 197 + 199	$ -	$ 6,552,919	$ 26,541,893	$ 21,616,721	$ 13,693,357	$ 9,043,998	$ 3,331,966		$ 80,780,853
202											
203	Hedge Contract (Savings)/Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
204											
205	**Total Commodity Costs**	lns 201 + 203	$ -	$ 6,552,919	$ 26,541,893	$ 21,616,721	$ 13,693,357	$ 9,043,998	$ 3,331,966		$ 80,780,853
206											
207	**Total Demand Costs**	ln 108	$ 3,040,245	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,291,205		$ 13,868,897
208	**Total Supply Costs**	ln 205	-	6,552,919	26,541,893	21,616,721	13,693,357	9,043,998	3,331,966		80,780,853
209											
210	**Total Direct Gas Costs**	lns 207 + 208	$ 3,040,245	$ 8,460,408	$ 28,449,382	$ 23,524,210	$ 15,600,847	$ 10,951,487	$ 4,623,171		$ 94,649,750
211											
212											

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Peak 2021 - 2022 Winter Cost of Gas Filing
Contracts Ranked on a per Unit Cost Basis

Line	Supplier (a)	Contract (b)	Contract Type (c)	Contract Unit (d)	Unit Dth (MDQ/ACQ) (e)	Peak Period Cost per Unit Dth (f)
10	**Demand Costs**					
11						[redacted]
12	Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
13	Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
14	National Fuel - Capacity Reservation	FSS-O02357	Storage	ACQ	670,800	
15	Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
16	Dominion - Demand	GSS 300076	Storage	MDQ	934	
17	National Fuel - Demand	FSS-O02357	Storage	MDQ	6,098	
18	National Fuel	FST N02358	Transportation	MDQ	6,098	
19	Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
20	Tenn Gas Pipeline	358905 FTA Z6-Z6	Transportation	MDQ	40,000	
21	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
22	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
23	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
24	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
25	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
26	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
27	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
28	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
29	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
30	ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	
31	TransCanada via Union to Portland	Dawn -Parkway to Portland	Transportation	MDQ	5,077	
32	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
33	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
34	Portland Natural Gas Trans Service	FT-208544	Transportation	MDQ	1,000	
35	Portland Natural Gas	FT 233320	Transportation	MDQ	5,000	
36	Peaking Demand	NSB041	Peaking	MDQ	10,000	
37						
38	**Supply Costs - Commodity**					
39	TGP Supply (Z4)		Pipeline	Dkt	1,475,358	[redacted]
40	Niagara Supply		Pipeline	Dkt	421,275	
41	Constellation COMBO		Pipeline	Dkt	434,541	
42	TGP Supply (Direct)		Pipeline	Dkt	1,728,355	
43	Dawn Supply		Pipeline	Dkt	523,333	
44	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	
45	TGP Storage		Storage	Dkt	1,999,970	
46	PNGTS		Pipeline	Dkt	131,394	
47	Propane Truck		Pipeline	Dkt	69,507	
48	LNG Truck		Pipeline	Dkt	74,782	
49	Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	
50	Dracut Supply 3 - Swing		Pipeline	Dkt	88,843	
51	Portland Natural Gas		Pipeline	Dkt	628,497	
52	Propane		Produced	Dkt	81,802	
53	LNG Vapor (Storage)		Produced	Dkt	197,875	
54						
55	**Supply Costs - Volumetric Transportation**					
56	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,065,077	[redacted]
57	Dracut Supply 2 - Swing		Pipeline	Dkt	916,571	
58	Niagara Supply		Pipeline	Dkt	421,275	
59	Dawn Supply		Pipeline	Dkt	523,333	
60	TGP Storage - Withdrawals		Pipeline	Dkt	1,999,970	
61	TGP Supply (Direct)		Pipeline	Dkt	1,728,355	

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

5			Prior Period Bal														
6			Apr-21														
7			Ending Bal	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Peak Period
8		Days in Month	Plus May Billings	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
10	**Account 1920-1740 COG (Over)/Under Balance - Interest Calculation**																
11																	
12	**Beginning Balance**	Account 1920-1740 1/	**$ 1,431,639**	$ 1,431,639	$ 707,644	$ 206,908	$ 714,886	$ 1,224,266	$ 1,734,921	$ 2,247,116	$ (2,080,567)	$ 6,650,087	$ 7,220,444	$ 3,857,680	$ (1,459,154)	$ (6,125,843)	$ 1,431,639
13	Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		506,708	506,708	506,708	506,708	506,708	506,708	8,460,408	28,449,382	23,524,210	15,600,847	10,951,487	4,623,171	-	94,649,751
14	Production & Storage & Misc Overhead			-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243		3,685,458
15	Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(3,470,585)	(19,452,911)	(22,763,151)	(19,191,164)	(16,365,099)	(9,888,993)	(4,742,392)	(95,874,295)
16	Projected Unbilled Revenue									(9,688,864)	(10,291,768)	(10,832,213)	(10,950,320)	(11,192,067)	(10,918,387)		(63,873,618)
17	Reverse Prior Month Unbilled										9,688,864	10,291,768	10,832,213	10,950,320	11,192,067	10,918,387	63,873,618
18	Adjustment			(1,233,644)	(1,008,659)					-							(2,242,302)
19	Add Net Adjustments	Schedule 4		-	-	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	(1,650,251)
20	Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		$ 1,431,639	$ 704,703	$ 205,692	$ 713,616	$ 1,221,594	$ 1,730,974	$ 2,241,628	$ (2,080,789)	$ 6,643,789	$ 7,201,327	$ 3,843,888	$ (1,462,460)	$ (6,115,726)	$ 50,153	$ -
22	Average Monthly Balance	(ln 12 + 21)/2		$ 1,068,171	$ 456,668	$ 460,262	$ 968,240	$ 1,477,620	$ 1,988,274	$ 83,163	$ 2,281,611	$ 6,925,707	$ 5,532,166	$ 1,197,610	$ (3,787,440)	$ (3,037,845)	
23																	
24	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
25																	
26	Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 2,940	$ 1,216	$ 1,270	$ 2,673	$ 3,947	$ 5,488	$ 222	$ 6,298	$ 19,117	$ 13,793	$ 3,306	$ (10,117)	$ -	$ 50,153
27																	
28	**(Over)/Under Balance**	ln 21 + ln 26	$ 1,431,639	$ 707,644	$ 206,908	$ 714,886	$ 1,224,266	$ 1,734,921	$ 2,247,116	$ (2,080,567)	$ 6,650,087	$ 7,220,444	$ 3,857,680	$ (1,459,154)	$ (6,125,843)	$ 50,153	50,153
29																	
30																	
31	**Calculation of COG with Interest**																
32																	
33	**Beginning Balance**	ln 12	$ 1,431,639	$ 1,431,639	$ 707,652	$ 206,920	$ 714,898	$ 1,224,278	$ 1,734,933	$ 2,247,129	$ (2,085,662)	$ 6,644,669	$ 7,214,753	$ 3,851,930	$ (1,465,043)	$ (6,131,617)	$ 1,431,639
34	Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		506,708	506,708	506,708	506,708	506,708	506,708	8,460,408	28,449,382	23,524,210	15,600,847	10,951,487	4,623,171	-	94,649,751
35	Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	614,243	614,243	614,243	614,243	614,243	614,243	-	3,685,458
36	Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(3,470,585)	(19,452,911)	(22,763,151)	(19,191,164)	(16,365,099)	(9,888,993)	(4,742,392)	(95,874,295)
37	Projected Unbilled Revenue									(9,693,964)	(10,297,185)	(10,837,914)	(10,956,084)	(11,197,958)	(10,924,134)		(63,907,240)
38	Reverse Prior Month Unbilled										9,693,964	10,297,185	10,837,914	10,956,084	11,197,958	10,924,134	63,907,240
39	Add Net Adjustments	ln 19		(1,233,644)	(1,008,659)	-	-	-	-	(243,108)	(283,455)	(283,617)	(282,374)	(279,025)	(278,672)	-	(3,892,553)
40	Gas Cost Billed	ln 20	-		-	-	-	-	-	-	-	-	-	-	-	-	-
41	Add Interest	ln 26		-	-	-	-	-	-	222	6,298	19,117	13,793	3,306	(10,117)	-	32,618
42	**(Over)/Under Balance**		$ 1,431,639	$ 704,703	$ 205,700	$ 713,628	$ 1,221,606	$ 1,730,986	$ 2,241,640	$ (2,085,655)	$ 6,644,675	$ 7,214,742	$ 3,851,927	$ (1,465,032)	$ (6,131,587)	$ 50,126	$ 32,618
43																	
44	Average Monthly Balance			$ 1,068,171	$ 456,676	$ 460,274	$ 968,252	$ 1,477,632	$ 1,988,287	$ 80,737	$ 2,279,507	$ 6,929,706	$ 5,533,340	$ 1,193,449	$ (3,798,315)	$ (3,040,745)	
45																	
46	Interest Applied	ln 24 * ln 44 / 365 * Days of Month		2,948	1,220	1,270	2,673	3,947	5,488	216	6,292	19,128	13,795	3,294	(10,146)	-	50,126
47																	
48	**(Over)/Under Balance**	-ln 41 +ln 42 + ln 46	$ 1,431,639	$ 707,652	$ 206,920	$ 714,898	$ 1,224,278	$ 1,734,933	$ 2,247,129	$ (2,085,662)	$ 6,644,669	$ 7,214,753	$ 3,851,930	$ (1,465,043)	$ (6,131,617)	$ 50,126	50,126
49																	
50																	
51	Forecast Sendout Therms	Sch 1								12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211		94,216,591
52	Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741
53	Less Forecast Unaccounted For	Sch 1								131,257	200,043	232,437	192,597	165,642	95,906		1,017,882
54	Less Forecast Company Use	Sch 1								15,738	23,986	27,870	23,093	19,861	11,500		122,048
55	Unbilled Volumes									8,836,890	549,888	492,921	107,722	220,489	-249,614	-4,325,377	5,632,919
56	Gross Unbilled									8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296	5,632,919	
57																	
58																	
59	COB w/o Interest	Sch. 3, pg. 4, ln 207 col. (c)								$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	$1.0964	
60																	
61	COG With Interest	Sch. 3, pg. 4, ln 207 col. (d)								$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	$1.0970	
62																	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

70 **Account 1163-1422 Working Capital (Over)/Under Balance - Interest Calculation**

Line	(a)	Days in Month (b)	Prior Period Bal Apr-21 Ending Bal + May Collections	May-21 31 (c)	Jun-21 30 (d)	Jul-21 31 (e)	Aug-21 31 (f)	Sep-21 30 (g)	Oct-21 31 (h)	Nov-21 30 (i)	Dec-21 31 (j)	Jan-22 31 (k)	Feb-22 28 (l)	Mar-22 31 (m)	Apr-22 30 (n)	May-22 31 (o)	Peak Period Total (p)
72	**Beginning Balance**	Account 1163-1422 1/	**$ (14,859)**	$ (14,859)	$ (14,801)	$ (15,276)	$ (14,156)	$ (13,033)	$ (11,906)	$ (10,777)	$ (18,789)	$ 4,665	$ 10,130	$ 5,749	$ (3,680)	$ (13,097)	$ (14,859)
74	Days Lag			0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705	0.0705		
75	Prime Rate			3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
76	Forecast Working Capital	ln 34 * 0.091%		1,160	1,160	1,160	1,160	1,160	1,160	19,375	65,153	53,874	35,728	25,080	10,588	-	216,761
78	Projected Revenues w/o Int.	ln 116 * ln 120		-	-	-	-	-	-	(7,213)	(40,427)	(47,306)	(39,883)	(34,010)	(20,551)	(9,856)	(199,245)
79	Projected Unbilled Revenue									(20,135)	(21,388)	(22,511)	(22,757)	(23,259)	(22,690)		(132,741)
80	Reverse Prior Month Unbilled										20,135	21,388	22,511	22,757	23,259	22,690	132,741
82	Add Net Adjustments			(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)
84	Working Capital Billed	Account 1163-1422 2/	-														-
86	Monthly (Over)/Under Recovery		$ (14,859)	$ (14,761)	$ (15,236)	$ (14,116)	$ (12,996)	$ (11,873)	$ (10,746)	$ (18,749)	$ 4,684	$ 10,109	$ 5,730	$ (3,682)	$ (13,074)	$ (262)	$ 0
88	Average Monthly Balance	(ln 72 + ln 86)/2		$ (14,810)	$ (15,019)	$ (14,696)	$ (13,576)	$ (12,453)	$ (11,326)	$ (14,763)	$ (7,052)	$ 7,387	$ 7,930	$ 1,033	$ (8,377)	$ (6,679)	
90	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
92	Interest Applied	ln 88 * ln 90 / 365 * Days of Month		$ (41)	$ (40)	$ (41)	$ (37)	$ (33)	$ (31)	$ (39)	$ (19)	$ 20	$ 20	$ 3	$ (22)	$ -	$ (262)
94	**(Over)/Under Balance**	ln 86 + ln 92	$ (14,859)	$ (14,801)	$ (15,276)	$ (14,156)	$ (13,033)	$ (11,906)	$ (10,777)	$ (18,789)	$ 4,665	$ 10,130	$ 5,749	$ (3,680)	$ (13,097)	$ (262)	(262)

97 **Calculation of Working Capital with Interest**

Line	(a)	(b)	Prior Period	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Peak Period Total
100	**Beginning Balance**	ln 72	$ (14,859)	$ (14,859)	$ (14,801)	$ (15,276)	$ (14,156)	$ (13,033)	$ (11,906)	$ (10,777)	$ (18,752)	$ 4,757	$ 10,287	$ 5,960	$ (3,422)	$ (12,812)	$ (14,859)
101	Forecast Working Capital	ln 76		1,160	1,160	1,160	1,160	1,160	1,160	19,375	65,153	53,874	35,728	25,080	10,588	-	216,761
102	Projected Rev. with interest	ln 116 * ln 122		-	-	-	-	-	-	(7,203)	(40,373)	(47,243)	(39,830)	(33,964)	(20,524)	(9,842)	(198,979)
103	Projected Unbilled Revenue									(20,108)	(21,360)	(22,481)	(22,727)	(23,228)	(22,660)		(132,565)
104	Reverse Prior Month Unbilled										20,108	21,360	22,481	22,727	23,228	22,660	132,565
105	Add Net Adjustments	ln 82	-	(1,062)	(1,595)	-	-	-	-	-	-	-	-	-	-	-	(2,657)
106	Working Capital Billed	ln 84	-	-	-	-	-	-	-								-
107	Add Interest	ln 92		-	-	-	-	-	-	(39)	(19)	20	20	3	(22)	-	(38)
108	Monthly (Over)/Under Recovery		$ (14,859)	$ (14,761)	$ (15,236)	$ (14,116)	$ (12,996)	$ (11,873)	$ (10,746)	$ (18,752)	$ 4,757	$ 10,286	$ 5,960	$ (3,423)	$ (12,813)	$ 6	$ 227
110	Average Monthly Balance			$ (14,810)	$ (15,019)	$ (14,696)	$ (13,576)	$ (12,453)	$ (11,326)	$ (14,765)	$ (6,998)	$ 7,522	$ 8,123	$ 1,269	$ (8,117)	$ (6,403)	
112	Interest Applied	ln 90 * ln 110 / 365 * Days of Month		(41)	(40)	(41)	(37)	(33)	(31)	(39)	(19)	21	20	4	(22)	-	$ (259)
114	**(Over)/Under Balance**	-ln 107 +ln 108 + ln 112	$ (14,859)	$ (14,801)	$ (15,276)	$ (14,156)	$ (13,033)	$ (11,906)	$ (10,777)	$ (18,752)	$ 4,757	$ 10,287	$ 5,960	$ (3,422)	$ (12,812)	$ 6	$ 6
116	Forecast Therm Sales	ln 52								3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741
117	Unbilled Therm	ln 55								8,836,890	549,888	492,921	107,722	220,489	(249,614)		
118	Gross Unbilled									8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296		
120	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 224 col. (c)								$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	
122	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 224 col. (d)								$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	$0.0023	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Updated Schedule 3
Page 3 of 3

123																	
124																	
125			Prior Period Bal														
126			Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	DemandPeriod
127		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
128	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
129																	
130	**Account 1920-1743 Bad Debt (Over)/Under Balance - Interest Calculation**																
131																	
132	Forecast Direct Gas Costs	ln 34		$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 8,460,408	$ 28,449,382	$ 23,524,210	$ 15,600,847	$ 10,951,487	$ 4,623,171	$ -	94,649,751
133	Forecast Working Capital	ln 101		1,160	1,160	1,160	1,160	1,160	1,160	4,516	65,153	53,874	35,728	25,080	10,588		201,902
134	Prior Period Balance	ln 42								238,607	238,607	238,607	238,607	238,607	238,607		1,431,639
135	Total Forecast Direct Gas Costs & Working Capital			507,868	507,868	507,868	507,868	507,868	507,868	8,703,531	28,753,142	23,816,690	15,875,181	11,215,174	4,872,365	-	94,851,652
136																	
137	**Beginning Balance**	Account 1920-1743 1/	**$ (223,340)**	$ (223,340)	$ (252,014)	$ (257,764)	$ (254,915)	$ (252,059)	$ (249,172)	$ (246,300)	$ (242,363)	$ (127,460)	$ (60,766)	$ (32,419)	$ (25,087)	$ (32,220)	$ (223,340)
138																	
139	Forecast Bad Debt	ln 135 * 0.007		3,555	3,555	3,555	3,555	3,555	3,555	60,925	201,272	166,717	111,126	78,506	34,107		673,983
140																	
141	Projected Revenues w/o int	ln 178 * ln 182		-	-	-	-	-	-	(14,858)	(83,278)	(97,450)	(82,158)	(70,059)	(42,335)	(20,302)	(410,440)
142	Projected Unbilled Revenue									(41,478)	(44,059)	(46,373)	(46,879)	(47,914)	(46,742)		(273,445)
143	Reverse Prior Month Unbilled										41,478	44,059	46,373	46,879	47,914	46,742	273,445
144																	
145	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
146																	
147	Add Net Adjustments		-	(31,575)	(8,627)	-	-	-	-		-	-	-	-	-	-	(40,203)
148																	
149	Monthly (Over)/Under Recovery		$ (223,340)	$ (251,360)	$ (257,086)	$ (254,209)	$ (251,360)	$ (248,504)	$ (245,617)	$ (241,711)	$ (126,951)	$ (60,507)	$ (32,303)	$ (25,008)	$ (32,144)	$ (5,781)	$ 0
150																	
151	Average Monthly Balance	(ln 137 + ln 149)/2		$ (237,350)	$ (254,550)	$ (255,986)	$ (253,138)	$ (250,281)	$ (247,395)	$ (244,006)	$ (184,657)	$ (93,984)	$ (46,535)	$ (28,714)	$ (28,615)	$ (19,000)	
152																	
153	Interest Rate	Prime Rate		3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%		
154																	
155	Interest Applied	ln 151 * ln 153 / 365 * Days of Month		$ (653)	$ (678)	$ (707)	$ (699)	$ (669)	$ (683)	$ (652)	$ (510)	$ (259)	$ (116)	$ (79)	$ (76)		$ (5,781)
156																	
157	**(Over)/Under Balance**	ln 149 + ln 155	$ (223,340)	$ (252,014)	$ (257,764)	$ (254,915)	$ (252,059)	$ (249,172)	$ (246,300)	$ (242,363)	$ (127,460)	$ (60,766)	$ (32,419)	$ (25,087)	$ (32,220)	$ (5,781)	(5,781)
158																	
159																	
160	**Calculation of Bad Debt with Interest**																
161																	
162	**Beginning Balance**	ln 137	$ (223,340)	$ (223,340)	$ (252,016)	$ (257,768)	$ (254,919)	$ (252,063)	$ (249,176)	$ (246,304)	$ (241,586)	$ (125,490)	$ (57,413)	$ (27,920)	$ (19,602)	$ (26,165)	$ (223,340)
163	Forecast Bad Debt	ln 139		3,555	3,555	3,555	3,555	3,555	3,555	60,925	201,272	166,717	111,126	78,506	34,107	-	673,983
164	Projected Revenues with int.	ln 178 * ln 184		-	-	-	-	-	-	(14,652)	(82,124)	(96,099)	(81,019)	(69,088)	(41,748)	(20,021)	(404,751)
165	Projected Unbilled Revenue									(40,903)	(43,449)	(45,730)	(46,229)	(47,249)	(46,094)		(269,654)
166	Reverse Prior Month Unbilled										40,903	43,449	45,730	46,229	47,249	46,094	269,654
167	Bad Debt Billed	ln 145	-		-	-	-	-	-	-	-	-	-	-	-	-	0
168	Add Interest	ln 155		-	-	-	-	-	-	(652)	(510)	(259)	(116)	(79)	(76)	-	(1,693)
169	Add Net Adjustments	ln 147	-	(31,575)	(8,627)					-	-	-	-	-	-	-	(40,203)
170	Monthly (Over)/Under Recovery		$ (223,340)	$ (251,360)	$ (257,088)	$ (254,213)	$ (251,364)	$ (248,508)	$ (245,621)	$ (241,586)	$ (125,493)	$ (57,413)	$ (27,920)	$ (19,602)	$ (26,165)	$ (92)	$ 3,997
171																	
172	Average Monthly Balance			$ (237,350)	$ (254,552)	$ (255,990)	$ (253,142)	$ (250,285)	$ (247,399)	$ (243,945)	$ (183,540)	$ (91,451)	$ (42,667)	$ (23,761)	$ (22,883)	$ (13,128)	
173																	
174	Interest Applied	ln 153 * ln 172 / 365 * Days of Month		(655)	(680)	(707)	(699)	(669)	(683)	(652)	(507)	(259)	(116)	(79)	(76)	-	$ (5,781)
175																	
176	**(Over)/Under Balance**	-ln 168 +ln 170 + ln 174	$ (223,340)	$ (252,016)	$ (257,768)	$ (254,919)	$ (252,063)	$ (249,176)	$ (246,304)	$ (241,586)	$ (125,490)	$ (57,413)	$ (27,920)	$ (19,602)	$ (26,165)	$ (92)	$ (92)
177																	
178	Forecast Term Sales	ln 52								3,165,404	17,742,350	20,761,510	17,503,620	14,926,060	9,019,420	4,325,377	87,443,741
179	Unbilled Therm	ln 55								8,836,890	549,888	492,921	107,722	220,489	(249,614)		
180	Gross Unbilled									8,836,890	9,386,778	9,879,699	9,987,421	10,207,910	9,958,296		
181																	
182	COG Rate Without Interest	Sch. 3, pg. 4, ln 241 col. (c)								$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	$0.0047	
183																	
184	COG With Interest	Sch. 3, pg. 4, ln 241 col. (d)								$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	$0.0046	
187																	
188																	
189	**Total Interest**	lns 46 + 112 + 174	$ -	$ 2,252	$ 500	$ 523	$ 1,936	$ 3,245	$ 4,774	$ (475)	$ 5,766	$ 18,889	$ 13,700	$ 3,218	$ (10,244)	$ -	$ 44,085

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty** Updated Schedule 4
3 **Peak 2021 - 2022 Winter Cost of Gas Filing** Page 1 of 1
4 **Adjustments to Gas Costs**
5

Line	Adjustments		Prior Period Adjustments	Refunds from Suppliers	Broker Revenue	Inventory Finance Charges	Transportation CGA Revenues (Schedule 17)	Interruptible Sales Margin	Off System Sales Margin	Capacity Release	Net Option Premiums	Fixed Price Option Administrative Costs	Total Adjustments
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-20		$ -	$ -	$ -	$ -	$ -	$ -	[redacted]	[redacted]	$ -	$ -	$ -
10	Jun-20		-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
11	Jul-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
12	Aug-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
13	Sep-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
14	Oct-20	1/	-	-	-	-	-	-	[redacted]	[redacted]	-	-	-
15	Nov-20	1/	-	-	(47)	-	(1,032)	-	[redacted]	[redacted]	-	36,800	(243,108)
16	Dec-20	1/	-	-	(624)	-	(1,276)	-	[redacted]	[redacted]	-	-	(283,455)
17	Jan-21	1/	-	-	(751)	-	(1,436)	-	[redacted]	[redacted]	-	-	(283,617)
18	Feb-21	1/	-	-	(816)	-	(1,199)	-	[redacted]	[redacted]	-	-	(282,374)
19	Mar-21	1/	-	-	(757)	-	(1,145)	-	[redacted]	[redacted]	-	-	(279,025)
20	Apr-21	1/	-	-	(605)	-	(851)	-	[redacted]	[redacted]	-	-	(278,672)
21													
22	Subtotal May 20 - Oct 20		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23													
24	Subtotal Nov 20 - Apr 21		$ -	$ -	$ (3,600)	$ -	$ (6,938)	$ -	$ -	$ (1,676,512)	$ -	$ 36,800	$ (1,650,251)
25													
26	Total Peak Period		$ -	$ -	$ (3,600)	$ -	$ (6,938)	$ -	$ -	$ (1,676,512)	$ -	$ 36,800	$ (1,650,251)
27													

1/ Estimates are based on prior years actual, except transportation revenue is calculated on Schedule 17. and Inventory Finance Charges for Nov 20 - Apr 21 calculated on Schedule 16

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** — **REDACTED**
2 **d/b/a Liberty** — **Updated Schedule 5A**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing** — **Page 1 of 1**
4 **Demand Costs**

Ln	(a)	Peak (b)	Reference (c)	Deferred to Peak May 20 -Oct 20 (d)	Nov-21 (e)	Dec-21 (f)	Jan-22 (g)	Feb-22 (h)	Mar-22 (i)	Apr-22 (j)	Peak Nov-Apr Total (k)
10											
11	**Supply**										
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand & Reservation Charges										
14											
15	**Pipeline**										
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days								
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	peak	Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	peak	Sch 5B, ln 19 * Sch 5C ln 25 x days								
24	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	Portland Natural Gas Trans Service		Sch 5B, ln 21 * Sch 5C ln 30 x days								
26	Portland Natural Gas		Sch 5B, ln 22 * Sch 5C ln 31 x days								
27	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 23 * Sch 5C ln 32 x days								
28	TransCanada via Union to Portland		Sch 5B, ln 24 * Sch 5C ln 33 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32	National Fuel FST 2358	peak	Sch 5B, ln 28 * Sch 5C ln 40 x days								
33											
34	Subtotal Pipeline Demand Charges			$ 3,900,053	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 1,609,874	$ 13,559,298
35											
36	**Peaking Supply**										
37	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 31 * Sch 5C ln 28 x days	[redacted]							
38	Demand FLS	peak	Per Contract								
39	Constellation Demand	peak	Per Contract								
40	Subtotal Peaking Demand Charges			$ -	$ 823,800	$ 823,800	$ 823,800	$ 823,800	$ 823,800	$ -	$ 4,119,000
41											
42	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 34 + ln 40	$ 3,900,053	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 2,433,674	$ 1,609,874	$ 17,678,298
43											
44	Less Transportation Capacity Credit			$ (1,320,558)	$ (613,043)	$ (613,043)	$ (613,043)	$ (613,043)	$ (613,043)	$ (405,527)	$ (4,791,298)
45											
46	**Total Supply, Pipeline & Peaking Demand**			$ 2,579,495	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,820,632	$ 1,204,347	$ 12,887,000
47											
48											
49	Dominion - Demand	peak	Sch 5B, ln 36 * Sch 5C ln 64 x days	$ 10,488	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 20,977
50	Dominion - Storage	peak	Sch 5B, ln 37 * Sch 5C ln 65 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
51	Honeoye - Demand	peak	Sch 5B, ln 38 * Sch 5C ln 68 x days	50,105	8,351	8,351	8,351	8,351	8,351	8,351	100,211
52	National Fuel - Demand	peak	Sch 5B, ln 40 * Sch 5C ln 70 x days	96,318	16,053	16,053	16,053	16,053	16,053	16,053	192,636
53	National Fuel - Capacity	peak	Sch 5B, ln 41 * Sch 5C ln 71 x days	191,580	31,930	31,930	31,930	31,930	31,930	31,930	383,161
54	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 42 * Sch 5C ln 74 x days	171,615	28,603	28,603	28,603	28,603	28,603	28,603	343,230
55	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 43 * Sch 5C ln 75 x days	167,586	27,931	27,931	27,931	27,931	27,931	27,931	335,172
56											
57	**Subtotal Storage Demand Costs**			$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 1,393,257
58											
59	Less Transportation Capacity Credit			$ (235,878)	$ (29,247)	$ (29,247)	$ (29,247)	$ (29,247)	$ (29,247)	$ (29,247)	$ (411,359)
60											
61	**Total Storage Demand Costs**		ln 57 + ln 59	$ 460,750	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 86,858	$ 981,898
62											
63	**Total Demand Charges**		ln 42 + ln 57	$ 4,596,681	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 2,549,779	$ 1,725,979	$ 19,071,554
64											
65	Total Transportation Capacity Credit		ln 44 + ln 59	$ (1,556,436)	$ (642,289)	$ (642,289)	$ (642,289)	$ (642,289)	$ (642,289)	$ (434,774)	$ (5,202,657)
66											
67	**Total Demand Charges less Cap. Cr.**		ln 63 + ln 65	$ 3,040,245	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,907,490	$ 1,291,205	$ 13,868,897
68											
69											

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing
<u>Demand Volumes</u>

Updated Schedule 5B
Page 1 of 1

	Peak	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Supply								
Niagara Supply			-	-	-	-	-	-
Pipeline								
Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
Tenn Gas Pipeline	peak	42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
Tenn Gas Pipeline	peak	358905 FTA Z6-Z6	40,000	40,000	40,000	40,000	40,000	40,000
Tenn Gas Pipeline (Concord Lateral)	peak	Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
Portland Natural Gas Trans Service		FT-208544	1,000	1,000	1,000	1,000	1,000	1,000
Portland Natural Gas		FT 233320	5,000	5,000	5,000	5,000	5,000	5,000
ANE (TransCanada via Union to Iroquois)		Dawn - Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
TransCanada via Union to Portland		Dawn -Parkway to Portland	5,077	5,077	5,077	5,077	5,077	5,077
Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
National Fuel	peak	FST N02358	6,098	6,098	6,098	6,098	6,098	6,098
Peaking								
Tenn Gas Pipeline (Concord Lateral)	peak		-	-	-	-	-	-
Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	-
Peaking Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	-
Storage								
Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
National Fuel - Demand	peak	FSS-O02357	6,098	6,098	6,098	6,098	6,098	6,098
National Fuel - Capacity Reservation	peak	FSS-O02357	670,800	670,800	670,800	670,800	670,800	670,800
Tenn Gas Pipeline - Demand	peak	FS-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Liberty Utilities (EnergyNorth Natural Gas) Corp. | **REDACTED**
d/b/a Liberty | Updated Schedule 5C
Peak 2021 - 2022 Winter Cost of Gas Filing | Page 1 of 2
Demand Rates

				Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov - Apr
<u>Tariff Rates</u>				30	31	31	28	31	30	181
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
Supply										
Niagara Supply		[redacted]		[redacted]						
Pipeline										
Iroquois Gas Trans Service	RTS 470-01	$ 5.2357	Forth Revised Sheet No. 4	$ 0.1745	$ 0.1689	$ 0.1689	$ 0.1870	$ 0.1689	$ 0.1745	$ 0.1738
Tenn Gas Pipeline	95346 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
Tenn Gas Pipeline	2302 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
Tenn Gas Pipeline	8587 Z0-Z6	$ 20.3736	FT-A (Z0 - Z6)	$ 0.6791	$ 0.6572	$ 0.6572	$ 0.7276	$ 0.6572	$ 0.6791	$ 0.6763
Tenn Gas Pipeline	8587 Z1-Z6	$ 18.0875	FT-A (Z1 - Z6)	$ 0.6029	$ 0.5835	$ 0.5835	$ 0.6460	$ 0.5835	$ 0.6029	$ 0.6004
Tenn Gas Pipeline	8587 Z4-Z6	$ 7.1645	FT-A (Z4 - Z6)	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
TGP Dracut	42076 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
TGP Dracut	358905 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
TGP Concord Lateral	Firm Transportatio	$ 12.2113	Per contract	$ 0.4070	$ 0.3939	$ 0.3939	$ 0.4361	$ 0.3939	$ 0.4070	$ 0.4053
Portland Natural Gas	FT-208544	$ 18.2633	Negot Dmd /CMDY=Part 4.1 V7	$ 0.6088	$ 0.5891	$ 0.5891	$ 0.6523	$ 0.5891	$ 0.6088	$ 0.6062
Portland Natural Gas	FT 233320	$ 22.8125	Negot Dmd /CMDY=Part 4.1 V7	$ 0.7604	$ 0.7359	$ 0.7359	$ 0.8147	$ 0.7359	$ 0.7604	$ 0.7572
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$ 6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
National Fuel	FST N02358	$ 4.5274	4.010 Version 31.0.1 Pg 1	$ 0.1509	$ 0.1460	$ 0.1460	$ 0.1617	$ 0.1460	$ 0.1509	$ 0.1503

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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **REDACTED**
2 **d/b/a Liberty** Updated Schedule 5C
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**

43	ANE Union Gas		$ 3.6665								
44	TransCanada Pipelines Limited		$ 11.9842	Dawn - Parkway to Iroquois							
45	Delivery Pressure Demand Charge		$ 0.6083	Dawn - Parkway to Iroquois							
46	Sub Total Demand Charges		$ 16.2590								
47	Conversion rate GJ to MMBTU		$ 1.0551								
48	Conversion rate to US$		$ 1.2589	1/0/1900							
49	Demand Rate/US$		$ 13.6260		$ 0.4542	$ 0.4395	$ 0.4395	$ 0.4866	$ 0.4395	$ 0.4542	$ 0.4523
50											
51	Union Gas		$ 3.6665								
52	TransCanada Pipelines Limited		$ 20.4218	Dawn -Parkway to Portland							
53	Delivery Pressure Demand Charge		$ 0.6083	Dawn -Parkway to Portland							
54	Sub Total Demand Charges		$ 24.6966								
55	Conversion rate GJ to MMBTU		$ 1.0551								
56	Conversion rate to US$		$ 1.2589	1/0/1900							
57	Demand Rate/US$		$ 20.6972		$ 0.6899	$ 0.6677	$ 0.6677	$ 0.7392	$ 0.6677	$ 0.6899	$ 0.6870
58											
59	**Peaking**										
60	Demand FLS		[redacted]		[redacted]						
61	Subtotal Peaking Demand Charges										
62											
63	**Storage**										
64	Dominion - Demand	GSS 300076	$ 1.8716	GSS Settled,Tariff Rec #10.30 \	$ 0.0624	$ 0.0604	$ 0.0604	$ 0.0668	$ 0.0604	$ 0.0624	$ 0.0621
65	Dominion - Capacity	GSS 300076	$ 0.0145	GSS Settled,Tariff Rec #10.30 \	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005
66			$ 1.8861		$ 0.0629	$ 0.0608	$ 0.0608	$ 0.0674	$ 0.0608	$ 0.0629	$ 0.0626
67											
68	Honeoye - Demand	SS-NY	$ 6.1299	Sub 1st Rev Sheet No. 5	$ 0.2043	$ 0.1977	$ 0.1977	$ 0.2189	$ 0.1977	$ 0.2043	$ 0.2033
69											
70	National Fuel - Demand	FSS-O02357	$ 2.6325	4.020 Version 26.0.0 Pg 1	$ 0.0878	$ 0.0849	$ 0.0849	$ 0.0940	$ 0.0849	$ 0.0878	$ 0.0873
71	National Fuel - Capacity	FSS-O02357	$ 0.0476	4.020 Version 26.0.0 Pg 1	$ 0.0016	$ 0.0015	$ 0.0015	$ 0.0017	$ 0.0015	$ 0.0016	$ 0.0016
72			$ 2.6801		$ 0.0893	$ 0.0865	$ 0.0865	$ 0.0957	$ 0.0865	$ 0.0893	$ 0.0889
73											
74	Tenn Gas Pipeline	FS-MA 523	$ 1.3094	20th Rev Sheet No.61	$ 0.0436	$ 0.0422	$ 0.0422	$ 0.0468	$ 0.0422	$ 0.0436	$ 0.0434
75	Tenn Gas Pipeline - Space	FS-MA 523	$ 0.0179	20th Rev Sheet No.61	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006	$ 0.0006
76			$1.3273		$ 0.0442	$ 0.0428	$ 0.0428	$ 0.0474	$ 0.0428	$ 0.0442	$ 0.0440
77											
78					**THIS PAGE HAS BEEN REDACTED**						

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2021 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 16, 2021

The annual charges unit charge (ACA) to be applied to in fiscal year 2022 for recovery of FY 2021 Current year and 2020 True-Up is **$0.0012** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2021.

The following calculations were used to determine the FY 2021 unit charge:

2021 CURRENT:

Estimated Program Cost $73,470,000 divided by 61,333,716,267 Dth = 0.0011978730

2020 TRUE-UP:

Debit/Credit Cost ($1,115,938) divided by 60,594,054,316 Dth = (0.0000184166)

TOTAL UNIT CHARGE = 0.0011794564

If you have any questions, please contact Raven A. Rodriguez at (202)502-6276 or e-mail at Raven.Rodriguez@ferc.gov.

PUBLIC

APPLICABLE TO SETTLING PARTIES PURSUANT TO THE DECEMBER 6, 2013 STIPULATION
IN DOCKET NO. RP14-262

(FOR RATES APPLICABLE TO SEVERED PARTIES IN THE ABOVE REFERENCED DOCKETS SEE TARIFF RECORD 10.31)

RATES APPLICABLE TO RATE SCHEDULES IN
FERC GAS TARIFF, VOLUME NO. 1
($ per DT)

Rate chedule (1)	Rate Component (2)	Base Tariff Rate [1] (3)	Current Acct 858 Base (4)	Current EPCA Base (5)	TCRA [5] Surcharge (6)	EPCA [6] Surcharge (7)	Current Rate [7] (8)	FERC ACA (9)
[2], [4]								
	Storage Demand	$1.7984	$0.0673	$0.0073	($0.0022)	$0.0008	$1.8716	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	GSS-TE Surcharge [3]	-	$0.0047	-	$0.0006	-	$0.0053	-
	From Customers Balance	$0.6163	$0.0144	$0.0016	($0.0006)	($0.0005)	$0.6313	[8]
-E [2], [4]								
	Storage Demand	$2.2113	$0.0673	$0.0073	($0.0022)	$0.0008	$2.2845	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overruns	$1.0657	$0.0144	$0.0016	($0.0006)	($0.0005)	$1.0807	[8]
[2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0001)	$0.0000	$0.0759	-
	Injection Charge	$0.0154	-	$0.0120	$0.0000	($0.0007)	$0.0267	-
	Withdrawal Charge	$0.0154	-	-	$0.0000	($0.0007)	$0.0147	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0144	$0.0016	($0.0006)	($0.0005)	$0.6313	[8]
	Excess Injection Charge	$0.2245	-	$0.0120	$0.0000	($0.0007)	$0.2358	-

[1] The base tariff rate is the effective rate on file with the FERC, excluding adjustments approved by the Commission.
[2] Storage Service Fuel Retention Percentage is 1.67% plus Adders of 0.28% (RP00-632 S&A approved 9/13/01) totaling 1.95%.
[3] Applies to withdrawals made under Rate Schedule GSS, Section 5.1.G.
[4] Daily Capacity Release Rate for GSS per Dt is $0.6166. Daily Capacity Release Rate for GSS-E per Dt is $1.0660.
[5] 858 over/under from previous TCRA period.
[6] Electric over/under from previous EPCA period.
[7] The Current Rate shall be increased for the Annual Charge Adjustment (ACA) as applicable.
[8] The applicable ACA rate is set forth on the FERC website (https://www.ferc.gov/industries-data/natural-gas/overview/general-information/annual-charges).

Statement of Transportation Rates
(Rates per DTH)

Rate Schedule	Rate Component	Base Rate	ACA Unit Charge 1/
FT	Recourse Reservation Rate		
	-- Maximum	$25.9843	---------
	-- Minimum	$00.0000	---------
	Seasonal Recourse Reservation Rate		
	-- Maximum	$49.3701	---------
	-- Minimum	$00.0000	---------
	Recourse Usage Rate		
	-- Maximum	$00.0000	2/
	-- Minimum	$00.0000	2/
	-- PXP Project	$00.0091	
FT-FLEX	Recourse Reservation Rate		
	--Maximum	$17.4406	---------
	--Minimum	$00.0000	---------
	Recourse Usage Rate		
	--Maximum	$00.2809	2/
	--Minimum	$00.0000	2/

The following adjustment applies to all Rate Schedules above:

MEASUREMENT VARIANCE FACTOR-LAUF:

Minimum	down to -1.00%
Maximum	up to +1.00%

MEASUREMENT VARIANCE FACTOR-FUEL 3/

1/ ACA assessed where applicable under Section 154.402 of the Commission's regulations and will be charged pursuant to Section 6.18 of the General Terms and Conditions at such time that initial and successive ACA assessments are made.

2/ The currently effective ACA unit charge as published on the Commission's website (www.ferc.gov) is incorporated herein by reference.

SCHEDULE 1

Receipt Point:	01-0100 Pittsburg, NH
Delivery Point:	02-0260 Berlin, NH
Maximum Daily Quantity:	1000 Dth/day
Maximum Contract Demand:	5478000 Dth
Effective Service Period:	Beginning on the In-Service Date as defined in Article VII to this Contract and continuing in full force and effect until fifteen (15) years after such In-Service Date.

Rate Provision(s) (check if applicable rate):

__ ___ Discounted Rate

__X___Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

$18.2633/Dth/month ($0.6000/Dth/day)

Additional Terms: Shipper shall have the right to deliver, on a secondary basis, to the following meters, at the Negotiated Rate of $18.2633/Dth/month ($0.6000/Dth/day). Delivery to all other secondary delivery points on this Negotiated Rate contract shall be priced at the Maximum Recourse Rate.

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
02-0650	Gorham	Maine Natural Gas
05-0725	Eliot	Granite State
05-0750	Eliot CNG	XPress Natural Gas
02-0775	Newington	Essential Power
02-0900	Newington	Eversource Energy
05-0850	Newington	Granite State
05-1000	Haverhill	Tennessee Gas Pipeline
05-1025	Haverhill	National Grid
05-1050	Methuen	M&NE
05-1150	Dracut	Tennessee Gas Pipeline

Revision No. 2

SCHEDULE 1

Primary Receipt Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	10100	Pittsburg (East Hereford)	1,855 (Phase I Quantity) plus
				2,577 (Phase II Quantity) plus
				568 (Phase III Quantity)

Primary Delivery Points

Begin Date	End Date	Scheduling Point No.	Scheduling Point Name	Maximum Daily Quantity (Dth/day)
1/	1/	51150	Dracut	1,855 (Phase I Quantity) plus
				2,577 (Phase II Quantity) plus
				568 (Phase III Quantity)

Maximum Contract Demand	1,855 Dth (Phase I Quantity)
plus	2,577 Dth (Phase II Quantity)
plus	568 Dth (Phase III Quantity)
Total Maximum Contract Demand	5,000 Dth (Phase I, II and III Quantities)

Effective Service Period 1/ to 1/

Rate Provision(s) (check if applicable rate):

______ Discounted Rate
___X__ Negotiated Rate

Shipper's charges and fees shall be calculated as follows:

For volumes received at the primary receipt point and delivered to the primary delivery point, the reservation charge shall be $0.7500/Dth/day (the "Negotiated Daily Demand Rate").

CURRENTLY EFFECTIVE RATES

FIRM STORAGE SERVICE (FSS)*

	RATE	UNITS
1. Reservation Rate		
Deliverability Reservation Rate	Market Based/ Negotiable	
Capacity Reservation Rate	Market Based/ Negotiable	
2. Injection/Withdrawal Rates		
Injection Rate	Market Based/ Negotiable	
Overrun Injection Rate	Market Based/ Negotiable	
Late Withdrawal Rate	$1/Dth/Day	
Overrun Withdrawal Rate	Market Based/ Negotiable	

*All quantities of natural gas are measured in dekatherms (Dth)

View Contract

General Information

Customer	Contract Category	Contract Number	Service Type	Status	Currency
Energy North Natural Gas Inc.	**Storage**	**EN-11234**	FT	Active	USD
Deal Maker	Deal Date	Deal Time (hh:mm)	Master Agreement	Units	
Richard Norman	01/17/1988	08:00	-- None --	Dth	
Contact Name	Contact Number 1	Contact Number 2	Contact Email		
Sarah Finagan	603-2163569		sarah.finagan@libertyutilities.com		

Contract Dates

Effective Date (First Gas Day)
05/01/2010

Termination Date (Last Gas Day)
01/01/2050

Nomination Deadlines

Day Before Flow Deadline
(hh:mm 24-hr CCT)

Day of Flow Deadline
(hh:mm 24-hr CCT)

Transaction Types and Rates

Transaction Type	Allow Transaction Yes	Allow Transaction No	Allow Transaction O.E.R. Only	Use Hourly Profiles	Volumetric Charge ($/Dth)	Other Rate ($/Dth)	Fuel Percentage	Invoice Qty Type
Storage Injection					0	0	0	Sch Qty
Storage Withdrawal					0	0	0	Sch Qty
Authorized Injection Overrun					0	0	0	Sch Qty
Authorized Withdrawal Overrun					0	0	0	Sch Qty

Storage and Other Rates

Use Monthly Flat Storage Fee ($/Month)

Monthly Flat Storage Fee Table

From	To	Rate
05/01/10	01/01/50	8,350.89000

FERC Information

Capacity Release Contract: Yes No

Shipper Affiliation: NONE

Maximum Tariff Rate: 0 OR Market Based Rates

Award:

Negotiated Rate Indicator: Yes No

Rate Schedule: 167

Contract Quantity Limits

Monthly MSQ Table

From	To	Max Qty	Min Qty
05/01/10	01/01/50	245,280	0

Iroquois Gas Transmission System, L.P.
FERC Gas Tariff
Second Revised Volume No. 1

Fourth Revised Sheet No. 4
Superseding
Third Revised Sheet No. 4

---------- NON-EASTCHESTER RATES (All in $ Per Dth) 1/ ----------

	Minimum	RP16-301 Rates 2/ Maximum			RP19-445 Rates Maximum	
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018	Effective 3/1/2019	Effective 4/1/2020
RTS DEMAND (Monthly):						
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5997	$5.4177	$5.2357
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998	$4.6438	$4.4878
Inter-Zone	$0.0000	$10.4755	$ 9.8672	$ 8.8026	$8.5165	$8.2304
RTS COMMODITY (Daily):						
Zone 1	$0.0034	$ 0.0034	$ 0.0034	$ 0.0034	$0.0034	$0.0034
Zone 2	$0.0022	$ 0.0022	$ 0.0022	$ 0.0022	$0.0022	$0.0022
Inter-Zone	$0.0056	$ 0.0056	$ 0.0056	$ 0.0056	$0.0056	$0.0056
ITS COMMODITY (Daily):						
Zone 1	$0.0034	$ 0.2070	$ 0.2006	$ 0.1875	$0.1815	$0.1755
Zone 2	$0.0022	$ 0.1777	$ 0.1721	$ 0.1600	$0.1549	$0.1497
Inter-Zone	$0.0056	$ 0.3500	$ 0.3300	$ 0.2950	$0.2856	$0.2762
VOLUMETRIC CAPACITY RELEASE (Daily) 3/:						
Zone 1	$0.0000	$ 0.2036	$ 0.1972	$ 0.1841	$0.1781	$0.1721
Zone 2	$0.0000	$ 0.1755	$ 0.1699	$ 0.1578	$0.1527	$0.1475
Inter-Zone	$0.0000	$ 0.3444	$ 0.3244	$ 0.2894	$0.2800	$0.2706

**SEE SHEET NOS. 4A, 4B, AND 4C FOR ADJUSTMENTS TO RATES WHICH MAY BE APPLICABLE

(Footnotes continued on Sheet 4.01)

Issued On: June 12, 2019

Effective On: July 1, 2019

RATES FOR TRANSPORTATION SERVICES

Rate Sch. (1)	Rate Component 1/ (2)		Base Rate (3)	TSCA (4)	TSCA Surch. (5)	Current Rate 2/ (6)
FT/FT-S						
	Reservation	(Max)	$4.5019	-	-	$4.5019 4/
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0140	-	-	$0.0140 plus ACA 3/
		(Min)	0.0140	-	-	$0.0140 plus ACA 3/
	Overrun	(Max)	0.1620	-	-	$0.1620 plus ACA 3/
		(Min)	0.0140	-	-	$0.0140 plus ACA 3/
EFT	Reservation	(Max)	$4.6455	0.0000	0.0000	$4.6455 4/
		(Min)	0.0000	0.0000	0.0000	$0.0000
	Commodity	(Max)	0.0148	0.0000	0.0000	$0.0148 plus ACA 3/
		(Min)	0.0148	0.0000	0.0000	$0.0148 plus ACA 3/
	Overrun	(Max)	0.1675	-	-	$0.1675 plus ACA 3/
		(Min)	0.0148	-	-	$0.0148 plus ACA 3/
FST	Reservation	(Max)	$4.5019	-	-	$4.5019 4/
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0140	-	-	$0.0140 plus ACA 3/
		(Min)	0.0140	-	-	$0.0140 plus ACA 3/
	Overrun	(Max)	0.1620	-	-	$0.1620 plus ACA 3/
		(Min)	0.0140	-	-	$0.0140 plus ACA 3/
IT	Commodity	(Max)	$0.1620	-		$0.1620 plus ACA 3/
		(Min)	0.0000	-	-	$0.0000 plus ACA 3/
	Overrun	(Max)	0.1620	-		$0.1620 plus ACA 3/
		(Min)	0.0000	-	-	$0.0000 plus ACA 3/

The NA15 Retention is 1.11% applicable to use of the Northern Access 2015 Lease. 2/ 3/

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Transportation Fuel and Company Use Retention and Transportation LAUF Retention. The Transportation Fuel and Company Use Retention for all applicable rate schedules is 0.84% and the Transportation LAUF Retention for all applicable rate schedules is 0.53%. Transporter may from time to time identify point pair transactions where the Transportation Fuel and Company Use Retention shall be zero ("Zero Fuel Point Pair Transactions"). Zero Fuel Point Pair Transactions will be assessed the applicable Transportation LAUF Retention.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Pursuant to Section 42 of the General Terms and Conditions, a per Dth charge of $0.0255 shall be added as a Transmission PS/GHG Surcharge, in addition to the specified rate.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1] (2)		Rate [2] (3)
ESS	Demand	(Max)	$2.6433 [5]
		(Min)	$0.0000
	Capacity	(Max)	$0.0485 [6]
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0458 plus ACA [3]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4]	$3.8600
		(Min)[4]	$0.0000
ISS	Injection	(Max)	$1.1271 plus ACA [3]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4]	$3.8600
		(Min)[4]	$0.0000
FSS	Demand	(Max)	$2.5326 [5]
		(Min)	$0.0000
	Capacity	(Max)	$0.0462 [6]
		(Min)	$0.0000
	Injection/Withdrawal	(Max)	$0.0439 plus ACA [3]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[4]	$3.8600
		(Min)[4]	$0.0000

1/ The unit of measure for each rate component is Dth unless otherwise indicated.
2/ All rates exclusive of Storage Operating and LAUF Retention, where applicable. The Storage Operating and LAUF Retention for all applicable rate schedules is 1.06%.
3/ Pursuant to Section 19 of the General Terms and Conditions, the ACA unit charge, as revised annually and posted on the Commission's website, will be charged in addition to the specified rate.
4/ Rate per nomination.
5/ Pursuant to Section 42 of the General Terms and Conditions, a per Dth charge of $0.0999 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.
6/ Pursuant to Section 42 of the General Terms and Conditions, a per Dth charge of $0.0014 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Seventeenth Revised Sheet No. 14
Superseding
Sixteenth Revised Sheet No. 14

RATES PER DEKATHERM

FIRM TRANSPORTATION RATES
RATE SCHEDULE FOR FT-A

Base
Reservation Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.8571		$10.1498	$13.6529	$13.8945	$15.2673	$16.2055	$20.3323
L		$4.3119						
1	$7.3119		$7.0090	$9.3276	$13.2135	$13.0132	$14.6759	$18.0462
2	$13.6530		$9.2716	$4.8222	$4.5078	$5.7679	$7.9331	$10.2407
3	$13.8945		$7.3440	$4.8611	$3.5070	$5.3870	$9.7428	$11.2581
4	$17.6413		$16.2638	$6.1979	$9.4190	$4.6105	$4.9861	$7.1232
5	$21.0347		$14.7807	$6.5015	$7.8669	$5.1218	$4.8044	$6.2544
6	$24.3333		$16.9768	$11.6840	$12.8717	$9.0920	$4.7831	$4.1405

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1597		$0.3337	$0.4489	$0.4568	$0.5019	$0.5328	$0.6685
L		$0.1418						
1	$0.2404		$0.2304	$0.3067	$0.4344	$0.4278	$0.4825	$0.5933
2	$0.4489		$0.3048	$0.1585	$0.1482	$0.1896	$0.2608	$0.3367
3	$0.4568		$0.2414	$0.1598	$0.1153	$0.1771	$0.3203	$0.3701
4	$0.5800		$0.5347	$0.2038	$0.3097	$0.1516	$0.1639	$0.2342
5	$0.6916		$0.4859	$0.2137	$0.2586	$0.1684	$0.1580	$0.2056
6	$0.8000		$0.5581	$0.3841	$0.4232	$0.2989	$0.1573	$0.1361

Maximum Reservation
Rates 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$4.8984		$10.1911	$13.6942	$13.9358	$15.3086	$16.2468	$20.3736
L		$4.3532						
1	$7.3532		$7.0503	$9.3689	$13.2548	$13.0545	$14.7172	$18.0875
2	$13.6943		$9.3129	$4.8635	$4.5491	$5.8092	$7.9744	$10.2820
3	$13.9358		$7.3853	$4.9024	$3.5483	$5.4283	$9.7841	$11.2994
4	$17.6826		$16.3051	$6.2392	$9.4603	$4.6518	$5.0274	$7.1645
5	$21.0760		$14.8220	$6.5428	$7.9082	$5.1631	$4.8457	$6.2957
6	$24.3746		$17.0181	$11.7253	$12.9130	$9.1333	$4.8244	$4.1818

Notes:

1/ Applicable to demand charge credits and secondary points under discounted rate agreements.
2/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0413.

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Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twenty Sixth Revised Sheet No. 19
Superseding
Twenty Fifth Revised Sheet No. 19

FIRM TRANSPORTATION RATES
RATE SCHEDULE FT-A

Recourse Rates Applicable to Shippers Utilizing Capacity
Pursuant to Incremental Capacity Expansions

	Base Tariff Rate	Total Rate
CP00-65 300 Line Expansion		
Reservation Charge:		
Maximum	$3.2691	$3.3104 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/
Minimum	$0.0000	$0.0000 2/,3/
CP05-355 Northeast ConneXion - New York/New Jersey Expansion		
Reservation Charge:		
Maximum	$9.1876	$9.2289 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/
Minimum	$0.0000	$0.0000 2/,3/
CP08-65 Concord Expansion		
Reservation Charge:		
Maximum	$10.8352	$10.8765 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/
Minimum	$0.0000	$0.0000 2/,3/
CP09-444 300 Line Project – Market Component		
Reservation Charge:		
Maximum	$22.9057	$22.9470 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/
Minimum	$0.0000	$0.0000 2/,3/
CP11-30-000 Northeast Supply Diversification Project		
Reservation Charge:		
Maximum	$5.5453	$5.5866 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/,5/
Minimum	$0.0000	$0.0000 2/,3/,5/
CP11-36-000 Northampton Expansion Project		
Reservation Charge:		
Maximum	$24.7109	$24.7522 1/,4/
Minimum	$0.0000	$0.0000
Commodity Charge:		
Maximum	$0.0000	$0.0016 2/,3/,4/
Minimum	$0.0000	$0.0000 2/,3/

Notes:
1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.0000.
2/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
3/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
4/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0413 Reservation, $0.0016 Commodity.
5/ Applicable fuel and lost and unaccounted for charges pursuant to the Dominion Lease.

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Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Seventeenth Revised Sheet No. 15
Superseding
Sixteenth Revised Sheet No. 15

RATES PER DEKATHERM

COMMODITY RATES
RATE SCHEDULE FOR FT-A

Base
Commodity Rates

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.2391	$0.2282	$0.2716
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2033	$0.2073	$0.2367
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0658	$0.1055	$0.1169
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0879	$0.1217	$0.1329
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0407	$0.0576	$0.0932
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0573	$0.0567	$0.0705
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0881	$0.0478	$0.0290

Minimum
Commodity Rates 1/, 2/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0032		$0.0115	$0.0177	$0.0219	$0.0250	$0.0284	$0.0346
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.0210	$0.0256	$0.0300
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0056	$0.0100	$0.0143
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0081	$0.0118	$0.0163
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0028	$0.0046	$0.0092
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0046	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0086	$0.0041	$0.0020

Maximum
Commodity Rates 1/, 2/, 3/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0039		$0.0122	$0.0184	$0.0226	$0.2398	$0.2289	$0.2723
L		$0.0019						
1	$0.0049		$0.0088	$0.0154	$0.0186	$0.2040	$0.2080	$0.2374
2	$0.0174		$0.0094	$0.0019	$0.0035	$0.0665	$0.1062	$0.1176
3	$0.0214		$0.0176	$0.0033	$0.0009	$0.0886	$0.1224	$0.1336
4	$0.0257		$0.0212	$0.0094	$0.0112	$0.0414	$0.0583	$0.0939
5	$0.0291		$0.0263	$0.0107	$0.0125	$0.0580	$0.0574	$0.0712
6	$0.0353		$0.0307	$0.0150	$0.0170	$0.0888	$0.0485	$0.0297

Notes:

1/ Rates stated above exclude the ACA Surcharge as revised annually and posted on the FERC website at http://www.ferc.gov on the Annual Charges page of the Natural Gas section. The ACA Surcharge is incorporated by reference into Transporter's Tariff and shall apply to all transportation under this Rate Schedule as provided in Article XXIV of the General Terms and Conditions.
2/ The applicable F&LR's and EPCR's, determined pursuant to Article XXXVII of the General Terms and Conditions, are listed on Sheet No. 32.
3/ Includes a per Dth charge for the PS/GHG Surcharge Adjustment per Article XXXVIII of the General Terms and Conditions of $0.0007.

Tennessee Gas Pipeline Company, L.L.C.
FERC NGA Gas Tariff
Sixth Revised Volume No. 1

Twentieth Revised Sheet No. 61
Superseding
Nineteenth Revised Sheet No. 61

RATES PER DEKATHERM

FIRM STORAGE SERVICE
RATE SCHEDULE FS

Rate Schedule and Rate	Base Tariff Rate	Max Tariff Rate	F&LR 2/, 3/	EPCR 2/
FIRM STORAGE SERVICE (FS) - PRODUCTION AREA				
Deliverability Rate	$1.7824	$1.7824 1/		
Space Rate	$0.0181	$0.0181 1/		
Injection Rate	$0.0073	$0.0073	1.62%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2139	$0.2139 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.3094	$1.3094 1/		
Space Rate	$0.0179	$0.0179 1/		
Injection Rate	$0.0087	$0.0087	1.62%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1572	$0.1572 1/		

Notes:

1/ Includes a per Dth charge for the PCB Surcharge Adjustment per Article XXXII of the General Terms and Conditions of $0.000.
2/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
3/ The applicable F&LR pursuant to Article XXXVII of the General Terms and Conditions, associated with Losses is equal to 0.03%.

Issued: March 1, 2021
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Accepted: March 31, 2021

FUEL AND EPCR

F&LR 1/, 2/, 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.43%		1.54%	2.34%	2.97%	3.59%	4.08%	4.66%
L		0.16%						
1	0.56%		1.09%	1.96%	2.43%	2.92%	3.55%	4.06%
2	2.40%		1.17%	0.15%	0.38%	0.79%	1.44%	1.96%
3	2.97%		2.37%	0.38%	0.03%	1.14%	1.67%	2.26%
4	3.46%		2.71%	1.16%	1.40%	0.40%	0.66%	1.22%
5	4.08%		3.55%	1.42%	1.67%	0.66%	0.65%	0.86%
6	4.88%		4.06%	1.96%	2.26%	1.14%	0.50%	0.20%

Broad Run Expansion Project – Market Component (23-21): 5/ 7.62%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0021		$0.0081	$0.0125	$0.0155	$0.0188	$0.0214	$0.0256
L		$0.0007						
1	$0.0028		$0.0057	$0.0104	$0.0127	$0.0157	$0.0193	$0.0221
2	$0.0125		$0.0061	$0.0007	$0.0018	$0.0041	$0.0074	$0.0102
3	$0.0155		$0.0127	$0.0018	$0.0000	$0.0060	$0.0088	$0.0118
4	$0.0188		$0.0145	$0.0060	$0.0074	$0.0019	$0.0034	$0.0063
5	$0.0214		$0.0193	$0.0074	$0.0088	$0.0033	$0.0033	$0.0044
6	$0.0256		$0.0221	$0.0102	$0.0118	$0.0059	$0.0025	$0.0009

Broad Run Expansion Project – Market Component (23-21): 5/ $0.0272

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.
2/ For service that is rendered entirely by displacement and for gas scheduled and allocated for receipt at the Dracut, Massachusetts receipt point, Shipper shall render only the quantity of gas associated with Losses of 0.00%.
3/ The F&LR's and EPCR's listed above are applicable to FT-A, FT-BH, FT-G, FT-GS, and IT.
4/ The F&LR's and EPCR's determined pursuant to Article XXXVII of the General Terms and Conditions.
5/ The incremental F&LR and EPCR set forth above are applicable to a Shipper(s) utilizing capacity on the Broad Run Expansion Project – Market Component facilities, from any receipt point(s) to any delivery point(s) located on the project's transportation path. Any service provided to a Shipper(s) outside the project's transportation path shall be subject to the greater of the incremental F&LR and EPCR for the project or the applicable F&LR and EPCR for the applicable receipt(s) and delivery point(s) as shown in the rate matrices above. Included in the above F&LR is the Losses component of the F&LR equal to 0.00%.

Effective
2021-07-01
Rate M12
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ENBRIDGE GAS INC.
UNION SOUTH
TRANSPORTATION RATES

(A) Applicability

The charges under this schedule shall be applicable to a Shipper who enters into a Transportation Service Contract with Union.

Applicable Points
Dawn as a receipt point: Dawn (TCPL), Dawn (Facilities), Dawn (Tecumseh), Dawn (Vector) and Dawn (TSLE).
Dawn as a delivery point: Dawn (Facilities).

(B) Services

Transportation Service under this rate schedule shall be for transportation on Union's Dawn - Parkway facilities.

(C) Rates

The identified rates represent maximum prices for service. These rates may change periodically.
Multi-year prices may also be negotiated, which may be higher than the identified rates.

	Monthly Demand Charges (applied to daily contract demand) Rate/GJ	Fuel and Commodity Charges			
		Union Supplied Fuel	Shipper Supplied Fuel		
		Fuel and Commodity Charge Rate/GJ	Fuel Ratio %	AND	Commodity Charge Rate/GJ
Firm Transportation (1), (5)					
Dawn to Parkway	$3.665	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall	$3.110				
Kirkwall to Parkway	$0.555				
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.530	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Limited Firm/Interruptible Transportation (1)					
Dawn to Parkway – Maximum	$8.796	Monthly fuel and commodity rates shall be in accordance with schedule "C".	Monthly fuel ratios shall be in accordance with schedule "C".		
Dawn to Kirkwall – Maximum	$8.796				
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.165%		
Carbon Charge (applied to all quantities transported)					
Facility Carbon Charge		$0.003			$0.003

North Bay Junction Long Term Fixed Price (NBJ LTFP) Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
1	NBJ LTFP	28.28750	0.9300
2	NBJ LTFP Differential Surcharge	0.00000	0.0000

Note: The toll for NBJ LTFP is inclusive of the applicable Abandonment Surcharge for FT service from Empress to North Bay Junction. The NBJ LTFP Differential Surcharge is zero provided the Abandonment Surcharge for FT service from Empress to North Bay Junction is equal or less than $6.69167/GJ/Month.

Enhanced Market Balancing Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
3	Union Parkway Belt to Union EDA	9.92374	0.3262	0.44408	0.0146

Delivery Pressure

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
4	Average Delivery Pressure Toll	0.60833	0.0200

Note: Delivery Pressure toll applies to the following locations: Emerson 1 , Emerson 2, Union SWDA, Enbridge SWDA, Dawn Export, Niagara Falls, Iroquois, Chippawa and East Hereford. The Daily Equivalent Toll is only applicable to STS Injections, IT, Diversions and STFT.

Union Dawn Receipt Point Surcharge

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
5	Union Dawn Receipt Point Surcharge	0.13135	0.0043

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
6	SNB Toll	2.97597	0.0978

Note: This SNB Toll is a representative toll for the Eastern Region.

Energy Deficient Gas Allowance (EDGA) Service

Line No.	Particulars	Capacity Charge ($/GJ/D)
	(a)	(b)
7	Western Section	0.9982
8	Eastern Section	0.3302

Note: The EDGA Service capacity charge for the Western Section is the effective Empress to North Bay Junction FT Toll and the capacity charge for the Eastern Section is the effective Parkway to North Bay Junction FT Toll. The EDGA Service fuel charge for the Western Section includes the effective Empress to North Bay Junction monthly fuel ratio and the fuel charge for the Eastern Section includes the effective Parkway to North Bay Junction monthly fuel ratio.

Line No.	Receipt Point	Delivery Point	FT Toll ($/GJ/Month)	Daily Equivalent FT for IT / STFT ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
1	Union NDA	Enbridge CDA	-	0.4489	-	0.0220
2	Union NDA	Enbridge Parkway CDA	-	0.4544	-	0.0223
3	Union NDA	Enbridge EDA	-	0.4776	-	0.0239
4	Union NDA	KPUC EDA	-	0.5755	-	0.0307
5	Union NDA	Energir EDA	-	0.6356	-	0.0348
6	Union NDA	Enbridge SWDA	-	0.6022	-	0.0325
7	Union NDA	Union SWDA	-	0.6036	-	0.0326
8	Union NDA	Chippawa	-	0.5424	-	0.0284
9	Union NDA	Cornwall	-	0.5231	-	0.0271
10	Union NDA	East Hereford	-	0.7551	-	0.0430
11	Union NDA	Emerson 1	-	0.6495	-	0.0724
12	Union NDA	Emerson 2	-	0.6495	-	0.0724
13	Union NDA	Iroquois	-	0.5015	-	0.0256
14	Union NDA	Kirkwall	-	0.4793	-	0.0240
15	Union NDA	Napierville	-	0.6232	-	0.0339
16	Union NDA	Niagara Falls	-	0.5408	-	0.0283
17	Union NDA	North Bay Junction	-	0.1249	-	0.0063
18	Union NDA	Philipsburg	-	0.6346	-	0.0347
19	Union NDA	Spruce	-	0.5990	-	0.0660
20	Union NDA	St. Clair	-	0.6177	-	0.0336
21	Union NDA	Welwyn	-	0.7378	-	0.0835
22	Union NDA	Dawn Export	-	0.6022	-	0.0325
23	Union Parkway Belt	Empress	38.33717	1.2604	3.89029	0.1279
24	Union Parkway Belt	TransGas SSDA	34.49250	1.1340	3.40667	0.1120
25	Union Parkway Belt	Centram SSDA	31.72763	1.0431	3.05688	0.1005
26	Union Parkway Belt	Centram MDA	29.00533	0.9536	2.71621	0.0893
27	Union Parkway Belt	Centrat MDA	29.57717	0.9724	2.66450	0.0876
28	Union Parkway Belt	Union WDA	24.64054	0.8101	2.04096	0.0671
29	Union Parkway Belt	Nipigon WDA	22.51748	0.7403	1.77329	0.0583
30	Union Parkway Belt	Union NDA	13.82133	0.4544	0.67829	0.0223
31	Union Parkway Belt	Calstock NDA	18.94350	0.6228	1.32313	0.0435
32	Union Parkway Belt	Tunis NDA	16.12996	0.5303	0.97029	0.0319
33	Union Parkway Belt	Energir NDA	13.74529	0.4519	0.66917	0.0220
34	Union Parkway Belt	Union SSMDA	16.67746	0.5483	1.16192	0.0382
35	Union Parkway Belt	Union NCDA	6.64604	0.2185	0.27983	0.0092
36	Union Parkway Belt	Union CDA	4.16100	0.1368	0.10950	0.0036
37	Union Parkway Belt	Union ECDA	3.47358	0.1142	0.06388	0.0021
38	Union Parkway Belt	Union EDA	9.02158	0.2966	0.44408	0.0146
39	Union Parkway Belt	Union Parkway Belt	2.92000	0.0960	0.02433	0.0008
40	Union Parkway Belt	Enbridge CDA	4.55946	0.1499	0.13688	0.0045
41	Union Parkway Belt	Enbridge Parkway CDA	2.92000	0.0960	0.02433	0.0008
42	Union Parkway Belt	Enbridge EDA	12.02067	0.3952	0.65092	0.0214
43	Union Parkway Belt	KPUC EDA	8.94250	0.2940	0.43800	0.0144
44	Union Parkway Belt	Energir EDA	15.63721	0.5141	0.89729	0.0295
45	Union Parkway Belt	Enbridge SWDA	7.41558	0.2438	0.33458	0.0110
46	Union Parkway Belt	Union SWDA	7.45817	0.2452	0.33763	0.0111
47	Union Parkway Belt	Chippawa	5.59667	0.1840	0.20683	0.0068
48	Union Parkway Belt	Cornwall	12.21838	0.4017	0.66308	0.0218
49	Union Parkway Belt	East Hereford	19.27504	0.6337	1.14671	0.0377
50	Union Parkway Belt	Emerson 1	27.28071	0.8969	2.49721	0.0821
51	Union Parkway Belt	Emerson 2	27.28071	0.8969	2.49721	0.0821
52	Union Parkway Belt	Iroquois	11.37888	0.3741	0.60529	0.0199
53	Union Parkway Belt	Kirkwall	3.67738	0.1209	0.07604	0.0025
54	Union Parkway Belt	Napierville	15.26004	0.5017	0.87296	0.0287
55	Union Parkway Belt	Niagara Falls	5.55104	0.1825	0.20379	0.0067
56	Union Parkway Belt	North Bay Junction	10.04358	0.3302	0.51404	0.0169
57	Union Parkway Belt	Philipsburg	15.60679	0.5131	0.89729	0.0295
58	Union Parkway Belt	Spruce	29.57717	0.9724	2.66450	0.0876
59	Union Parkway Belt	St. Clair	7.88704	0.2593	0.36500	0.0120
60	Union Parkway Belt	Welwyn	31.72763	1.0431	3.05688	0.1005
61	Union Parkway Belt	Dawn Export	7.41558	0.2438	0.33458	0.0110
62	Union SSMDA	Empress	-	0.8516	-	0.0979
63	Union SSMDA	TransGas SSDA	-	0.7252	-	0.0819
64	Union SSMDA	Centram SSDA	-	0.6344	-	0.0705
65	Union SSMDA	Centram MDA	-	0.5448	-	0.0592
66	Union SSMDA	Centrat MDA	-	0.5385	-	0.0584
67	Union SSMDA	Union WDA	-	0.7145	-	0.0806
68	Union SSMDA	Nipigon WDA	-	1.0474	-	0.0877
69	Union SSMDA	Union NDA	-	0.8256	-	0.0597

Line		Reference							
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 1 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 66 * ln 107	[redacted]						
13	Niagara Supply	ln 67 * ln 112							
14	TGP Supply (Direct)	ln 68 * ln 132							
15	Dracut Supply 1 - Baseload	ln 69 * ln 117							
16	Dracut Supply 2 - Swing	ln 70 * ln 122							
17	Dracut Supply 3 - Swing	ln 71 * ln 123							
18	Constellation COMBO	ln 72 * ln 138							
19	LNG Truck	ln 73 * ln 140							
20	Propane Truck	ln 74 * ln 142							
21	PNGTS	ln 75 * ln 147							
22	Portland Natural Gas	ln 76 * ln 152							
23	TGP Supply (Z4)	ln 77 * ln 157							
24									
25	Subtotal Pipeline Gas Costs		$ 6,488,894	$ 25,785,739	$ 19,058,558	$ 11,866,845	$ 7,408,521	$ 3,274,803	$ 73,883,360
26									
27	**Volumetric Transportation Costs**								
28	Dawn Supply	ln 66 * ln 204	[redacted]						
29	Niagara Supply	ln 67 * ln 215							
30	TGP Supply (Direct)	ln 68 * ln 242							
31	Dracut Supply 1 - Baseload	ln 69 * ln 263							
32	Dracut Supply 2 - Swing	ln 70 * ln 263							
33	Dracut Supply 3 - Swing	ln 71 * ln 264							
34	Constellation COMBO	ln 72 * ln 263							
35	TGP Storage - Withdrawals	ln 82 * ln 179							
36									
37	**Total Volumetric Transportation Costs**		$ 288,190	$ 216,647	$ 275,048	$ 239,882	$ 238,945	$ 59,504	$ 1,318,217
38									
39	**Less - Gas Refill:**								
40	LNG Truck	ln 91 * ln 164	[redacted]						
41	Propane	ln 92 * ln 165							
42	TGP Storage Refill	ln 93 * ln 130							
43	Storage Refill (Trans.)	ln 93 * ln 242							
44									
45	Subtotal Refills		$ (1,077,566)	$ (15,566)	$ (37,152)	$ (1,041,646)	$ (244,164)	$ (434,450)	$ (2,850,544)
46									
47	**Total Supply & Pipeline Commodity Costs**	ln 25 + ln 37 + ln 45	$ 5,699,518	$ 25,986,820	$ 19,296,454	$ 11,065,081	$ 7,403,303	$ 2,899,858	$ 72,351,034
48									
49	**Storage Gas:**								
50	TGP Storage - Withdrawals	ln 82 * ln 171	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423	$ 6,130,435
51									
52	**Produced Gas:**								
53	LNG Vapor	ln 85 * ln 159	[redacted]						
54	Propane	ln 86 * ln 161							
55									
56	**Total Produced Gas**	ln 53 + ln 54	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685	$ 2,299,384
57									
58									
59	**Total Commodity Gas & Trans. Costs**	ln 47 + ln 50 + ln 56	$ 6,552,919	$ 26,541,893	$ 21,616,721	$ 13,693,357	$ 9,043,998	$ 3,331,966	$ 80,780,853
60									$ 94,216,591
61					**THIS PAGE HAS BEEN REDACTED**				

Line	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 2 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
62									
63	**Volumes (Therms)**								
64									
65	**Pipeline Gas:**	See Schedule 11A							
66	Dawn Supply		876,821	926,304	927,705	840,605	911,138	750,758	5,233,331
67	Niagara Supply		691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
68	TGP Supply (Direct)		4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346	17,283,547
69	Dracut Supply 1 - Baseload		-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
70	Dracut Supply 2 - Swing		1,775,785	5,569,137	771,324	-	969,754	79,714	9,165,713
71	Dracut Supply 3 - Swing		-	596,455	290,490	-	1,484	-	888,430
72	Constellation COMBO		89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
73	LNG Truck		20,666	21,875	51,371	291,824	362,081	-	747,817
74	Propane Truck		-	-	-	695,072	-	-	695,072
75	PNGTS		219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
76	Portland Natural Gas		1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355	6,284,969
77	TGP Supply (Z4)		1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
78									
79	Subtotal Pipeline Volumes		11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749	75,575,334
80									
81	**Storage Gas:**								
82	TGP Storage		2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
83									
84	**Produced Gas:**								
85	LNG Vapor		21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
86	Propane		-	-	244,014	574,010	-	-	818,023
87									
88	Subtotal Produced Gas		21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
89									
90	**Less - Gas Refill:**								
91	LNG Truck		(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-	(747,817)
92	Propane		-	-	-	(695,072)	-	-	(695,072)
93	TGP Storage Refill		(1,750,690)	-	-	-	-	(961,638)	(2,712,328)
94									
95	Subtotal Refills		(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
96									
97	**Total Sendout Volumes**		12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591
98									
99									
100									

Line	Description	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 3 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
101	**Gas Costs and Volumetric Transportation Rates**								
102									
103	**Pipeline Gas:**								
104	**Dawn Supply**								Average Rate
105	NYMEX Price	Sch 7, ln 10/10	[redacted]						
106	Basis Differential								
107	**Net Commodity Costs**								
108									
109	**Niagara Supply**								
110	NYMEX Price	Sch 7, ln 10/10	[redacted]						
111	Basis Differential								
112	**Net Commodity Costs**								
113									
114	**Dracut Supply 1 - Baseload**								
115	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
116	Basis Differential								
117	**Net Commodity Costs**								
118									
119	**Dracut Supply 2 - Swing**								
120	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
121	Basis Differential								
122	**Net Commodity Costs**								
123									
124	**Dracut Supply 3 - Swing**								
125	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
126	Basis Differential								
127	**Net Commodity Costs**								
128									
129	**TGP Supply (Direct)**								
130	NYMEX Price	Sch 7, ln 10/10	[redacted]						
131	Basis Differential								
132	**Net Commodity Costs**								
133									
134									
135	**Constellation COMBO**								
136	NYMEX Price	Sch 7, ln 10/10	[redacted]						
137	Basis Differential								
138	**Net Commodity Costs**								
139									
140	**LNG Truck**	Sch 7, ln 10/10	[redacted]						
141									
142	**Propane Truck**	Propane WACOG	[redacted]						
143									
144	**PNGTS**								
145	NYMEX Price	Sch 7, ln 10/10	[redacted]						
146	Basis Differential								
147	**Net Commodity Cost**								
148									
149	**PNGTS EXP**								
150	NYMEX Price	Sch 7, ln 10/10	[redacted]						
151	Basis Differential								
152	**Net Commodity Cost**								
153									
154	**TGP Supply (Z4)**								
155	NYMEX Price	Sch 7, ln 10/10	[redacted]						
156	Basis Differential								
157	**Net Commodity Cost**								
158									
159	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	[redacted]						
160									
161	**Propane**	Sch 16, ln 66 /10	[redacted]						
162									
163	**Storage Refill:**								
164	**LNG Truck**	ln 140	[redacted]						
165	**Propane**	ln 142							
166									
167					**THIS PAGE HAS BEEN REDACTED**				

Ln									
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 4 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
168									
169									
170	**TGP Storage**								
171	**Commodity Costs - Storage withdrawal**	Sch 16, ln 34 /10	$0.3046	$0.3046	$0.3046	$0.3046	$0.3046	$0.3361	$0.3098
172									
173	TGP - Max Commodity - Z 4-6	19th Rev Sheet No. 15	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928
174	TGP - Max Comm. ACA Rate - Z 4-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
175	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.00940	$0.00940	$0.00940	$0.00940	$0.00940	$0.00940	$0.00940
176	TGP - Fuel Charge % - Z 4-6	17th Rev Sheet No. 32	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
177	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00372	$0.00372	$0.00372	$0.00372	$0.00372	$0.00410	$0.00378
178	TGP - Withdrawal Charge	20th Rev Sheet No.61	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087
179	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.01399	$0.01399	$0.01399	$0.01399	$0.01399	$0.01437	$0.01405
180									
181	**Total TGP - Comm. & Vol. Trans. Rate**	ln 171 + ln 179	**$0.31856**	**$0.31856**	**$0.31856**	**$0.31856**	**$0.31856**	**$0.35044**	**$0.32387**
182									
183									
184	**Per Unit Volumetric Transportation Rates**								
185	**Dawn Supply Volumetric Transportation Charge**								
186	**Commodity Costs**	ln 107	**$0.5418**	**$0.5718**	**$0.5844**	**$0.5888**	**$0.5587**	**$0.3978**	**$0.5405**
187									
188	TransCanada - Commodity Rate/GJ	Dawn - Parkway to Iroquois	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
189	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
190	Conversion Rate to US$	1/0/1900	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589
191	Commodity Rate/US$	ln 188 x ln 189 x ln 190	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040
192	TransCanada Fuel %	Dawn - Parkway to Iroquois	0.97%	0.95%	1.20%	1.09%	0.97%	0.78%	0.99%
193	TransCanada Fuel * Percentage	ln 186 x ln 192	$0.00524	$0.00545	$0.00702	$0.00639	$0.00540	$0.00311	$0.00544
194	Subtotal TransCanada		**$0.00564**	**$0.00585**	**$0.00742**	**$0.00679**	**$0.00580**	**$0.00351**	**$0.00583**
195	IGTS - Z1 RTS Commodity	Forth Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
196	IGTS - Z1 RTS ACA Rate Commodity	Forth Revised Sheet No. 4	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
197	IGTS - Z1 RTS Deferred Asset Surcharge	Forth Revised Sheet No. 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
198	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**
199	TGP NET-NE - Comm. Segments 3 & 4	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
200	IGTS -Fuel Use Factor - Percentage	Forth Revised Sheet No. 4	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
201	IGTS -Fuel Use Factor - Fuel * Percentage	ln 186 x ln 200	**$0.00542**	**$0.00572**	**$0.00584**	**$0.00589**	**$0.00559**	**$0.00398**	**$0.00541**
202	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
203	TGP FTA Fuel * Percentage	ln 186 x ln 202	**$0.00466**	**$0.00492**	**$0.00503**	**$0.00506**	**$0.00480**	**$0.00342**	**$0.00465**
204	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01630**	**$0.01706**	**$0.01887**	**$0.01832**	**$0.01677**	**$0.01149**	**$0.01647**
205									
206									
207	**Niagara Supply Volumetric Transportation Charge**								
208	**Commodity Costs**	Ln 112	[redacted]						
209									
210	TGP FTA - FTA Z 5-6 Comm. Rate	19th Rev Sheet No. 15	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705
211	TGP FTA - FTA Z 5-6 - ACA Rate	19th Rev Sheet No. 15	$0.00012	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
212	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00717**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**
213	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
214	TGP FTA Fuel * Percentage	ln 208 x ln 213	[redacted]						
215	**Total Volumetric Transportation Rate - Niagara Supply**								
216									
217					**THIS PAGE HAS BEEN REDACTED**				

Ln		Reference							
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty**								Updated Schedule 6
3	**Peak 2021 - 2022 Winter Cost of Gas Filing**								Page 5 of 5
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
218									
219									
220									
221	**TGP Direct Volumetric Transportation Charge**								Average Rate
222	**Commodity Costs**	Ln 130	[redacted]						
223									
224	TGP - Max Comm. Base Rate - Z 0-6	19th Rev Sheet No. 15	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672
225	TGP - Max Commodity ACA Rate - Z 0-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
226	Subtotal TGP - Max Comm. Rate Z 0-6		$0.02684	$0.02684	$0.02684	$0.02684	$0.02684	$0.02684	$0.02684
227	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
228	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**
229	TGP - Max Comm. Base Rate - Z 1-6	19th Rev Sheet No. 15	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331
230	TGP - Max Commodity ACA Rate - Z 1-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
231	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02343	$0.02343	$0.02343	$0.02343	$0.02343	$0.02343	$0.02343
232	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
233	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**
234	TGP - Fuel Charge % - Z 0 -6	17th Rev Sheet No. 32	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%
235	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
236	Prorated TGP Fuel Charge % - Z 0-6		1.52%	1.52%	1.52%	1.52%	1.52%	1.52%	1.52%
237	TGP - Fuel Charge % - Z 1 -6	17th Rev Sheet No. 32	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
238	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
239	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
240	TGP - Fuel Charge % - Z 0-6	ln 222 x ln 236	**$0.00849**	**$0.00874**	**$0.00889**	**$0.00874**	**$0.00825**	**$0.00623**	**$0.00822**
241	TGP - Fuel Charge % - Z 1-6	ln 222 x ln 239	**$0.01530**	**$0.01574**	**$0.01602**	**$0.01573**	**$0.01486**	**$0.01121**	**$0.01481**
242	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04833**	**$0.04902**	**$0.04945**	**$0.04901**	**$0.04765**	**$0.04198**	**$0.04757**
243									
244	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
245	**Commodity Costs**	Ln 130	[redacted]						
246									
247	TGP - Max Comm. Base Rate - Z 6-6	19th Rev Sheet No. 15	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300
248	TGP - Max Commodity ACA Rate - Z 6-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
249	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
250	TGP - Fuel Charge % - Z 6-6	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
251	TGP - Fuel Charge	ln 245 x ln 250	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**
252	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
253									
254									
255	**TGP Dracut**								
256	**Commodity Costs - NYMEX Price**	Ln 117	[redacted]						
257									
258	TGP - Trans Charge - Comm. - Z 6-6	19th Rev Sheet No. 15	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300
259	TGP - Trans Charge - ACA Rate - Z6-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
260	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
261	TGP - Fuel Charge % - Z 6-6	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
262	TGP - Fuel Charge	ln 256 x ln 261	[redacted]						
263	**Total Volumetric Transportation Rate - TGP Dracut**								
264									
265					**THIS PAGE HAS BEEN REDACTED**				

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty** — Updated Schedule 7
3 **Peak 2021 - 2022 Winter Cost of Gas Filing** — Page 1 of 1
4 **NYMEX Futures @ Henry Hub**
5

5											Peak
6	For Month of:		Reference		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Strip Average
7		(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**										
9	Opening Prices				$5.5900	$5.7530	$5.8540	$5.7500	$5.4290	$4.0980	$5.4123
10	NYMEX			**Filed COG**	$5.5900	$5.7530	$5.8540	$5.7500	$5.4290	$4.0980	$5.4123

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty**
2 **Peak 2021 - 2022 Winter Cost of Gas Filing**
3 **Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Residential Heating Rate R-3**
4
5

Updated Schedule 8
Page 1 of 5

6 **November 1, 2021 - April 30, 2022**
7 **Residential Heating (R3)**

8	**PROPOSED**									**Winter**
9				**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Nov-Apr**
10	**average Usage (Therms)**			62	110	123	148	132	92	667
11			8/1/2021 - Current							
12	**Winter:**									
13	Cust. Chg		$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34
14	Headblock		$ 0.5632							
15	Tailblock		$ 0.5632	$ 34.92	$ 61.95	$ 69.27	$ 83.35	$ 74.34	$ 51.81	$ 375.65
16	HB Threshold		-							
17										
24	Total Base Rate Amount			$ 50.31	$ 77.34	$ 84.66	$ 98.74	$ 89.73	$ 67.20	$ 467.99
25										
26	COG Rate - (Seasonal)			$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339
27	COG amount			$ 70.30	$ 124.73	$ 139.47	$ 167.82	$ 149.67	$ 104.32	$ 756.31
28										
29	LDAC			$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
30	LDAC amount			$ 8.95	$ 15.89	$ 17.76	$ 21.37	$ 19.06	$ 13.29	$ 96.33
31										
32	**Total Bill**			**$ 129.56**	**$ 217.96**	**$ 241.90**	**$ 287.94**	**$ 258.47**	**$ 184.81**	**$ 1,320.63**
33										
34	**November 1, 2020 - April 30, 2021**									
35	**Residential Heating (R3)**									
36	**CURRENT**									**Winter**
37				**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Nov-Apr**
38	**average Usage (Therms)**			62	110	123	148	132	92	667
39										
40	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
41	Cust. Chg	$ 15.50	$ 15.39	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 93.00
42	Headblock	$ 0.5678	$ 0.5632							
43	Tailblock	$ 0.5678	$ 0.5632	$ 35.20	$ 62.46	$ 69.84	$ 84.03	$ 74.95	$ 52.24	$ 378.72
44	HB Threshold	-	-							
45										
52	Total Base Rate Amount			$ 50.70	$ 77.96	$ 85.34	$ 99.53	$ 90.45	$ 67.74	$ 471.72
53										
54	COG Rate - (Seasonal)			$ 0.5571	$ 0.5571	$ 0.4664	$ 0.4276	$ 0.5156	$ 0.6050	$ 0.5100
55	COG amount			$ 34.54	$ 61.28	$ 57.37	$ 63.28	$ 68.06	$ 55.66	$ 340.19
56										
57	LDAC			$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
58	LDAC amount			$ 3.65	$ 6.48	$ 7.24	$ 8.72	$ 7.77	$ 5.42	$ 39.29
59										
60	**Total Bill**			**$ 88.90**	**$ 145.72**	**$ 149.95**	**$ 171.54**	**$ 166.28**	**$ 128.82**	**$ 851.20**
61										
62	**DIFFERENCE:**									
63	**Total Bill**			**$40.67**	**$72.24**	**$91.95**	**$116.40**	**$92.19**	**$55.99**	**$469.43**
64	% Change			**45.75%**	**49.57%**	**61.32%**	**67.86%**	**55.44%**	**43.47%**	**55.15%**
65										
66	**Base Rate**			$ (0.40)	$ (0.62)	$ (0.68)	$ (0.79)	$ (0.72)	$ (0.53)	$ (3.73)
67	% Change			-0.78%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%
68										
69	**COG & LDAC**			**$ 41.06**	**$ 72.86**	**$ 92.62**	**$ 117.19**	**$ 92.90**	**$ 56.53**	**$ 473.16**
70	% Change			**118.89%**	**118.89%**	**161.45%**	**185.18%**	**136.51%**	**101.56%**	**139.09%**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

1 **d/b/a Liberty**
2 **Peak 2021 - 2022 Winter Cost of Gas Filing**
3 **Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-41**

Updated Schedule 8
Page 2 of 5

6 **November 1, 2021 - April 30, 2022**
7 **Commercial Rate (G-41)**

Line			Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
8	**PROPOSED**								
9									
10	**average Usage (Therms)**		89	277	504	457	331	297	1,955
11									
12	**Winter:**	8/1/2021 - Current							
13	Cust. Chg	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 342.36
14	Headblock	$ 0.4688	$ 41.72	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 276.12
15	Tailblock	$ 0.3149	$ -	$ 55.74	$ 127.22	$ 112.42	$ 72.74	$ 62.04	$ 430.15
16	HB Threshold	100							
17									
24	Total Base Rate Amount		$ 98.78	$ 159.68	$ 231.16	$ 216.36	$ 176.68	$ 165.98	$ 1,048.64
25									
26	COG Rate - (Seasonal)		$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341
27	COG amount		$ 100.93	$ 314.15	$ 571.59	$ 518.28	$ 375.39	$ 336.83	$ 2,217.17
28									
29	LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
30	LDAC amount		$ 7.81	$ 24.32	$ 44.25	$ 40.13	$ 29.06	$ 26.08	$ 171.66
31									
32	**Total Bill**		**$207.53**	**$498.15**	**$847.00**	**$774.77**	**$581.13**	**$528.88**	**$3,437.46**

33

34 **November 1, 2020 - April 30, 2021**
35 **Commercial Rate (G-41)**

Line				Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
36	**CURRENT**									
37										
38	**average Usage (Therms)**			89	277	504	457	331	297	1,955
39										
40	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
41	Cust. Chg	$ 57.46	$ 57.06	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 344.76
42	Headblock	$ 0.4711	$ 0.4688	$ 41.93	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 277.48
43	Tailblock	$ 0.3165	$ 0.3149	$ -	$ 56.02	$ 127.87	$ 112.99	$ 73.11	$ 62.35	$ 432.34
44	HB Threshold	100	100							
45										
52	Total Base Rate Amount			$ 99.39	$ 160.59	$ 232.44	$ 217.56	$ 177.68	$ 166.92	$ 1,054.58
53										
54	COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5018
55	COG amount			$ 49.41	$ 153.79	$ 234.11	$ 194.54	$ 170.03	$ 179.12	$ 981.01
56										
57	LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
58	LDAC amount			$ 4.94	$ 15.37	$ 27.97	$ 25.36	$ 18.37	$ 16.48	$ 108.50
59										
60	**Total Bill**			**$153.74**	**$329.75**	**$494.52**	**$437.47**	**$366.09**	**$362.52**	**$2,144.09**

61

62 **DIFFERENCE:**

Line								
63	**Total Bill**	**$ 53.79**	**$ 168.39**	**$ 352.48**	**$ 337.30**	**$ 215.05**	**$ 166.36**	**$ 1,293.37**
64	% Change	**34.99%**	**51.07%**	**71.28%**	**77.10%**	**58.74%**	**45.89%**	**60.32%**
65								
66	**Base Rate**	$ (0.60)	$ (0.91)	$ (1.28)	$ (1.20)	$ (1.00)	$ (0.95)	$ (5.94)
67	% Change	-0.61%	-0.57%	-0.55%	-0.55%	-0.56%	-0.57%	-0.56%
68								
69	**COG & LDAC**	$ 54.40	$ 169.30	$ 353.76	$ 338.50	$ 216.05	$ 167.30	$ 1,299.31
70	% Change	110.09%	110.09%	151.11%	174.00%	127.06%	93.40%	132.45%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 d/b/a Liberty
2 Peak 2021 - 2022 Winter Cost of Gas Filing
71 Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-42
72
73

Updated Schedule 8
Page 3 of 5

74 **November 1, 2021 - April 30, 2022**
75 **C&I High Winter Use Medium G-42**

76	**PROPOSED**									**Winter**
77				**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**Nov-Apr**
78	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,131
79			8/1/2021 - Current							
80	**Winter:**									
81	Cust. Chg		$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
82	Headblock		$ 0.4261	$ 353.66	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 2,484.16
83	Tailblock		$ 0.2839	$ -	$ 337.56	$ 768.80	$ 683.06	$ 455.09	$ 396.04	$ 2,640.55
84	HB Threshold		1,000							
85										
92	Total Base Rate Amount			$ 524.85	$ 934.85	$ 1,366.09	$ 1,280.35	$ 1,052.38	$ 993.33	$ 6,151.86
93										
94	COG Rate - (Seasonal)			$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341
95	COG amount			$ 941.30	$ 2,482.54	$ 4,205.24	$ 3,862.74	$ 2,952.06	$ 2,716.17	$ 17,160.07
96										
97	LDAC			$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
98	LDAC amount			$ 72.88	$ 192.21	$ 325.59	$ 299.07	$ 228.56	$ 210.30	$ 1,328.61
99										
100	**Total Bill**			**$ 1,539.04**	**$ 3,609.60**	**$ 5,896.92**	**$ 5,442.17**	**$ 4,233.01**	**$ 3,919.80**	**$ 24,640.53**

101
102 **November 1, 2020 - April 30, 2021**
103 **C&I High Winter Use Medium G-42**

104	**CURRENT**									**Winter**
105				**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**Nov-Apr**
106	**average Usage (Therms)**			830	2,189	3,708	3,406	2,603	2,395	15,131
107										
108	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
109	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
110	Headblock	$ 0.4284	$ 0.4261	$ 355.57	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 2,497.57
111	Tailblock	$ 0.2855	$ 0.2839	$ -	$ 339.46	$ 773.13	$ 686.91	$ 457.66	$ 398.27	$ 2,655.44
112	HB Threshold	1,000	1,000							
113										
120	Total Base Rate Amount			$ 527.96	$ 940.25	$ 1,373.92	$ 1,287.70	$ 1,058.45	$ 999.06	$ 6,187.35
121										
122	COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$0.5043
123	COG amount			$ 460.82	$ 1,215.33	$ 1,722.37	$ 1,449.93	$ 1,337.16	$ 1,444.42	$ 7,630.03
124										
125	LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	0.0555
126	LDAC amount			$ 46.07	$ 121.49	$ 205.79	$ 189.03	$ 144.47	$ 132.92	$ 839.77
127										
128	**Total Bill**			**$ 1,034.84**	**$ 2,277.07**	**$ 3,302.08**	**$ 2,926.67**	**$ 2,540.07**	**$ 2,576.41**	**$ 14,657.15**

129
130 **DIFFERENCE:**

131	**Total Bill**	**$ 504.19**	**$ 1,332.53**	**$ 2,594.84**	**$ 2,515.50**	**$ 1,692.93**	**$ 1,343.39**	**$ 9,983.38**
132	% Change	**48.72%**	**58.52%**	**78.58%**	**85.95%**	**66.65%**	**52.14%**	**68.11%**
133								
134	**Base Rate**	$ (3.11)	$ (5.40)	$ (7.83)	$ (7.35)	$ (6.06)	$ (5.73)	$ (35.49)
135	% Change	-0.59%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%
136								
137	**COG & LDAC**	$ 507.30	$ 1,337.93	$ 2,602.67	$ 2,522.85	$ 1,699.00	$ 1,349.12	$ 10,018.87
138	% Change	110.09%	110.09%	151.11%	174.00%	127.06%	93.40%	131.31%

Updated Schedule 8
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Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty**
2 **Peak 2021 - 2022 Winter Cost of Gas Filing**
139 **Annual Bill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-52**
140
141
142 **November 1, 2021 - April 30, 2022**
143 **Commercial Rate (G-52)**

Row			Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
144	**PROPOSED**								
146	**average Usage (Therms)**		1,352	1,866	2,284	2,160	1,886	1,760	11,308
147									
148	**Winter:**	8/1/2021 - Current							
149	Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
150	Headblock	$ 0.2428	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 1,456.80
151	Tailblock	$ 0.1617	$ 56.92	$ 140.03	$ 207.62	$ 187.57	$ 143.27	$ 122.89	$ 858.30
152	HB Threshold	1,000							
153									
160	Total Base Rate Amount		$ 470.91	$ 554.02	$ 621.61	$ 601.56	$ 557.26	$ 536.88	$ 3,342.24
161									
162	COG Rate - (Seasonal)		$1.1324	$1.1324	$1.1324	$1.1324	$1.1324	$1.1324	$ 1.1324
163	COG amount		$ 1,531.00	$ 2,113.06	$ 2,586.40	$ 2,445.98	$ 2,135.71	$ 1,993.02	$ 12,805.18
164									
165	LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
166	LDAC amount		$ 118.72	$ 163.85	$ 200.55	$ 189.66	$ 165.60	$ 154.54	$ 992.92
167									
168	**Total Bill**		**$2,120.63**	**$2,830.93**	**$3,408.57**	**$3,237.21**	**$2,858.57**	**$2,684.45**	**$17,140.34**

169
170 **November 1, 2020 - April 30, 2021**
171 **Commercial Rate (G-52)**

Row				Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
172	**CURRENT**									
174	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,308
175										
176	**Winter:**	7/1/20 - 7/31/21	8/1/2021 - Current							
177	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
178	Headblock	$ 0.2439	$ 0.2428	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 1,463.40
179	Tailblock	$ 0.1624	$ 0.1617	$ 57.16	$ 140.64	$ 208.52	$ 188.38	$ 143.89	$ 123.42	$ 862.02
180	HB Threshold	1,000	1,000							
181										
188	Total Base Rate Amount			$ 473.45	$ 556.93	$ 624.81	$ 604.67	$ 560.18	$ 539.71	$ 3,359.76
189										
190	COG Rate - (Seasonal)			$ 0.5660	$ 0.5660	$ 0.4753	$ 0.4365	$ 0.5245	$ 0.6139	$ 0.5235
191	COG amount			$ 765.23	$ 1,056.16	$ 1,085.59	$ 942.84	$ 989.21	$ 1,080.46	$ 5,919.48
192										
193	LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
194	LDAC amount			$ 75.04	$ 103.56	$ 126.76	$ 119.88	$ 104.67	$ 97.68	$ 627.59
195										
196	**Total Bill**			**$1,313.72**	**$1,716.65**	**$1,837.16**	**$1,667.39**	**$1,654.06**	**$1,717.86**	**$9,906.84**

197
198 **DIFFERENCE:**

Row								
199	**Total Bill**	**$ 806.91**	**$ 1,114.28**	**$ 1,571.41**	**$ 1,569.82**	**$ 1,204.51**	**$ 966.59**	**$ 7,233.51**
200	% Change	**61.42%**	**64.91%**	**85.53%**	**94.15%**	**72.82%**	**56.27%**	**73.02%**
201								
202	**Base Rate**	$ (2.55)	$ (2.91)	$ (3.20)	$ (3.11)	$ (2.92)	$ (2.83)	$ (17.52)
203	% Change	-0.54%	-0.52%	-0.51%	-0.51%	-0.52%	-0.52%	-0.52%
204								
205	**COG & LDAC**	$ 809.45	$ 1,117.19	$ 1,574.61	$ 1,572.93	$ 1,207.43	$ 969.42	$ 7,251.02
206	% Change	105.78%	105.78%	145.05%	166.83%	122.06%	89.72%	122.49%

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty**
2 **Peak 2021 - 2022 Winter Cost of Gas Filing**
207 **Residential Heating**

Updated Schedule 8
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Line		Winter 2020-21	Winter 2021-22
208			
209	Customer Charge	$ 15.50	$ 15.39
210	First 100 Therms	$ 0.5678	$ 0.5632
211	Excess 100 Therms	$ 0.5678	$ 0.5632
212	LDAC	$ 0.0589	$ 0.1444
213	COG	$ 0.5100	$ 1.1339
214	Total Adjust	$ 0.5689	$ 1.2783
215			
216			
217			

Line					Total		Base Rate		COG		LDAC	
219			Winter 2020-21 COG @	Winter 2021-22 @	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
220			$0.5689	$1.2783	$0.71	125%						
221												
222	Cooking alone	5	$21.05	$24.60	$3.55	16.85%	$0.00	0%	$3.12	13%	$0.43	2.03%
223												
224		10	$26.71	$33.81	$7.09	26.56%	$0.00	0%	$6.24	18%	$0.86	3.20%
225												
226		20	$38.03	$52.22	$14.19	37.30%	$0.00	0%	$12.48	24%	$1.71	4.50%
227												
228	Water Heating alone	30	$49.35	$70.64	$21.28	43.12%	$0.00	0%	$18.72	26%	$2.57	5.20%
229												
230		45	$66.34	$98.26	$31.92	48.12%	$0.00	0%	$28.07	29%	$3.85	5.80%
231												
232		50	$72.00	$107.47	$35.47	49.27%	$0.00	0%	$31.19	29%	$4.28	5.94%
233												
234	Heating Alone	80	$100.30	$153.50	$53.20	53.04%	$0.00	0%	$46.79	30%	$6.41	6.39%
235												
236		125	$165.96	$260.31	$94.35	56.85%	$0.00	0%	$82.97	32%	$11.37	6.85%
237												
238		150	$185.21	$291.62	$106.41	57.45%	$0.00	0%	$93.58	32%	$12.83	6.93%
239												
240		200	$241.82	$383.69	$141.88	58.67%	$0.00	0%	$124.77	33%	$17.10	7.07%
241												

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 9
2 **d/b/a Liberty** Page 1 of 1
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4 **Variance Analysis of the Components of the Winter 2020-2021 Actual Results vs Proposed Winter 2021-2022 Cost of Gas Rate**

		WINTER 2020-2021 ACTUAL RESULTS (6 months actual)			WINTER 2021-2022 (6 months Proposed)		
11	Therm Sales (COG)	124,069,459			87,443,741		
12-14		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
16	Demand Charges		$ 11,374,016	$ 0.0917		$ 13,868,897	$ 0.1586
18	Purchased Gas		26,038,931	0.2099	71,420,117	72,351,034	0.8274
20	Storage/Produced Gas		-	-	22,796,474	8,429,820	0.0964
22	Hedging (Gain)/Loss		-	-		-	-
25	Total Volumes and Cost	91,441,600	$ 37,412,947	$ 0.3015	94,216,591	$ 94,649,750	$ 1.0824
27	Direct Costs						
28	Prior Period Balance		$ 2,901,813	$ 0.0234		$ 1,431,639	$ 0.0164
29	Interest		29,768	0.0002		44,085	0.0005
30	Prior Period Adjustment		-	-		335,667	0.0038
31	Broker Revenues		(1,528,286)	(0.0123)		(3,600)	(0.0000)
32	Refunds from Suppliers		-	-		-	-
33	Fuel Financing		-	-		-	-
34	Transportation CGA Revenues		(56,511)	(0.0005)		(6,938)	(0.0001)
35	280 Day Margin		-	-		-	-
36	Interruptible Sales Margin		-	-		-	-
37	Capacity Release and Off System Sales Margins		(1,676,512)	(0.0135)		(1,676,512)	(0.0192)
38	Hedging Costs		-	-		-	-
39	FPO Admin Costs		-	-		36,800	0.0004
40	Indirect Costs		-	-			
41	Misc Overhead		-	-		-	-
42	Occupant Disallowance/Credits		-			-	-
43	Production & Storage		1,990,996	0.0160		3,685,458	0.0421
44	Bad Debt Adjustment %		-	-		652,544	0.0075
45	Cashout, Broker penalty, Canadian Managed,…		-	-		-	-
46	Total Adjusted Cost		$ 39,074,214	**$ 0.3149**		$ 99,148,893	**$ 1.1339**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty

Peak 2021 - 2022 Winter Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
Derivation of Class Assignments and Weightings

Updated Schedule 10A
Page 1 of 3

Basic assumptions:
1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
a The base use portion of the class design day demand based on base use
b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

				Column A	**Column B**	**Column C**	**Column D**	**Column E**	**Column F**
				Design Day Demand. Dktherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			659	715	0.4%		103	613
2	RATE R-3-Resi Htg			66,114	72,399	42.2%		3,617	68,783
3	RATE G-41 (T)			28,689	31,499	18.4%		750	30,749
4	RATE G-51 (S)			2,361	2,534	1.5%		641	1,893
5	RATE G-42 (V)			36,728	40,301	23.5%		1,198	39,104
6	RATE G-52			5,125	5,490	3.2%		1,498	3,992
7	RATE G-43			9,793	10,710	6.2%		678	10,031
8	RATE G-53			5,922	6,346	3.7%		1,715	4,631
9	RATE G-54			1,495	1,608	0.9%		378	1,230
10									
11	Total			156,887	171,602	100.0%		10,577	161,025
12									-
13	Residential Total			66,773	73,115	**42.607%**		3,719	69,396
14	LLF Total			75,211	82,510	**48.083%**		2,626	79,885
15	HLF Total			14,903	15,977	**9.310%**		4,232	11,745
16	Total			156,887	171,602	100.0%		10,577	161,025
17									
18	C&I Breakdown								
19	LLF Total							2,626	79,885
20	HLF Total							4,232	11,745
21	Total							6,858	91,630
22									
23	C&I Breakdown Percentage								
24	LLF Total							38.291%	87.182%
25	HLF Total							61.709%	12.818%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$16,344,325	119,718	$11.3770			
30	Storage			$4,121,310	28,115	$12.2156			
31									
32	Peaking			$4,119,000					
33	Peaking Additional Costs								
34	Subtotal Peaking Costs			$4,119,000	23,769	$14.4412			
35	Total			$24,584,635	171,602	$11.9388			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,443,958	10,577	$11.3770			
39	Pipeline - Remaining			14,900,367	109,141	$11.3770			
40	Storage			4,121,310	28,115	$12.2156			
41	Peaking			4,119,000	23,769	$14.4412			
42	Total			24,584,635	171,602	$11.9388			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**42.607%**	615,228	4,506	$11.3770			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.607%**	6,348,623	46,502	$11.3770			
48	Storage	Line 40 * Line 13 Col C	**42.607%**	1,755,962	11,979	$12.2156			
49	Peaking	Line 41 * Line 13 Col C	**42.607%**	1,754,952	10,127	$14.4412			
50	Total		**42.607%**	10,474,751	73,114	$11.9388			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty

Peak 2021 - 2022 Winter Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
Derivation of Class Assignments and Weightings

Line	Description	Reference					Ratios for COG
51							
52							
53	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
54	Pipeline - Base	Line 38 - Line 46		828,730	6,070	$11.3770	
55	Pipeline - Remaining	Line 39 - Line 47		8,551,745	62,640	$11.3769	
56	Storage	Line 40 - Line 48		2,365,348	16,136	$12.2157	
57	Peaking	Line 41 - Line 49		2,364,048	13,642	$14.4410	
58	Total		**57.393%**	14,109,870	98,488	$11.9388	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		317,329	2,324	$11.3787	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		7,455,589	54,610	$11.3770	
64	Storage	Line 56 * Line 24 Col F		2,062,160	14,068	$12.2154	
65	Peaking	Line 57 * Line 24 Col F		2,061,026	11,893	$14.4415	
66	Total		**48.3884%**	11,896,104	82,895	$11.9590	**1.0017**
67			38.291%	84%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		511,401	3,746	$11.3766	
71	Pipeline - Remaining	Line 55 - Line 63		1,096,156	8,030	$11.3756	
72	Storage	Line 56 - Line 64		303,188	2,068	$12.2174	
73	Peaking	Line 57 - Line 65		303,022	1,749	$14.4379	
74	Total		**9.0047%**	2,213,767	15,593	$11.8310	**0.9910**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 11.3770	$ 11.3770	$ 11.3770	
80	Storage			$ 12.2156	$ 12.2156	$ 12.2156	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 11.9388	$ 11.9590	$ 11.8310	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			69.77%	**68.68%**	**75.52%**	
88	Storage			16.38%	**16.97%**	**13.26%**	
89	Peaking			13.85%	**14.35%**	**11.22%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			42.61%	47.56%	9.84%	100.00%
96	Storage			42.61%	50.04%	7.36%	100.00%
97	Peaking			42.61%	50.04%	7.36%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 10A
2 **d/b/a Liberty** Page 3 of 3
3 **2021 - 2022 Winter Cost of Gas Filing**
4 **Correction Factor Calculation**
5
6

Ln		Nov	Dec	Jan	Feb	Mar	Apr	Total Sales
7		d	e	f	g	h	i	
8	Data Source: Schedule 10B							
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070
12	G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880
13	G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940
14	High Winter Use	3,959,000	6,328,450	7,579,850	6,386,830	5,348,890	3,069,870	32,672,890
15								
16	G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800
17	G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940
18	G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710
19	G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810
21	Low Winter Use	982,230	1,240,000	1,333,450	1,098,400	1,136,750	812,430	6,603,260
22								
23	Gross Total	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150

Ln				
24				
25				
26	Total Sales	39,276,150		
27	Low Winter Use	6,603,260		
28	Winter Ratio for Low Winter Use	**0.9910**	Schedule 10A p 2, ln 74	
29	High Winter Use	32,672,890		
30	Winter Ratio for High Winter Use	**1.0017**	Schedule 10A p 2, ln 66	
31				
32	Correction Factor =	Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use))		
33	Correction Factor =	**100.0099%**		
34				
35				
36	**Allocation Calculation for Miscellaneous Overhead**			
37				
38	Projected Winter Sales Volume	11/1/21- 4/30/22	91,676,680	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/21 - 10/31/22	115,042,810	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		79.69%	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 10 B
2 **d/b/a Liberty** Page 1 of 1
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
4
5
6 **Dry Therms**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Subtotal PK 21-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Subtotal OP 22	Total
7	**Firm Sales**															
8																
9	R-1	68,340	87,950	100,820	86,060	85,740	64,450	493,360	51,360	38,850	33,950	34,160	38,040	51,620	247,980	741,340
10	R-3	6,259,770	9,415,520	10,967,410	9,270,440	7,794,900	4,711,810	48,419,850	2,667,890	1,294,670	1,005,090	1,028,340	1,719,640	4,100,280	11,815,910	60,235,760
11	R-4	454,380	670,430	779,980	661,890	559,780	360,860	3,487,320	203,890	100,540	76,380	75,540	119,390	284,380	860,120	4,347,440
12	Total Residential.	6,782,490	10,173,900	11,848,210	10,018,390	8,440,420	5,137,120	52,400,530	2,923,140	1,434,060	1,115,420	1,138,040	1,877,070	4,436,280	12,924,010	65,324,540
13																
14	G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160	19,479,230
15	G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140	15,779,020
16	G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940	179,740	73,660	58,680	59,440	100,920	204,000	676,440	3,523,380
17	G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890	3,056,690
18	G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290	3,482,230
19	G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370	4,133,080
20	G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810	15,120	18,750	22,560	24,140	22,080	24,180	126,830	264,640
21	Total C/I	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120	49,718,270
22																
23	**Sales Volume**	**11,723,720**	**17,742,350**	**20,761,510**	**17,503,620**	**14,926,060**	**9,019,420**	**91,676,680**	**5,274,850**	**2,751,830**	**2,286,170**	**2,318,030**	**3,434,190**	**7,301,060**	**23,366,130**	**115,042,810**
24																
25	Transportation Sales															
26	G-41	574,020	867,030	1,039,180	856,480	763,130	450,870	4,550,710	261,840	140,990	106,460	95,760	156,800	326,870	1,088,720	5,639,430
27	G-42	1,968,530	2,914,590	3,391,170	2,830,750	2,515,270	1,523,590	15,143,900	906,300	496,460	395,030	398,340	659,800	1,261,210	4,117,140	19,261,040
28	G-43	771,060	1,044,290	1,235,960	1,039,110	971,040	538,960	5,600,420	365,460	237,030	213,480	240,670	339,080	530,620	1,926,340	7,526,760
29	G-51	84,590	105,400	113,700	94,860	99,260	81,810	579,620	77,390	64,770	61,300	61,170	63,740	76,000	404,370	983,990
30	G-52	497,790	617,920	679,580	565,210	579,610	430,990	3,371,100	389,470	360,850	367,700	363,660	373,650	442,840	2,298,170	5,669,270
31	G-53	855,560	987,600	1,082,920	916,680	934,740	840,440	5,617,940	724,650	621,190	623,930	659,410	675,470	791,330	4,095,980	9,713,920
32	G-54	1,585,390	1,292,050	1,269,400	1,054,210	1,161,320	1,357,730	7,720,100	1,561,020	1,567,000	1,631,330	1,739,250	1,682,640	1,755,260	9,936,500	17,656,600
33																
34	Total Trans. Sales	**6,336,940**	**7,828,880**	**8,811,910**	**7,357,300**	**7,024,370**	**5,224,390**	**42,583,790**	**4,286,130**	**3,488,290**	**3,399,230**	**3,558,260**	**3,951,180**	**5,184,130**	**23,867,220**	**66,451,010**
35																
36	Total All Sales	**18,060,660**	**25,571,230**	**29,573,420**	**24,860,920**	**21,950,430**	**14,243,810**	**134,260,470**	**9,560,980**	**6,240,120**	**5,685,400**	**5,876,290**	**7,385,370**	**12,485,190**	**47,233,350**	**181,493,820**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
5 **Updated Schedule 11A**
6 **Page 1 of 1**
7 **Volumes (Therms)** **Normal Year**
8
9 **For the Months of May 21 - October 21**

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov - Apr
13	Pipeline Gas:							
14	Dawn Supply	876,821	926,304	927,705	840,605	911,138	750,758	5,233,331
15	Niagara Supply	691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
16	TGP Supply (Gulf)	4,587,074	3,104,022	3,109,472	2,817,427	3,053,203	612,346	17,283,547
17	Dracut Supply 1 - Baseload	-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
18	Dracut Supply 2 - Swing	1,775,785	5,569,137	771,324	-	969,754	79,714	9,165,713
19	Dracut Supply 3 - Swing	-	596,455	290,490	-	1,484	-	888,430
20	Constellation Combo	89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
21	LNG Truck	20,666	21,875	51,371	291,824	362,081	-	747,817
22	Propane Truck	-	-	-	695,072	-	-	695,072
23	PNGTS	219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
24	Portland Natural Gas	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	812,355	6,284,969
25	TGP Supply (Z4)	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
26	Subtotal Pipeline Volumes	11,146,258	17,266,150	15,271,258	12,655,305	10,660,614	8,575,749	75,575,334
27		11,146,258	17,666,150	15,671,258	12,655,305	10,660,614	8,575,749	76,375,334
28	Storage Gas:							
29	TGP Storage	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
30								
31	Produced Gas:							
32	LNG Vapor	21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
33	Propane	-	-	244,014	574,010	-	-	818,023
34	Subtotal Produced Gas	21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
35								
36	Less - Gas Refills:							
37	LNG Truck	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)		(747,817)
38	Propane	-	-	-	(695,072)	-	-	(695,072)
39	TGP Storage Refill	(1,750,690)	-	-	-	-	(961,638)	(2,712,328)
40	Subtotal Refills	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
41								
42	Total Sendout Volumes	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591
43								

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty**
3 **Peak 2021 - 2022 Winter Cost of Gas Filing**
44 **Normal and Design Year Volumes** **Updated Schedule 11B**
45 **Page 1 of 1**
46
47 **Volumes (Therms)** **Design Year**
48
49 **For the Months of May 21 - October 21**
50

Line		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Peak Nov - Apr
53	Pipeline Gas:							
54	Dawn Supply	876,821	926,304	927,705	840,605	911,138	774,673	5,257,245
55	Niagara Supply	691,567	730,181	731,285	662,478	718,226	679,016	4,212,753
56	TGP Supply (Gulf)	4,633,572	3,104,022	3,109,472	2,817,427	3,053,203	763,078	17,480,776
57	Dracut Supply 1 - Baseload	-	2,800,032	4,674,030	3,176,712	-	-	10,650,774
58	Dracut Supply 2 - Swing	4,407,724	6,104,703	1,534,339	1,478,827	2,256,328	1,863,127	17,645,050
59	Dracut Supply 3 - Swing	271,608	619,085	866,906	226,637	179,557	43,480	2,207,273
60	Constellation Combo	-	353,776	1,356,806	1,284,025	1,354,094	-	4,348,701
61	LNG Truck	20,666	21,875	63,459	528,315	118,715	-	753,030
62	Propane Truck	-	-	15,109	680,670	-	-	695,779
63	PNGTS	219,205	231,576	231,926	209,962	227,785	193,487	1,313,941
64	Portland Natural Gas	1,070,932	1,130,724	1,132,434	1,026,311	1,112,212	919,607	6,392,220
65	TGP Supply (Z4)	1,820,806	1,924,268	1,927,178	1,746,396	1,892,764	5,620,543	14,931,954
66	Subtotal Pipeline Volumes	14,012,903	17,946,545	16,570,649	14,678,365	11,824,022	10,857,011	85,889,495
67								
68	Storage Gas:							
69	TGP Storage	2,752,983	850,117	5,503,525	4,890,514	4,760,475	1,242,085	19,999,699
70								0
71	Produced Gas:							0
72	LNG Vapor	21,404	421,875	547,315	694,098	273,045	21,015	1,978,752
73	Propane	-	-	244,014	574,010	-	-	818,023
74	Subtotal Produced Gas	21,404	421,875	791,328	1,268,108	273,045	21,015	2,796,775
75								
76	Less - Gas Refills:							
77	LNG Truck	(20,666)	(21,875)	(51,371)	(291,824)	(362,081)	-	-747,817
78	Propane	-	-	-	(695,072)	-	-	-695,072
79	TGP Storage Refill	(1,750,690)	-	-	-	-	(961,638)	-2,712,328
80	Subtotal Refills	(1,771,356)	(21,875)	(51,371)	(986,895)	(362,081)	(961,638)	(4,155,217)
81								
82	Total Sendout Volumes	15,015,933	19,196,663	22,814,130	19,850,092	16,495,460	11,158,474	104,530,752

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing
Capacity Utilization
Volumes (Therms)

	Peak Period Normal Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate	Peak Period Design Year Use (Therms)	MDQ (MMBtu/day)	Seasonal Quantity (Therms)	Utilization Rate
Pipeline Gas:								
Dawn Supply	5,233,331	4,000	7,240,000	72%	5,257,245	4,000	7,240,000	73%
Niagara Supply	4,212,753	3,122	5,650,820	75%	4,212,753	3,122	5,650,820	75%
TGP Supply (Gulf + Z4)	32,037,125	21,596	39,088,760	82%	32,412,730	21,596	39,088,760	83%
Dracut Supply 1 & 2 & 3	20,704,916	90,000	162,900,000	13%	30,503,096	90,000	162,900,000	19%
LNG Truck	747,817	-	-	-	753,030	-	-	-
Propane Truck	695,072	-	-	-	695,779	-	-	-
PNGTS	1,313,941	1,000	1,810,000	73%	1,313,941	1,000	1,810,000	73%
Portland Natural Gas	6,284,969	5,000	9,050,000	69%	6,392,220	5,000	9,050,000	71%
Constellation Vapor	4,345,410	7,000	6,300,000	69%	4,348,701	7,000	6,300,000	69%
Subtotal Pipeline Volumes	75,575,334				85,889,495			
Storage Gas:								
TGP Storage	19,999,699		25,791,710	78%	19,999,699		25,791,710	78%
Produced Gas:								
LNG Vapor	1,978,752				1,978,752			
Propane	818,023.3				818,023			
Subtotal Produced Gas	2,796,775				2,796,775			
Less - Gas Refills:								
LNG Truck	(747,817)				(747,817)			
Propane	(695,072)				(695,072)			
TGP Storage Refill	(2,712,328)				(2,712,328)			
Subtotal Refills	(4,155,217)				(4,155,217)			
Total Sendout Volumes	94,216,591				104,530,752			

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Updated Schedule 11D**
d/b/a Liberty **Page 1 of 1**
Peak 2021 - 2022 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2020 / 2021 Heating Season
(Therms)

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

Requirements

Firm Sales	1,283,926
Interruptible Sales	0
Firm Transportation	432,092
Interruptible Transportation	0
Total Requirements	1,716,018

Resources

Purchased Pipeline Gas	1,197,180
Underground Storage Gas	281,150
Propane Air Production	41,688
LNG Produced Gas	126,000
Third-Party Supply	70,000
Total Resources	1,716,018

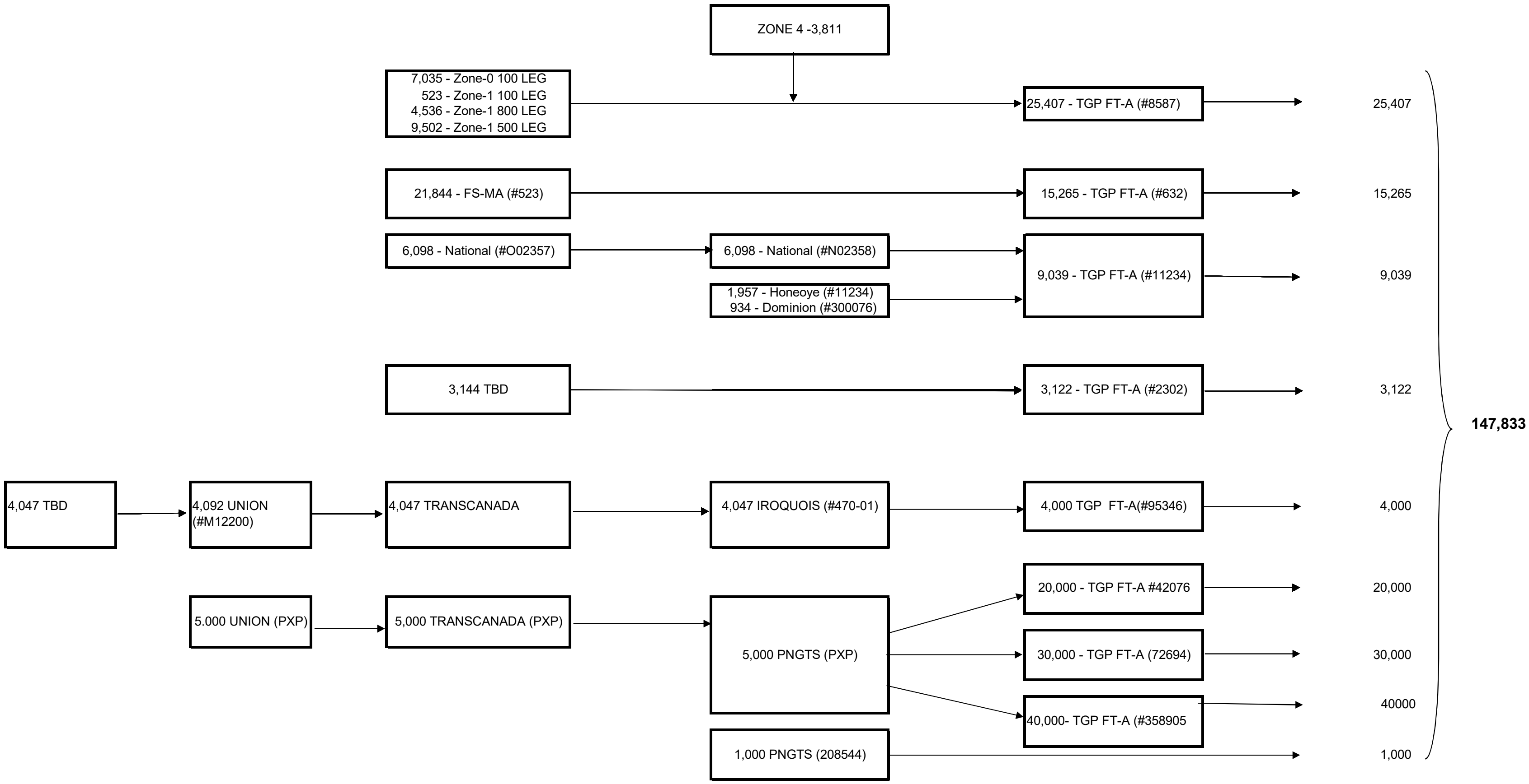
Please refer to the ENNG 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

Preparation of this report was supervised by:

Deborah Gilbertson
Sr. Manager, Energy Procurement

Note: Forecasted Firm Transportation volumes are for customers using utility capacity only.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2021 - 2022 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2021 - 2022 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage

Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
Constellation	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2021 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2021	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2021	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2023	3/31/2021	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2022	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2022	3/31/2022	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2022	3/31/2022	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2022	11/1/2021	Evergreen Provision
Portland Natural Gas Transmission System	FT	208544	Transportation	1,000	365,000	11/30/2032	11/31/2031	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2039	Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2028	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2021	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	358905	Transportation	40,000	14,600,000	10/31/2041	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2026	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2024	Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2023	10/31/2021	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	5,000	1,825,000	10/31/2040	10/31/2021	Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing

Load Migration From Sales to Transportation in the C&I High and Low Winter Use Classes

July 2020 - June 2021 Normalized Sales and Transportation Volumes (Therms)

C&I Rate Classes	Annual Sales	% of Total by Class	% of Sales to Total Volume by Class
G-41	18,356,822	40.75%	78.44%
G-42	15,353,253	34.08%	45.73%
G-43	3,841,684	8.53%	31.47%
G-51	2,891,430	6.42%	76.18%
G-52	3,253,957	7.22%	38.33%
G-53	1,018,263	2.26%	10.14%
G-54	330,714	0.73%	1.92%
Total C/I	45,046,124	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,045,712	7.92%	21.56%
G-42	18,223,357	28.60%	54.27%
G-43	8,366,118	13.13%	68.53%
G-51	903,966	1.42%	23.82%
G-52	5,236,072	8.22%	61.67%
G-53	9,026,718	14.17%	89.86%
G-54	16,915,516	26.55%	98.08%
Total C/I	63,717,458	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	23,402,533	21.52%	100.00%
G-42	33,576,610	30.87%	100.00%
G-43	12,207,803	11.22%	100.00%
G-51	3,795,396	3.49%	100.00%
G-52	8,490,028	7.81%	100.00%
G-53	10,044,981	9.24%	100.00%
G-54	17,246,230	15.86%	100.00%
Total C/I	108,763,581	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Updated Schedule 14
Peak 2021 - 2022 Winter Cost of Gas Filing Page 1 of 1

Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior Year

	Off-Peak	**Peak**	**Total**	
	May 20 - Oct 20	**Nov 20-Apr 21**	**May 20 - Apr 21**	
	(Therms)	(Therms)	(Therms)	
Pipeline Deliveries	18,824,010	84,277,810	103,101,820	
All Others	132,500	1,914,540	2,047,040	
	18,956,510	86,192,350	105,148,860	
				Ratio
Total Winter Supplies				86,192,350
Total Pipeline Deliveries				103,101,820
Ratio Winter Supplies to Pipeline Supplies				0.836

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Updated Schedule 15
Peak 2021 - 2022 Winter Cost of Gas Filing Page 1 of 1

July and August Consumption of C&I High and Low Winter Classes as a Percentage of Their Annual Consumption

C&I Sales Normalized (Therms)	**Jul-20**	**Aug-20**	**Jul - Aug Total**	**Total Annual**	**% of Jul-Aug to Total**
(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
G-41	174,747	138,891	313,637	18,356,822	1.71%
G-42	195,842	150,099	345,941	15,353,253	2.25%
G-43	52,926	47,293	100,219	3,841,684	2.61%
G-51	155,287	140,064	295,352	2,891,430	10.21%
G-52	183,712	169,419	353,131	3,253,957	10.85%
G-53	84,472	58,190	142,662	1,018,263	14.01%
G-54	15,457	18,585	34,042	330,714	10.29%
Total C/I	862,442	722,541	1,584,983	45,046,124	3.52%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty** | Updated Schedule 16
2 **Peak 2021 - 2022 Winter Cost of Gas Filing** | Page 1 of 2
3
4 **Storage Inventory, Undergound, LPG and LNG including Calculation of Money Pool Interest Costs Associated with Natural Gas**
5
6 **Underground Storage Gas**

Ln	Description	Reference	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Actual)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Nov-21 (Estimate)	Dec-21 (Estimate)	Jan-22 (Estimate)	Feb-22 (Estimate)	Mar-22 (Estimate)	Apr-22 (Estimate)	Total
9	Beginning Balance (MMBtu)		512,647	743,431	993,080	1,249,640	1,509,640	1,769,640	1,897,860	1,750,782	1,665,770	1,115,418	626,366	150,319	512,647
10															
11	Injections (MMBtu)	Sch 11A ln 39 /10	234,130	253,870	260,938	260,000	260,000	128,220	128,220	-	-	-	-	96,164	1,621,542
12															
13	Subtotal		746,777	997,301	1,254,018	1,509,640	1,769,640	1,897,860	2,026,080	1,750,782	1,665,770	1,115,418	626,366	246,482	
14															
15	Storage Sale/Adjustments		(3,346)	(4,221)	(4,378)	-	-	-	-	-	-	-	-	-	(11,945)
16															
17	Withdrawals (MMBtu)	Sch 11A ln 29 /10	-	-	-	-	-	-	(275,298)	(85,012)	(550,352)	(489,051)	(476,047)	(124,208)	(1,999,970)
18															
19	Ending Balance (MMBtu)		743,431	993,080	1,249,640	1,509,640	1,769,640	1,897,860	1,750,782	1,665,770	1,115,418	626,366	150,319	122,274	122,274
20															
21															
22	Beginning Balance		$ 921,816	$ 1,463,053	$ 2,088,182	$ 2,854,560	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 457,826	$ 921,816
23															
24	Injections	ln 11 * ln 36	$ 534,796	$ 619,603	$ 760,761	$ 1,060,538	$ 1,060,538	$ 523,008	$ 672,193	$ -	$ -	$ -	$ -	$ 370,519	$ 5,601,957
25															
26	Subtotal		$ 1,456,612	$ 2,082,656	$ 2,848,943	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 6,170,838	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 828,345	
27															
28	Storage Sale/Adjustments		$ 6,441	$ 5,526	$ 5,618			$ -							
29															
30	Withdrawals	ln 17 * ln 34	-	-	-	-	-	-	(838,477)	(258,921)	(1,676,210)	(1,489,505)	(1,449,899)	(417,423)	$ (6,130,435)
31															
32	Ending Balance		$ 1,463,053	$ 2,088,182	$ 2,854,560	$ 3,915,098	$ 4,975,636	$ 5,498,645	$ 5,332,361	$ 5,073,441	$ 3,397,231	$ 1,907,725	$ 457,826	$ 410,922	$ 393,337
33															
34	Average Rate For Withdrawals	ln 22 /ln 9	$ 1.9505	$ 2.0883	$ 2.2719	$ 2.5934	$ 2.8117	$ 2.8973	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.0457	$ 3.3607	
35															
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$ 2.2842	$ 2.4406	$ 2.9155	$ 4.0790	$ 4.0790	$ 4.0790	$ 5.2425	$ 5.5130	$ 5.6315	$ 5.5075	$ 5.2565	$ 3.8530	
37															
38	For Informational Purposes								Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
39	Summer Hedge Contracts - Vols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$ -	$ -	$ -	$ -	$ -	$ -	
41	NYMEX								$ 5.5900	$ 5.7530	$ 5.8540	$ 5.7500	$ 5.4290	$ 4.0980	
42															
43	Hedged Volumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX								$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Hedge (Savings)/Loss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
46															
47	Month Dollar Average	ln (22 + ln 32) /2				$ 3,384,829	$ 4,445,367	$ 5,237,141	$ 5,415,503	$ 5,202,901	$ 4,235,336	$ 2,652,478	$ 1,182,776	$ 434,374	
48															
49	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
50															
51	Inventory Finance Charge	ln 47 * ln 49				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	Financial Expenses					-	-	-	-	-	-	-	-	-	
53	Total Inventory Finance Charges					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
54															
55															
38															

Updated Schedule 16
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Ln	Description	Reference	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
41	**Liquid Propane Gas (LPG)**														
42			May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
43			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
44	Beginning Balance		74,752	73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	48,995	61,101	61,101	74,752
46	Injections	Sch 11A ln 38 /10	-	-	-	-	-	-	-	-	-	69,507	-	-	69,507
48	Subtotal		74,752	73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	118,502	61,101	61,101	
50	Withdrawals	Sch 11A ln 33 /10	-	-	-	-	-	-	-	-	(24,401)	(57,401)	-	-	(81,802)
52	Adjustment for change in temperature		(1,113)	192	(435)	-	-	-	-	-	-	-	-	-	(1,356)
53	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
54	Ending Balance		73,639	73,831	73,396	73,396	73,396	73,396	73,396	73,396	48,995	61,101	61,101	61,101	61,101
57	Beginning Balance		$ 802,029	$ 790,087	$ 792,147	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 525,673	$ 701,107	$ 701,107	$ 802,029
59	Injections	ln 46 * ln 69	-	-	-	-	-	-	-	-	-	834,086	-	-	834,086
61	Subtotal		$ 802,029	$ 790,087	$ 792,147	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 1,359,759	$ 701,107	$ 701,107	
63	Withdrawals/ Adjust	ln 52 * ln 67	(11,942)	2,060	(4,667)	-	-	-	-	-	(261,807)	(658,652)	-	-	(935,008)
65	Ending Balance		$ 790,087	$ 792,147	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 525,673	$ 701,107	$ 701,107	$ 701,107	$ 701,107
67	Average Rate For Withdrawals		$10.7292	$10.7292	$10.7292	$10.7292	$10.7292	$10.7292	$10.7292	$10.7292	$10.7292	$11.4746	$11.4746	$11.4746	
69	Propane Rate for Injections	Actual or Sch. 6, ln 165 * 10	$10.7292	$10.7292	$10.7292	$0.0000	$0.0000	$0.0000	$12.0000	$12.0000	$12.0000	$12.0000	$12.0000	$12.0000	
72	Month Dollar Average	ln (57 + ln 65) /2				$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 787,480	$ 656,576	$ 613,390	$ 701,107	$ 701,107	
74	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
76	Inventory Finance Charge	ln 72 * ln 74				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
79	**Liquid Natural Gas (LNG)**		May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Total
80			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
81	Beginning Balance		9,988	9,326	8,208	7,858	6,740	5,622	4,504	4,430	(35,570)	(85,164)	(125,392)	(116,488)	9,988
83	Injections	Sch 11A ln 37 /10	809	781	1,468	781	781	781	2,067	2,188	5,137	29,182	36,208	-	80,183
85	Subtotal		10,797	10,107	9,676	8,639	7,521	6,403	6,571	6,618	(30,433)	(55,982)	(89,183)	(116,488)	
87	Withdrawals	Sch 11A ln 32 /10	(1,471)	(1,899)	(1,818)	(1,899)	(1,899)	(1,899)	(2,140)	(42,188)	(54,731)	(69,410)	(27,304)	(2,102)	(208,760)
89	Ending Balance		9,326	8,208	7,858	6,740	5,622	4,504	4,430	(35,570)	(85,164)	(125,392)	(116,488)	(118,589)	(118,589)
92	Beginning Balance		$ 44,513	$ 45,885	$ 44,350	$ 47,345	$ 42,683	$ 37,410	$ 31,495	$ 30,889	$ (249,697)	$ (594,794)	$ (867,353)	$ (813,985)	$ 44,513
94	Injections	ln 83 * ln 104	8,611	8,739	13,841	7,364	7,364	7,364	14,318	15,566	37,152	207,560	244,164	-	572,044
96	Subtotal		$ 53,124	$ 54,624	$ 58,192	$ 54,709	$ 50,047	$ 44,774	$ 45,813	$ 46,456	$ (212,545)	$ (387,234)	$ (623,189)	$ (813,985)	
98	Withdrawals	ln 87 * ln 102	(7,239)	(10,274)	(10,847)	(12,026)	(12,636)	(13,279)	(14,924)	(296,153)	(382,250)	(480,118)	(190,796)	(14,685)	(1,445,226)
100	Ending Balance		$ 45,885	$ 44,350	$ 47,345	$ 42,683	$ 37,410	$ 31,495	$ 30,889	$ (249,697)	$ (594,794)	$ (867,353)	$ (813,985)	$ (828,670)	$ (828,670)
102	Average Rate For Withdrawals		$4.9203	$5.4046	$6.0140	$6.3328	$6.6543	$6.9927	$6.9725	$7.0199	$6.9841	$6.9172	$6.9877	$6.9877	
104	LNG Rate for Injections	Actual or Sch. 6, ln 164 * 10	$10.6445	$11.1895	$9.4287	$9.4287	$9.4287	$9.4287	$6.9285	$7.1160	$7.2321	$7.1125	$6.7434	$0.0000	
107	Month Dollar Average	ln (92 + ln 100) /2				$ 45,014	$ 40,047	$ 34,453	$ 31,192	$ (109,404)	$ (422,246)	$ (731,073)	$ (840,669)	$ (821,327)	
109	Money Pool Finance Rate (per Nov 10 - Apr 11 Actuals)					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
111	Inventory Finance Charge	ln 107 * ln 109				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
114	Total Fuel Financing	lns 53 + 76 + 111				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing

Forecast of Firm Transportation Volumes and Cost of Gas Revenues

Firm Transportation

	Therms 1/	Cost of Gas Rate 2/	Cost of Gas Revenue
Nov-21	6,336,940	$ 0.0002	$ 1,032
Dec-21	7,828,880	0.0002	1,276
Jan-22	8,811,910	0.0002	1,436
Feb-22	7,357,300	0.0002	1,199
Mar-22	7,024,370	0.0002	1,145
Apr-22	5,224,390	0.0002	851
Total	**42,583,790**		**$ 6,938**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.
2/ Refer to Proposed Second Revised Page 98 for calculation of rate.

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty — Updated Schedule 19
Local Delivery Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment — RCE
For LDAC effective November 1, 2021 - October 31, 2022 — Page 1 of 2

1	Rate Case Exepense	
2	Prior Period Balance	($11,949)
3	Expenses thru June 30, 2021	$785,177
4	Balance at June 30, 2021	$773,228
5	Less: Accrual Balance	($26,000)
6	Adjusted Rate Case Expense	$747,228
7		
8	Recoupment	
9	Distribution Recoupment from Docket No. DG 20-105	($568,780)
10	Indirect Costs Recoupment from Docket No. DG 20-105	$1,900,000
11	Total Recoupment	$1,331,220
12		
13	Beginning Balance	$2,078,448
14		
15	Estimated Remaining Expenses	$97,375
16		
17	Plus Estimated Interest from July 2021 through October 2021	$19,820
18		
19	Minus Estimated Recoveries from July 2021 through October 2021	($7,864)
20		
21	Total Estimated Remaining Recovery As of November 1, 2021	$2,187,779
22		
23	Estimated November 2021 - October 2022 Interest	$26,727
24		
25	Total Remaining Recovery	$2,214,505
26		
27	Estimated November 2021 - October 2022 Sales (therms)	182,829,872
28		
29	RCE & Recoupment rate per therm November 2021 - October 2022	$0.0121

Updated Schedule 19
RCE
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Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
JULY 2021 THROUGH OCTOBER 2022
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)
1	**FOR THE MONTH OF:**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Nov-21**	**Dec-21**	**Jan-22**	**Feb-22**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**
3	Beginning Balance	$ 747,228	$ 2,092,979	$ 2,180,900	$ 2,184,876	$ 2,187,779	$ 1,972,912	$ 1,665,779	$ 1,308,911
4									
5	Add: Additional Rate Case Expense	13,875	83,501	-	-	-	-	-	-
6									
7	Add: Recoupment	1,331,220	-	-	-	-	-	-	-
8									
9	Less: Collected Revenue	(1,423)	(1,471)	(1,847)	(3,123)	(220,417)	(312,148)	(360,968)	(303,766)
10									
11	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-
12									
13	Ending Balance Pre-Interest	$ 2,090,900	$ 2,175,009	$ 2,179,052	$ 2,181,752	$ 1,967,362	$ 1,660,764	$ 1,304,811	$ 1,005,145
14									
15	Month's Average Balance	$ 753,454	$ 2,133,994	$ 2,179,976	$ 2,183,314	$ 2,077,571	$ 1,816,838	$ 1,485,295	$ 1,157,028
16									
17	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
18									
19	Interest Applied	$ 2,080	$ 5,890	$ 5,823	$ 6,027	$ 5,550	$ 5,015	$ 4,100	$ 2,885
20									
21	Ending Balance	**$ 2,092,979**	**$ 2,180,900**	**$ 2,184,876**	**$ 2,187,779**	**$ 1,972,912**	**$ 1,665,779**	**$ 1,308,911**	**$ 1,008,029**

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Mar-22**	**Apr-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**Total**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 1,008,029	$ 742,408	$ 570,514	$ 455,322	$ 380,344	$ 311,946	$ 241,019	$ 151,743	$ 10,996,706
4										
5	Add: Additional Rate Case Expense	-	-	-	-	-	-	-	-	-
6										
7	Add: Recoupment	-	-	-	-	-	-	-	-	-
8										
9	Less: Collected Revenue	(268,034)	(173,704)	(116,560)	(76,129)	(69,352)	(71,664)	(89,818)	(151,945)	(2,214,506)
10										
11	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-
12										
13	Ending Balance Pre-Interest	$ 739,995	$ 568,704	$ 453,953	$ 379,192	$ 310,992	$ 240,282	$ 151,201	$ (202)	**$ 8,782,201**
14										
15	Month's Average Balance	$ 874,012	$ 655,556	$ 512,234	$ 417,257	$ 345,668	$ 276,114	$ 196,110	$ 75,770	
16										
17	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
18										
19	Interest Applied	$ 2,413	$ 1,810	$ 1,368	$ 1,152	$ 954	$ 738	$ 541	$ 202	**26,727**
20										
21	Ending Balance	**$ 742,408**	**$ 570,514**	**$ 455,322**	**$ 380,344**	**$ 311,946**	**$ 241,019**	**$ 151,743**	**$ (0)**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities
Revenue Decoupling Adjustment Factor (RDAF)
For LDAC effective November 1, 2021 - October 31, 2022

	Residential	
1	Residential Projected September 1, 2021 Reconciliation Balance of Prior Recoveries / (Refunds)	($523,704)
2	Residential Revenue Decoupling Deficiency / (Excess) - Current Period	$1,522,705
3	Total Residential Revenue Decoupling Deficiency / (Excess) - Prior to Adjustments	$999,001
4	Adjustments to Residential prior year filings for low income customer treatment	
5	2019 Filing (total adjustment is $1,932,224 collected over two years)	$966,112
6	2020 Filing (total adjustment is $2,092,605 collected over two years)	$1,046,302
7	Removal of Adjustments to Residential prior year filings for low income customer treatment	($2,012,414)
8	Total Residential Revenue Decoupling Deficiency / (Excess) - September 1, 2021	$999,001
9	Estimated Residential November 2021 - October 2022 Sales (therms)	65,649,919
10	Residential Revenue Decoupling rate per therm November 2020 - October 2021	$0.0152
	Commercial	
11	Commercial Projected September 1, 2021 Reconciliation Balance of Prior Recoveries / (Refunds)	($446,234)
12	Residential Revenue Decoupling Deficiency / (Excess) - Current Period	$903,659
13	Total Commercial Revenue Decoupling Deficiency / (Excess) - Current Period	$457,424
14	Estimated Commercial November 2021 - October 2022 Sales (therms)	117,179,952
15	Commercial Revenue Decoupling rate per therm November 2020 - October 2021	$0.0039

Liberty Utilities (EnergyNorth Natural Gas) Corp.
November 2020 through August 2021
Revenue Decoupling - Credits by Sector

RESIDENTIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
FOR THE MONTH OF:	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
DAYS IN MONTH	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
Over / Under Beginning Balance	$ (3,682,012)	$ (3,465,584)	$ (3,070,769)	$ (2,529,984)	$ (1,925,470)	$ (1,325,885)	$ (964,491)	$ (760,172)	$ (654,619)	$ (581,484)
Monthly billing activity	$ 225,962	$ 403,824	$ 548,504	$ 610,062	$ 604,066	$ 364,448	$ 206,696	$ 107,440	$ 74,839	$ 59,303
Ending Balance Pre-Interest	$ (3,456,051)	$ (3,061,761)	$ (2,522,265)	$ (1,919,923)	$ (1,321,404)	$ (961,436)	$ (757,795)	$ (652,732)	$ (579,780)	$ (522,181)
Month's Average Balance	$ (3,569,032)	$ (3,263,672)	$ (2,796,517)	$ (2,224,953)	$ (1,623,437)	$ (1,143,661)	$ (861,143)	$ (706,452)	$ (617,200)	$ (551,832)
Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Applied	$ (9,534)	$ (9,009)	$ (7,719)	$ (5,547)	$ (4,481)	$ (3,055)	$ (2,377)	$ (1,887)	$ (1,704)	$ (1,523)
Ending Balance	**$ (3,465,584)**	**$ (3,070,769)**	**$ (2,529,984)**	**$ (1,925,470)**	**$ (1,325,885)**	**$ (964,491)**	**$ (760,172)**	**$ (654,619)**	**$ (581,484)**	**$ (523,704)**

COMMERCIAL & INDUSTRIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
FOR THE MONTH OF:	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
DAYS IN MONTH	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
Over / Under Beginning Balance	$ (2,441,102)	$ (2,273,218)	$ (2,038,784)	$ (1,750,239)	$ (1,422,472)	$ (1,089,831)	$ (870,841)	$ (725,225)	$ (617,318)	$ (528,882)
Monthly billing activity	$ 174,172	$ 240,378	$ 293,767	$ 331,718	$ 336,103	$ 221,606	$ 147,815	$ 109,698	$ 90,016	$ 83,991
Ending Balance Pre-Interest	$ (2,266,930)	$ (2,032,841)	$ (1,745,017)	$ (1,418,522)	$ (1,086,369)	$ (868,225)	$ (723,025)	$ (615,527)	$ (527,302)	$ (444,890)
Month's Average Balance	$ (2,354,016)	$ (2,153,030)	$ (1,891,900)	$ (1,584,380)	$ (1,254,420)	$ (979,028)	$ (796,933)	$ (670,376)	$ (572,310)	$ (486,886)
Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
Interest Applied	$ (6,288)	$ (5,943)	$ (5,222)	$ (3,950)	$ (3,463)	$ (2,615)	$ (2,200)	$ (1,791)	$ (1,580)	$ (1,344)
Ending Balance	**$ (2,273,218)**	**$ (2,038,784)**	**$ (1,750,239)**	**$ (1,422,472)**	**$ (1,089,831)**	**$ (870,841)**	**$ (725,225)**	**$ (617,318)**	**$ (528,882)**	**$ (446,234)**

Total Ending Balance	**$ (5,738,803)**	**$ (5,109,553)**	**$ (4,280,223)**	**$ (3,347,941)**	**$ (2,415,716)**	**$ (1,835,332)**	**$ (1,485,397)**	**$ (1,271,937)**	**$ (1,110,366)**	**$ (969,938)**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
September 2020 through August 2021
Revenue Decoupling Activity by Sector

	RESIDENTIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
1	**FOR THE MONTH OF:**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
2	**DAYS IN MONTH**	**30**	**31**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
3	Over Under Beginning Balance		$ 257,090	$ 810,822	$ 1,511,842	$ 1,582,770	$ 2,215,950	$ 2,187,009	$ 2,273,003	$ 1,546,131	$ 1,519,036	$ 1,546,764	$ 1,364,717
4													
5	Monthly revenue difference Inc/(Dec) revenue	$ 240,943	$ 517,074	$ 585,965	$ (5,280)	$ 630,944	$ (31,172)	$ 4,026	$ (790,048)	$ (59,223)	$ 21,114	$ (186,059)	$ 154,008
6													
7	True up	15,804	35,187	111,956	71,943	(2,999)	(3,251)	75,821	58,082	27,903	2,525		
8													
9	Ending Balance Pre-Interest	$ 256,747	$ 809,350	$ 1,508,744	$ 1,578,505	$ 2,210,715	$ 2,181,527	$ 2,266,856	$ 1,541,037	$ 1,514,811	$ 1,542,674	$ 1,360,705	$ 1,518,726
10													
11	Month's Average Balance	$ 128,373	$ 533,220	$ 1,159,783	$ 1,545,174	$ 1,896,742	$ 2,198,738	$ 2,226,932	$ 1,907,020	$ 1,530,471	$ 1,530,855	$ 1,453,734	$ 1,441,721
12													
13	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
14													
15	Interest Applied	$ 343	$ 1,472	$ 3,098	$ 4,265	$ 5,236	$ 5,482	$ 6,147	$ 5,094	$ 4,225	$ 4,089	$ 4,013	$ 3,980
16													
17	Ending Balance	**$ 257,090**	**$ 810,822**	**$ 1,511,842**	**$ 1,582,770**	**$ 2,215,950**	**$ 2,187,009**	**$ 2,273,003**	**$ 1,546,131**	**$ 1,519,036**	**$ 1,546,764**	**$ 1,364,717**	**$ 1,522,705**

	COMMERCIAL & INDUSTRIAL	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)
18	**FOR THE MONTH OF:**	**Sep-20**	**Oct-20**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**
19	**DAYS IN MONTH**	**30**	**31**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**
20	Over Under Beginning Balance		$ 29,045	$ (347,758)	$ (718,458)	$ (1,539,810)	$ (908,753)	$ (595,095)	$ 382,115	$ 405,459	$ 771,334	$ 960,953	$ 838,916
21													
22	Monthly revenue difference Inc/(Dec) revenue	$ 30,086	$ (399,411)	$ (532,021)	$ (762,675)	$ 638,015	$ 406,808	$ 946,452	$ (57,824)	$ 362,977	$ 219,735	$ (124,518)	$ 62,341
23													
24	True up	(1,079)	23,047	162,743	(55,564)	(3,584)	(91,277)	31,051	80,118	1,276	(32,427)		
25													
26	Ending Balance Pre-Interest	$ 29,007	$ (347,319)	$ (717,036)	$ (1,536,698)	$ (905,379)	$ (593,222)	$ 382,409	$ 404,409	$ 769,712	$ 958,642	$ 836,435	$ 901,257
27													
28	Month's Average Balance	$ 14,503	$ (159,137)	$ (532,397)	$ (1,127,578)	$ (1,222,594)	$ (750,988)	$ (106,343)	$ 393,262	$ 587,586	$ 864,988	$ 898,694	$ 870,086
29													
30	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%
31													
32	Interest Applied	$ 39	$ (439)	$ (1,422)	$ (3,112)	$ (3,375)	$ (1,872)	$ (294)	$ 1,050	$ 1,622	$ 2,311	$ 2,481	$ 2,402
33													
34	Ending Balance	**$ 29,045**	**$ (347,758)**	**$ (718,458)**	**$ (1,539,810)**	**$ (908,753)**	**$ (595,095)**	**$ 382,115**	**$ 405,459**	**$ 771,334**	**$ 960,953**	**$ 838,916**	**$ 903,659**

35	Total Ending Balance	**$ 286,135**	**$ 463,064**	**$ 793,384**	**$ 42,960**	**$ 1,307,197**	**$ 1,591,914**	**$ 2,655,118**	**$ 1,951,590**	**$ 2,290,370**	**$ 2,507,716**	**$ 2,203,633**	**$ 2,426,364**

Updated Schedule 19
RDAF
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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Revenue Decoupling
Adjustments to Residential prior year filings for low income customer treatment

2019-2020 Filing

		Filing	Adjusted (1)	Difference
	Residential			
1.	Allowed Base Revenue	$ 40,585,321	$ 42,517,544	$ 1,932,224
2.	less: Actual and Estimated Base Revenue	44,670,474	44,670,474	-
3.	Revenue Deficiency / (Excess)	(4,085,152.93)	(2,152,929.54)	$ 1,932,224
	Commercial			
4.	Allowed Base Revenue	$ 31,436,763	$ 31,436,763	$ -
5.	less: Actual and Estimated Base Revenue	34,368,401	34,368,401	-
6.	Revenue Deficiency / (Excess)	(2,931,638.28)	(2,931,638.28)	$ -
7.	**TOTAL Revenue Deficiency / (Excess)**	**(7,016,791.21)**	**(5,084,567.82)**	**$ 1,932,224**

2020-2021 Filing

		Filing	Adjusted (1)	Difference
	Residential			
8.	Allowed Base Revenue	$ 47,055,148	$ 49,147,752	$ 2,092,605
9.	less: Actual and Estimated Base Revenue	50,205,891	50,205,891	-
10.	Revenue Deficiency / (Excess)	(3,150,743.35)	(1,058,138.97)	$ 2,092,605
	Commercial			
11.	Allowed Base Revenue	$ 36,558,043	$ 36,558,043	$ -
12.	less: Actual and Estimated Base Revenue	38,373,247	38,373,247	-
13.	Revenue Deficiency / (Excess)	(1,815,203.44)	(1,815,203.44)	$ -
14.	**TOTAL Revenue Deficiency / (Excess)**	**(4,965,946.79)**	**(2,873,342.41)**	**$ 2,092,605**

(1) The calculations of the adjusted allowed revenue are included in attachment Attachment 2019-2020 RDAF Adjustment and Attachment 2020-2021 RDAF Adjustment

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2021 - October 31, 2022
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	Actual DSM Expenditures Low-Income	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Monthly Federal Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Residential Therm Sales	Residential Therm Sales	# of Days
May 21	Actual	(765,079)	($0.0831)	(305,597)	404,158	211,716	10,302	15,989	(832,670)	(798,875)	3.25%	(3,178)	(835,848)	2,887,019	3,677,744	31
June 21	Actual	(835,848)	($0.0831)	(158,833)	404,158	537,081	111,395	15,989	(330,215)	(583,031)	3.25%	(2,775)	(332,990)	1,308,632	1,911,618	30
July 21	Forecast	(332,990)	($0.0831)	(93,229)	404,158	0	0	0	(22,061)	(177,525)	3.25%	(490)	(22,551)	1,121,890	0	31
August 21	Forecast	(22,551)	($0.0831)	(90,152)	404,158	0	0	0	291,456	134,453	3.25%	371	291,827	1,084,856	0	31
September 21	Forecast	291,827	($0.0831)	(133,428)	404,158	0	0	0	562,557	427,192	3.25%	1,141	563,698	1,605,635	0	30
October 21	Forecast	563,698	($0.0831)	(235,825)	404,158	0	0	0	732,031	647,865	3.25%	1,788	733,819	2,837,843	0	31
November 21	Forecast	733,819	($0.0861)	(594,247)	404,158	0	0	0	543,731	638,775	3.25%	1,706	545,437	6,901,820	0	30
December 21	Forecast	545,437	($0.0861)	(865,560)	404,158	0	0	0	84,035	314,736	3.25%	869	84,904	10,052,958	0	31
January 22	Forecast	84,904	($0.0861)	(995,446)	412,449	0	0	0	(498,093)	(206,595)	3.25%	(570)	(498,664)	11,561,514	0	31
February 22	Forecast	(498,664)	($0.0861)	(777,324)	412,449	0	0	0	(863,539)	(681,101)	3.25%	(1,698)	(865,237)	9,028,156	0	28
March 22	Forecast	(865,237)	($0.0861)	(753,706)	412,449	0	0	0	(1,206,494)	(1,035,866)	3.25%	(2,859)	(1,209,354)	8,753,844	0	31
April 22	Forecast	(1,209,354)	($0.0861)	(448,422)	412,449	0	0	0	(1,245,327)	(1,227,340)	3.25%	(3,279)	(1,248,606)	5,208,158	0	30
May 22	Forecast	(1,248,606)	($0.0861)	(249,823)	412,449	0	0	0	(1,085,980)	(1,167,293)	3.25%	(3,222)	(1,089,202)	2,901,545	0	31
June 22	Forecast	(1,089,202)	($0.0861)	(113,450)	412,449	0	0	0	(790,203)	(939,703)	3.25%	(2,510)	(792,713)	1,317,656	0	30
July 22	Forecast	(792,713)	($0.0861)	(83,483)	412,449	0	0	0	(463,747)	(628,230)	3.25%	(1,734)	(465,481)	969,602	0	31
August 22	Forecast	(465,481)	($0.0861)	(85,759)	412,449	0	0	0	(138,792)	(302,137)	3.25%	(834)	(139,626)	996,041	0	31
September 22	Forecast	(139,626)	($0.0861)	(154,591)	412,449	0	0	0	118,232	(10,697)	3.25%	(29)	118,203	1,795,484	0	30
October 22	Forecast	118,203	($0.0861)	(383,367)	412,449	0	0	0	147,285	132,744	3.25%	366	147,652	4,452,576	0	31
November 22	Forecast	147,652	($0.0861)	(594,247)	412,449	0	0	0	(34,146)	56,753	3.25%	152	(33,995)	6,901,820	0	30
December 22	Forecast	(33,995)	($0.0861)	(865,560)	412,449	0	0	0	(487,105)	(260,550)	3.25%	(719)	(487,825)	10,052,958	0	31

Estimated Residential Conservation Charge Effective November 1, 2021 - October 31, 2022		
Beginning Balance	$	733,819
Program Budget Nov 2021-Oct 2022		**4,932,804**
Projected Interest		(13,794)
Projected Budget with Interest	$	5,652,830
Total Charges	**$**	**5,652,830**
Projected Therm Sales		**65,649,919**
Residential Rate		**$0.0861**
Total Charges with Interest	**$**	**5,652,830**
Projected Therm Sales		**65,649,919**
Residential Rate		**$0.0861**

Residential Non Heating Therm Sales	0%	**741,340**	**741,340**	0%
Residential Heating Therm Sales	35%	**64,908,579**	**64,908,579**	35%
C&I Therm Sales	64%	**117,249,138**	**117,249,138**	64%
Total Therms	100%	**182,899,057**	**182,899,057**	100%
		Budget **2021**	Budget **2022**	
Low-Income Program Budget		**$ 1,523,570**	**$ 1,627,400**	
Other Refund		-	-	
Total Shared Budget		**$ 1,523,570**	**$ 1,627,400**	
Residential Program Budget		**$ 3,926,326**	**$ 4,059,085**	
Residential Performance Incentive		**$ 299,744**	**$ 312,757**	
Total Residential Program Budget		**$ 4,226,070**	**$ 4,371,842**	
Commercial/Industrial Program Budget		**$ 3,512,260**	**$ 3,886,433**	
Commercial/Industrial Program Incentive		**$ 193,174**	**$ 213,754**	
Total Commercial/Industrial Program Budget		**$ 3,705,434**	**$ 4,100,187**	
Total Program Budget		**$ 9,455,074**	**$ 10,099,429**	
Shared Expenses Allocation to Residential		$ 546,871	$ 577,544	
Shared Expenses Allocation to C&I		976,699	1,043,260	
Total Allocated Shared Expenses		**$ 1,523,570**	**$ 1,620,804**	
Total Residential (including allocation of Shared Budget)		$ 4,772,941	$ 4,949,386	
Total C&I (including allocation of Shared Budget)		4,682,133	5,143,447	
Total Budget		**$ 9,455,074**	**$ 10,092,833**	

Total Residential (including allocation of Shared Budget)	$ 4,772,941	$ 4,949,386
Total C&I (including allocation of Shared Budget)	4,682,133	5,143,447
Total Budget	**$ 9,455,074**	**$ 10,092,833**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2021 - October 31, 2022
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures C&I	Actual DSM Expenditures Low-Income	Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Fed Reserve Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Commercial/ Industrial Therm Sales	Actual Commercial/ Industrial Therm Sales	# of Days
May 21	Actual	(1,366,413)	($0.0441)	(316,425)	455,607	170,075	13,657	14,818	(1,484,288)	(1,425,351)	3.25%	(2,945)	(1,487,233)	6,635,508	7,175,611	31
June 21	Actual	(1,487,233)	($0.0441)	(234,819)	455,607	224,152	147,663	14,818	(1,335,419)	(1,411,326)	3.25%	(2,572)	(1,337,991)	4,794,620	5,325,135	30
July 21	Forecast	(1,337,991)	($0.0441)	(194,811)	455,607	0	0		(1,077,195)	(1,207,593)	3.25%	(3,333)	(1,080,528)	4,417,480	0	31
August 21	Forecast	(1,080,528)	($0.0441)	(190,167)	455,607	0	0		(815,088)	(947,808)	3.25%	(2,616)	(817,705)	4,312,181	0	31
September 21	Forecast	(817,705)	($0.0441)	(210,967)	455,607	0	0		(573,065)	(695,385)	3.25%	(1,858)	(574,922)	4,783,833	0	30
October 21	Forecast	(574,922)	($0.0441)	(279,638)	455,607	0	0		(398,954)	(486,938)	3.25%	(1,344)	(400,298)	6,340,998	0	31
November 21	Forecast	(400,298)	($0.0408)	(467,051)	455,607	0	0		(411,742)	(406,020)	3.25%	(1,085)	(412,826)	11,447,324	0	30
December 21	Forecast	(412,826)	($0.0408)	(627,711)	455,607	0	0		(584,931)	(498,879)	3.25%	(1,377)	(586,308)	15,385,075	0	31
January 22	Forecast	(586,308)	($0.0408)	(711,095)	428,621	0	0		(868,782)	(727,545)	3.25%	(2,008)	(870,791)	17,428,801	0	31
February 22	Forecast	(870,791)	($0.0408)	(609,932)	428,621	0	0		(1,052,102)	(961,446)	3.25%	(2,397)	(1,054,499)	14,949,322	0	28
March 22	Forecast	(1,054,499)	($0.0408)	(536,719)	428,621	0	0		(1,162,598)	(1,108,549)	3.25%	(3,060)	(1,165,658)	13,154,881	0	31
April 22	Forecast	(1,165,658)	($0.0408)	(369,458)	428,621	0	0		(1,106,496)	(1,136,077)	3.25%	(3,035)	(1,109,530)	9,055,353	0	30
May 22	Forecast	(1,109,530)	($0.0408)	(272,836)	428,621	0	0		(953,746)	(1,031,638)	3.25%	(2,848)	(956,594)	6,687,163	0	31
June 22	Forecast	(956,594)	($0.0408)	(197,195)	428,621	0	0		(725,168)	(840,881)	3.25%	(2,246)	(727,414)	4,833,207	0	30
July 22	Forecast	(727,414)	($0.0408)	(185,428)	428,621	0	0		(484,221)	(605,818)	3.25%	(1,672)	(485,894)	4,544,800	0	31
August 22	Forecast	(485,894)	($0.0408)	(192,519)	428,621	0	0		(249,792)	(367,843)	3.25%	(1,015)	(250,807)	4,718,593	0	31
September 22	Forecast	(250,807)	($0.0408)	(223,802)	428,621	0	0		(45,988)	(148,398)	3.25%	(396)	(46,385)	5,485,342	0	30
October 22	Forecast	(46,385)	($0.0408)	(324,175)	428,621	0	0		58,061	5,838	3.25%	16	58,077	7,945,466	0	31
November 22	Forecast	58,077	($0.0408)	(467,051)	428,621	0	0		19,646	38,862	3.25%	104	19,750	11,447,324	0	30
December 22	Forecast	19,750	($0.0408)	(627,711)	428,621	0	0		(179,340)	(79,795)	3.25%	(220)	(179,560)	15,385,075	0	31

Estimated C&I Conservation Charge November 1, 2021 - October 31, 2022	
Beginning Balance	(400,298)
Program Budget Nov 2021-Oct 2022	**5,197,419**
Projected Interest	(21,123)
Program Budget with Interest	4,775,998
Total Charges	**$4,775,998**
Projected Therm Sales	**117,179,952**
C&I Rate	$0.0408
Total Charges with Interest	**$4,780,942**
Projected Therm Sales	**117,179,952**
C&I Rate	**$0.0408**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2021 - October 31, 2022
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures				Incentive	Ending Balance (Over)/Under	Average Balance (Over)/Under	Interest Plus Interest Prime Rate	Interest @ Fed Reserve Bank Loan Rate	Ending Bal. Plus Interest (Over)/Under	Forecasted Therm Sales	Actual Therm Sales	# of Days
						Residential	C&I	Low-Income	Total									
May 21	Actual	(2,131,493)	n/a	(622,023)	859,765	211,716	170,075	23,959	405,750	30,807	(2,316,958)	(2,224,225)	3.25%	(6,123)	(2,323,081)	12,333,808	12,290,578	31
June 21	Actual	(2,323,081)	n/a	(393,652)	859,765	537,081	224,152	259,058	1,020,292	30,807	(1,665,634)	(1,994,358)	3.25%	(5,346)	(1,670,980)	7,703,669	7,740,734	30
July 21	Forecast	(1,670,980)	n/a	(288,040)	859,765	0	0	0	0		(1,099,255)	(1,385,118)	3.25%	(3,823)	(1,103,079)	5,471,615	2,303,736	31
August 21	Forecast	(1,103,079)	n/a	(280,319)	859,765	0	0	0	0		(523,633)	(813,356)	3.25%	(2,245)	(525,878)	5,317,216	0	31
September 21	Forecast	(525,878)	n/a	(344,395)	859,765	0	0	0	0		(10,508)	(268,193)	3.25%	(716)	(11,225)	6,269,177	0	30
October 21	Forecast	(11,225)	n/a	(515,463)	859,765	0	0	0	0		333,077	160,926	3.25%	444	333,522	9,068,225	0	31
November 21	Forecast	333,522	n/a	(1,061,298)	859,765	0	0	0	0		131,989	232,755	3.25%	622	132,611	13,857,797	0	30
December 21	Forecast	132,611	n/a	(1,493,271)	859,765	0	0	0	0		(500,895)	(184,142)	3.25%	(508)	(501,404)	21,185,695	0	31
January 22	Forecast	(501,404)	n/a	(1,706,541)	841,069	0	0	0	0		(1,366,876)	(934,140)	3.25%	(2,578)	(1,369,454)	28,674,991	0	31
February 22	Forecast	(1,369,454)	n/a	(1,387,257)	841,069	0	0	0	0		(1,915,641)	(1,642,548)	3.25%	(4,095)	(1,919,737)	30,438,317	0	28
March 22	Forecast	(1,919,737)	n/a	(1,290,425)	841,069	0	0	0	0		(2,369,092)	(2,144,414)	3.25%	(5,919)	(2,375,011)	26,349,344	0	31
April 22	Forecast	(2,375,011)	n/a	(817,881)	841,069	0	0	0	0		(2,351,823)	(2,363,417)	3.25%	(6,313)	(2,358,136)	19,706,228	0	30
May 22	Forecast	(2,358,136)	n/a	(522,659)	841,069	0	0	0	0		(2,039,726)	(2,198,931)	3.25%	(6,070)	(2,045,796)	12,611,378	0	31
June 22	Forecast	(2,045,796)	n/a	(310,645)	841,069	0	0	0	0		(1,515,371)	(1,780,583)	3.25%	(4,756)	(1,520,128)	7,850,220	0	30
July 22	Forecast	(1,520,128)	n/a	(268,911)	841,069	0	0	0	0		(947,969)	(1,234,048)	3.25%	(3,406)	(951,375)	5,539,370	0	31
August 22	Forecast	(951,375)	n/a	(278,278)	841,069	0	0	0	0		(388,583)	(669,979)	3.25%	(1,849)	(390,433)	5,397,037	0	31
September 22	Forecast	(390,433)	n/a	(378,393)	841,069	0	0	0	0		72,244	(159,095)	3.25%	(425)	71,819	6,389,467	0	30
October 22	Forecast	71,819	n/a	(707,542)	841,069	0	0	0	0		205,346	138,582	3.25%	383	205,729	9,178,841	0	31
November 22	Forecast	205,729	n/a	(1,061,298)	841,069	0	0	0	0		(14,500)	95,615	3.25%	255	(14,244)	13,857,797	0	30
December 22	Forecast	(14,244)	n/a	(1,493,271)	841,069	0	0	0	0		(666,446)	(340,345)	3.25%	(939)	(667,385)	21,185,695	0	31

Residential (R-1 & R-3) and C & I Conservation Charge November 1, 2021 - October 31, 2022		
Beginning Balance	$	333,522
Program Budget Nov 2021-Oct 2022	$	10,130,223
Projected Interest	$	(34,917)
Program Budget with Interest	$	10,428,828
Total Charges		**$10,428,828**

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

Gas Assistance Program

1	**Distribution**	**Customer Charge**	**Block**	**Total**	
2	R-3 Base Rates	$ 15.39	$ 0.5632		
3	R-4 Base Rates at 55% of R-3	$ 8.47	$ 0.3098		
4	Program Distribution Subsidy	$ 6.9260	$ 0.2534		
5	Normal Winter Therms			595	
6					
7	Estimated Winter 2021/2022 Distribution Subsidy	$ 41.56	$ 150.82	$ 192.38	
8					
9	Number of Estimated 2021/2022 Participants	5,273	47	5,320	(a)
10					
11	**COG**	**ENNG**	**Keene**	**Total**	
12	R-3 COG Rates	$ 1.1339	$ 1.2816		
13	R-4 COG Rates at 55% of R-3	$ 0.6236	$ 0.7049		
14	Program COG Subsidy	$ 0.5103	$ 0.5767		
15					
16	Estimated Winter 2021/2022 COG Subsidy (Ln 5 * Ln 14)	$ 303.68	$ 343.21	$ 646.89	
17					
18	Winter Distribution Subsidy times Number of Participants (Ln 7 * Ln 9)			$ 1,023,450	
19	Winter COG Subsidy times Number of Participants (Ln 9 * Ln 16)			$ 1,617,433	
20	Prior Year Ending Balance - Gas Assistance Page 2			$ 208,239	
21	Estimated Annual Administrative Costs			-	
22	Total Program Costs			$ 2,849,123	
23					
24	Estimated weather normalized firm therms billed for the				
25	Twelve months ended 10/31/22 sales and transportation			182,829,872	
26					
27	**Total Gas Assistance Program Charge**			**$ 0.0156**	

(a) Estimated number of participants for 2021/22 is based on the actual number participants as of April 2021.

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

NOVEMBER 2020 THROUGH OCTOBER 2021
RESIDENTIAL GAS ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.6

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-20**	**Dec-20**	**Jan-21**	**Feb-21**	**Mar-21**	**Apr-21**	**May-21**	**Jun-21**	**Jul-21**	**Aug-21**	**Sep-21**	**Oct-21**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ 476,374	$ 426,171	$ 451,615	$ 480,838	$ 502,871	$ 554,416	$ 624,872	$ 664,070	$ 586,516	$ 518,743	$ 448,452	$ 359,568	$ 476,374
4														
5	Add: Actual Costs	85,033.7	251,496.7	331,032.5	350,580.8	361,433.3	277,505.0	168,741.3	8,335.5	-	-	-	-	1,834,159
6														
7	Less: Collected Revenue	(136,437.3)	(227,260.1)	(303,090.8)	(329,769.2)	(311,340.9)	(208,617.9)	(131,314.9)	(87,553.7)	(69,295.6)	(71,623.9)	(89,962.5)	(152,110.8)	(2,118,378)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 424,971	$ 450,408	$ 479,556	$ 501,649	$ 552,963	$ 623,304	$ 662,299	$ 584,852	$ 517,220	$ 447,119	$ 358,490	$ 207,457	**$ 192,156**
12														
13	Month's Average Balance	$ 450,673	$ 438,290	$ 465,585	$ 491,244	$ 527,917	$ 588,860	$ 643,585	$ 624,461	$ 551,868	$ 482,931	$ 403,471	$ 283,512	
14														
15	Interest Rate	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
16														
17	Interest Applied	$ 1,201	$ 1,207	$ 1,282	$ 1,221	$ 1,453	$ 1,569	$ 1,772	$ 1,664	$ 1,523	$ 1,333	$ 1,078	$ 783	**16,084**
18														
19	Ending Balance	**$ 426,171**	**$ 451,615**	**$ 480,838**	**$ 502,871**	**$ 554,416**	**$ 624,872**	**$ 664,070**	**$ 586,516**	**$ 518,743**	**$ 448,452**	**$ 359,568**	**$ 208,239**	**$ 208,239**

Liberty Utilities (EnergyNorth Natural Gas) Corp d/b/a Liberty
Quarterly Report
Gas Assistance Program (GAP)
2020-21 Discounted 45%

	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summary		
													Actual/ Projected Total To Date (1)	Original Projection (2)	Variance
Customer Count	Actual	Actual	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected	Projected			
Actual / Projected No. of Customers													Average		
LIHEAP	3,882	3,905	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,207	4,155	4,137	(18)
Non-LIHEAP	680	666	673	673	673	673	673	673	673	673	673	673	673	743	70
Total (a)	4,562	4,571	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,880	4,828	4,880	52
GAP Recoveries															
Actual / Projected															
Therm Sales	11,132,422	18,766,131	28,990,315	23,977,478	21,908,725	14,263,510	9,588,709	6,150,863	5,514,402	5,714,634	7,280,826	12,398,042	165,686,055	179,574,679	13,888,624
GAP Rate Per Therm	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	$0.0121	
Total	$134,702	$227,070	$350,783	$290,127	$265,096	$172,588	$116,023	$74,425	$66,724	$69,147	$88,098	$150,016	$2,004,801	$2,172,854	$168,052
Adjustment	$1,735	$190	$0	$0	$0	$0	$0	$0	$0	$0	$0		$1,925	$0	
Total Adjusted Recoveries (3)	$136,438	$227,260	$350,783	$290,127	$265,096	$172,588	$116,023	$74,425	$66,724	$69,147	$88,098	$150,016	$2,006,727	$2,172,854	$166,127
Program Costs															
Actual & Projected Costs															
IT	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Admin. (b)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Education	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Prior Period Ending Balance (c)	476,374	0	0	0	0	0	0	0	0	0	0	0	476,374	476,754	379
Other (incl. Reporting Costs)	789	0	0	0	0	0	0	0	0	0	0	0	789	0	(789)
Fixed Discount	25,724	35,733	34,038	34,038	34,038	34,038	0	0	0	0	0	0	197,609	204,228	6,619
Variable Discount	44,619	116,135	143,737	145,405	136,727	101,372	0	0	0	0	0	0	687,995	749,186	61,191
COG Discount	13,902	99,629	109,389	110,659	104,054	77,148	0	0	0	0	0	0	514,781	737,749	222,968
Avg Monthly Residential Customer	$ 66.50	$ 108.64	$ 146.69	$ 160.62	$ 151.71	$ 124.41	$ 63.52	$ 41.86	$ 30.56	$ 28.68	$ 28.68	$ 35.27	$987.15	$1,907.80	$920.65
v	$ 48.53	$ 81.61	$ 115.53	$ 130.93	$ 121.07	$ 93.93	$ 63.52	$ 41.86	$ 30.56	$ 28.68	$ 28.68	$ 35.27	$820.18	$228.58	($591.61)
Avg Monthly GAP Customer Disco	$17.97	$27.03	$31.17	$29.69	$30.64	$30.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$166.97	$1,679.22	$1,512.25
v	27.02%	24.88%	21.25%	18.49%	20.19%	24.50%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	16.91%	88.02%	
Gross Monthly Revenues	$10,019,053	$18,375,801	$28,990,263	$20,353,998	$18,671,873	$11,875,246	$7,698,494	$5,238,262	$4,997,762	$6,467,910	$5,113,368	$8,930,712	$146,732,741	$161,677,049	$14,944,308
ot	5.60%	1.37%	0.99%	1.43%	1.47%	1.79%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	1.28%	1.34%	

(1) This column represents actual data for the months in which such data is available plus projected data for the remaining months in the 12-month program year.
(2) GAP Projection on Bates 127 of the 2020-21 Cost of Gas Filing, DG 20-141
(3) Ties to the Company's GAP deferral accounts 8840-2-0000-10-1169-1756 & 8843-2-0000-10-1169-1756

(a) The actual number of customers provided for this report are the number of registered customers that were billed during the month.
(b) Actual administrative costs consists of bill inserts and advertising.
(c) The Prior Year 2019-20 under/(over) ending balance.

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Required Annual Environmental Increase	$2,351,805	
Second one-third of prior period under recoveries (through June 2019)	$341,389	
July 2020 - June 2021 recovery difference between actual and estimate	$139,028	
Environmental Subtotal	$2,832,222	
Overall Annual Net Increase to Rates	$2,832,222	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/2022 - sales and transportation	182,829,872	therms
Surcharge per therm	$0.0155	per therm
Total Environmental Surcharge	$0.0155	

1. SITE LOCATION: 38 Bridge Street, Nashua, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: At the end of 1998, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Nashua Manufactured Gas Plant (MGP) to the former plant owners/operators: EnergyNorth Natural Gas, Inc. d/b/a National Grid (ENGI)[1], and Public Service Company of New Hampshire (PSNH) and its parent company, Northeast Utilities Services Company (NU). NHDES designated the site DES #199810022.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site and in the adjacent Nashua River. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations, in groundwater, and in localized river sediments.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - Prior to the time NHDES issued its notice letter to ENGI, the US Environmental Protection Agency (EPA) was remediating contamination (asbestos) at the former Johns Manville plant located adjacent to, and downstream from the 38 Bridge Street property. In the course of that work, EPA detected what it determined to be MGP related residuals in Nashua River sediments containing asbestos. EPA sought reimbursement from ENGI and PSNH of only those incremental additional costs it incurred to dispose of sediments containing MGP related wastes in addition to asbestos. ENGI and PSNH entered into a settlement agreement with the EPA at the end of September 2000. Under the terms of the agreement, each company received a release from liability associated with the so-called Nashua River Superfund Site and contribution protection against future claims associated with that site. The settlement agreement made it clear that EPA does not contend that ENGI or PSNH contributed any asbestos to the Nashua River.

   - In response to the 1998 notice from NHDES, QST Environmental, Inc. (QST, subsequently Environmental Science and Engineering, Inc. (ESE), and later Harding ESE, Inc. (Harding ESE)), submitted a Scoping Phase Field Investigation Scope of Work to NHDES on behalf of ENGI in February 1999.

[1] In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

- In response to comments from NHDES, QST and ENGI refined the Scope of Work for the Scoping Phase Field Investigation and resubmitted to NHDES in April 1999.
- NHDES approved the refined Scoping Phase Field Investigation Scope of Work in May 1999.
- During the summer of 1999, ENGI and QST conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Nashua MGP and the adjacent Nashua River.
- ENGI and ESE submitted the Scoping Phase Field Investigation Report to NHDES in December 1999.
- NHDES provided comments to ENGI and ESE in February 2000 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.
- On behalf of ENGI, ESE submitted a Draft Phase II Investigation Work Plan to NHDES in April 2000.
- ENGI and ESE met with the NHDES site manager in April 2000 to discuss the Draft Phase II Investigation Work Plan.
- NHDES provided written comments on the Draft Phase II Investigation Work Plan in June 2000.
- ENGI and ESE met with NHDES in August 2000 to discuss NHDES' comments on the Phase II Work Plan.
- ENGI submitted a letter to NHDES in August 2000 discussing revisions to the Draft Phase II Investigation Work Plan in response to comments from NHDES and PSNH/NU, along with a proposed schedule for implementation of the work.
- NHDES approved the Revised Phase II Work Plan for the site at the end of August 2000.
- NHDES provided comments to ENGI and Harding ESE on the proposed schedule for Phase II Work Plan implementation in September 2000.

- ENGI submitted an addendum to the Phase II Work Plan, including a proposed approach for risk evaluation, to NHDES in November 2000.

- Subsequent to meetings and discussions throughout 2000, ENGI and PSNH reached agreement in late 2000 regarding sharing of costs for the remediation work and transfer of management of the remediation work to ENGI.

- Harding ESE implemented the Phase II Work Plan during the fall and winter of 2000/2001. Work entailed a comprehensive field program that included the advancement of river borings and collection of sediment samples as well as the installation of borings and monitoring wells on and off the property.

- NHDES provided comments on the Phase II Work Plan addendum in February 2001.

- Harding ESE responded to NHDES comments on the Phase II Work Plan addendum in March 2001.

- In May 2001, ENGI submitted to NHDES a Draft Site Conceptual Model to assist with finalization of the Phase II Work Plan Addendum and met with NHDES to discuss.

- ENGI and Harding ESE revised the Draft Site Conceptual Model and outlined supplemental field activities to be included in the Phase II Work Plan Addendum and submitted to NHDES in June 2001.

- In July 2001, ENGI and Harding ESE met with NHDES to review the Site Conceptual Model and proposed Phase II supplemental investigation activities.

- ENGI and NHDES met in August 2001 to discuss the overall site objectives.

- In September 2001, Harding ESE, on behalf of ENGI, submitted a Phase IIB Supplemental Site Investigation (SI) Scope of Work to NHDES.

- NHDES provided verbal approval for the Phase IIB Supplemental SI, and Harding ESE initiated the field program on behalf of ENGI in October 2001.

- NHDES provided written approval of the Phase IIB Supplemental SI in October 2001. A modification to the proposed scope of work relating to investigations adjacent to the gas lines was proposed and verbal approval was obtained from NHDES on November 19, 2001.

- Property owners north of the Nashua River did not provide access to install monitoring wells proposed in the Phase IIB SOW. Harding ESE completed all on-site work outlined in the Phase IIB SOW in February 2002.

- ENGI received access from PSNH to install Phase IIB monitoring wells west of the site in March 2002.

- Harding ESE installed additional groundwater monitoring wells west of the site in March and sampled all newly installed monitoring wells in April 2002. All work outlined in the Phase IIB SOW was completed except for the proposed monitoring wells north of the Nashua River where access was denied.

- The Phase II Report was submitted to NHDES in February 2003. The report was approved by NHDES in August 2003. At the time of approval, NHDES required ENGI to begin work on the Remedial Action Plan for the site, due in 2004.

- ENGI met with NHDES on November 3, 2003, to review the proposed remedial schedule, which called for the Remedial Action Plan to be submitted in July 2004, and remediation to occur in 2005. NHDES approved the schedule by letter dated December 1, 2003. In that letter they concurred with ENGI's request to divide the site into terrestrial and aquatic portions, to facilitate remediation of sediments concurrent with re-armoring of ENGI's gas mains crossing the river.

- By way of a May 5, 2004 letter, ENGI requested that NHDES waive the Remedial Action Plan (RAP) requirement for the aquatic portion of the site and allow ENGI to proceed with capping sediments in conjunction with gas main rearmoring, which was scheduled for completion in 2004. NHDES approved the request by letter dated May 14, 2004.

- ENGI held pre-application meetings with state and federal agencies (NHDES Wetlands Bureau, United States Army Corps of Engineers, United States Department of Fish and Wildlife, United States Environmental Protection Agency and National Oceanic and Atmospheric Administration) in June 2004. These meetings were held in advance of permit application submission for the capping/rearmoring project, to review the project and expedite the approval process. The application was submitted to these agencies as well as the City of Nashua on July 1, 2004. On July 6, 2004, NHDES deemed the permit application administratively complete. The hearing was closed on July 26, 2004 and the permit was issued in September 2004.

The capping and re-armoring was completed in October 2004 and the Remedial Completion Report, submitted to NHDES in January 2005, was subsequently approved.

- In October 2005, ENGI submitted the Terrestrial Remedial Action Plan to NHDES, and the document was deemed complete by NHDES in March 2006. NHDES requested supplemental information to be submitted before ENGI proceeded with remediation, and in 2007 ENGI gathered the requested data.

- In November 2007, ENGI submitted a Workplan for DNAPL Recovery Pilot Test to NHDES and the document was approved by NHDES on November 14, 2007.

- ENGI applied for three permits required for the implementation of the NHDES-approved DNAPL pilot testing activities: Nashua Conservation Commission Permit, Nashua Zoning Board of Appeals Permit and NHDES Dredge and Fill Permit. ENGI attended numerous hearings related to obtaining the permits and obtained the three permits on April 21, 2008, April 23, 2008, and May 31, 2008, respectively.

- In June 2008, ENGI installed six extraction wells for DNAPL recovery pilot testing at the site. ENGI completed the construction of the coal tar recovery system trailer (i.e., the equipment that will be used to pump, collect and temporarily store the coal tar) in December 2008. Trenching for the subsurface piping and final system installation was delayed in late 2008 due to weather. ENGI performed manual DNAPL recovery throughout 2008 and the first three quarters of 2009.

- In Spring 2009, ENGI began trenching and final system installation activities for the DNAPL recovery pilot testing. The trenching, pump installations and system electrical work were completed in July 2009. Electrical service was installed in late August 2009. The system was started up in November 2009 and has been operational since that time.

- In September 2010, ENGI submitted an Installation Summary and DNAPL Recovery Pilot test summary report to NHDES. This report recommended that DNAPL extraction activities continue. In October 2010, a work plan for an off-site groundwater investigation program to support the delineation of a Groundwater Management Zone was submitted to NHDES. This work plan was approved by NHDES in a letter dated November 5, 2010. Access negotiations and environmental permitting for the NHDES-approved investigation were completed in June 2011.

- The NHDES-approved subsurface soil and groundwater investigation program was initiated on September 26, 2011. The goal of this program was to delineate a Groundwater Management Zone for the site, and allow for the filing of a Groundwater Management Permit (GMP). Due to known asbestos in the off-site area to be investigated, ENGI submitted an "In-active Asbestos Disposal Site (ADS) Work Plan"; NHDES approved the asbestos work plan in October 2011. Soil boring and well installation work was performed between October and December 2011. An In-active ADS Site Completion Report was submitted to and accepted by NHDES on May 4, 2012. Groundwater sampling events were conducted in February and May 2012. A meeting to discuss the preliminary results of the Groundwater Management Zone (GMZ) investigation program with NHDES took place on August 16, 2012. It was agreed that two more rounds of groundwater sampling should occur before a delineation of the GMZ is considered.

- On November 27, 2012 and December 6, 2012, 8.25 feet and 10.83 feet of DNAPL appeared in MW-106, situated in the foot print of historical Holder #2. A weekly monitoring and removal plan was initiated at this time and is ongoing as of July 2013. To date, 109 gallons of DNAPL has been removed manually, in addition to the system removal discussed above.

- In January 2013, a Supplemental Investigation Report (SIR) and DNAPL Recovery System Pilot Test Progress report was submitted to NHDES reporting on additional investigation activities, including the installation of sixteen additional wells in 2011, and the May and September 2012 (second and third of three) rounds of sampling to define groundwater quality and hydrogeologic conditions at the site, so that the GMZ can be delineated. Additionally, the report includes information regarding DNAPL recovery system O&M activities and DNAPL recovery rates demonstrating that the system still effectively recovers DNAPL. A meeting with NHDES took place on March 22, 2013, to discuss these results and next steps.

- NHDES responded to the January 2013 submittal via letter dated May 21, 2013, accepting the SI Report and authorizing ENGI to proceed with the delineation of the GMZ in order to submit a Groundwater Management Permit (GMP) application, and the preparation of a revised Remedial Action Plan (RAP) for the terrestrial portion of the site. NHDES allows ENGI to utilize manual removal of DNAPL as these methods are more effective than the automated recovery system.

- ENGI responded to the NHDES letter on June 19 with a schedule targeting December 31, 2013, for submittal of the GMP application and revised RAP.

- In December 2013, ENGI submitted a request to revise the RAP. The purpose of the request was to summarize activities conducted since submittal of the 2013 Supplemental Investigation Report and to propose a revision to the approved RAP for the area on site known as “Holder # 2.”

- The RAP submitted in 2005 selected asphalt capping in the area of Holder #2. The entire area of the Holder was not designated to be capped with asphalt. At the time of the preparation of the RAP, separate phase NAPL was not considered to be present in recoverable quantities in Holder #2. In order to address what appears to be a limited area and quantity of NAPL in a monitoring well in Holder #2, continued manual NAPL recovery from two additional wells in the Holder #2 area was proposed as part of the GMP monitoring program.

- In addition to the NAPL recovery activity, the area of asphalt capping was proposed to be expanded to include all of former Holder #2. This expansion of paving will also address the asbestos contaminated material (ACM) present in this area of the site. The asphalt cap detail presented in the proposed RAP revision will be modified (as necessary) to address the relevant solid waste regulations for ACM in soil.

- On June 4, 2014, the NHDES approved of the requested RAP revision and required that a RAP Summary Report, with the necessary engineering details for the selected remedies, be provided. ENGI plans to submit this RAP Summary Report by December 31, 2014.

- The GMP Application was submitted in March 2014. The GMP proposed a list of monitoring wells and analytical methods in order to monitor the Groundwater Management Zone.

- On June 5, 2014, the NHDES approved the GMP application. This Permit was issued for a period of five years requiring the monitoring of groundwater quality, assessing and recovering any free product found, and visually inspecting the Nashua River sediment cap area. During the first year of the Permit, monitoring events will be conducted in October 2014 and April 2015, and each successive April and October. Annual summary reports are submitted to the NHDES in January of each year.

- The first groundwater monitoring annual summary report was submitted to NHDES in February 2015, and included the groundwater data from the first GMP round of sampling on October 27, 2014.

- ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. ENGI received comments from NHDES on December 15, 2016. NHDES altered the design to include an impermeable capping layer, and incorporation of standards in the Waste Management Bureau's Asbestos Disposal Site rules. As ENGI is planning to pave the Nashua property in 2018, the cap will be installed in conjunction with this capital project.

- In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018.

- The capping remedy was planned for 2018 in conjunction with an overall paving of the property, however a portion of the City's sewer pipe that transects the property collapsed in early February 2018 prompting the City to plan a lining upgrade to it during summer 2018. This event has caused the remedy construction to be pushed out to 2019.

- In a letter dated May 2, 2019, NHDES approved ENGI's 5-year Groundwater Management Permit (GMP) renewal application decreasing the frequency of sampling for all but two wells in the perimeter groundwater management zone. Additionally, NHDES required that a second confirmatory round of PFAS samples be taken in the 2019 GMP monitoring round.

- In the same May 2, 2019 letter, NHDES approved GZA Geoenvironmental's (GZA) proposed cap design transmitted to them on January 30, 2019. The cap design was altered to require an impermeable barrier only under "non-paved" surfaces.

- The cap installation and subsequent paving of the entire property has been pushed out to 2021, due to delays in permitting and the COVID-19 pandemic. **ENGI is still on schedule to complete this project, and has been working toward final design to be used for construction. During the 2020-21 period, ENGI has been working with the City of Nashua to assess the condition of subsurface stormwater and sewer lines, and is preparing applications for NHDES Alteration of Terrain permitting for the property paving.**

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: All Supplemental Phase II Site Investigation Work that could be performed (based on property access) has been completed. Phase II Report was submitted to NHDES in February 2003, and approved by NHDES on August 28, 2003. Remediation of the Nashua River sediments was completed in the fall of 2004. A Remedial Action Plan (RAP) for the upland and groundwater was submitted in October 2005, and approved by NHDES in March 2006. DNAPL recovery is on-going. A Groundwater Management Permit was granted on June 5, 2014. A RAP Summary, involving the asphalt capping of the area over Holder #2 and continued groundwater monitoring, was submitted on April 2, 2015. A Monitoring Summary and Progress Report was submitted by ENGI on February 7, 2015. NHDES accepted the RAP Summary on April 10, 2015, with the provisions that ENGI submit the draft Activity and Use Restriction (AUR) and final engineering design plan for the cap by September 15, 2015. ENGI submitted the draft Activity and Use Restriction (AUR) and RAP Engineering Design details for the cap on September 14, 2015. NHDES responded to ENGI with their comments on December 15, 2016. **Design for the engineered cap remedy is complete and approved by NHDES. ENGI is in the process of obtain State and City permitting for this construction, now planned for the 2021 construction season.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Nashua Gas Light Company built the original coal gas facility in 1852 or 1853. In 1889, the Nashua Gas Light Company merged with the Nashua Electric Company to form the Nashua Light, Heat and Power Company (NHLPC). In 1914, the NLHPC merged with the Manchester Traction Light & Power Company, and PSNH acquired the facility in 1926. The MGP facility was upgraded and expanded. In 1945, PSNH divested the gas operations to Gas Service, Inc. Gas production was eliminated in 1952 when natural gas was supplied to the city via pipeline. In 1981, Gas Service, Inc. merged with Manchester Gas Company to form ENGI. ENGI currently owns the majority of the former gas plant property.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: The EPA made a claim against ENGI and PSNH related to the so-called Nashua River Asbestos Site located adjacent to the former MGP. EPA was removing asbestos from the Nashua River, when some was found to be mixed with wastes allegedly from the MGP. Without admitting any facts or liability, by agreement effective December 21, 2000, ENGI resolved EPA’s claim in exchange for a payment of $387,371.46, plus interest accrued between settlement and final approval of an administrative consent order by EPA.

ENGI and PSNH have entered into a confidential Site Responsibility and Indemnity Agreement effective as of September 15, 2000, which governs the financial and decision-making responsibilities of the two companies through the remainder of site study and remediation. Under this agreement, ENGI will take the lead on site investigation and remediation.

Numerous, confidential insurance settlements have been entered into. A jury trial commenced against the London Market Insurers and Century Indemnity on November 1, 2005. On November 14, 2005, the jury returned a verdict in favor of EnergyNorth finding that the defendants were obligated to indemnify EnergyNorth for response costs incurred at the site. The Court then awarded ENGI its reasonable costs and attorneys fees to be paid by the defendants. Subsequent to the verdict, the London Market and ENGI entered into a confidential settlement. Century appealed to the First Circuit Court of Appeals in the summer of 2006. However, on the day its brief was due at the First Circuit, Century withdrew its appeal. Because the site has not yet been remediated, the jury was not asked to make a damage determination. Future proceedings will take place after the remedy has been approved by the NHDES to determine the indemnification amounts to be paid by Century. The New Hampshire Supreme Court's ruling and guidance on the proper manner in which costs are to be allocated among insurers (discussed in more detail in the Manchester MGP summary) will be used in the calculation of that figure.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

1. SITE LOCATION: 130 Elm Street, Manchester, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: The New Hampshire Department of Environmental Services (NHDES) compiled a list of all former Manufactured Gas Plants (MGPs) in New Hampshire that were not already subject to a site investigation or remediation. In March of 2000, NHDES sent out notice letters to all parties it deemed responsible for the sites. EnergyNorth Natural Gas, Inc. (ENGI)[1] received a "Notification of Site Listing and Request for Site Investigation" for the former Manchester MGP from NHDES, which designated the site DES #200003011.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the site. These residuals, which include tars and oils, have been found mainly in subsurface soil at discrete locations and in groundwater at the former MGP, as well as in the downgradient Singer Park and river sediment.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

   - On behalf of ENGI, Harding ESE, Inc. (Harding ESE), submitted a Scoping Phase Field Investigation Scope of Work to NHDES in March 2000.

   - NHDES approved the Scoping Phase Field Investigation Scope of Work in June 2000.

   - During the summer and fall of 2000, ENGI and Harding ESE conducted the Scoping Phase Field Investigation, collecting site background information and soil, groundwater, surface water and sediment samples from the former Manchester MGP and the nearby Merrimack River.

   - On August 31, 2000, an underground tank containing MGP residuals was discovered at the site. As required by NHDES regulations, the tank contents were removed and disposed of subject to a permit from NHDES. Harding ESE, on behalf of ENGI, submitted a summary report to NHDES in January 2001 documenting the response action.

   - ENGI and Harding ESE submitted the Scoping Phase Field Investigation Report to NHDES in February 2001.

[1] In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

- NHDES provided comments to ENGI and Harding ESE in April 2001 on the Scoping Phase Field Investigation Report and requested a Phase II Investigation Scope of Work.

- ENGI responded to NHDES' comments on the Scoping Phase Investigation Report and indicated that ENGI planned to solicit bids for the Phase II Scope of Work.

- In July 2001, on behalf of ENGI, Harding ESE submitted a Scope of Work to NHDES to fence the ravine near the former Manchester MGP to prevent access to impacted sediments. In October 2001, NHDES accepted ENGI's fence installation plan, but requested clarification on the fence location and signage. In correspondence dated April 3, 2002, ENGI provided proposed language to NHDES for the signs to be attached to the ravine fence. NHDES approved the ravine sign language in April 2002.

- On May 1, 2002, ENGI issued a Request for Proposals to eight environmental consultants for the Phase II Site Investigation and Risk Characterization. ENGI received six proposals for the Phase II work in June 2002.

- In June 2002, the City of Manchester approved the ravine fence location and granted access to City property to install. The work was completed in August 2002.

- URS Consultants were awarded the contract to undertake the next phase of work. A Phase II Site Investigation Scope of Work was submitted in September 2002.

- Phase II field investigations began in the fall of 2002.

- In June 2003, the City of Manchester approved a proposal to construct a minor league ballpark, retail shops, parking garage, hotel and high-rise condominium complex on the Singer Park site, in the same general areas that MGP impacts were detected in ongoing Phase II investigations. Following supplemental ravine investigations during the spring and summer of 2003, the Drainage Ravine Engineering Evaluation was submitted to NHDES in January 2004, and presented four potential remedial alternatives for the ravine, which is located on a portion of Singer Park.

- ENGI had been a regular participant in monthly Singer Park redevelopment meetings with NHDES, the City of Manchester and the various developers from April 2003 until the regular meetings ended on November 15, 2004. ENGI had attended these coordination meetings to ensure that the environmental and construction aspects of the redevelopment were being addressed concurrently and that ENGI avoided incurring costs associated with another entity's contamination.

- ENGI entered into confidential agreements with Manchester Parkside Place (the owner of the ravine property) for access and cleanup of MGP byproducts in the ravine in January 2005.

- In January 2005, ENGI submitted a Remedial Design Report to NHDES selecting excavation and off-site disposal of source material and impacted soils as the remedial alternative for the ravine. NHDES approved of this alternative via a letter dated February 7, 2005. Eleven contractors were invited to bid on the ravine remediation in January 2005. The contract was awarded to the low bidder (ENTACT) in February 2005. Remediation of the ravine began in March and was completed in July 2005. A remedial completion report was submitted to NHDES on September 2, 2005.

- ENGI submitted a Phase II Site Investigation Report to NHDES in March 2004. The report concluded that MGP impacts (including impacted soil and groundwater and separate phase coal tar) were present in the subsurface beneath the 130 Elm Street property, portions of Singer Park at depth and the Merrimack River sediment. Further investigations were recommended by ENGI to further assess the nature and extent of this contamination and a work plan proposing those investigations was submitted to NHDES in May 2004 and approved in July 2004. These supplemental investigations were completed and documented in the Supplemental Phase II Investigation Report and the Stage I Ecological Screening Report for the Merrimack River, submitted to NHDES in February and March 2005, respectively. The reports concluded that Remedial Action Plans for the upland and Merrimack River portions of the site were required. On September 15, 2005, NHDES issued a letter accepting the reports and requested ENGI prepare a Remedial Action Plan (RAP) to address impacted sediments in the Merrimack River, as well as MGP-related impacts on the upland portion of the site. Preparation of the RAPs began in August 2006.

- Additional Merrimack River investigations were completed in 2007 and the Remedial Design Report for dredging approximately 9,000 cubic yards of coal tar-impacted sediments from the river was submitted to NHDES on May 11, 2007. ENGI applied for, and was granted, a Dredge and Fill Permit for the remedial dredging from NHDES and the United States Army Corps of Engineers on May 18, 2007. Dredging of the river commenced in June 2007 and was substantially completed by the end of the year. Final site restoration activities associated with the sediment remediation were complete in May 2008. A Remedial Action Implementation Report documenting the sediment remediation activities was submitted to NHDES in May 2008.

- Certain pre-design investigations were completed on the upland portion of the site in 2008/2009. ENGI also completed interim Phase I Corrective Actions at the site, including pilot scale light non-aqueous phase liquid (LNAPL) recovery, pilot scale dense non-aqueous phase (DNAPL) recovery, and design for repair/replacement of a deteriorated portion of the site drainage system located within a known LNAPL area of the site. Limited surface soil removal activities were conducted during the summer/fall of 2008 in an area with detected Upper Concentration Limit exceedances in shallow soils.

- ENGI was issued a Groundwater Management Zone (GMZ) permit No. GWP-200003011-M-001 for the former MGP site on June 15, 2009. The permit establishes a groundwater management zone in the vicinity of the former MGP site with associated notification/groundwater monitoring requirements. Groundwater monitoring events to support this GMZ permit have been ongoing, every April and October.

- ENGI submitted an RAP for the upland portion of the site to NHDES on June 30, 2010. The remedial objectives for the site include control of mobile DNAPL, reduction in contaminant mass (where practicable), and management of residual contamination through the use of administrative controls. The recommended remedial alternative includes removal of the contents of certain subsurface structures where removal is anticipated to provide a reduction in the potential for the further release of DNAPL to the subsurface; NAPL recovery from the subsurface; construction of a barrier wall proximate to the Merrimack River to mitigate potential DNAPL migration; and use of administrative controls to address potential human exposure to residual soil and groundwater contamination. Additional investigation activities were recommended to support the preparation of Design Plans and Construction Specifications following NHDES approval of the RAP and to confirm the appropriateness of certain remedial alternatives recommended in the RAP.

- In Fall 2010, ENGI performed storm drain rehabilitation activities on a deteriorated portion of the site drainage system that is located within a known LNAPL area. This work was performed to mitigate the migration of LNAPL to the Merrimack River via the storm drain system. These activities were mainly completed in late 2010.

- In April 2011, NHDES approved of the upland RAP and requested that ENGI proceed with the additional investigation activities recommended in the June 2010 RAP. In addition, ENGI was contacted by both the developer and condominium association associated with the property directly downgradient of the site regarding potential impacts to the property, as well as the proposed remedy; ENGI met with both parties in early and mid-2011.

- After meeting with the developer of the property directly downgradient of the site at the potential location of the barrier wall regarding potential impacts to the property in September/October 2011, access was obtained to conduct certain approved pre-design off-site investigation activities as recommended in the June 2010 RAP. The off-property investigations were substantially completed in December 2011. A meeting was held with NHDES in December 2011 to discuss the results. A Remedial Design Report for the off-site property is currently being finalized.

- On-site pre-design investigation activities were conducted during the spring and summer of 2012 including: additional groundwater quality monitoring, former gas holder foundation test pit excavations, supplemental LNAPL delineation, cyanide source investigation test pit excavations, cyanide delineation and source investigation monitoring well installation, and storm drain inspection.

- Further storm drain inspections occurred during July and August 2013. The remedial design and construction specifications report was drafted including a summary of the design investigation activities and findings. The remedial design includes the monitoring and practicable recovery of NAPL at strategic on-site and off-site locations, as well as excavation of subsurface structures with concurrent source removal if encountered. The Remedial Design Report drafted, also summarizes the results of cyanide source investigation and delineation work, with further source delineation work anticipated.

- In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was also submitted to NHDES in July 2014, with the Annual Summary Report for the 2013/2014 groundwater Monitoring year. The Remedial Design Report was submitted to NHDES on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions involving further remediation of historical Holder 3, and further investigation of the storm drain system beneath and downstream of the site. ENGI responded to NHDES' comments and requests on May 12, 2017.

- Per the 2010 Remedial Action Plan and the 2014 Remedial Design Report ENGI removed material from a tar separator, tar well and other subsurface structures, dug four test pits, and installed three new monitoring wells and an extraction well on-site, prior to property paving in Fall 2017. Further removals from subsurface structures were planned for 2018.

- During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

- In 2019, ENGI continued to address potential site impacts per the 2014 Remedial Design Report by removing approximately 9,000 gallons of contaminated liquids and sludge from a subsurface tar liquor decanter structure in the gas plant area. After removal, ENGI cleaned the structure and filled it with inert fill. **The details of these activities were reported to NHDES in the 2018/2019 Annual Summary Report dated July 24, 2019.**

- In June 2019, three extraction wells were also installed at the western boundary of the site where an existing well in that area was detecting recoverable product. These wells will be used to remove free product on an ongoing basis. Three additional groundwater monitoring wells were installed in the Holder #3 area to monitor potential impacts detected during previous test pit excavation.

- A pump-down of an existing well on the east side of the property, installed in 2017 to recover oil from a known historical oil tank impact in that area, took place in June 2019. The test succeeded to return recoverable product to the well and it will be used to remove free product on an ongoing basis.

- In addition to routine Groundwater Management Permit (GMP) sampling and reporting, an application for GMP renewal was submitted to NHDES in May 2020 with requests to reduce the frequency of sampling of two wells and adding sampling of the 6 new wells installed in 2017-18. Annual Summary Reports detailing the results of groundwater monitoring at the site continue to be submitted.

- ENGI reconstructed a water supply line near the entrance to the plant generating a substantial amount of soil that required disposal at ESMI, Loudon, NH.

- **ENGI received the renewed GMP on February 26, 2021, effective until 2026, covering the monitoring of 42 groundwater monitoring wells each April and October.**

- **A sinkhole in the LNG Area over Holder #3 was discovered in October 2020. Fill materials were excavated and the sinkhole was repaired. A new sinkhole reappeared in the same area in May 2021, and the process was repeated to**

stabilize the area. This area was historically filled with soil and debris when the old holder was decommissioned.

5. NEW HAMPSHIRE SITE REMEDIATION PHASE: Phase I Site Investigation complete. Phase II Site Investigation complete and supplemental report submitted to NHDES in February 2005. Remedial Action Plan (RAP) for the ravine submitted and approved by NHDES in 2005; remediation of ravine completed in July 2005. Remediation of the river sediment was completed in 2007. A RAP for the upland portion of the site was submitted to NHDES for review on June 30, 2010. NHDES issued its approval of the RAP for the upland portion of the site in a letter dated April 11, 2011. The Remedial Design Report summarizing the activities for addressing on-site and off-site impacts was submitted on December 19, 2014. On July 15, 2015, NHDES accepted the proposed remedial design with exceptions. ENGI addressed these concerns and implemented the remedial activities on-site and off-site in 2017.

In 2019, ENGI continued to address potential site impacts per the Remedial Design Report by removing approximately 9,000 gallons of contaminated liquids and sludge from a subsurface structure in the gas plant area, installing three extraction wells at the western boundary of the site, and installing three groundwater monitoring wells in one of the gas holder footprints. Also in 2019, needed reconstruction of a major water supply line near the entrance to the property resulted in the removal of a substantial amount of MGP-impacted soil.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The former Manchester MGP is believed to have started producing coal gas in 1852. Gas was produced at the site by the Manchester Gas Company and its predecessors until the MGP was shut down in 1952 when natural gas was supplied to the city via pipeline. ENGI is the successor by merger to the Manchester Gas Company. ENGI continues to own and operate the 130 Elm Street property as an operations center.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: In late 2000, ENGI filed suit against UGI Utilities, Inc. in the United States District Court for the District of New Hampshire, alleging that during much of the early part of the 20th century, a predecessor to that entity “operated” the Manchester Gas Plant, as defined by the Comprehensive Environmental Response, Compensation and Liability Act (commonly referred to as “CERCLA” or “Superfund”). This claim was similar to a claim litigated and ultimately settled by the parties in the late 1990s, related to the former gas plant in Concord, NH. The case went to trial in June 2003 and was settled after 8 days of trial.

Insurance recovery efforts are complete, and confidential settlements have been entered into with all insurance company defendants. An agreement with the last remaining insurance carrier was negotiated in August 2008, under which that carrier paid ENGI's legal fees incurred in the litigation. That settlement came about after a ruling from the New Hampshire Supreme Court, in response to a question certified by the United States District Court, on allocation of coverage, and the scope and meaning of NH RSA 491:22-a, as it relates to awards of attorneys' fees. EnergyNorth Natural Gas, Inc. v. Certain Underwriters at Lloyds, 156 N.H. 333 (2007). As to allocation, the Court ruled as proposed by the carrier that insurance coverage should be allocated on a *pro rata* basis when multiple policies are triggered by an ongoing event. ENGI had argued for an "all sums" allocation approach in which the insured could choose the policy years from which to obtain indemnity. With respect to legal fees, the Court held that " [i]f the insured has obtained rulings that require the excess insurer to indemnify it, the insured has prevailed within the meaning of RSA 491:22-b, and is immediately entitled to recover its reasonable attorneys' fees and costs. Recovery of these fees and costs does not depend on whether, after all is said and done; the excess insurer actually has to pay any indemnification. The insured becomes entitled to the fees and costs once it obtains rulings that demonstrate there is coverage under the excess insurance policy." Under that finding, the insurance carrier was obligated to reimburse legal fees even if the *pro rata* allocation analysis resulted in the carrier owning no indemnity.

Note: This summary is an overview and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

1. SITE LOCATION: The former MGP was located on Messer Street in Laconia. Sometime in the early 1950s, during decommissioning of the MGP, wastes from the MGP were disposed of at a location on Liberty Hill Road in Gilford. At the time of the disposal, the property was utilized as a gravel pit, and the disposal reportedly occurred with the permission of the gravel pit owner. The property currently comprises part of a residential neighborhood.

2. DATE SITE WAS FIRST INVESTIGATED: In 1994 and 1995, Public Service Company of New Hampshire (PSNH), one of the former owners and operators of the Laconia Manufactured Gas Plant (MGP), conducted limited site investigations at the plant. In 1996, the New Hampshire Department of Environmental Services (NHDES) sent a "Notification of Site Listing and Request for Site Investigation" for the former Laconia MGP to PSNH and its parent company, Northeast Utilities Services Company (NU), and to EnergyNorth Natural Gas, Inc. (ENGI)[1], another former owner. NHDES designated the site DES #199312038. ENGI and PSNH reached a settlement, reported previously to the New Hampshire Public Utilities Commission (NHPUC), in September 1999. As a result of that settlement, PSNH has had responsibility for the MGP site remediation and interactions with NHDES.

   Per the aforementioned settlement, ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal. Therefore, in October 2004, ENGI notified NHDES of the possibility that wastes from the MGP were disposed of at a location on Liberty Hill Road sometime in the early 1950s during decommissioning of the plant. Drinking water samples were collected from two residential properties in the vicinity in December 2004, and from three additional properties in June and July 2005 by the NHDES; no MGP-related contaminants were detected. At the request of NHDES, ENGI began preliminary site investigations in July 2005 that culminated in the submission of a Site Investigation Report to NHDES in June 2006. As detailed in the report, MGP-related constituents have been detected in soil and shallow groundwater on four residential properties, and in the abutting brook. The report concluded that further investigations were necessary to determine the extent of the contamination. Additional investigation activities were completed between 2006 and 2009.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the former MGP have been identified at the Laconia MGP site and in the adjacent Winnipesaukee River. Please contact PSNH and refer to PSNH filings with NHDES for complete information on the nature and extent of site contamination at the MGP. Residual materials

[1] In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

from the former MGP were disposed of at the Liberty Hill disposal area, and MGP-related constituents have been detected in soil and ground water.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES: Based on the settlement with PSNH that has previously been reported to the Commission, ENGI has had no further involvement with the MGP site since the summer of 1999, except with regard to the Liberty Hill disposal area. Please contact PSNH and refer to PSNH filings with NHDES for complete information on material developments and interactions with environmental authorities.

With respect to the Liberty Hill disposal area, in October 2004, ENGI notified NHDES of the possible existence of this disposal site; the site was assigned disposal site number 200411113 by NHDES. NHDES collected drinking water samples from two residential wells in the vicinity in December 2004 and from three additional residential wells in June and July 2005; no MGP-related contaminants were detected. In January 2005, NHDES requested that ENGI conduct a preliminary site investigation on the two residential properties. ENGI submitted a scope of work for the investigation to NHDES on March 2, 2005. The investigation began in July 2005 and was completed in June 2006 with the submission of the Site Investigation Report.

Additional site investigations were conducted in 2006 and summarized in the December 20, 2006, Interim Data Report #2 submitted to NHDES. Based upon the results of the investigations, remediation is required at the site. In response, a Remedial Action Plan (RAP) was submitted to NHDES on February 28, 2007. The RAP presented NHDES with several remedial alternatives to address soil and groundwater contamination at the site. The February 2007 RAP identified soil excavation (to a depth of 3 feet), construction of a containment wall and impermeable cap on the four residential properties purchased by ENGI as the recommended alternative. In September 2007, NHDES responded to the February 2007 RAP and required that ENGI evaluate additional remedial alternatives that included further soil removal. In November 2007, a RAP Addendum was submitted to NHDES. The revised RAP recommended a remedial alternative that included removal of tar-saturated soils to a depth of approximately 45 feet, construction of a containment wall and impermeable cap on the four residential properties owned by ENGI. On February 29, 2008, NHDES issued a letter to ENGI indicating that NHDES had reached a preliminary determination that the remedy recommended in the November 2007 RAP met the NHDES requirements and that a final decision would be reached following a public meeting and comment period.

On March 24, 2008, NHDES held a public comment meeting to discuss the recommended alternative and began 30-day public comment period. In April 2008, NHDES received a request to extend the public comment period closing date to May 8, 2008, to allow the Town time to provide technical comment. On June 26, 2008, NHDES issued a letter deferring its final decision on the recommended remedial alternative for the Liberty Hill site pending further data analysis following the development of a scope prepared collaboratively between the Town of Gilford and ENGI. In July and August 2008, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met twice to discuss the comments provided to NHDES during the public comment period and discuss the scope for additional groundwater modeling activities and limited additional site data collection. The Company submitted Scopes of Work for additional data collection and groundwater modeling to NHDES in September and October 2008, respectively. The field activities were completed between November 2008 and January 2009. Modeling efforts began in late 2008 and were completed in May 2009. In March and May 2009, technical representatives from ENGI, the Town of Gilford, the Liberty Hill neighborhood and NHDES met to discuss the results of the field investigations and the modeling activities. One topic discussed with the technical team was that the modelling results indicate that low-flow pumping would need to be added to the selected remedy meet the remedial goals for the site. On June 30, 2009, NHDES issued a letter to ENGI requesting that a second RAP Addendum be prepared for the site to evaluate the technical changes (mainly the addition of low-flow pumping) to the proposed remedy that resulted from the modeling effort. ENGI submitted the second RAP Addendum to NHDES on August 17, 2009 and presented the findings at a public meeting held in Gilford on September 10, 2009. In October 2009, NHDES hired a third party consultant to review the RAP cost estimates and the results were presented in a report to NHDES in April 2010. In October 2010, NHDES issued a Preliminary Decision on RAP Addendum No. 2, in which NHDES indicated that it did not concur with ENGI's recommended remedial alternative and further recommended the complete removal of coal tar-impacted soils at the site. On January 28, 2011, ENGI submitted a comment letter to NHDES further explaining its rationale for the remedial alternative recommended in RAP Addendum No. 2. On November 2, 2011, NHDES announced a Final Decision indicating that it did not concur with ENGI's recommended remedial approach and selecting the full removal option as the remedy for the site. On December 2, 2011, ENGI filed an appeal of the NHDES Final Decision with the New Hampshire Waste Management Council. In March 2012, ENGI attended the Pre-Conference Hearing with the Council related to the appeal. Hearings on the matter were scheduled for October 18 and November 15, 2012. On July 26, 2012, the Hearing Officer granted an Assented to Motion to Continue the hearing until a date after January 3, 2013.

During the period of time the appeal was subject to the continuance, the company, the New Hampshire Department of Justice and NHDES engaged in settlement discussions on a confidential basis. At the conclusion of those negotiations, NHDES and the company agreed on a final remedy for the site, which was approved by NHDES. That approval allowed ENGI to withdraw its appeal as of December 19, 2012, and proceed with implementation of the remedy. The town of Gilford was briefed on the agreed-upon remedy concurrently with NHDES approval and ENGI's withdrawal of the appeal.

ENGI has also performed numerous other activities requested by NHDES between 2008 and 2011, including remediation of the groundwater seep area near Jewett Brook in accordance with NHDES-approved September 2008 Initial Response Action Plan; evaluation of options for providing financial assurances to NHDES for the site remediation activities; coal tar recovery; semi-annual groundwater and surface water sampling activities; and drinking water well sampling. Groundwater sampling is reported to the NHDES in semi-annual reports. In addition, ENGI developed a Liberty Hill Road site website to assist in updating interested parties.

In conjunction with the Site Investigation work, ENGI has acquired 4 properties on Liberty Hill Road to facilitate remediation activities, and eliminate any potential risk to residents associated with a significant remediation and construction project. The properties were obtained based upon arms-length negotiations, and in one instance to settle potential litigation.

The site was remediated in 2014-2015 construction seasons, and was restored to a grass field by December 2015. NHDES approved the Notice of Activity and Use Restriction (AUR) in February 2017. In May 2017, ENGI received the post-construction groundwater monitoring permit, requiring annual groundwater sampling.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE: On December 10, 2012, ENGI submitted a Conceptual Remedial Design Report to NHDES describing the approach for full removal. NHDES approved this Conceptual RAP Addendum design on December 18, 2012, and ENGI withdrew their appeal before the New Hampshire Waste Management Council on December 19, 2012. A public meeting was held in the Town of Gilford to present the approved Conceptual Remedial Design on January 23, 2013. The pre-design investigation to confirm extent and depth of contamination commenced on February 20, 2013 and was completed first week in April 2013. A public meeting was held on September 25, 2013 to present the design to the Town. The Remedial Design Report was finalized and approved by NHDES in December 2013. Plans and Specifications were developed concurrently, and the bidding process commenced in September 2013 with a Request for

Information to ten (10) prospective contractors. On October 28, six (6) contractors were selected to participate in the bidding for the construction, with bids due back on December 6, 2013. On January 9, 2014, three (3) of the bidders were interviewed and Charter Environmental of Boston, MA (the Contractor) was selected for the project. A public meeting took place on February 12, 2014 to further explain details of the anticipated construction and to introduce the project team to the community.

The Contractor mobilized to the site and began set-up in May 2014, with the first load of soil being hauled from the site on June 6, 2014. Construction began to remove tar-impacted soil on the south side of the site in the first season, with little to no impact to the surrounding community. In 2014, approximately 65% of the impacted soil was removed for treatment. On April 8, 2015, ENGI presented the results of the first season of construction at a Gilford Town Select Board meeting, and presented expectations for the second season to the community. Starting on April 13, 2015, the north side of the site was remediated, with the removal of all tar-impacted soil completed on August 3, 2015. The entire project was completed on September 24, 2015 with 2,662 truckloads hauling 93,502 tons of tar-impacted soil removed for thermal treatment. Some additional site restoration work was needed in October 2015 and another seeding in April 2016 to repair damage to the original restoration caused by a heavy rainstorm that occurred on September 30, 2015. Throughout the course of the project there was no disruption to the neighboring community and no safety incidents, logging 26,975 safe working hours. The project was completed within budget parameters.

The only activities on this site during the past year and ongoing are mowing and groundwater and surface sampling, per the new post-remedial Groundwater Management Permit received on May 10, 2017. In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018. **ENGI continues to mow the site twice a year and sample the groundwater per the Groundwater Management Permit each September.**

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: ENGI is the successor by merger to Gas Service, Inc. (GSI). In 1945, GSI acquired the gas manufacturing assets of PSNH. The Laconia MGP, which began operating in 1894, was included in that transaction. Gas manufacturing took place at the property until 1952, when the MGP was converted to propane. Half of the property is now owned by Robert Irwin and maintained

as an open field, and the other half is owned by PSNH, which operates an electric substation on the parcel.

The Liberty Hill Road parcel on which disposal was believed to have occurred was utilized as a gravel pit at the time of the disposal. It was subdivided in May 1970, and currently constitutes part of a residential subdivision.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: ENGI and PSNH entered into a confidential settlement in 1999. Under this agreement, PSNH took the lead on the MGP site investigation and remediation and all communications with NHDES. ENGI retained responsibility for any decommissioning-related liabilities, including off-site disposal.

Insurance recovery efforts are complete with respect to the MGP, and numerous confidential settlements have been entered into. In 2003, the United States District Court certified a question to the New Hampshire Supreme Court asking what “trigger of coverage” should be applied to the insurance policies issued by Lloyds of London to ENGI’s predecessor, Gas Service, Inc. In May 2004, the Supreme Court responded that a “continuous injury-in-fact” trigger should be applied. The federal court conducted a jury trial against Lloyds of London - the only remaining defendant – in October 5, 2004. At the end of that trial the jury returned a verdict in favor of ENGI. Subsequent to the verdict, ENGI and Lloyds of London entered into a confidential settlement.

With respect to Liberty Hill, insurance carriers have been placed on notice of a potential claim, but no litigation has been initiated. The Company does not expect to pursue any insurance litigation.

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

LIBERTYUTILITIES (ENERGYNORTH NATURAL GAS) CORP.
d/b/a LIBERTY

CONCORD FORMER MGP

LINE
NO.

1. SITE LOCATION: One Gas Street, Concord, New Hampshire.

2. DATE SITE WAS FIRST INVESTIGATED: EnergyNorth Natural Gas, Inc. (ENGI)[1] received a Notice Letter from the New Hampshire Department of Environmental Services (NHDES) in September 1992. The Notice related primarily to contamination identified in the pond adjacent to Exit 13 off Interstate 93, although it was broad enough to also include the former manufactured gas plant (MGP) site itself.

3. NATURE AND SCOPE OF SITE CONTAMINATION: Residual materials from the historic operation of the MGP were discovered in the area of the Exit 13 pond, as the NHDOT began site preparation work for the reconfiguration of that interchange. Subsequent investigations by ENGI and others indicate that contaminants originating from the MGP on Gas Street are present in soil and groundwater between the MGP and the Merrimack River, including within the Exit 13 pond.

4. SUMMARY OF MATERIAL DEVELOPMENTS AND INTERACTIONS WITH ENVIRONMENTAL AUTHORITIES:

Concord MGP: The New Hampshire Department of Transportation (NHDOT) contacted ENGI in August 2001 and February 2002 regarding possible coal tar-related impacts in a sewer line on a parcel adjacent to the former gas plant. NHDOT is currently conducting groundwater monitoring as part of a Groundwater Management Zone Permit on this parcel. ENGI met with NHDOT and NHDES in January 2003 to review the results of its 2002 site investigation. Limited coal tar impacts were observed in groundwater and subsurface soils at select locations.

On July 15, 2003, NHDES issued a letter to ENGI requesting submission of a schedule and scope of work for a site investigation of the MGP site by mid-September 2003. ENGI proposed a May 2005 date for submission of a Site Investigation Report for the MGP site on Gas Street to NHDES by way of a letter dated October 6, 2003. NHDES agreed to the proposed schedule in their response letter dated October 31, 2003.

[1] In July 2012, EnergyNorth was acquired by Liberty Utilities and its legal name changed to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty. For consistency purposes, the acronym ENGI will be used throughout this document.

ENGI submitted the work plan for the MGP site investigation to NHDES on May 20, 2004. NHDES accepted the work plan on June 16, 2004. The investigation took place between September 2004 and March 2005, and the Site Investigation Report was submitted to NHDES on June 6, 2005. The report indicated that subsurface impacts are present at the MGP, and additional investigation as well as limited remediation will be required. NHDES accepted the report on August 12, 2005, and requested ENGI submit a supplemental scope of work to complete the delineation of MGP-related impacts on and off Site. The document was submitted in November 2005. Site investigation activities at and downgradient of the MGP were conducted in 2006. ENGI submitted an additional supplemental scope of work to further delineate MGP impacts on May 31, 2007 and NHDES subsequently approved the scope on June 5, 2007. ENGI bid the NHDES-approved scope of work in June 2008 and awarded the contract in late July 2008. ENGI met with NHDES at the site in August 2008 to discuss the additional supplemental site investigation activities. The field work took place during October through December 2008, during which time 8 groundwater monitoring wells were installed at 4 off-site locations. The Additional Supplemental Site Investigation Report was submitted to NHDES in September 2009. ENGI met with NHDES to discuss the report findings and strategy for moving forward in October 2009. NHDES issued an approval letter for the Supplemental Site Investigation Report on February 9, 2010. The correspondence approved the report and requested that certain additional activities be completed by ENGI. These requested activities include the following: a) preparation and submission of an Initial Response Action Work Plan to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots and tar wells at the MGP property on Gas Street; b) evaluation of the groundwater conditions in the vicinity of the “Tar Pond” which is depicted on a referenced NHDOT site plan; and c) evaluation of potential indoor air impacts at select locations identified during the additional SSI work.

ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. In addition, ENGI submitted a Supplemental Data Collection Work Plan for the additional off-ENGI-owned property investigation activities (items b and c above) to NHDES in August 2010. NHDES approved of the Work Plan on September 16, 2010. ENGI obtained access to 4 properties in the vicinity of the site in order to conduct the supplemental investigation activities, which included soil, ground water and soil vapor sampling, along with further investigation of the brick tar sewer. ENGI submitted a revised Work Plan with revised sampling locations to NHDES in November 2011; the revision was necessary because site access was not granted by the property owners for some of the originally proposed locations. The investigation work was completed in July 2012, and summarized in a Supplement Data Collection Report that was submitted in August 2013, in preparation for submittal of the Remedial Action Plan. This Supplement Data Collection Report was accepted by NHDES on

October 24, 2013, and ENGI was authorized to prepare a RAP and Groundwater Management Permit (GMP) application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014.

On June 16, 2013, wind during a thunderstorm caused a tree to fall on the northern side of the roof of the Holder House located on the former Concord MGP property. Damage to the slate roof and brick was sustained. In a letter dated February 24, 2014 NHDES stated that the holder structure "…serves as a physical barrier to prevent infiltration of precipitation into the foundation and thereby limits the amount of MGP byproducts that may be released to the environment."

On March 31, 2015, ENGI submitted a proposed Remedial Action Plan involving removal of shallow soils displaying MGP-related residual impacts, investigation and remediation of remaining known subsurface structures, capping of components of the local storm water drainage system, site capping design, and continued monitoring of groundwater on the site. NHDES approved the RAP on May 29, 2015, with the condition that roof of the brick gas holder either be restored, or the holder be razed and the soils beneath it remediated. Soil vapor monitoring; soil vapor probe installation; and remedial design investigations including subsurface structure location and inspection, shallow tar-saturated soil delineation, and site storm drain system inspections, as approved by the RAP, were performed in December 2015. A Remedial Design Report (RDR) was submitted to NHDES on March 16, 2016 summarizing the above remedial design investigations. The remediation activities, required to be completed prior to site capping, include tar-impacted material removals and plugging of the on-site drain system, took place in 2017.

In early 2016 ENGI was approached by a commercial developer who was interested in purchasing the property and repurposing the holder house structure. Several site meetings took place with the developer, and ENGI was negotiating the terms of the property's sale. If the property is transferred, the purchaser's future use design will be taken into account when the final design of the engineered cap is being developed. This site developer has not contacted ENGI since May 2017, and appears to have lost interest in the redevelopment project.

Although a developer had approached the Company during 2016 and into 2017 regarding potential purchase of the property, there has been no movement or activity on a transfer of the holder site. In 2020, further deterioration of the holder structure was observed. In addition, fencing was repaired and added to the areas around the deteriorated areas near the vestibule and the outside scaffolding where the tree fell in 2013.

In 2019, the City and the Company jointly prepared a report that details various use options for the Gas Holder site on the east side of the highway, including costs for various scenarios ranging from cleaning and fortifying the holder structure for public entry to demolition of the structure. In response to Liberty's communication that the gas holder needed to be demolished, as the condition of the structure raises significant safety concerns, the Concord City Council established a working group in 2020, comprised of representatives of the City Council, City Staff, Liberty, and the New Hampshire Preservation Alliance ("NHPA"), and charged with developing a plan and assigning responsibilities for stabilization and preservation of the holder house structure. The working group discussions resulted in a plan for the NHPA to raise funds to stabilize the holder house and to manage the relevant construction, and for Liberty to seek Commission approval to contribute up to the estimated costs of demolition and remediation beneath the holder house, as the least cost option for customers.

The City, the NHPA, and Liberty met with Commission Staff in February 2021 and obtained Staff's support for the plan, provided Liberty can demonstrate that the Company's contribution toward the stabilization of the holder house is less than the estimated costs of demolition and remediation that would otherwise have been incurred. In April 2021, the City, the NHPA, and Liberty signed an MOU documenting the above understanding as the parties worked toward a formal agreement. As of the date of this report, the parties are near completion of a formal Emergency Stabilization License Agreement to govern the repairs to the holder house. The NHPA has substantially completed the engineering for the stabilization work and has obtained a contractor to complete the work before the end of 2021. Liberty has substantially completed the estimate to demolish the holder house and remedy any contamination, which estimate will serve as the cap of Liberty's contribution toward stabilization.

On January 21, 2020, NHDES issued a renewed GMP for the site and ENGI continues to monitor wells in the groundwater monitoring system on site every June and October under this permit. ENGI requested that soil vapor monitoring be ceased and NHDES removed this requirement from the new permit. The last GMP Annual Summary Report, submitted to NHDES in February 2021, summarized the results of the 2020 GMP sampling rounds and also described various small source remediation activities undertaken on site in late 2020**.**

<u>Concord Pond</u>: ENGI has continued to monitor groundwater semi-annually at the Exit 13 pond, in May and November, as required by the Groundwater Management Zone Permit that was issued in 1999 as part of the overall remedy following the remediation of the southern end of the Exit 13 pond. The permit was renewed in 2003, 2007,2012

and 2017, and NHDES specified semiannual collection of surface water samples from the pond as an additional condition of the permit.

When the Exit 13 pond was remediated in 1999, NHDES required that the northern portion remained untouched, allowing for storm water input to the pond, with the knowledge that some contamination remained and may require remediation in the future. In 2006, NHDES requested ENGI address the residual contamination in the pond, and in response, ENGI submitted an Interim Data Collection Report and Scope of Work in May 2006, which was approved in July 2006. This Scope of Work was implemented in 2006 and the results were to be used to prepare the Remedial Action Plan (RAP) which NHDES requested be submitted by August 31, 2006. In July 2006, NHDES extended the deadline for submittal of the RAP to June 30, 2007, to allow ENGI additional time for data collection and design. ENGI submitted an Interim Data Collection Report to NHDES in September 2006, and a Conceptual Remedial Design in March 2007. On March 25, 2009, ENGI submitted a Presumptive Remedy Approval Request to NHDES, in order to allow for the design and implementation of an engineered cap without the need to prepare a RAP. On May 4, 2009, NHDES granted the Presumptive Remedy Approval, and the project moved into the remedial design phase.

The proposed remedial work is to be performed on city-owned land and within a NHDOT right-of-way; therefore ENGI is working with these parties to come to agreement on the design features, negotiate access and clarify the responsibilities of the three parties. In April 2010, ENGI met with representatives from NHDES, the City of Concord, and NHDOT to present the proposed remedy, and ENGI submitted the draft design plans to the parties in June 2010. ENGI met with the regulatory permitting agencies in October 2010. The agencies requested that ENGI modify the remedial design to include an upland cap versus a wetland cap to minimize the impacts of the project. The cap was redesigned and ENGI met with the stakeholders in December 2010. At a subsequent meeting in January 2011, the City of Concord requested that the design be further modified to relocate the City's storm water outfall location.

ENGI met with the City in March 2011 to present the feasibility evaluation that was conducted for several alternatives, and concluded that the original design was the appropriate design. Contact was reconvened with the City in 2013, and adjustments to the original design were made to address outfall maintenance and access concerns of the City and NHDOT, respectively. The design was presented to the City on January 26, 2016. A rigorous schedule toward construction in late summer 2017 was agreed to by ENGI and the City in February 2016. The City did not meet an early deadline to determine and communicate details regarding access to their storm water system. Communication was again resumed in July 2016 by the City, however the City remained unresponsive to ENGI on implementation of the joint remedial design.

In March 2018, discussions with the new City Engineer took place and the City's engagement level has increased to come to a design solution on outfall maintenance. These discussions are frequent and ongoing.

Semiannual groundwater monitoring at the pond is ongoing, as is recovery of separate phase coal tar from a monitoring well in the vicinity of the pond. In May 2017, the NHDES requested by letter that all active hazardous waste sites managed by the Hazardous Waste Remediation Bureau include sampling for Per- and Polyfluoroalkyl Substances (PFAS) in one of their groundwater sampling rounds, as part of a statewide study of these compounds. ENGI fulfilled this request during regularly scheduled sampling in 2018.

During May 19 through May 22, 2009, ENGI implemented a NHDES-approved sediment sampling program in the Merrimack River to evaluate potential MGP-related impacts. ENGI met with NHDES in October 2009 to present the results of the sediment investigation, and submitted the sediment sampling data report to NHDES in October 2009. The investigation indicated limited site-related impacts to the shallow near-shore sediments of the Merrimack River. Based upon the results of the sediment investigation, it is unlikely that remedial actions will be necessary in the river. ENGI met with NHDES on February 20, 2013 to discuss all sampling activities to date, summarized in an SIR Addendum Report, submitted in June 2013.

In May 2016, ENGI submitted a proposed plan for monitoring the near-bank sediments to the pond area in the Merrimack River. After discussions regarding frequency, duration of the Monitored Natural Recovery (MNR) program, and methodologies to be used in determining the contaminant trending in the river sediment, NHDES approved a revised MNR Plan in a letter dated July 2017. The 5-year sampling plan began in 2017 with the first of 5 annual samplings. The second round of sediment sampling was conducted in October 2018, the third round of sediment sampling took place in October 2019**, and the fourth in October 2020**. NHDES has accepted the MNR reports submitted by ENGI summarizing the sediment sampling results.

5. NEW HAMPSHIRE SITE REMEDIATION PROGRAM PHASE:

Concord MGP: In July 2003, NHDES requested that ENGI submit a schedule and scope of work for completion of a site investigation of the MGP site. ENGI submitted the scope to NHDES in May 2004 and implemented the work between September 2004 and March 2005. The results of the investigation were documented in the Site Investigation Report, dated June 6, 2005, which was subsequently approved by NHDES. Supplemental investigation activities were performed in 2006. Additional investigation activities were performed in 2008. The additional SSI report was submitted to NHDES in September 2009. In addition, ENGI submitted the Initial Response Work Plan to NHDES in July 2010 to remove approximately 3,500 gallons of liquid and sludge from historic subsurface drip pots. NHDES issued an approval letter for this Work Plan on August 3, 2010 and the work was completed in June 2011. The Supplemental Data Collection report summarizing the investigation activities was accepted in October 2013, authorizing ENGI to prepare a RAP and GMP Application. The GMP application was submitted on September 4, 2014, and the permit was received on December 1, 2014. On March 31, 2015, ENGI submitted a proposed RAP, and NHDES approved the RAP with conditions. A Remedial Design Report, summarizing pre-design investigations, was provided to NHDES in March 2016**.**

Outstanding remedial activities including the investigation for decommissioning of the deep well (historic water supply well), closure of the "old tar separator" and a small drip pot, closure of the on-site storm drain, and removal of an area of soil containing hardened tar were completed in late 2020, and results of these activities were reported to NHDES in the 2020 Annual Summary Report submitted in February 2021 as a requirement of the GMP.

<u>Concord Pond</u>: ENGI submitted an application for a five-year Groundwater Management Zone Permit to the NHDES in April 2002 for the Exit 13 pond. The permit was renewed in October 2007, with the collection of pond surface water samples as an additional condition. Under that permit, groundwater monitoring is expected to be required for the foreseeable future. In addition, as requested by NHDES, ENGI undertook a review of remedial technologies to address the residual contamination remaining in the pond. A conceptual remedial design was submitted to NHDES in March 2007, a Presumptive Remedy Approval was granted by NHDES in May 2009, and the engineered cap design has been drafted. The work will be undertaken pending agreement between the City, NHDOT, and ENGI. ENGI met with these parties on several occasions in 2010 and 2011. The Company reinitiated discussion with the City in July 2014 regarding access to the site to implement the approved design of the wetland cap. The design was adjusted to accommodate the City's desire to simplify maintenance of the storm water system. ENGI has altered the design of the construction to provide temporary access through the wetland area and a permanent access road that does not encroach on the NHDOT right-of-way.

In 2020, ENGI obtained the access agreement from the City to the property to allow access for the wetland cap remedy construction. ENGI has commenced the pre-design investigation in 2021. ENGI is designing the wetland cap remedy and is preparing associated NHDES permit applications, with plans to construct the remedy in late summer 2021.

A renewal application for the Groundwater Management Permit was submitted on August 24, 2017, and the renewed permit was granted by NHDES on November 22, 2017. Groundwater and surface water monitoring continues under this permit every

May and November. The 5-year sediment sampling plan to monitor natural attenuation of MGP residuals in the river began in autumn 2017 and are ongoing each October.

6. HISTORY AND CURRENT STATUS OF USE AND OWNERSHIP: The Concord MGP operated from approximately 1850 to 1952, when the natural gas pipeline was extended to Concord. The plant was constructed and operated by predecessors of the Concord Gas Company, which later became known as the Concord Natural Gas Company. By virtue of a merger, ENGI acquired Concord Natural Gas. As has been reported previously by ENGI, it filed a contribution claim in the United States District Court for the District of New Hampshire against the successor to the United Gas Improvement Company. In that claim, ENGI alleged that under the federal Superfund statute, the United Gas Improvement Company exercised control over the operations of the Concord Gas Plant to the extent that the United Gas Improvement Company should be considered an "operator" under the statute. That matter was settled in 1997.

7. LISTING AND STATUS OF INSURANCE AND 3RD PARTY LAWSUITS AND SETTLEMENTS: Numerous confidential settlements with insurance carriers and with one private party have been entered into. *Insurance recovery efforts at the Concord Site are complete.*

Note: This summary is an overview only and is not intended to be a comprehensive recitation of all relevant information relating to the site and the associated liability.

ENERGYNORTH NATURAL GAS, INC.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS

REDACTED
Schedule 20.2
Page 1 of 7

2021 SUMMARY BY SITE

LINE NO.	SITE	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	100 % RECOVERABLE EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL
1	Concord Pond	DEF056	0.00	316,868.13	0.00	0.00	45,831.64	362,699.77	[redacted]	[redacted]	313,043.04
2	Concord MGP	DEF077	2,734.00	84,993.95	0.00	0.00	340,224.44	427,952.39	[redacted]	[redacted]	383,711.57
3	Laconia/Liberty Hill	DEF086	0.00	12,243.50	0.00	0.00	2,657.60	14,901.10	[redacted]	[redacted]	14,901.10
4	Manchester MGP	DEF057	0.00	32,277.20	0.00	0.00	12,198.45	44,475.65	[redacted]	[redacted]	5,080.33
5	Nashua MGP	DEF054	0.00	95,857.14	0.00	0.00	1,006.70	96,863.84	[redacted]	[redacted]	61,016.23
6	General Expenses	DEF064	0.00	0.00	0.00	0.00	5,645.56	5,645.56	[redacted]	[redacted]	5,645.56
	Total Pool Activity		**2,734.00**	**542,239.92**	**0.00**	**0.00**	**407,564.39**	**952,538.31**	**0.00**	**(169,140.48)**	**783,397.83**

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
NASHUA - REMEDIATION
PROJECT DEF054

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	[redacted]										(3,520.34)
2	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13487		2,825.73				2,825.73			2,825.73
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13550		17,644.77				17,644.77			17,644.77
4	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 072920					156.85	156.85			156.85
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13578		3,686.41				3,686.41			3,686.41
6	[redacted]										(4,468.48)
7	GZA GEOENVIRONMENTAL INC	0789550		2,385.30				2,385.30			2,385.30
8	GZA GEOENVIRONMENTAL INC	0789549		1,339.50				1,339.50			1,339.50
9	INNOVATIVE ENERGY SYSTEMS, LLC	13658		2,470.09				2,470.09			2,470.09
10	INNOVATIVE ENERGY SYSTEMS, LLC	13686		2,426.35				2,426.35			2,426.35
11	INNOVATIVE ENERGY SYSTEMS, LLC	13631		6,877.47				6,877.47			6,877.47
12	[redacted]										(10,454.92)
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13686		2,426.35				2,426.35			2,426.35
14	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13603		3,371.33				3,371.33			3,371.33
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13631		6,877.47				6,877.47			6,877.47
16	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13658		2,470.09				2,470.09			2,470.09
17	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13728		2,842.81				2,842.81			2,842.81
18	[redacted]										(6,664.45)
19	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13743		6,987.34				6,987.34			6,987.34
20	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13807		2,105.28				2,105.28			2,105.28
21	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13776		2,321.75				2,321.75			2,321.75
22	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13828		21,636.08				21,636.08			21,636.08
23	[redacted]										(10,739.42)
24	INNOVATIVE ENGINEERING SOLUTIONS, INC.	13856		5,163.02				5,163.02			5,163.02
25								0.00			0.00
26	Environmental Staff Time						849.85	849.85			849.85
	[redacted]										

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD POND - REMEDIATION
PROJECT DEF056

REDACTED
Schedule 20.2

			1101	1102.00	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	GEI CONSULTANTS, INC.	3074183		9,409.09				9,409.09			9,409.09
2	ANCHOR QEA LLC	69017		8,525.67				8,525.67			8,525.67
3	ANCHOR QEA LLC	69459		9,358.75				9,358.75			9,358.75
4	[redacted]										(12,852.50)
5	GEI CONSULTANTS, INC.	3077029		1,348.99				1,348.99			1,348.99
6	ANCHOR QEA LLC	69892		5,424.75				5,424.75			5,424.75
7	GEI CONSULTANTS, INC.	3075631		3,043.98				3,043.98			3,043.98
8	[redacted]										(7,174.35)
9	ANCHOR QEA LLC	70380		2,924.64				2,924.64			2,924.64
10	NH DEPT OF ENVIRONMENTAL SERVICES	199212014					1,667.65	1,667.65			1,667.65
11	GEI CONSULTANTS, INC.	3079961		3,474.73				3,474.73			3,474.73
12	ANCHOR QEA LLC	70672		27,832.90				27,832.90			27,832.90
13	NH DEPT OF ENVIRONMENTAL SERVICES	CON PD SQG SELF SERT					270.00	270.00			270.00
14	ANCHOR QEA LLC	71255		21,545.22				21,545.22			21,545.22
15	CLEAN HARBORS	1003544340					726.00	726.00			726.00
16	GEI CONSULTANTS, INC.	3082478		1,717.02				1,717.02			1,717.02
17	GEI CONSULTANTS, INC.	3082662		935.48				935.48			935.48
18	[redacted]										(5,110.09)
19	ANCHOR QEA LLC	71773		5,555.03				5,555.03			5,555.03
20	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 012821					215.18	215.18			215.18
21	GEI CONSULTANTS, INC.	3084717		1,765.64				1,765.64			1,765.64
22	AON RISK SERVICES NORTHEAST	6100000228541					39,467.00	39,467.00			39,467.00
23	[redacted]										(9,620.64)
24	CASEY MARY	EXP0317-031721					73.50	73.50			73.50
25	ANCHOR QEA LLC	01198		51,170.32				51,170.32			51,170.32
26	AON RISK SERVICES NORTHEAST	6100000228572					1,081.01	1,081.01			1,081.01
27	GEI CONSULTANTS, INC.	3087661		1,299.12				1,299.12			1,299.12
28	GEI CONSULTANTS, INC.	3089541		1,638.59				1,638.59			1,638.59
29	ANCHOR QEA LLC	01955		83,567.66				83,567.66			83,567.66
30	GEI CONSULTANTS, INC.	3086465		1,719.64				1,719.64			1,719.64
31	[redacted]										(14,899.15)
32	ANCHOR QEA LLC	02474		70,414.75				70,414.75			70,414.75
33	CLEAN HARBORS	1003747648					933.00	933.00			933.00
34	GEI CONSULTANTS, INC.	3091181		4,196.16				4,196.16			4,196.16
35								-			0.00
36								-			0.00
37	Environmental Staff Time						1,398.30	1,398.30			1,398.30
	[redacted]										

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
MANCHESTER - REMEDIATION
PROJECT DEF057

REDACTED
Schedule 20.2

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUBTOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSE	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	[redacted]										(17,964.57)
2	GZA GEOENVIRONMENTAL INC	0802008		28,652.90				28,652.90			28,652.90
3	CLEAN HARBORS	1003471907					65.70	65.70			65.70
4	[redacted]										(4,560.14)
5	ENVIRONMENTAL SOIL MANAGEMENT	1019104					2,193.60	2,193.60			2,193.60
6	CLEAN HARBORS	1003492682					1,895.45	1,895.45			1,895.45
7	ENVIRONMENTAL SOIL MANAGEMENT	1019158					2,010.08	2,010.08			2,010.08
8	CLEAN HARBORS	1003524063					131.40	131.40			131.40
9	CLEAN HARBORS	1003524661					3,496.88	3,496.88			3,496.88
10	CLEAN HARBORS	1003554332					2,011.90	2,011.90			2,011.90
11	GZA GEOENVIRONMENTAL INC	0808710		2,601.30				2,601.30			2,601.30
12	GZA GEOENVIRONMENTAL INC	0810861		1,023.00				1,023.00			1,023.00
13	[redacted]										(15,171.72)
14											(1,359.11)
15											(339.78)
16								0.00			0.00
17	Environmental Staff Time						393.44	393.44			393.44
	[redacted]										

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
GENERAL EXPENSES
PROJECT DEF064

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1								0.00			0.00
2								0.00			0.00
3	Environmental Staff Time						5,645.56	5,645.56			5,645.56
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**5,645.56**	**5,645.56**	**0.00**	**0.00**	**5,645.56**

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
CONCORD MGP - REMEDIATION
PROJECT DEF077

REDACTED
Schedule 20.2
Page 6 of 7

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUBTOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSE	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	CLEAN HARBORS	1003346959					65.70	65.70			65.70
3	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 072920					1,990.42	1,990.42			1,990.42
4	JOE GAUCI LANDSCAPING LLC	2020-7-3576					736.00	736.00			736.00
5	COLLINS TREE SERVICE INC.	41104					10,800.00	10,800.00			10,800.00
6	PARKER FENCE	20-592					6,208.60	6,208.60			6,208.60
7	PARKER FENCE	20-533					29,515.05	29,515.05			29,515.05
8	GZA GEOENVIRONMENTAL INC	0800144		10,500.00				10,500.00			10,500.00
9	CITY OF CONCORD GSD	410184-001 0620					10.21	10.21			10.21
10	CITY OF CONCORD GSD	410184-001 0720					11.01	11.01			11.01
11	[redacted]										(8,027.73)
12	JOE GAUCI LANDSCAPING LLC	2020-6-3576					667.00	667.00			667.00
13	JOE GAUCI LANDSCAPING LLC	2020-8-3576					618.00	618.00			618.00
14	GZA GEOENVIRONMENTAL INC	0801794		816.50				816.50			816.50
15	GZA GEOENVIRONMENTAL INC	0802009		21,005.73				21,005.73			21,005.73
16	[redacted]										(628.61)
17	JOE GAUCI LANDSCAPING LLC	2020-9-3576					184.00	184.00			184.00
18	CITY OF CONCORD GSD	410184-001 083020					10.21	10.21			10.21
19	CITY OF CONCORD GSD	410184-001 093020					10.37	10.37			10.37
20	JOE GAUCI LANDSCAPING LLC	2020-10-3576					1,040.00	1,040.00			1,040.00
21	NH DEPT OF ENVIRONMENTAL SERVICES	198904063					3,550.48	3,550.48			3,550.48
22	CLEAN HARBORS	1003524639					40,795.32	40,795.32			40,795.32
23	NH DEPT OF ENVIRONMENTAL SERVICES	CON-MGP SQG SELF CER					270.00	270.00			270.00
24	CITY OF CONCORD GSD	410184-001 1120					10.36	10.36			10.36
25	CLEAN HARBORS	1003544340					2,072.40	2,072.40			2,072.40
26	CLEAN HARBORS	1003561844					19,411.37	19,411.37			19,411.37
27	[redacted]										(9,168.30)
28	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 012821					161.39	161.39			161.39
29	CLEAN HARBORS	1003604344					34,067.04	34,067.04			34,067.04
30	CITY OF CONCORD GSD	410184-001 0121					10.36	10.36			10.36
31	CITY OF CONCORD GSD	410184-001 1220					10.36	10.36			10.36
32	GZA GEOENVIRONMENTAL INC	0808711		9,493.66				9,493.66			9,493.66
33	GZA GEOENVIRONMENTAL INC	0810412		16,869.24				16,869.24			16,869.24
34	GZA GEOENVIRONMENTAL INC	0810862		26,308.82				26,308.82			26,308.82
35	CITY OF CONCORD GSD	410184-001 022821					10.21	10.21			10.21
36	[redacted]										(10,464.81)
37	CLEAN HARBORS	1003679747					95,186.93	95,186.93			95,186.93
38	CLEAN HARBORS	1003626238					69,422.24	69,422.24			69,422.24
39	CITY OF CONCORD GSD	410184-001 033021					10.21	10.21			10.21
40	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1479A					215.18	215.18			215.18
41	NH DEPT OF ENVIRONMENTAL SERVICES	051577452FLE					8,412.00	8,412.00			8,412.00
42	CLEAN HARBORS	1003717760					13,177.16	13,177.16			13,177.16
43	CITY OF CONCORD GSD	410184-001 043021					10.68	10.68			10.68
44	ORR & RENO, P.A.	128324	2,734.00					2,734.00			2,734.00
45	[redacted]										(15,951.37)
46	CLEAN HARBORS	1003747648					621.95	621.95			621.95
46	CITY OF CONCORD GSD	410184-001 0521					10.21	10.21			10.21
48								0.00			0.00
49	Environmental Staff Time						922.02	922.02			922.02
50	[redacted]										

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LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
MANUFACTURED GAS PLANT ENVIRONMENTAL COSTS
LIBERTY HILL - REMEDIATION
PROJECT DEF086

LINE NO.	VENDOR	REF NO.	1101 LEGAL EXPENSES	1102 CONSULTING EXPENSES	1105 REMEDIATION EXPENSES	1106 SETTLEMENT EXPENSES	1107 OTHER EXPENSES	SUB-TOTAL EXPENSES	1108 INSURANCE & THIRD PARTY EXPENSES	1109 INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	GEI CONSULTANTS, INC.	3077028		1,385.10				1,385.10			1,385.10
2	GEI CONSULTANTS, INC.	3078905		10,858.40				10,858.40			10,858.40
3	MULLER'S LAWN & LANDSCAPING, LLC	5554					800.00	800.00			800.00
4	GEI CONSULTANTS, INC.	3079960					1,516.84	1,516.84			1,516.84
5	NH DEPT OF ENVIRONMENTAL SERVICES	LHR SQG SELF CERT					270.00	270.00			270.00
6								0.00			0.00
7								0.00			0.00
8								0.00			0.00
9								0.00			0.00
10								0.00			0.00
11	Environmental Staff Time						70.76	70.76			70.76
	Total Pool Activity		**0.00**	**12,243.50**	**0.00**	**0.00**	**2,657.60**	**14,901.10**			**14,901.10**

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

Schedule 20.3

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
Tariff page 99

Concord Pond

		(thru - 9/07) ool #1 - #8	(9/07 - 9 08) ool #9	(9/08 - 9/09) ool #10	(9/09 - 9/10) ool #11	(9/10 - 9/11) ool #12	(9/11 - 9/12) ool #13	(9/12 - 6/13) ool #1	(7/13 - 6/1) ool #15	(7/1 - 6/15) ool #16	(7/15 - 6/16) ool #17	(7/16 - 6/17) ool #18	(7/17 - 6/18) ool #19	(7/18 - 6/19) ool #20	(7/19 - 6/20) ool #21	DEF056 (7/20 - 6/21) ool #22	s total
1	1 Remediation costs (i.o. 500061)	5,883,850	95,37	128,187	1 3,000	2 9,160	86, 12	78,387	0,31	89,626	3,20	102,196	138,701	87,282	187,358	362,700	7,715,7 8
2	Remediation costs (i.o. 500005)																0
3	A Subtotal - remediation costs	5,883,850	95,37	128,187	1 3,000	2 9,160	86, 12	78,387	0,31	89,626	3,20	102,196	138,701	87,282	187,358	362,700	7,715,7 8
																	0
5	Cash recover es (i.o. 500061)	-2,075,70	0	-12,608	-6,06	-32, 17	-5,173	-19,318	-7,990	-11,392	-8,61	-1 ,0 7	-11,3 5	-1 ,998	-1 ,59	- 9,657	-2,283,920
6	Cash recoveries (i.o. 50000)	- 5,985															- 5,985
7	Recovery costs (i.o. 50000)	623,78	0	0	0	0	0	0	0	0	0	0	0	0	0	0	623,78
8	Transfer Credit from Gas Restructuring																
9	B Subtotal - net recoveries	-1,897,905	0	-12,608	-6,06	-32, 17	-5,173	-19,318	-7,990	-11,392	-8,61	-1 ,0 7	-11,3 5	-1 ,998	-1 ,59	- 9,657	-2,106,121
10																	
11	A-B Total net expenses to recover	3,985,9	95,37	115,579	136,936	216,7 3	81,238	59,069	32,32	78,235	3 ,590	88,1 8	127,356	72,283	172,76	313,0 3	5,609,627
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	-5 ,889															-5 ,889
16	Act November 1998 - October 1999	-538,1 3															-538,1 3
17	Act November 1999 - October 2000	-760,871															-760,871
18	Act November 2000 - October 2001	-6 0,539															-6 0,539
19	Act November 2001 - October 2002	-625,11															-625,11
20	Act November 2002 - October 2003	-607,87															-607,87
21	Act November 2003 - October 200	-305,907															-305,907
22	Act November 200 - October 2005	-85,078															-85,078
23	Act November 2005- October 2006	-13,750															-13,750
2	Act November 2006- October 2007	-1 ,091	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-1 ,091
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013	0				-5,002	-5,002										-10,003
27	Act November 2013- October 201	0				-12,7 9	-12,7 9										-25, 97
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				- , 23											- , 23
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-32,310											-32,310
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-28, 8											-28, 8
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				-2,1 3	-2,1 3										- ,286
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	-69,391	-12,620	-12,90	-13,1 5	-13,221	-13,738	-13,725	-13,9 8	-1 ,173	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	-266,571
35	Gas Street overcollection	-23,511															-23,511
36	Pr or Period Pool under/overcollect on	332,837	38,5 8	5,088	50,73	155, 09	60,721	116,708	0	0	0	0	0	0	0	0	
37																	
38																	
39	C Surcharge Subtotal	-3,739,158	-12,620	-12,90	-13,1 5	-98,295	-33,631	-13,725	-13,9 8	-1 ,173	-1 , 05	-1 ,66	-1 858	-1 ,999	-15,312	-15, 68	- ,0 1,305
0																	
1																	
2	D Net balance to be recovered (A-B C)	2 6,787	82,753	102,675	123,791	118, 8	7,608	5,3 5	18,376	6 ,062	20,185	73, 8	112, 98	57,28	157, 51	297,575	1,568,323
3																	
	E Allocat on of Lit gated Recovery		-329,5 0	-102,675	-123,791	- 8,569	0	0	0	0	0	0	0	0	0	0	-60 ,575
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	-2 6,787	0	0	0	0	0	0	9,152	5,767	31, 93	6 ,285	0,917	13 ,958	297,575	337,361
8	remaining life	168	72	8	8	8	12	12	12	12	2	36	8	60	72	8	
9	one year	8	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	9,152	2,88	10, 98	16,071	8,183	22, 93	2,511	111,791
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	9,152	2,88	10, 98	16,071	8,183	22, 93	2,511	111,791
5																	
55	forecasted therm sales	1, 56,39 ,990	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	182,899,057	182,899,057
56																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0001	$0.0001	$0.0000	$0.0001	$0.0002	$0.0006

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

REDACTED
Schedule 20.3
Page 2 of 9

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
Tariff page 99

Laconia & Liberty Hill

DEF086

i.o. no. 500005

		(thru - 9/07) ool #1 - #6	(9/07 - 9/08) ool #7 Incl. Aud t Corr	(9/08 - 9/09) ool #8 Incl. Audit Corr	(9/09 - 9/10) ool #9	(9/10 - 9/11) ool #10	(9/11 - 9/12) ool #11	(9/12 - 6/13) ool #12	(7/13 - 6/14) pool #13	(7/14 - 6/15) pool #14	(7/15 - 6/16) pool #15	(7/16 - 6/17) pool #16	(7/17 - 6/18) pool #17	(7/18 - 6/19) pool #18	(7/19 - 6/20) pool #18	(7/20 - 6/21) pool #19	s total
1	1 Remediation costs (i.o. 500061)	0							[redacted]								0
2	Remediation costs (i.o. 500005)	9,670, 88	28,225	607,876	262,678	210,532	269,281	6 2,986									2 ,751,360
3	A Subtotal - remediation costs	9,670, 88	28,225	607,876	262,678	210,532	269,281	6 2,986									2 ,751,360
5	Cash recover es (i.o. 500061)	0	0	0													0
6	Cash recover es (i.o. 50000)	0	0	0													0
7	Recovery costs (i.o. 50000)	11,6 3	21,729	0	0												33,372
8	Transfer Credit from Gas Restructuring	0	0	0													0
9	B Subtotal - net recoveries	11,6 3	21,729	0	0	0	0	0									33,372
10																	
11	A-B Total net expenses to recover	9,682,131	9,95	607,876	262,678	210,532	269,281	6 2,986									2 ,78 ,732
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
16	Act November 1998 - October 1999	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
17	Act November 1999 - October 2000	-151,933	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-151,933
18	Act November 2000 - October 2001	-696,237	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-696,237
19	Act November 2001 - October 2002	-796,71	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-796,71
20	Act November 2002 - October 2003	-805, 3	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-805, 3
21	Act November 2003 - October 200	-699,215															-699,215
22	Act November 200 - October 2005	-652,26															-652,26
23	Act November 2005- October 2006	-691,159	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-691,159
2	Act November 2006- October 2007	-958,171	0	0	0	0	0	0	-	-	-	-	-	-	-	-	-958,171
25	Act November 2007- October 2008	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
26	Act November 2012- October 2013	0					-20,006										-20,006
27	Act November 2013- October 201	0					-25, 97	-76, 91									-101,988
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				- ,296											- ,296
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-31,38											-31,38
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-27,632											-27,632
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-1 ,208										-1 ,208
32	Act Nov 2013-Oct 201 Base Rate Rev	0					-28, 33	-28, 33	(28,433)								-85,298
33	Act Nov 201 -Oct 2015 Base Rate Rev	0					-21,639	-21,639	(21,639)	(21,639)	-	-	-	-	-	-	-86,55
3	AES co lections	0	0	0	0	0	0	0	-	-	-	-	-	-	-	-	0
35	Gas Street overcollection	0															0
36	Pr or Period Pool under/overcollect on	2,395,362	,2 2, 38	0	0	0	-87,311	0	-	-	-	-	-	-	-	-	
37																	
38																	
39	C Surcharge Subtotal	-3,055,765	,2 2, 38	0	0	-63,313	-197,093	-126,563	(50,071)	(21,639)	-	-	-	-	-	-	-5,822, 9
0																	
1																	
2	D Net balance to be recovered (A-B C)	6,626,365	,692,393	607,876	262,678	1 7,219	72,188	516, 2	[redacted]								18,962,237
3																	
	E Allocat on of Lit gated Recovery	0	- ,692,393	-607,876	-262,678	-23 ,530	0	0									-5,797, 76
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	0	0	0	0	0	0									2,127,600
8	remaining life	1	72	8	8	8	12	12									
9	one year	36	12	12	12	12	12	12									
50	F amortization		0	0	0	0	0	0									1,588,357
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	[redacted]								1,588,357
5																	
55	forecas ed therm sales	1,10 ,8 9,639	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	182,899,057	182,899,057
56																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]								$0.0087
											5 68.8086	1 333.37571	862.888571	2199.96	3989.371 29	2128.728571	

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation   MGPs
Tariff page 99

Manchester

DEF057

		(9/00 - 9/07) ool #1 - #7	(9/07 - 9/08) ool #8	(9/08 - 9/09) ool #9	(9/09 - 9/10) ool #10	(9/10 - 9/11) ool #11	(9/11 - 9/12) ool #12	(9/12 - 6/13) ool #13	(7/13 - 6/1) ool #1	(7/1 - 6/15) ool #15	(7/15 - 6/16) ool #16	(7/16 - 6/17) ool #17	(7/17 - 6/18) ool #18	(7/18 - 6/19) ool #19	(7/19 - 6/20) ool #20	(7/20 - 6/21) ool #21	s total
			Incl. Audit Corr														
1	1 Remediation costs (i.o. 500061)	3,762,097	,387,6 5	312,185	369,037	372,237	507,622	82,113	92,900	116, 96	71,011	5 ,333	70,725	182,093	312, 33	, 76	11,137, 03
2	Remediation costs (i.o. 500005)	825,092															825,092
3	A Subtotal - remediation costs	,587,189	,387,6 5	312,185	369,037	372,237	507,622	82,113	92,900	116, 96	71,011	5 ,333	70,725	182,093	312, 33	, 76	11,962, 95
5	Cash recover es (i.o. 500061)	-765,892	-1,127, 36		- 0,359	-23 ,6 8	-65,32	-270,732	-31,690	- 1,057	- 8,322	-3,810	-12 ,681	-1 ,07	-157, 01	-39,395	-3,09 ,822
6	Cash recover es (i.o. 50000)	0															0
7	Recovery costs (i.o. 50000)	1,2 ,872	0														1,2 ,872
8	Transfer Credit from Gas Restructuring	0	0														0
9	B Subtotal - net recoveries	78,979	-1,127, 36	0	- 0,359	-23 ,6 8	-65,32	-270,732	-31,690	- 1,057	- 8,322	-3,810	-12 ,681	-1 ,07	-157, 01	-39,395	-1,8 9,950
10																	
11	A-B Total net expenses to recover	5,066,169	3,260,209	312,185	328,678	137,589	2,298	-188,619	61,210	75, 0	22,690	50,523	3 6,0 3	38,019	155,032	5,080	10,112,5 5
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0															0
16	Act November 1998 - October 1999	0															0
17	Act November 1999 - October 2000	0															0
18	Act November 2000 - October 2001	0															0
19	Act November 2001 - October 2002	-73,5 3															-73,5 3
20	Act November 2002 - October 2003	-75,98															-75,98
21	Act November 2003 - October 200	-138,576															-138,576
22	Act November 200 - October 2005	-326,132	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-326,132
23	Act November 2005- October 2006	-563,732	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-563,732
2	Act November 2006- October 2007	-662,265	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-662,265
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013	0					- 0,012										- 0,012
27	Act November 2013- October 201	0					-50,99										-50,99
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-23,337										-23,337
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	0															0
35	Gas Street overcollection	0															0
36	Pr or Period Pool under/overcollect on	7,525,691	3,302,330	0	0	0	0	0	0	0	0	0	0	0	0	0	
37																	
38																	
39	C Surcharge Subtotal	5,685, 59	3,302,330	0	0	0	-11 ,3 3	0	0	0	0	0	0	0	0	0	-1,95 ,576
0																	
1																	
2	D Net balance to be recovered (A-B C)	10,751,628	6,562,539	312,185	328,678	137,589	327,955	-188,619	61,210	75, 0	22,690	50,523	3 6,0 3	38,019	155,032	5,080	8,157,969
3		0															
	E Allocat on of Lit gated Recovery	0	-6,562,539	-312,185	-328,678	-9 ,3 0	0	0	0	0	0	0	0	0	0	0	-7,297,7 2
5		0															
6	Surcharge calculation	0															
7	Unrecovered costs (D E)	0	0	0	0	0	0	0	0	10,777	6, 83	21,653	197,739	27,156	132,885	5,080	01,773
8	remaining life	168	70	8	8	12	12	12	12	12	2	36	8	60	72	8	
9	one year	8	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	10,777	3,2 1	7,218	9, 35	5, 31	22,1 7	726	
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	10,777	3,2 1	7,218	9, 35	5, 31	22,1 7	726	98,975
5		0															
55	forecas ed therm sales	1,28 , 2 ,318	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	182,899,057	182,899,057
56																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0 0000	$0.0001	$0.0000	$0.0005

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
Tariff page 99

Nashua

		(9/00 - 9/07) ool #1 - #7	(9/07 - 9/08) ool #8	(9/08 - 9/09) ool #9	(9/09 - 9/10) ool #10	(9/10 - 9/11) ool #11	Corrected per 2/08 Audit (9/11 - 9/12) ool #12	(9/12 - 6/13) ool #13	(7/13 - 6/1) ool #1	(7/1 - 6/15) ool #15	(7/15 - 6/16) ool #16	(7/16 - 6/17) ool #17	(7/17 - 6/18) ool #18	(7/18 - 6/19) ool #19	(7/19 - 6/20) ool #20	DEF054 (7/20 - 6/21) ool #21	s total
1	1 Remediation costs (i.o. 500061)	250,299	107,605	78,535	162,729	65,118	399, 00	119,095	63,397	105,917	106,129	100,3 2	61, 78	128,071	39 533	96,86	1,88 ,513
2	Remediation costs (i.o. 500005)	1,771,567															1,771,567
3	A Subtotal - remediation costs	2,021,866	107,605	78,535	162,729	65,118	399, 00	119,095	63,397	105,917	106,129	100,3 2	61, 78	128,071	39 533	96,86	3,656,080
5	Cash recover es (i.o. 500061)	-22,732	-10, 1	-62,2 6	-63,753	-31,767	-2,990	-199,336	-27, 7	- 0,699	- 3,69	-15,029	- 5,955	- 6,103	-28,062	-35,8 8	-676,075
6	Cash recover es (i.o. 50000)	0															0
7	Recovery costs (i.o. 50000)	18,388	0	0													18,388
8	Transfer Credit from Gas Restructuring	0	0	0													0
9	B Subtotal - net recoveries	- ,3	-10, 1	-62,2 6	-63,753	-31,767	-2,990	-199,336	-27, 7	- 0,699	- 3,69	-15,029	- 5,955	- 6,103	-28,062	-35,8 8	-657,687
10																	0
11	A-B Total net expenses to recover	2,017,521	97,191	16,289	98,975	33,351	396, 11	-80,2 1	35,950	65,217	62, 35	85,31	15,523	81,969	11, 72	61,016	2,998,392
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0															0
16	Act November 1998 - October 1999	0															0
17	Act November 1999 - October 2000	0															0
18	Act November 2000 - October 2001	0															0
19	Act November 2001 - October 2002	-183,857															-183,857
20	Act November 2002 - October 2003	-2 3,150															-2 3,150
21	Act November 2003 - October 200	-2 7,639															-2 7,639
22	Act November 200 - October 2005	-2 1,05															-2 1,05
23	Act November 2005- October 2006	-27 ,991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-27 ,991
2	Act November 2006- October 2007	-281,815	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-281,815
25	Act November 2007- October 2008	0															0
26	Act November 2012- October 2013	0					- 0,012										- 0,012
27	Act November 2013- October 201	0					-38,2 6										-38,2 6
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				0	-20,916										-20,916
32	Act Nov 2013-Oct 201 Base Rate Rev	0															0
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															0
3	AES co lections	0															0
35	Gas Street overcollection	0															0
36	Pr or Period Pool under/overcollect on	3,186,601	733, 79	0	0	0	0	5,616	0	0	0	0	0	0	0	0	
37																	
38																	
39	C Surcharge Subtotal	1,71 ,096	733, 79	0	0	0		-93,558	0	0	0	0	0	0	0	0	-1,571,680
0																	
1																	
2	D Net balance to be recovered (A-B C)	3,731,617	830,669	16,289	98,975	33,351	302,853	-80,2 1	35,950	65,217	62, 35	85,31	15,523	81,969	11, 72	61,016	1, 26,713
3																	
	E Allocat on of Lit gated Recovery	0	-830,669	-16,289	-98,975	-27,735	0	0	0	0	0	0	0	0	0	0	-973,668
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	0	0	0		0	0	0	9,317	17,838	36,563	8,870	58,5 9	9,833	61,016	201,987
8	remaining life	36	72	8	8	72	12	12	12	12	2	36	8	60	72	8	
9	one year	36	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717	
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	9,317	8,919	12,188	2,218	11,710	1,639	8,717	5 ,707
5																	
55	forecas ed therm sales	738,096,27	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179 57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	182,899,057	182,899,057
56																	
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0 0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

Schedule 20.3
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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
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		Dover												
												DEF059		
		(9/02 - 9/03)	(9/0 - 9/05)	(9/05 - 9/06)	(9/06 - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9/10 - 9/11)	(9/11 - 9/12)	(9/12 - 6/13)	(7/13 - 6/1)	(7/1 - 6/15)	
		ool #1	ool #2	ool #3	ool #	ool #5	ool #6	ool #7	ool #8	ool #9	ool #10	ool #11	ool #12	s total
1	1 Remediation costs (i.o. 500061)	0	18,85	2,288	0	0	0	0	0	0	0	0	0	21,1 2
2	Remediation costs (i.o. 500005)	181,066												181,066
3	A Subtotal - remediation costs	181,066	18,85	2,288	0	0	0	0	0	0	0	0	0	202,208
5	Cash recover es (i.o. 500061)	0					0	0	0	0	0	0	0	0
6	Cash recover es (i.o. 50000)	0												0
7	Recovery costs (i.o. 50000)	0												0
8	Transfer Credit from Gas Restructuring													0
9	B Subtotal - net recoveries	0	0	0	0	0	0	0	0	0	0	0	0	0
10														
11	A-B Total net expenses to recover	181,066	18,85	2,288	0	0	0	0	0	0	0	0	0	202,208
12														
13														
1	Surcharge revenue:													
15	Act June 1998 - October 1998	0												0
16	Act November 1998 - October 1999	0												0
17	Act November 1999 - October 2000	0												0
18	Act November 2000 - October 2001	0												0
19	Act November 2001 - October 2002	0												0
20	Act November 2002 - October 2003	0												0
21	Act November 2003 - October 200	-29,13												-29,13
22	Act November 200 - October 2005	-28 359												-28,359
23	Act November 2005- October 2006	-27, 99	0			0	0	0	0	0	0	0	0	-27, 99
2	Act November 2006- October 2007	-28,181	0	0	0	0	0	0	0	0	0	0	0	-28,181
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0
26	Act November 2012- October 2013													0
27	Act November 2013- October 201													0
28	Act Nov 2009-Oct 2010 Base Rate Rev													0
29	Act Nov 2010-Oct 2011 Base Rate Rev													0
30	Act Nov 2011-Oct 2012 Base Rate Rev													0
31	Act Nov 2012-Oct 2013 Base Rate Rev													0
32	Act Nov 2013-Oct 201 Base Rate Rev													0
33	Act Nov 201 -Oct 2015 Base Rate Rev													0
3	AES co lections													0
35	Gas Street overcollection													0
36	Pr or Period Pool under/overcollect on		67,892	86,7 6	89,03	89,03	0	0	0	0	0	0	0	
37														
38														
39	C Surcharge Subtotal	-113,17	67,892	86,7 6	89,03	89,03	0	0	0	0	0	0	0	-113,17
0														
1														
2	D Net balance to be recovered (A-B C)	67,892	86,7 6	89,03	89,03	89,03	0	0	0	0	0	0	0	89,03
3														
	E Allocat on of Lit gated Recovery		0		0	-89,03	0	0	0	0	0	0	0	-89,03
5														
6	Surcharge calculation													
7	Unrecovered costs (D E)	0	0	0		0	0	0	0	0	0	0	0	0
8	remaining life	2	36	8	60	72	8	8	8	8	8	8	8	
9	one year	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	0	0	0	0	0	0	0	0	0	0	0	0	
51														
52	Required annual increase in rates:													
53	smal er of D or F	0	0	0	0	0	0	0	0	0	0	0	0	0
5														
55	forecas ed therm sales	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 679	182,899,057
56														
####	surcharge per therm	$0.0000	$0.0000	$0 0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

Filed under the following protective orders:
Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

REDACTED
Schedule 20.3
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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
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		Keene												
													DEF055	
		(9/03 - 9/0) ool #1	(9/0 - 9/05) ool #2	(9/05 - 9/06) ool #3	(9/06 - 9/07) ool #	(9/07 - 9/08) ool #5	(9/08 - 9/09) ool #6	(9 09 - 9/10) ool #7	(9/10 - 9/11) ool #8	(9/11 - 9/12) ool #9	(9 12 - 6/13) ool #10	(7/13 - 6/14) pool #11	(7/14 - 6/15) pool #12	subtotal
1	1 Remediation costs (i.o. 500061)	0										[redacted]		
2	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	0	0	88	1, 00			
3	A Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	0	0	88	1, 00			
5	Cash recover es (i.o. 500061)	0												
6	Cash recover es (i.o. 50000)	0												
7	Recovery costs (i.o. 50000)			18,831	823	0	0	0	0					
8	Transfer Credit from Gas Restructuring				0	0	0							
9	B Subtotal - net recoveries	0	0	18,831	823	0	0	0	0	0	0			
10														
11	A-B Total net expenses to recover	10,165	6,606	53,9 2	9,589	32	269	0	0	88	1, 00			
12														
13														
1	Surcharge revenue:													
15	Act June 1998 - October 1998	0												-
16	Act November 1998 - October 1999	0												-
17	Act November 1999 - October 2000	0												-
18	Act November 2000 - October 2001	0												-
19	Act November 2001 - October 2002	0												-
20	Act November 2002 - October 2003	0												-
21	Act November 2003 - October 200	0												-
22	Act November 200 - October 2005	0	0				0	0	0	0	0	-	-	-
23	Act November 2005- October 2006	0	0				0	0	0	0	0	-	-	-
2	Act November 2006- October 2007	0	0	-1 ,091										(14,091)
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	-	-	-
26	Act November 2012- October 2013													-
27	Act November 2013- October 201													-
28	Act Nov 2009-Oct 2010 Base Rate Rev													-
29	Act Nov 2010-Oct 2011 Base Rate Rev													-
30	Act Nov 2011-Oct 2012 Base Rate Rev													-
31	Act Nov 2012-Oct 2013 Base Rate Rev													-
32	Act Nov 2013-Oct 201 Base Rate Rev													-
33	Act Nov 201 -Oct 2015 Base Rate Rev													-
3	AES co lections													-
35	Gas Street overcollection													-
36	Pr or Period Pool under/overcollect on		10,165	16,771	56,622	66,211	0	0	0	0	0	-	-	
37														
38														
39	C Surcharge Subtotal	0	10,165	2,680	56,622	66,211	0	0	0	0	0	-	-	(14,091)
0														
1														
2	D Net balance to be recovered (A-B C)	10,165	16,771	56,622	66,211	66,2	269	0	0	88	1, 00	[redacted]		
3														
	E Allocat on of Lit gated Recovery	0	0	0	0	-66,2	-269	0	0	0	0			
5														
6	Surcharge calculation													
7	Unrecovered costs (D E)	0	0	0			0	0	0	0	0			
8	remaining life	2	36	8	60	72	8	8	8	12	12			
9	one year	12	12	12	12	12	12	12	12	12	12			
50	F amortization	0	0	0	0	0	0	0	0	0	0			
51														
52	Required annual increase in rates:													
53	smal er of D or F	0	0	0	0	0	0	0	0	0	0	[redacted]		
5														
55	forecas ed therm sales	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,574,679	179,574,679	182,899,057
56														
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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Order No. 22,853 dated February 18, 1998 in Docket No. DR 97 130
Order No. 23,316 dated October 11, 1999 in Docket No. DG 99 132

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
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		Concord															
							Corrected per 2/08 Audit									DEF077	
		(9/03 - 9/07) ool #1 - #	(9/07 - 9/08) ool #5	(9/08 - 9/09) ool #6	(9/09 - 9/10) ool #7	(9/10 - 9/11) ool #8	(9/11 - 9/12) ool #9	(9/12 - 6/13) ool #10	(7/13 - 6/1) ool #11	(7/1 - 6/15) ool #12	(7/15 - 6/16) ool #13	(7/16 - 6/17) pool #14	(7/17 - 6/18) pool #15	(7/18 - 6/19) pool #16	(7/19 - 6/20) pool #17	(7/20 - 6/21) pool #18	s total
1	1 Remediation costs (i.o. 500061)	0										[redacted]					
2	Remediation costs (i.o. 500005)	397,110	8,006	77,063	9, 03	179,732	289,103	8 ,256	135,673	192,525	11 ,7 9						
3	A Subtotal - remediation costs	397,110	8,006	77,063	9, 03	179,732	289,103	8 ,256	135,673	192,525	11 ,7 9						
5	Cash recover es (i.o. 500061)	-70,215	-12,601	16,623	-3,213	-11,39	-31,575	-38,871	-12,319	-28,7 2	-19,197						
6	Cash recover es (i.o. 50000)	0															
7	Recovery costs (i.o. 50000)		1, 32	-1,007													
8	Transfer Credit from Gas Restructuring	0															
9	B Subtotal - net recoveries	-70,215	-11,169	15,616	-3,213	-11,39	-31,575	-38,871	-12,319	-28,7 2	-19,197						
10																	
11	A-B Total net expenses to recover	326,89	-3,163	92,679	6,190	168,338	257,528	5,38	123,355	163,783	95,553						
12																	
13																	
1	Surcharge revenue:																
15	Act June 1998 - October 1998	0															-
16	Act November 1998 - October 1999	0															-
17	Act November 1999 - October 2000	0															-
18	Act November 2000 - October 2001	0															-
19	Act November 2001 - October 2002	0															-
20	Act November 2002 - October 2003	0															-
21	Act November 2003 - October 200	0															-
22	Act November 200 - October 2005	0															-
23	Act November 2005- October 2006	-27, 99	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(27,499)
2	Act November 2006- October 2007	-28,181	0	0	0	0	0	0	0	0	0	-	-	-	-	-	(28,181)
25	Act November 2007- October 2008	0															-
26	Act November 2012- October 2013	0				-20,006	-20,006										(40,012)
27	Act November 2013- October 201	0				-12,7 9	-25, 97										(38,246)
28	Act Nov 2009-Oct 2010 Base Rate Rev	0				-1,891											(1,891)
29	Act Nov 2010-Oct 2011 Base Rate Rev	0				-13,816											(13,816)
30	Act Nov 2011-Oct 2012 Base Rate Rev	0				-12,16											(12,164)
31	Act Nov 2012-Oct 2013 Base Rate Rev	0				-6,79	-6,79										(13,588)
32	Act Nov 2013-Oct 201 Base Rate Rev	0															-
33	Act Nov 201 -Oct 2015 Base Rate Rev	0															-
3	AES co lections	0															-
35	Gas Street overcollection	0															-
36	Pr or Period Pool under/overcollect on	19,182	271,21	0	0	0	0	0	0	0	0	-	-	-	-	-	
37																	
38																	
39	C Surcharge Subtotal	363,501	271,21	0	0	-67, 20	-52,297	0	0	0	0	-	-	-	-	-	(175,398)
0																	
1																	
2	D Net balance to be recovered (A-B C)	690,395	268,051	92,679	6,190	100,919	205,231	5,38	123,355	163,783	95,553	[redacted]					
3																	
	E Allocat on of Lit gated Recovery	0	-268,051	-92,679	- 6,190	-1 ,702	0	0	0	0	0						
5																	
6	Surcharge calculation																
7	Unrecovered costs (D E)	0	0	0	0	0	0	0	0	23,398	27,301						
8	remaining life	1	72	8	8	12	12	12	12	12	2						
9	one year	36	12	12	12	12	12	12	12	12	12						
50	F amortization	0	0	0	0	0	0	0	0	23,398	13,650						
51																	
52	Required annual increase in rates:																
53	smal er of D or F	0	0	0	0	0	0	0	0	23,398	13,650	[redacted]					
5																	
55	forecas ed therm sales	553,96 ,622	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,574,679	179,574,679	179,574,679	179,574,679	182,899,057	182,899,057
56																	
####	surcharge per therm	$0.0000	$0.0000	$0 0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0001	[redacted]					

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		General																
																DEF064		**2021 MGP**
		(9/02 - 9/07) ool #1 - #5	(9/07 - 9/08) ool #6	(9/08 - 9/09) ool #7	(9/09 - 9/10) ool #8	(9/10 - 9/11) ool #9	(9/11 - 9/12) ool #10	(9/12 - 6/13) ool #11	(7/13 - 6/1) ool #12	(7/1 - 6/15) ool #13	(7/15 - 6/16) ool #1	(7/16 - 6/17) ool #15	(7/17 - 6/18) ool #16	(7/18 - 6/19) ool #17	(7/19 - 6/20) ool #18	(7/20 - 6/21) ool #19	s total	Remediat on s total
1	1 Remediation costs (i.o. 500061)																0	[redacted]
2	Remediation costs (i.o. 500005)	806,611	-181,000	-26,88	,199	69,286	93 03	75,20	13,139	16,612	11,879	6,5 7	10,799	6,868	7,111	5,6 6	919,051	
3	A Subtotal - remediation costs	806,611	-181,000	-26,88	,199	69,286	93 03	75,20	13,139	16,612	11,879	6,5 7	10,799	6,868	7,111	5,6 6	919,051	
5	Cash recover es (i.o. 500061)	0	0	0													0	
6	Cash recover es (i.o. 50000)																0	
7	Recovery costs (i.o. 50000)		16,012	23,953	0	0	-1 068	-1,358	0	-2 ,250	0	0	0	0	0	0	288	
8	Transfer Credit from Gas Restructuring		-3,331														-3,331	
9	B Subtotal - net recoveries	0	12,681	23,953	0	0	-1 068	-1,358	0	-2 ,250	0	0	0	0	0	0	-3,0 3	
10																		
11	A-B Total net expenses to recover	806,611	-168,319	-2,931	,199	69,286	78 967	73,8 6	13,139	-7,638	11,879	6,5 7	10,799	6,868	7,111	5,6 6	916,009	
12																		
13																		
1	Surcharge revenue:																	
15	Act June 1998 - October 1998																0	(54,889)
16	Act November 1998 - October 1999																0	(538,143)
17	Act November 1999 - October 2000																0	(912,804)
18	Act November 2000 - October 2001																0	(1,336,776)
19	Act November 2001 - October 2002																0	(1,679,228)
20	Act November 2002 - October 2003																0	(1,732,442)
21	Act November 2003 - October 200	-8,265															-8,265	(1,428,735)
22	Act November 200 - October 2005	-70,898															-70,898	(1,403,787)
23	Act November 2005- October 2006	-96,2 7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-96,2 7	(1,694,877)
2	Act November 2006- October 2007	- 9,318	0	0	0	0	0	0	0	0	0	0	0	0	0	0	- 9,318	(2,036,113)
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
26	Act November 2012- October 2013	0	0	0	0	-5,002	-5 002	0	0	0	0	0	0	0	0	0	-10,003	(160,048)
27	Act November 2013- October 201					-12,7 9	-12,7 9	-12,7 9									-38,2 6	(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev																0	(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev																0	(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev																0	(68,244)
31	Act Nov 2012-Oct 2013 Base Rate Rev																0	(76,335)
32	Act Nov 2013-Oct 201 Base Rate Rev																0	(85,298)
33	Act Nov 201 -Oct 2015 Base Rate Rev																0	(86,554)
3	AES co lections																0	(266,571)
35	Gas Street overcollection																0	(23,511)
36	Pr or Period Pool under/overcollect on	1, 86,6	2,068,527	0	0	0	0	0	0	0	0	0	0	0	0	0		
37																		
38																		
39	C Surcharge Subtotal	1,261,916	2,068,527	0	0	-17,750	-17 750	-12,7 9	0	0	0	0	0	0	0	0	-272,977	(13,965,693)
0																		
1																		
2	D Net balance to be recovered (A-B C)	2,068,527	1,900,208	-2,931	,199	51,536	61,217	61,098	13,139	-7,638	11,879	6,5 7	10,799	6,868	7,111	5,6 6	6 3,032	[redacted]
3																		
	E Allocat on of Lit gated Recovery	0	-1,900,208	2,931	- ,199	-8,562	0	0	0	0	0	0	0	0	0	0	-1,910,037	
5																		
6	Surcharge calculation																	
7	Unrecovered costs (D E)		0	0	0	0	0	0	0	-1,091	3,39	2,806	6,171	,906	6,095	5,6 6	27,926	
8	remaining life	72	8	8	8	12	12	12	12	12	2	36	8	60	72	8		
9	one year	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12		
50	F amortization	0	0	0	0	0	0	0	0	-1,091	1,697	935	1 5 3	981	1,016	807		
51																		
52	Required annual increase in rates:																	
53	smal er of D or F	0	0	0	0	0	0	0	0	-1,091	1,697	935	1,5 3	981	1 016	807	5,887	
5																		
55	forecas ed therm sales	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 ,679	179,57 679	179,57 679	182,899,057	182,899,057	**182,899,057**
56																		
####	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0 0000	$0.0000	$0.0000	**$0.0129**

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Liberty Utilities (EnergyNorth Natural Gas) Corp.
Environmental Remediation MGPs
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Expense and Collection Summary per Year

		(thru - 9/07)	(9/07 - 9/08)	(9/08 - 9/09)	(9/09 - 9/10)	(9 10 - 9/11)	(9 11 - 9/12)	(7/13 - 6/1)	(7/1 - 6/15)	(7/15 - 6/16)	(7/16 - 6/17)	(7/17 - 6/18)	(7/18 - 6/19)	(7/19 - 6/20)	(7/20 - 6/21)	Total
1	1 Remediation costs (i.o. 500061)	9,917,388	,590,62	518,907	67 ,766	686,515	993, 3	76,206	312,039	220,3	256,871	670,90	397, 6	539,32	50 ,039	[redacted]
2	Remediation costs (i.o. 500005)	13,712,581	255,263	658,32	316,280	59,550	651,906	2,605,250	7,975,39	3,307,910	260,380	115,8 1	69,261	11 ,228	8, 99	
3	A Subtotal - remediation costs	23,629,969	,8 5,887	1,177 231	991,0 5	1,1 6,065	1,6 5,3 0	3,081, 56	8,287, 33	3,528,25	517,250	786,7 5	66,707	653,552	952,538	
5	Cash recover es (i.o. 500061)	-2,93 ,5	-1,150, 52	-58 231	-113,390	-310,226	-105,062	-607,70	-121,889	-119,826	-53,116	-195, 23	-208,5	-212,660	-169,1 0	
6	Cash recover es (i.o. 50000)	- 5,985	0	0	0	0	0	0	0	0	0	0	0	0	0	
7	Recovery costs (i.o. 50000)	1,918,3 0	39,173	22,9 6	0	0	-1 ,068	2,500,000	2, 75,750	0	0	0	0	0	0	
8	Transfer Credit from Gas Restructuring	0	-3 331	0	0	0	0	0	0	0	0	0	0	0	0	
9	B Subtotal - net recoveries	-1, 62,188	-1,11 ,609	-35 285	-113,390	-310,226	-119,129	1,892,296	2,353,861	-119,826	-53,116	-195, 23	-208,5	-212,660	-169,1 0	
10																
11	A-B Total net expenses to recover	22,167,780	3,731 277	1,1 1,9 6	877,655	835,839	1,526,211	,973,753	10,6 1,29	3, 08, 28	6 ,13	591,322	258,163	0,892	783,398	
12																
13																
1	Surcharge revenue:															
15	Act June 1998 - October 1998	-5 ,889	0	0	0	0	0	0	0	0	0	0	0	0	0	(5 ,889)
16	Act November 1998 - October 1999	-538,1 3	0	0	0	0	0	0	0	0	0	0	0	0	0	(538,1 3)
17	Act November 1999 - October 2000	-912 80	0	0	0	0	0	0	0	0	0	0	0	0	0	(912,80)
18	Act November 2000 - October 2001	-1,336 776	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,336,776)
19	Act November 2001 - October 2002	-1,679,228	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,679,228)
20	Act November 2002 - October 2003	-1,732, 2	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,732, 2)
21	Act November 2003 - October 200	-1, 28,735	0	0	0	0	0	0	0	0	0	0	0	0	0	(1, 28,735)
22	Act November 200 - October 2005	-1, 03,787	0	0	0	0	0	0	0	0	0	0	0	0	0	(1, 03,787)
23	Act November 2005- October 2006	-1,69 ,877	0	0	0	0	0	0	0	0	0	0	0	0	0	(1,69 ,877)
2	Act November 2006- October 2007	-2,036,113	0	0	0	0	0	0	0	0	0	0	0	0	0	(2,036,113)
25	Act November 2007- October 2008	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-
26	Act November 2012- October 2013	0	0	0	0	-30,009	-130,039	0	0	0	0	0	0	0	0	(160,0 8)
27	Act November 2013- October 201	0	0	0	0	-38,2 6	-165,731	-89,2 0	0	0	0	0	0	0	0	(293,217)
28	Act Nov 2009-Oct 2010 Base Rate Rev	0	0	0	0	-10,611	0	0	0	0	0	0	0	0	0	(10,611)
29	Act Nov 2010-Oct 2011 Base Rate Rev	0	0	0	0	-77,509	0	0	0	0	0	0	0	0	0	(77,509)
30	Act Nov 2011-Oct 2012 Base Rate Rev	0	0	0	0	-68,2	0	0	0	0	0	0	0	0	0	(68,2)
31	Act Nov 2012-Oct 2013 Base Rate Rev	0	0	0	0	-8,937	-67,398	0	0	0	0	0	0	0	0	(76,335)
32	Act Nov 2013-Oct 201 Base Rate Rev	0	0	0	0	0	-28, 33	-56,865	0	0	0	0	0	0	0	(85,298)
33	Act Nov 201 -Oct 2015 Base Rate Rev	0	0	0	0	0	-21,639	- 3,277	-21,639	0	0	0	0	0	0	(86 55)
3	AES co lections	-69,391	-12,620	-12,90	-13,1 5	-13,221	-13,738	-27,673	-1 ,173	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	(266 571)
35	Gas Street overcollection	-23,511	0	0	0	0	0	0	0	0	0	0	0	0	0	(23 511)
36	Pr or Period Pool under/overcollect on	15,673,5 7												0	0	[redacted]
37																
38																
39	C Surcharge Subtotal	2,762,851	-12,620	-12,90	-13,1 5	-2 6,777	- 26,978	-217,055	-35,811	-1 , 05	-1 ,66	-1 ,858	-1 ,999	-15,312	-15, 68	1,707,85
0																
1																
2	D Net balance to be recovered (A-B C)	2 ,930,631	3,718,657	1,129,0 2	86 ,510	589,062	1,099,233	,756,698	10,605, 83	3,39 ,023	9, 70	576, 6	2 3,165	25,579	767,930	[redacted]
3																
	E Allocat on of Lit gated Recovery															
5																
6	Surcharge calculation															
7	Unrecovered costs (D E)															
8	remaining life															
9	one year															
50	F amortization															
51																
52	Required annual increase in rates:															
53	smal er of D or F															
5																
55	forecas ed therm sales															
56																
####	surcharge per therm															

1. While the recoveries are displayed on the Summary, Cash Recoveries by s te, are not exclusive to a particu ar site.

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

Calculation of Supplier Balancing Charge
2020-2021

Rate: $ 0.1807 /MMBtu

		Rate	Volume		Total	
Injection Cost		$ 0.0087	**386,014**	$	3,358	
Fuel	1.75%	$ 0.0481	**386,014**	$	18,577	
Withdrawal Cost		$ 0.0087	**195,768**	$	1,703	
Delivery Rate		$ 0.0431	195,768	$	8,432	
FTA Demand Charge		$ 0.2357	195,768	$	46,138	
FTA Commodity Charge		$ 0.1003	195,768	$	19,636	
Fuel	1.35%	$ 0.0371	195,768	$	7,268	
			Total Cost	$	105,112	
		Absolute Value of the	Sendout Error		**581,782**	MMBtu
			Rate	$	0.1807	/MMBTU

NOTES: See Tennessee Gas Pipeline Tariff Pages in PK Schedule 6

TGP FSMA Injection Charge	$	0.0087	/ MMBtu
TGP FSMA Withdrawal Charge	$	0.0087	/ MMBtu
TGP FSMA Deliverability Charge	$	1.3094	/ MMBtu per month
	$	0.0431	/ MMBtu per day
TGP Z4-6 Demand Charge	$	7.1645	/ MMBtu per month
	$	0.2357	/ MMBtu per day
TGP Z4-6 Commodity Charge	$	0.1003	/ MMBtu

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

Calculation of Supplier Balancing Charge
2020-2021

Estimated Monthly Imbalances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout (MMBtu)	Actual Sendout (MMBtu)	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Nov	599	589	10	1,423,420	1,408,975	14,445	66,447	40,446	26,001
Dec	986	997	(11)	2,217,499	2,237,310	(19,812)	84,649	32,419	52,230
Jan	1,122	1,118	4	2,564,525	2,556,052	8,473	84,733	46,603	38,130
Feb	1,086	1,059	27	2,484,194	2,438,118	46,075	86,870	66,473	20,397
Mar	731	724	7	1,759,139	1,745,972	13,168	69,602	41,385	28,217
Apr	595	568	27	1,279,771	1,242,675	37,097	53,584	45,340	8,244
May	262	237	25	685,310	660,496	24,814	34,740	29,777	4,963
Jun	32	21	11	221,781	216,450	5,330	7,269	6,300	969
Jul	-	-	-	432,376	432,376	-	-	-	-
Aug	15	5	10	324,442	316,893	7,549	7,549	7,549	-
Sep	105	78	27	415,806	401,671	14,135	16,155	15,145	1,010
Oct	446	407	39	906,155	867,184	38,971	70,184	54,578	15,607
Total	**5,979**	**5,803**	**176**	**14,714,420**	**14,524,173**	**190,246**	**581,782**	**386,014**	**195,768**

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Calculation of Supplier Balancing Charge
2021-2022

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 2020	24	21	3	48383.82627	44261.97983	4121.846436	4121.846436	4121.846436	0
Apr 2, 2020	21	22	-1	44261.97983	45635.92864	-1373.94881	1373.948812	0	1373.948812
Apr 3, 2020	20	20	0	42888.03102	42888.03102	0	0	0	0
Apr 4, 2020	21	18	3	44261.97983	40140.1334	4121.846436	4121.846436	4121.846436	0
Apr 5, 2020	13	14	-1	33270.38934	34644.33815	-1373.94881	1373.948812	0	1373.948812
Apr 6, 2020	17	16	1	38766.18458	37392.23577	1373.948812	1373.948812	1373.948812	0
Apr 7, 2020	15	12	3	36018.28696	31896.44052	4121.846436	4121.846436	4121.846436	0
Apr 8, 2020	17	18	-1	38766.18458	40140.1334	-1373.94881	1373.948812	0	1373.948812
Apr 9, 2020	22	23	-1	45635.92864	47009.87745	-1373.94881	1373.948812	0	1373.948812
Apr 10, 2020	24	24	0	48383.82627	48383.82627	0	0	0	0
Apr 11, 2020	23	23	0	47009.87745	47009.87745	0	0	0	0
Apr 12, 2020	10	10	0	29148.5429	29148.5429	0	0	0	0
Apr 13, 2020	13	10	3	33270.38934	29148.5429	4121.846436	4121.846436	4121.846436	0
Apr 14, 2020	18	15	3	40140.1334	36018.28696	4121.846436	4121.846436	4121.846436	0
Apr 15, 2020	24	23	1	48383.82627	47009.87745	1373.948812	1373.948812	1373.948812	0
Apr 16, 2020	27	27	0	52505.6727	52505.6727	0	0	0	0
Apr 17, 2020	22	23	-1	45635.92864	47009.87745	-1373.94881	1373.948812	0	1373.948812
Apr 18, 2020	26	27	-1	51131.72389	52505.6727	-1373.94881	1373.948812	0	1373.948812
Apr 19, 2020	13	11	2	33270.38934	30522.49171	2747.897624	2747.897624	2747.897624	0
Apr 20, 2020	21	21	0	44261.97983	44261.97983	0	0	0	0
Apr 21, 2020	24	24	0	48383.82627	48383.82627	0	0	0	0
Apr 22, 2020	26	26	0	51131.72389	51131.72389	0	0	0	0
Apr 23, 2020	20	17	3	42888.03102	38766.18458	4121.846436	4121.846436	4121.846436	0
Apr 24, 2020	23	18	5	47009.87745	40140.1334	6869.744059	6869.744059	6869.744059	0
Apr 25, 2020	13	11	2	33270.38934	30522.49171	2747.897624	2747.897624	2747.897624	0
Apr 26, 2020	21	21	0	44261.97983	44261.97983	0	0	0	0
Apr 27, 2020	26	24	2	51131.72389	48383.82627	2747.897624	2747.897624	2747.897624	0
Apr 28, 2020	19	18	1	41514.08221	40140.1334	1373.948812	1373.948812	1373.948812	0
Apr 29, 2020	15	15	0	36018.28696	36018.28696	0	0	0	0
Apr 30, 2020	17	16	1	38766.18458	37392.23577	1373.948812	1373.948812	1373.948812	0
May 1, 2020	10	9	1	23643.67895	22651.10414	992.5748165	992.5748165	992.5748165	0
May 2, 2020	7	3	4	20665.9545	16695.65524	3970.299266	3970.299266	3970.299266	0
May 3, 2020	1	0	1	14710.50561	13717.93079	992.5748165	992.5748165	992.5748165	0
May 4, 2020	14	12	2	27613.97822	25628.82859	1985.149633	1985.149633	1985.149633	0
May 5, 2020	17	17	0	30591.70267	30591.70267	0	0	0	0
May 6, 2020	15	13	2	28606.55304	26621.4034	1985.149633	1985.149633	1985.149633	0
May 7, 2020	12	10	2	25628.82859	23643.67895	1985.149633	1985.149633	1985.149633	0
May 8, 2020	18	18	0	31584.27749	31584.27749	0	0	0	0
May 9, 2020	24	25	-1	37539.72639	38532.3012	-992.574817	992.5748165	0	992.5748165
May 10, 2020	16	15	1	29599.12785	28606.55304	992.5748165	992.5748165	992.5748165	0
May 11, 2020	15	14	1	28606.55304	27613.97822	992.5748165	992.5748165	992.5748165	0
May 12, 2020	18	18	0	31584.27749	31584.27749	0	0	0	0
May 13, 2020	15	14	1	28606.55304	27613.97822	992.5748165	992.5748165	992.5748165	0
May 14, 2020	6	2	4	19673.37969	15703.08042	3970.299266	3970.299266	3970.299266	0
May 15, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 16, 2020	4	7	-3	17688.23006	20665.9545	-2977.72445	2977.72445	0	2977.72445
May 17, 2020	4	2	2	17688.23006	15703.08042	1985.149633	1985.149633	1985.149633	0
May 18, 2020	9	7	2	22651.10414	20665.9545	1985.149633	1985.149633	1985.149633	0
May 19, 2020	10	10	0	23643.67895	23643.67895	0	0	0	0
May 20, 2020	8	7	1	21658.52932	20665.9545	992.5748165	992.5748165	992.5748165	0
May 21, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 22, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 23, 2020	12	10	2	25628.82859	23643.67895	1985.149633	1985.149633	1985.149633	0
May 24, 2020	11	9	2	24636.25377	22651.10414	1985.149633	1985.149633	1985.149633	0
May 25, 2020	3	4	-1	16695.65524	17688.23006	-992.574817	992.5748165	0	992.5748165
May 26, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 27, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 28, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 29, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 30, 2020	0	0	0	13717.93079	13717.93079	0	0	0	0
May 31, 2020	13	11	2	26621.4034	24636.25377	1985.149633	1985.149633	1985.149633	0
Jun 1, 2020	10	10	0	16305.53853	16305.53853	0	0	0	0
Jun 2, 2020	3	2	1	12913.42533	12428.83773	484.5875993	484.5875993	484.5875993	0
Jun 3, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 4, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 5, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jun 6, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 7, 2020	5	2	3	13882.60053	12428.83773	1453.762798	1453.762798	1453.762798	0
Jun 8, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 9, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 10, 2020	0	1	-1	11459.66253	11944.25013	-484.587599	484.5875993	0	484.5875993
Jun 11, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 12, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 13, 2020	3	4	-1	12913.42533	13398.01293	-484.587599	484.5875993	0	484.5875993
Jun 14, 2020	6	2	4	14367.18813	12428.83773	1938.350397	1938.350397	1938.350397	0
Jun 15, 2020	3	0	3	12913.42533	11459.66253	1453.762798	1453.762798	1453.762798	0
Jun 16, 2020	2	0	2	12428.83773	11459.66253	969.1751986	969.1751986	969.1751986	0
Jun 17, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 18, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 19, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 20, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 21, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 22, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 23, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 24, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 25, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 26, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 27, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 28, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 29, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jun 30, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
Jul 1, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 2, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 3, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 4, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 5, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 6, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 7, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 8, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 9, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 10, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 11, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 12, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 13, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 14, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 15, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 16, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 17, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 18, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 19, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 20, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 21, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 22, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 23, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 24, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 25, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 26, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 27, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 28, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 29, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 30, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Jul 31, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
Aug 1, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 2, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 3, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 4, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 5, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 6, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 7, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 8, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 9, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 10, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 11, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Aug 12, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 13, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 14, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 15, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 16, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 17, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 18, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 19, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 20, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 21, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 22, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 23, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 24, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 25, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 26, 2020	5	1	4	13884.05439	10864.54385	3019.510544	3019.510544	3019.510544	0
Aug 27, 2020	6	2	4	14638.93203	11619.42148	3019.510544	3019.510544	3019.510544	0
Aug 28, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 29, 2020	0	0	0	10109.66621	10109.66621	0	0	0	0
Aug 30, 2020	4	2	2	13129.17676	11619.42148	1509.755272	1509.755272	1509.755272	0
Aug 31, 2020	2	0	2	11619.42148	10109.66621	1509.755272	1509.755272	1509.755272	0
Sep 1, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 2, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 3, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 4, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 5, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 6, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 7, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 8, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 9, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 10, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 11, 2020	7	4	3	15678.88572	14163.85588	1515.029842	1515.029842	1515.029842	0
Sep 12, 2020	8	5	3	16183.89567	14668.86583	1515.029842	1515.029842	1515.029842	0
Sep 13, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 14, 2020	8	5	3	16183.89567	14668.86583	1515.029842	1515.029842	1515.029842	0
Sep 15, 2020	6	8	-2	15173.87577	16183.89567	-1010.01989	1010.019895	0	1010.019895
Sep 16, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 17, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 18, 2020	12	10	2	18203.93546	17193.91556	1010.019895	1010.019895	1010.019895	0
Sep 19, 2020	16	13	3	20223.97525	18708.94541	1515.029842	1515.029842	1515.029842	0
Sep 20, 2020	17	14	3	20728.9852	19213.95535	1515.029842	1515.029842	1515.029842	0
Sep 21, 2020	14	14	0	19213.95535	19213.95535	0	0	0	0
Sep 22, 2020	8	4	4	16183.89567	14163.85588	2020.03979	2020.03979	2020.03979	0
Sep 23, 2020	2	0	2	13153.83598	12143.81609	1010.019895	1010.019895	1010.019895	0
Sep 24, 2020	1	0	1	12648.82604	12143.81609	505.0099475	505.0099475	505.0099475	0
Sep 25, 2020	1	1	0	12648.82604	12648.82604	0	0	0	0
Sep 26, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 27, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 28, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 29, 2020	0	0	0	12143.81609	12143.81609	0	0	0	0
Sep 30, 2020	6	3	3	15173.87577	13658.84593	1515.029842	1515.029842	1515.029842	0
Oct 1, 2020	5	3	2	19175.97949	17095.09572	2080.883772	2080.883772	2080.883772	0
Oct 2, 2020	15	14	1	29580.39835	28539.95646	1040.441886	1040.441886	1040.441886	0
Oct 3, 2020	12	12	0	26459.07269	26459.07269	0	0	0	0
Oct 4, 2020	12	10	2	26459.07269	24378.18892	2080.883772	2080.883772	2080.883772	0
Oct 5, 2020	11	8	3	25418.6308	22297.30515	3121.325658	3121.325658	3121.325658	0
Oct 6, 2020	6	4	2	20216.42137	18135.5376	2080.883772	2080.883772	2080.883772	0
Oct 7, 2020	9	5	4	23337.74703	19175.97949	4161.767544	4161.767544	4161.767544	0
Oct 8, 2020	18	16	2	32701.72401	30620.84024	2080.883772	2080.883772	2080.883772	0
Oct 9, 2020	12	9	3	26459.07269	23337.74703	3121.325658	3121.325658	3121.325658	0
Oct 10, 2020	4	0	4	18135.5376	13973.77006	4161.767544	4161.767544	4161.767544	0
Oct 11, 2020	16	14	2	30620.84024	28539.95646	2080.883772	2080.883772	2080.883772	0
Oct 12, 2020	15	14	1	29580.39835	28539.95646	1040.441886	1040.441886	1040.441886	0
Oct 13, 2020	13	13	0	27499.51458	27499.51458	0	0	0	0
Oct 14, 2020	10	10	0	24378.18892	24378.18892	0	0	0	0
Oct 15, 2020	5	0	5	19175.97949	13973.77006	5202.20943	5202.20943	5202.20943	0
Oct 16, 2020	14	15	-1	28539.95646	29580.39835	-1040.44189	1040.441886	0	1040.441886
Oct 17, 2020	21	21	0	35823.04967	35823.04967	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Oct 18, 2020	17	17	0	31661.28212	31661.28212	0	0	0	0
Oct 19, 2020	13	9	4	27499.51458	23337.74703	4161.767544	4161.767544	4161.767544	0
Oct 20, 2020	7	3	4	21256.86326	17095.09572	4161.767544	4161.767544	4161.767544	0
Oct 21, 2020	4	3	1	18135.5376	17095.09572	1040.441886	1040.441886	1040.441886	0
Oct 22, 2020	7	4	3	21256.86326	18135.5376	3121.325658	3121.325658	3121.325658	0
Oct 23, 2020	8	5	3	22297.30515	19175.97949	3121.325658	3121.325658	3121.325658	0
Oct 24, 2020	16	14	2	30620.84024	28539.95646	2080.883772	2080.883772	2080.883772	0
Oct 25, 2020	21	21	0	35823.04967	35823.04967	0	0	0	0
Oct 26, 2020	16	18	-2	30620.84024	32701.72401	-2080.88377	2080.883772	0	2080.883772
Oct 27, 2020	21	19	2	35823.04967	33742.16589	2080.883772	2080.883772	2080.883772	0
Oct 28, 2020	22	22	0	36863.49155	36863.49155	0	0	0	0
Oct 29, 2020	25	36	-11	39984.81721	51429.67796	-11444.8607	11444.86075	0	11444.86075
Oct 30, 2020	35	36	-1	50389.23607	51429.67796	-1040.44189	1040.441886	0	1040.441886
Oct 31, 2020	30	29	1	45187.02664	44146.58475	1040.441886	1040.441886	1040.441886	0
Nov 1, 2020	21	20	1	48939.99847	47495.49736	1444.501114	1444.501114	1444.501114	0
Nov 2, 2020	29	29	0	60496.00739	60496.00739	0	0	0	0
Nov 3, 2020	31	30	1	63385.00961	61940.5085	1444.501114	1444.501114	1444.501114	0
Nov 4, 2020	20	20	0	47495.49736	47495.49736	0	0	0	0
Nov 5, 2020	9	4	5	31605.9851	24383.47953	7222.505571	7222.505571	7222.505571	0
Nov 6, 2020	7	5	2	28716.98287	25827.98065	2889.002228	2889.002228	2889.002228	0
Nov 7, 2020	6	7	-1	27272.48176	28716.98287	-1444.50111	1444.501114	0	1444.501114
Nov 8, 2020	10	10	0	33050.48622	33050.48622	0	0	0	0
Nov 9, 2020	9	10	-1	31605.9851	33050.48622	-1444.50111	1444.501114	0	1444.501114
Nov 10, 2020	2	0	2	21494.4773	18605.47508	2889.002228	2889.002228	2889.002228	0
Nov 11, 2020	2	0	2	21494.4773	18605.47508	2889.002228	2889.002228	2889.002228	0
Nov 12, 2020	18	19	-1	44606.49513	46050.99624	-1444.50111	1444.501114	0	1444.501114
Nov 13, 2020	25	27	-2	54718.00293	57607.00516	-2889.00223	2889.002228	0	2889.002228
Nov 14, 2020	27	28	-1	57607.00516	59051.50627	-1444.50111	1444.501114	0	1444.501114
Nov 15, 2020	19	18	1	46050.99624	44606.49513	1444.501114	1444.501114	1444.501114	0
Nov 16, 2020	23	23	0	51829.0007	51829.0007	0	0	0	0
Nov 17, 2020	29	29	0	60496.00739	60496.00739	0	0	0	0
Nov 18, 2020	40	40	0	76385.51964	76385.51964	0	0	0	0
Nov 19, 2020	25	23	2	54718.00293	51829.0007	2889.002228	2889.002228	2889.002228	0
Nov 20, 2020	16	14	2	41717.4929	38828.49067	2889.002228	2889.002228	2889.002228	0
Nov 21, 2020	25	22	3	54718.00293	50384.49959	4333.503342	4333.503342	4333.503342	0
Nov 22, 2020	21	22	-1	48939.99847	50384.49959	-1444.50111	1444.501114	0	1444.501114
Nov 23, 2020	27	25	2	57607.00516	54718.00293	2889.002228	2889.002228	2889.002228	0
Nov 24, 2020	34	33	1	67718.51296	66274.01184	1444.501114	1444.501114	1444.501114	0
Nov 25, 2020	24	29	-5	53273.50181	60496.00739	-7222.50557	7222.505571	0	7222.505571
Nov 26, 2020	21	25	-4	48939.99847	54718.00293	-5778.00446	5778.004457	0	5778.004457
Nov 27, 2020	20	20	0	47495.49736	47495.49736	0	0	0	0
Nov 28, 2020	24	25	-1	53273.50181	54718.00293	-1444.50111	1444.501114	0	1444.501114
Nov 29, 2020	25	26	-1	54718.00293	56162.50404	-1444.50111	1444.501114	0	1444.501114
Nov 30, 2020	10	6	4	33050.48622	27272.48176	5778.004457	5778.004457	5778.004457	0
Dec 1, 2020	20	18	2	50268.23604	46666.1398	3602.096234	3602.096234	3602.096234	0
Dec 2, 2020	29	28	1	66477.66909	64676.62097	1801.048117	1801.048117	1801.048117	0
Dec 3, 2020	25	23	2	59273.47662	55671.38039	3602.096234	3602.096234	3602.096234	0
Dec 4, 2020	21	21	0	52069.28415	52069.28415	0	0	0	0
Dec 5, 2020	30	31	-1	68278.71721	70079.76533	-1801.04812	1801.048117	0	1801.048117
Dec 6, 2020	34	35	-1	75482.90968	77283.95779	-1801.04812	1801.048117	0	1801.048117
Dec 7, 2020	35	37	-2	77283.95779	80886.05403	-3602.09623	3602.096234	0	3602.096234
Dec 8, 2020	38	38	0	82687.10214	82687.10214	0	0	0	0
Dec 9, 2020	33	32	1	73681.86156	71880.81344	1801.048117	1801.048117	1801.048117	0
Dec 10, 2020	31	32	-1	70079.76533	71880.81344	-1801.04812	1801.048117	0	1801.048117
Dec 11, 2020	27	29	-2	62875.57286	66477.66909	-3602.09623	3602.096234	0	3602.096234
Dec 12, 2020	24	27	-3	57472.42851	62875.57286	-5403.14435	5403.144351	0	5403.144351
Dec 13, 2020	25	36	-11	59273.47662	79085.00591	-19811.5293	19811.52929	0	19811.52929
Dec 14, 2020	33	31	2	73681.86156	70079.76533	3602.096234	3602.096234	3602.096234	0
Dec 15, 2020	42	43	-1	89891.29461	91692.34273	-1801.04812	1801.048117	0	1801.048117
Dec 16, 2020	43	44	-1	91692.34273	93493.39085	-1801.04812	1801.048117	0	1801.048117
Dec 17, 2020	45	42	3	95294.43896	89891.29461	5403.144351	5403.144351	5403.144351	0
Dec 18, 2020	45	47	-2	95294.43896	98896.5352	-3602.09623	3602.096234	0	3602.096234
Dec 19, 2020	41	42	-1	88090.2465	89891.29461	-1801.04812	1801.048117	0	1801.048117
Dec 20, 2020	34	36	-2	75482.90968	79085.00591	-3602.09623	3602.096234	0	3602.096234
Dec 21, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0
Dec 22, 2020	34	29	5	75482.90968	66477.66909	9005.240585	9005.240585	9005.240585	0
Dec 23, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Dec 24, 2020	13	13	0	37660.89922	37660.89922	0	0	0	0
Dec 25, 2020	20	19	1	50268.23604	48467.18792	1801.048117	1801.048117	1801.048117	0
Dec 26, 2020	36	35	1	79085.00591	77283.95779	1801.048117	1801.048117	1801.048117	0
Dec 27, 2020	34	34	0	75482.90968	75482.90968	0	0	0	0
Dec 28, 2020	28	28	0	64676.62097	64676.62097	0	0	0	0
Dec 29, 2020	39	39	0	84488.15026	84488.15026	0	0	0	0
Dec 30, 2020	27	28	-1	62875.57286	64676.62097	-1801.04812	1801.048117	0	1801.048117
Dec 31, 2020	32	32	0	71880.81344	71880.81344	0	0	0	0
Jan 1, 2021	30	31	-1	69606.61887	71724.95338	-2118.3345	2118.334502	0	2118.334502
Jan 2, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
Jan 3, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
Jan 4, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
Jan 5, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
Jan 6, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
Jan 7, 2021	35	35	0	80198.29138	80198.29138	0	0	0	0
Jan 8, 2021	36	36	0	82316.62588	82316.62588	0	0	0	0
Jan 9, 2021	37	35	2	84434.96038	80198.29138	4236.669003	4236.669003	4236.669003	0
Jan 10, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
Jan 11, 2021	35	36	-1	80198.29138	82316.62588	-2118.3345	2118.334502	0	2118.334502
Jan 12, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
Jan 13, 2021	33	31	2	75961.62238	71724.95338	4236.669003	4236.669003	4236.669003	0
Jan 14, 2021	32	31	1	73843.28788	71724.95338	2118.334502	2118.334502	2118.334502	0
Jan 15, 2021	28	26	2	65369.94987	61133.28087	4236.669003	4236.669003	4236.669003	0
Jan 16, 2021	27	24	3	63251.61537	56896.61186	6355.003505	6355.003505	6355.003505	0
Jan 17, 2021	29	25	4	67488.28437	59014.94637	8473.338006	8473.338006	8473.338006	0
Jan 18, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
Jan 19, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
Jan 20, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
Jan 21, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
Jan 22, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
Jan 23, 2021	46	46	0	103499.9709	103499.9709	0	0	0	0
Jan 24, 2021	43	43	0	97144.96739	97144.96739	0	0	0	0
Jan 25, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
Jan 26, 2021	34	36	-2	78079.95688	82316.62588	-4236.669	4236.669003	0	4236.669003
Jan 27, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
Jan 28, 2021	47	47	0	105618.3054	105618.3054	0	0	0	0
Jan 29, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
Jan 30, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
Jan 31, 2021	46	48	-2	103499.9709	107736.6399	-4236.669	4236.669003	0	4236.669003
Feb 1, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
Feb 2, 2021	36	33	3	83276.32165	78176.98524	5099.336415	5099.336415	5099.336415	0
Feb 3, 2021	35	32	3	81576.54285	76477.20643	5099.336415	5099.336415	5099.336415	0
Feb 4, 2021	37	39	-2	84976.10046	88375.65807	-3399.55761	3399.55761	0	3399.55761
Feb 5, 2021	32	36	-4	76477.20643	83276.32165	-6799.11522	6799.11522	0	6799.11522
Feb 6, 2021	39	37	2	88375.65807	84976.10046	3399.55761	3399.55761	3399.55761	0
Feb 7, 2021	37	40	-3	84976.10046	90075.43687	-5099.33642	5099.336415	0	5099.336415
Feb 8, 2021	46	45	1	100274.1097	98574.3309	1699.778805	1699.778805	1699.778805	0
Feb 9, 2021	45	45	0	98574.3309	98574.3309	0	0	0	0
Feb 10, 2021	43	43	0	95174.77329	95174.77329	0	0	0	0
Feb 11, 2021	49	47	2	105373.4461	101973.8885	3399.55761	3399.55761	3399.55761	0
Feb 12, 2021	49	46	3	105373.4461	100274.1097	5099.336415	5099.336415	5099.336415	0
Feb 13, 2021	42	38	4	93474.99448	86675.87926	6799.11522	6799.11522	6799.11522	0
Feb 14, 2021	38	36	2	86675.87926	83276.32165	3399.55761	3399.55761	3399.55761	0
Feb 15, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
Feb 16, 2021	36	35	1	83276.32165	81576.54285	1699.778805	1699.778805	1699.778805	0
Feb 17, 2021	43	41	2	95174.77329	91775.21568	3399.55761	3399.55761	3399.55761	0
Feb 18, 2021	38	39	-1	86675.87926	88375.65807	-1699.77881	1699.778805	0	1699.778805
Feb 19, 2021	38	38	0	86675.87926	86675.87926	0	0	0	0
Feb 20, 2021	40	41	-1	90075.43687	91775.21568	-1699.77881	1699.778805	0	1699.778805
Feb 21, 2021	42	42	0	93474.99448	93474.99448	0	0	0	0
Feb 22, 2021	33	31	2	78176.98524	74777.42763	3399.55761	3399.55761	3399.55761	0
Feb 23, 2021	27	26	1	67978.31241	66278.5336	1699.778805	1699.778805	1699.778805	0
Feb 24, 2021	25	20	5	64578.7548	56079.86077	8498.894025	8498.894025	8498.894025	0
Feb 25, 2021	37	32	5	84976.10046	76477.20643	8498.894025	8498.894025	8498.894025	0
Feb 26, 2021	35	33	2	81576.54285	78176.98524	3399.55761	3399.55761	3399.55761	0
Feb 27, 2021	29	30	-1	71377.87002	73077.64882	-1699.77881	1699.778805	0	1699.778805
Feb 28, 2021	26	26	0	66278.5336	66278.5336	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Mar 1, 2021	39	38	1	86165.16337	84284.03473	1881.128637	1881.128637	1881.128637	0
Mar 2, 2021	41	41	0	89927.42064	89927.42064	0	0	0	0
Mar 3, 2021	29	28	1	67353.87699	65472.74835	1881.128637	1881.128637	1881.128637	0
Mar 4, 2021	38	38	0	84284.03473	84284.03473	0	0	0	0
Mar 5, 2021	42	41	1	91808.54928	89927.42064	1881.128637	1881.128637	1881.128637	0
Mar 6, 2021	42	40	2	91808.54928	88046.292	3762.257275	3762.257275	3762.257275	0
Mar 7, 2021	40	37	3	88046.292	82402.90609	5643.385912	5643.385912	5643.385912	0
Mar 8, 2021	32	30	2	72997.2629	69235.00563	3762.257275	3762.257275	3762.257275	0
Mar 9, 2021	26	24	2	61710.49108	57948.23381	3762.257275	3762.257275	3762.257275	0
Mar 10, 2021	21	20	1	52304.84789	50423.71926	1881.128637	1881.128637	1881.128637	0
Mar 11, 2021	8	5	3	27850.17561	22206.78969	5643.385912	5643.385912	5643.385912	0
Mar 12, 2021	22	20	2	54185.97653	50423.71926	3762.257275	3762.257275	3762.257275	0
Mar 13, 2021	28	28	0	65472.74835	65472.74835	0	0	0	0
Mar 14, 2021	38	40	-2	84284.03473	88046.292	-3762.25727	3762.257275	0	3762.257275
Mar 15, 2021	43	45	-2	93689.67792	97451.93519	-3762.25727	3762.257275	0	3762.257275
Mar 16, 2021	31	31	0	71116.13427	71116.13427	0	0	0	0
Mar 17, 2021	21	21	0	52304.84789	52304.84789	0	0	0	0
Mar 18, 2021	24	27	-3	57948.23381	63591.61972	-5643.38591	5643.385912	0	5643.385912
Mar 19, 2021	32	32	0	72997.2629	72997.2629	0	0	0	0
Mar 20, 2021	22	23	-1	54185.97653	56067.10517	-1881.12864	1881.128637	0	1881.128637
Mar 21, 2021	17	18	-1	44780.33334	46661.46198	-1881.12864	1881.128637	0	1881.128637
Mar 22, 2021	16	16	0	42899.20471	42899.20471	0	0	0	0
Mar 23, 2021	13	12	1	37255.81879	35374.69016	1881.128637	1881.128637	1881.128637	0
Mar 24, 2021	11	11	0	33493.56152	33493.56152	0	0	0	0
Mar 25, 2021	7	6	1	25969.04697	24087.91833	1881.128637	1881.128637	1881.128637	0
Mar 26, 2021	7	7	0	25969.04697	25969.04697	0	0	0	0
Mar 27, 2021	16	17	-1	42899.20471	44780.33334	-1881.12864	1881.128637	0	1881.128637
Mar 28, 2021	17	20	-3	44780.33334	50423.71926	-5643.38591	5643.385912	0	5643.385912
Mar 29, 2021	25	24	1	59829.36244	57948.23381	1881.128637	1881.128637	1881.128637	0
Mar 30, 2021	15	13	2	41018.07607	37255.81879	3762.257275	3762.257275	3762.257275	0
Mar 31, 2021	7	9	-2	25969.04697	29731.30424	-3762.25727	3762.257275	0	3762.257275
Apr	595	568	27	1279771	1242675	37097	53584	45340	8244
May	262	237	25	685310	660496	24814	34740	29777	4963
Jun	32	21	11	359297	353966	5330	7269	6300	969
Jul	0	0	0	304689	304689	0	0	0	0
Aug	17	5	12	326233	317174	9059	9059	9059	0
Sep	109	81	28	419361	405220	14140	16160	15150	1010
Oct	440	404	36	890981	853525	37456	68669	53063	15607
Nov	599	589	10	1423420	1408975	14445	66447	40446	26001
Dec	986	997	-11	2217499	2237310	-19812	84649	32419	52230
Jan	1122	1118	4	2564525	2556052	8473	84733	46603	38130
Feb	1047	1021	26	2398028	2353834	44194	84989	64592	20397
Mar	770	762	8	1845305	1830256	15049	71483	43266	28217
Total	5,979	5,803	176	14,714,419	14,524,172	190,245	581,782	386,015	195,768

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

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

					Source:
1	Peak Day		171,602	Dekatherm	
2					
3	Pipeline MDQ				Attachment B Page 2 of 3: EnergyNorth Capacity Resources
4		PNGTS	1,000	Dekatherm	
5		TGP NET-NE 95346	4,000		
6		TGP FT-A (Z5-Z6) 2302	3,122		
7		TGP FT-A (Z0-Z6) 8587	7,035		
8		TGP FT-A (Z1-Z6) 8587	14,561		
9		TGP FT-A (Z6-Z6) 42076	20,000		
		TGP FT-A (Z6-Z6) 358905	40,000		
		TGP FT-A (Z6-Z6) 72694	30,000		
10			119,718	Dekatherm	
11					
12	Underground Storage MDQ				Attachment B Page 3 of 3: EnergyNorth Capacity Resources
13		TGP FT-A (Z4-Z6) 632	15,265	Dekatherm	
14		TGP FT-A (Z4-Z6) 8587	3,811		
15		TGP FT-A (Z4-Z6) 11234	7,082		
16		TGP FT-A (Z5-Z6) 11234	1,957		
17			28,115		
18					
19					
20	Peaking MDQ		23,769	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$ 4,119,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$ 3,685,458		Summary Page Line 68
26	Granite Ridge		$ -		Attachment B Page 3 Line 1
27	Total		$ 7,804,458		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$ 328.35		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$ 54.72**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations:

Resource Type	High Load Factor	Low Load Factor
Pipeline	76.2%	69.1%
Storage	12.9%	16.8%
Peaking	10.9%	14.1%
TOTAL:	100.00%	100.00%

Capacity Resources effective November 1, 2020*:

*proposed

Resource	Pipeline Company	Rate Schedule	Contract #	Peak MDQ/ MDWQ	Storage MSQ	Rate $/Dth/Month Demand	Storage Capacity	Termination Date	LDC Managed
Pipeline									
	TCPL + Union	FT to Parkway & IGTS	M12200 & 41232	4,000		$13.6260		10/31/2026	
	Iroquois	RTS to Wright	470-01	4,047		$5.2357		11/1/2022	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$6.2957		11/30/2022	
	TGP	FT-A (Z5-Z6)	2302	3,122		$6.2957		10/31/2025	
	TGP	FT-A (Z0-Z6)	8587	7,035		$20.3736		10/31/2025	
	TGP	FT-A (Z1-Z6)	8587	14,561		$18.0875		10/31/2025	
	TCPL + Union	FT to Parkway & PNGTS	M12284 & TC	5,000		$20.6972		10/31/2040	
	PNGTS	FT	225800	5,000		$22.8125		10/31/2040	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4.1818		10/31/2025	
	TGP	FT-A (Z6-Z6)	358905	40,000		$4.1818		10/31/2041	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12.2113		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523*	21,844	1,560,391	$1.3094	$0.0179	10/31/2025	
	TGP	FT-A (Z4-Z6)	632	15,265		$7.1645		10/31/2025	
	TGP	FT-A (Z4-Z6)	8587	3,811		$7.1645		10/31/2025	
	National Fuel	FSS-1 (Storage)	O02357*	6,098	670,800	$2.6325	$0.0476	3/31/2023	
	National Fuel	FST (Transport)	N02358	6,098		$4.5274		3/31/2023	
	TGP	FT-A (Z4-Z6)	11234	6,150		$7.1645		10/31/2025	
	Honeoye	SS-NY (Storage)	SS-NY**	1,957	245,380	$4.2672	$0.0000	3/31/2023	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$6.2957		10/31/2025	
	Dominion	GSS (Storage)	300076*	934	102,700	$1.8716	$0.0145	3/31/2024	
	TGP	FT-A (Z4-Z6)	11234	932		$7.1645		10/31/2025	
Peaking									
	Energy North	LNG/Propane****		23,769	-	$54.7200	$0.0000		X

* All gas transferred for storage contracts will be based on LDC's monthly WACOG
**All commodity volumes nominated will be invoiced at LDC's WACOG + fuel retention. Demand charge applicable for 6 months

Note: **All capacity will be released at maximum tariff rates. Above rates are maximum tariff rates effective 11/01/21. Because rates can change, please refer to the applicable pipeline tariff for current rates.**

Above capacity is for all customers in the EnergyNorth Service territory with the exception of Berlin, NH. Any customers behind the Berlin citygate will be allocated 100% PNGTS capacity at a demand rate of $18.2633 /dth.

REDACTED
Updated Schedule 21
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ENERGYNORTH NATURAL GAS, INC.

Docket 98-124 Gas Restructuring
Peaking Demand Rate
Peaking Costs

		Volume	Rate	Monthly Cost	Months/Year		Annual Cost	
1		[redacted]						
2								
3								
4	Subtotal					$	**4,119,000.00**	*
5								
6	**Total**					**$**	**4,119,000.00**	

* Contract currently being negotiated for an effective date of November 1, 2021

SUBJECT TO CONFIDENTIAL TREATMENT

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Capacity Assignment Table

			% of Peak Day Requirement			
			Pipeline	Storage	Peaking	Total
G-41	**LAHW**	Low Annual C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	59.3%	12.9%	27.9%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	59.3%	12.9%	27.9%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	46.1%	17.1%	36.8%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	59.3%	12.9%	27.9%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	59.3%	12.9%	27.9%	100.0%

HLF	High Load Factor	59.25%	12.89%	27.85%	100%
LLF	Low Load Factor	46.09%	17.06%	36.85%	100%
	Total	47.29%	16.68%	36.03%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocation of Peak Day

Design Day Throughput Allocated to Rate Classes

Design DD		Base load	71.544 Heat load	Total
HLF	R-1 RNSH	102	457	558
LLF	R-3 RSH	3,545	69,811	73,356
LLF	G-41 SL	770	30,823	31,593
HLF	G-51 SH	739	1,812	2,551
LLF	G-42 ML	1,473	37,931	39,404
HLF	G-52 MH	1,781	3,820	5,601
LLF	G-43 LL	663	8,239	8,901
HLF	G-53 LLL90	1,146	2,222	3,368
HLF	G-54 LLG90	461	2,780	3,241
	TOTAL	10,678	157,896	168,574

HLF	4,227	11,092	15,319
LLF	6,450	146,804	153,255
Total	10,678	157,896	168,574

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	102	200	301	81	175.73	558
R-3 RSH	3,545	30,525	34,070	12,431	26,856	73,356
G-41 SL	770	13,477	14,247	5,488	11,857	31,593
G-51 SH	739	792	1,531	323	697	2,551
G-42 ML	1,473	16,585	18,058	6,754	14,592	39,404
G-52 MH	1,781	1,670	3,451	680	1,470	5,601
G-43 LL	663	3,602	4,265	1,467	3,169	8,901
G-53 LLL90	1,146	972	2,117	396	855	3,368
G-54 LLG90	461	1,216	1,676	495	1,070	3,241
TOTAL	10,678	69,040	79,718	28,115	60,741	168,574

HLF	4,227	4,850	9,077	1,975	4,267	15,319
LLF	6,450	64,190	70,641	26,140	56,474	153,255
Total	10,678	69,040	79,718	28,115	60,741	168,574

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	54.0%	14.6%	31.5%	100.0%
R-3 RSH	46.4%	16.9%	36.6%	100.0%
G-41 SL	45.1%	17.4%	37.5%	100.0%
G-51 SH	60.0%	12.6%	27.3%	100.0%
G-42 ML	45.8%	17.1%	37.0%	100.0%
G-52 MH	61.6%	12.1%	26.2%	100.0%
G-43 LL	47.9%	16.5%	35.6%	100.0%
G-53 LLL90	62.9%	11.7%	25.4%	100.0%
G-54 LLG90	51.7%	15.3%	33.0%	100.0%
TOTAL	47.3%	16.7%	36.0%	100.0%

High Load Factor	59.25%	12.89%	27.85%	100%
Low Load Factor	46.09%	17.06%	36.85%	100%
Total	47.29%	16.68%	36.03%	100%

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Allocate Design Day Sendout

Calculate Design Day Throughput (BBTU)

Design DD **71.544**

	Daily Baseload * 1000	Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total
R-1 RNSH	102	6.01	430	532
R-3 RSH	3,545	918.47	65,711	69,256
G-41 SL	770	405.52	29,013	29,783
G-51 SH	739	23.84	1,706	2,445
G-42 ML	1,473	499.04	35,703	37,176
G-52 MH	1,781	50.26	3,596	5,376
G-43 LL	663	108.39	7,755	8,418
G-53 LLL90	1,146	29.24	2,092	3,238
G-54 LLG90	461	36.58	2,617	3,078
TOTAL	10,678	1,939.15	148,622	159,300

HLF	4,227	146	10,440	14,668
LLF	6,450	1,793	138,182	144,632
Total	10,678	1,939	148,622	159,300

Design Day from 2020-2021 COG		**168,574**
Design Day from Gas Load Calculation		159,300
Variance		9,274

Baseload as % of Total Class Load	Heat Load as % of Total
19%	0.289%
5%	44.214%
3%	19.521%
30%	1.148%
4%	24.023%
33%	2.419%
8%	5.218%
35%	1.408%
15%	1.761%
	100.000%

Allocate Design Day Sendout to Rate Classes

Base Load	Heat Load	Total
102	457	558
3,545	69,811	73,356
770	30,823	31,593
739	1,812	2,551
1,473	37,931	39,404
1,781	3,820	5,601
663	8,239	8,901
1,146	2,222	3,368
461	2,780	3,241
10,678	157,896	168,574

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

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CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	7	9	9	8	8	6	5	4	3	3	4	5	70	3.149	0.102
LLF	R-3 RSH	731	957	994	889	717	509	274	143	111	110	142	327	5,904	109.892	3.545
LLF	G-41 SL	285	394	409	364	274	188	88	36	24	24	36	106	2,228	23.872	0.770
HLF	G-51 SH	36	43	43	40	34	30	30	25	23	25	25	29	383	22.908	0.739
LLF	G-42 ML	394	516	531	474	375	262	142	64	46	48	71	175	3,100	45.648	1.473
HLF	G-52 MH	91	103	106	98	79	71	67	56	55	58	60	73	917	55.198	1.781
LLF	G-43 LL	98	127	130	121	102	70	45	25	21	22	27	49	836	20.550	0.663
HLF	G-53 LLL90	50	56	61	59	53	44	46	39	38	40	36	48	571	35.515	1.146
HLF	G-54 LLL110	20	26	27	25	20	18	18	14	16	16	15	18	233	14.280	0.461
HLF	G-99 LLG110															
	TOTAL	1,713	2,229	2,311	2,080	1,662	1,198	714	406	337	346	416	829	14,242	341.449	11.014
	HLF	204	235	246	231	194	168	166	138	136	142	140	173	2,174	131.050	4.480
	LLF	1,509	1,994	2,064	1,849	1,468	1,030	549	268	201	204	276	656	12,067	199.962	6.534

Baseload (= the lesser of actual volumes or the average of July and August volumes)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
		30	31	31	29	31	30	31	30	31	31	30	31	366
HLF	R-1 RNSH	3	3	3	3	3	3	3	3	3	3	3	3	37
LLF	R-3 RSH	106	110	110	103	110	106	110	106	111	110	106	110	1,297
LLF	G-41 SL	23	24	24	22	24	23	24	23	24	24	23	24	282
HLF	G-51 SH	22	23	23	21	23	22	23	22	23	25	22	23	270
LLF	G-42 ML	44	46	46	43	46	44	46	44	46	48	44	46	539
HLF	G-52 MH	53	55	55	52	55	53	55	53	55	58	53	55	652
LLF	G-43 LL	20	21	21	19	21	20	21	20	21	22	20	21	243
HLF	G-53 LLL90	34	36	36	33	36	34	36	34	38	40	34	36	419
HLF	G-54 LLL110	14	14	14	13	14	14	14	14	16	16	14	14	169
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	320	331	331	310	331	320	331	320	337	346	320	331	3,908
	HLF	127	131	131	123	131	127	131	127	136	142	127	131	1,547
	LLF	194	200	200	187	200	194	200	194	201	204	194	200	2,361

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
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Heating Volumes (= Actual Volumes - Baseload)

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
HLF	R-1 RNSH	4	5	6	5	5	3	2	1	0	0	0	2	32
LLF	R-3 RSH	625	848	884	786	607	403	164	37	0	0	35	217	4,607
LLF	G-41 SL	262	370	386	342	250	165	64	13	0	0	13	82	1,946
HLF	G-51 SH	14	20	20	19	11	8	7	2	0	0	3	6	112
LLF	G-42 ML	350	470	485	432	329	218	97	20	0	0	27	129	2,561
HLF	G-52 MH	38	48	50	46	24	17	12	3	0	0	7	18	265
LLF	G-43 LL	78	106	110	102	81	50	24	5	0	0	7	29	593
HLF	G-53 LLL90	15	20	26	26	18	10	11	5	0	0	1	13	152
HLF	G-54 LLL110	6	11	13	12	6	4	4	0	0	0	2	3	65
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	1,393	1,898	1,980	1,771	1,331	878	383	86	0	0	95	498	10,333

	Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total
HLF	78	104	115	109	63	42	35	11	0	0	13	42	627
LLF	1,315	1,794	1,864	1,662	1,268	836	349	74	0	0	82	456	9,707

Actual BDD	**846.0**	**1054.0**	**1025.0**	**963.0**	**724.0**	**491.0**	**257.0**	**31.0**	**0.0**	**4.0**	**87.0**	**341.0**	5823.0

Heat Factors

		Nov-19	Dec-19	Jan-20	Feb-20	Mar-20	Apr-20	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Total	AVG	AVG Peak
HLF	R-1 RNSH	0.0046	0.0051	0.0056	0.0054	0.0063	0.0061	0.0072	0.0237	0.0000	0.0000	0.0052	0.0047	0.0063	0.0062	0.0055
LLF	R-3 RSH	0.7389	0.8042	0.8621	0.8165	0.8388	0.8206	0.6374	1.1853	0.0000	0.0000	0.4063	0.6357	0.8621	0.6455	0.8135
LLF	G-41 SL	0.3101	0.3511	0.3762	0.3553	0.3448	0.3361	0.2481	0.4058	0.0000	0.0000	0.1467	0.2396	0.3762	0.2595	0.3456
HLF	G-51 SH	0.0168	0.0186	0.0200	0.0197	0.0154	0.0154	0.0258	0.0799	0.0000	0.0000	0.0350	0.0178	0.0200	0.0220	0.0177
LLF	G-42 ML	0.4137	0.4462	0.4733	0.4481	0.4550	0.4445	0.3764	0.6498	0.0000	0.0000	0.3128	0.3797	0.4733	0.3666	0.4468
HLF	G-52 MH	0.0448	0.0453	0.0492	0.0481	0.0335	0.0353	0.0449	0.0868	0.0000	0.0000	0.0776	0.0526	0.0492	0.0432	0.0427
LLF	G-43 LL	0.0921	0.1006	0.1073	0.1059	0.1123	0.1019	0.0951	0.1524	0.0000	0.0000	0.0805	0.0837	0.1123	0.0860	0.1034
HLF	G-53 LLL90	0.0180	0.0191	0.0253	0.0271	0.0242	0.0201	0.0427	0.1650	0.0000	0.0000	0.0132	0.0372	0.0271	0.0326	0.0223
HLF	G-54 LLL110	0.0074	0.0107	0.0122	0.0126	0.0082	0.0079	0.0139	0.0149	0.0000	0.0000	0.0183	0.0098	0.0126	0.0097	0.0098
HLF	G-63 LLG110	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	TOTAL	1.6465	1.8008	1.9312	1.8387	1.8386	1.7879	1.4914	2.7635	0.0000	0.0000	1.0957	1.4609	1.9391	1.4713	1.8073

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

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Actual HDD	**846.0**	**1,054.0**	**1,025.0**	**963.0**	**724.0**	**491.0**	**257.0**	**31.0**	**0.0**	**4.0**	**87.0**	**341.0**	**5823.0**
Norm HDD	**715.2**	**1,044.9**	**1,216.8**	**1,071.2**	**893.6**	**508.8**	**226.5**	**49.9**	**5.0**	**8.2**	**108.0**	**407.2**	**6255.0**

Normal Volumes (= Heating Volumes * Normal HDD/Actual HDD + Baseload)

		Nov-19	**Dec-19**	**Jan-20**	**Feb-20**	**Mar-20**	**Apr-20**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
HLF	**R-1 RNSH**	6	8	10	9	9	6	5	4	3	3	4	5	72
LLF	**R-3 RSH**	635	950	1,159	977	859	524	254	165	111	110	150	369	6,264
LLF	**G-41 SL**	245	391	482	403	332	194	80	43	24	24	39	121	2,378
HLF	**G-51 SH**	34	42	47	43	37	30	29	26	23	25	26	30	392
LLF	**G-42 ML**	340	512	622	523	452	270	131	77	46	48	78	200	3,298
HLF	**G-52 MH**	85	103	115	103	85	71	65	58	55	58	62	77	937
LLF	**G-43 LL**	86	126	151	133	121	72	42	27	21	22	29	55	883
HLF	**G-53 LLL90**	47	55	66	62	57	45	45	43	38	40	36	51	585
HLF	**G-54 LLL110**	19	25	29	27	22	18	17	15	16	16	16	18	238
HLF	**G-63 LLG110**	-	-	-	-	-	-	-	-	-	-	-	-	-
	TOTAL	1,498	2,213	2,681	2,279	1,974	1,230	669	458	337	346	439	926	15,049

HLF	192	234	268	244	209	170	161	145	136	142	143	181	2,225
LLF	1,306	1,978	2,413	2,036	1,765	1,060	507	313	201	204	296	745	12,823

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2021 - 2022 Winter Cost of Gas Filing
Fixed Price Option

		Participation	Premium	FPO Volumes	Premium Revenue	FPO Rate	Residential Average COG Rate	Residential Total Bill FPO Rate	Residential Total Bill COG Rate	Difference	% Difference	FPO Rate	C&I Average COG Rate	C&I Total Bill FPO Rate	C&I Total Bill COG Rate	Difference	% Difference
1	Nov 98 - Mar 99	6.0%				0.3927	0.3722	943.3700	926.9333	$ 16.44	1.77%	0.3927	0.3736	$ 1,570.86	$ 1,546.08	$ 24.79	1.60%
2	Nov 99 - Mar 00	9.0%				0.4724	0.4628	679.8500	672.2235	$ 7.63	1.13%	0.4724	0.4636	$ 1,161.81	$ 1,149.15	$ 12.67	1.10%
3	Nov 00 - Mar 01	20.0%				0.6408	0.7656	816.2500	916.0900	$ (99.84)	-10.90%	0.6408	0.7189	$ 1,376.64	$ 1,533.43	$ (156.79)	-10.22%
4	Nov 01 - Apr 02	24.0%				0.5141	0.4818	790.6522	760.5504	$ 30.10	3.96%	0.5238	0.4928	$ 1,301.07	$ 1,256.88	$ 44.19	3.52%
5	Nov 02 - Apr 03	24.0%	0.0051	25,107,016	$ 128,045.78	0.5553	0.5758	821.3224	840.4371	$ (19.11)	-2.27%	0.5658	0.5860	$ 1,344.02	$ 1,372.86	$ (28.84)	-2.10%
6	Nov 03 - Apr 04	23.0%	0.0219	25,220,575	$ 552,330.59	0.8597	0.8220	1,115.5548	1,080.4628	$ 35.09	3.25%	0.8759	0.8352	$ 1,798.38	$ 1,740.30	$ 58.08	3.34%
7	Nov 04 - Apr 05	29.6%	0.0100	27,378,128	$ 273,781.28	0.8925	0.9425	1,142.9556	1,189.5541	$ (46.60)	-3.92%	0.9092	0.9562	$ 1,844.75	$ 1,911.86	$ (67.10)	-3.51%
8	Nov 05 - Apr 06	29.8%	0.0200	25,944,091	$ 518,881.82	1.2951	1.1342	1,526.0076	1,376.0122	$ 150.00	10.90%	1.3192	1.1686	$ 2,450.66	$ 2,235.77	$ 214.89	9.61%
9	Nov 06 - Apr 07	15.1%	0.0200	13,135,684	$ 262,713.68	1.2664	1.1656	1,509.7908	1,415.8032	$ 93.99	6.64%	1.2666	1.1647	$ 2,321.15	$ 2,175.70	$ 145.45	6.68%
10	Nov 07 - Apr 08	15.8%	0.0200	14,078,553	$ 281,571.06	1.2043	1.1746	1,433.0900	1,405.4000	$ 27.69	1.97%	1.2044	1.1725	$ 2,232.39	$ 2,186.92	$ 45.47	2.08%
11	Nov 08 - Apr 09	15.2%	0.0200	13,041,335	$ 260,826.70	1.2835	1.0888	1,555.3140	1,373.8536	$ 181.46	13.21%	1.2836	1.0958	$ 2,467.49	$ 2,199.54	$ 267.95	12.18%
12	Nov 09 - Apr 10	11.4%	0.0200	8,405,413	$ 168,108.26	0.9863	0.9416	1,250.8032	1,209.1161	$ 41.69	3.45%	0.9865	0.9408	$ 1,984.29	$ 1,919.03	$ 65.26	3.40%
13	Nov 10 - Apr 11	12.6%	0.0200	10,379,804	$ 207,596.08	0.8420	0.8029	1,175.0264	1,138.5767	$ 36.45	3.20%	0.8434	0.8030	$ 1,880.96	$ 1,823.34	$ 57.63	3.16%
14	Nov 11 - Apr 12	11.9%	0.0200	7,835,197	$ 156,703.94	0.8126	0.7309	1,165.6100	1,089.4400	$ 76.17	6.99%	0.8129	0.7327	$ 1,845.28	$ 1,730.88	$ 114.40	6.61%
15	Nov 12 - Apr 13	10.9%	0.0200	8,179,524	$ 163,590.48	0.6919	0.7680	743.0298	792.4756	$ (49.45)	-6.24%	0.6936	0.7724	$ 1,989.86	$ 2,132.90	$ (143.03)	-6.71%
16	Nov 13 - Apr 14	10.5%	0.0200	8,930,779	$ 178,615.58	0.9095	1.0980	857.7200	981.2100	$ (123.49)	-12.59%	0.9108	1.1058	$ 2,899.04	$ 3,280.18	$ (381.14)	-11.62%
17	Nov 14 - Apr 15	15.1%	0.0795	8,779,742	$ 697,989.49	1.2425	0.5100	1,127.6600	948.0700	$ 179.59	18.94%	0.5143	1.1341	$ 2,135.42	$ 2,340.00	$ (204.58)	-8.74%
18	Nov 15 - Apr 16	15.3%	0.0200	4,941,157	$ 98,823.14	0.7716	0.7516	869.1500	712.7315	$ 156.42	21.95%						
19	Nov 16 - Apr 17	11.5%	0.0106	5,419,967	$ 57,451.65	0.7268	0.7162	827.1400	812.3754	$ 14.76	1.82%						
20	Nov 17 - Apr 18	10.6%	0.0200	5,298,900	$ 105,978.00	0.6645	0.6445	878.7000	865.9400	$ 12.76	1.47%						
21	Nov 18 - Apr 19	10.8%	0.0200	5,708,925	$ 114,178.50	0.7611	0.7411	984.8300	972.1200	$ 12.71	1.31%						
22	Nov 19 - Apr 20	7.2%	0.0200	3,447,167	$ 68,943.34	0.6403	0.6203	930.4600	917.7400	$ 12.72	1.39%						
23	Nov 20 - Apr 21	11.1%	0.0200	5,373,268	$ 107,465.36	0.5771	0.5571	895.3200	882.6000	$ 12.72	1.44%						
24	Nov 21 - Apr 22					0.9256	0.9056	1,200.9474	1,187.6074	$ -	0.00%						
24	Total									$ 734.45						$ 273.86	

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Peak 2021 - 2022 Winter Cost of Gas Filing
Short-Term Debt Limitations

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	94,810,891
Total Indirect Gas Costs		4,338,002
Total Gas Costs	$	99,148,894
% of Debt to Total Gas Costs		30%
Short Term Debt	$	29,744,668

		For Purposes Other Than Fuel Financing
12/31/2022 Projected Net Plant	$	577,357,182
% of Debt to Net Plant		20%
Short Term Debt	$	115,471,436

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty
2021 - 2022 Winter Cost of Gas Filing

Company Allowance Calculation

	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Apr-2021	May-2021	Jun-2021	Total
Total Sendout- Therms	4,938,887	5,112,192	5,945,559	10,622,623	16,152,030	24,369,322	27,682,105	25,333,064	19,358,615	12,846,303	8,102,604	5,396,076	165,859,380
Total Throughput- Therms	4,935,276	5,092,677	5,227,989	6,532,773	11,027,584	18,555,165	24,820,512	26,998,121	25,544,486	17,127,373	10,787,513	7,181,623	163,831,092
Variance	3,611	19,515	717,570	4,089,850	5,124,446	5,814,157	2,861,593	(1,665,057)	(6,185,871)	(4,281,070)	(2,684,909)	(1,785,547)	2,028,288
Company Allowance													**1.22%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	Jan-2021	Feb-2021	Mar-2021	Apr-2021	May-2021	Jun-2021	Total
Total Sendout- Therms	4,938,887	5,112,192	5,945,559	10,622,623	16,152,030	24,369,322	27,682,105	25,333,064	19,358,615	12,846,303	8,102,604	5,396,076	165,859,380
Total Throughput- Therms	4,935,276	5,092,677	5,227,989	6,532,773	11,027,584	18,555,165	24,820,512	26,998,121	25,544,486	17,127,373	10,787,513	7,181,623	163,831,092
Company Use	3,851	3,369	4,202	7,264	17,411	30,017	40,656	56,444	38,332	18,882	10,038	5,937	236,403
Variance	(240)	16,146	713,368	4,082,586	5,107,035	5,784,140	2,820,937	(1,721,501)	(6,224,203)	(4,299,952)	(2,694,947)	(1,791,484)	1,791,885
LAUF													**1.08%**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty
Fuel Inventory Revenue Requirement

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**5 Quarter Avg**	**Q2 2020**	**Q3 2020**	**Q4 2020**	**Q1 2021**	**Q2 2021**
2	Gas Stored Underground	$ 1,861,932	$ 1,684,887	$ 2,749,506	$ 2,331,076	$ 456,008	$ 2,088,182
3	Fuel Stock - Propane	$ 1,103,820	$ 1,182,985	$ 1,306,812	$ 1,314,267	$ 879,390	$ 835,646
4	UG Storage - LNG	$ 50,349	$ 48,351	$ 54,291	$ 52,792	$ 51,959	$ 44,351
5		$ 3,016,100					
6	ROR	8.76%	Pre-Tax Rate of 6.64% and Statuatory Tax Rate of 27.08%				
		$ 264,132					
7	Income Tax Gross-up	1.2708					
8	Revenue Requirement	$ 335,667					

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II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 1, 2021 - April 30, 2022 ~~Rates effective November 1, 2021 - April 30, 2021~~ **Winter Period**				Rates Effective May 1, 2022 - October 31, 2022 ~~Rates Effective May 1, 2021 - October 31, 2021~~ **Summer Period**			
	Delivery Charge	**Cost of Gas Rate Page 95**	**LDAC Page 101**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 92**	**LDAC Page 101**	**Total Rate**
Residential Non Heating - R-1	~~$ 15.50~~			~~$ 15.50~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
All Therms	$ 0.3844	$ 1.1339	$ 0.1444	$ 1.6627	$ 0.3844	$ 0.5587	$ 0.1444	$ 1.0875
	~~$ 0.3860~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.0020~~	~~$ 0.3860~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 0.9363~~
Residential Heating - R-3	~~$ 15.50~~			~~$ 15.50~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 15.39			$ 15.39	$ 15.39			$ 15.39
Size of the first block	all therms							
Therms in the first block per month at	$ 0.5632	$ 1.1339	$ 0.1444	$ 1.8415	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.5678~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1838~~	~~$ 0.5678~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 1.1181~~
Residential Heating - R-4	~~$ 8.52~~			~~$ 8.52~~	~~$ 15.50~~			~~$ 15.50~~
Customer Charge per Month per Meter	$ 8.47			$ 8.47	$ 15.39			$ 15.39
Size of the first block	all therms				20 therms			
Therms in the first block per month at	$ 0.3098	$ 0.6236	$ 0.1444	$ 1.0778	$ 0.5632	$ 0.5587	$ 0.1444	$ 1.2663
	~~$ 0.3123~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.6776~~	~~$ 0.5678~~	~~$ 0.4914~~	~~$ 0.0589~~	~~$ 1.1181~~
Commercial/Industrial - G-41	~~$ 57.46~~			~~$ 57.46~~	~~$ 57.46~~			~~$ 57.46~~
Customer Charge per Month per Meter	$ 57.06			$ 57.06	$ 57.06			$ 57.06
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.4688	$ 1.1341	$ 0.0878	$ 1.6907	$ 0.4688	$ 0.5593	$ 0.0878	$ 1.1159
	~~$ 0.4711~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0818~~	~~$ 0.4711~~	~~$ 0.4868~~	~~$ 0.0555~~	~~$ 1.0134~~
All therms over the first block per month at	$ 0.3149	$ 1.1341	$ 0.0878	$ 1.5368	$ 0.3149	$ 0.5593	$ 0.0878	$ 0.9620
	~~$ 0.3165~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9272~~	~~$ 0.3165~~	~~$ 0.4868~~	~~$ 0.0555~~	~~$ 0.8588~~
Commercial/Industrial - G-42	~~$ 172.39~~			~~$ 172.39~~	~~$ 172.39~~			~~$ 172.39~~
Customer Charge per Month per Meter	$ 171.19			$ 171.19	$ 171.19			$ 171.19
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4261	$ 1.1341	$ 0.0878	$ 1.6480	$ 0.4261	$ 0.5593	$ 0.0878	$ 1.0732
	~~$ 0.4284~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0391~~	~~$ 0.4284~~	~~$ 0.4868~~	~~$ 0.0555~~	~~$ 0.9707~~
All therms over the first block per month at	$ 0.2839	$ 1.1341	$ 0.0878	$ 1.5058	$ 0.2839	$ 0.5593	$ 0.0878	$ 0.9310
	~~$ 0.2855~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.8962~~	~~$ 0.2855~~	~~$ 0.4868~~	~~$ 0.0555~~	~~$ 0.8278~~
Commercial/Industrial - G-43	~~$ 739.83~~			~~$ 739.83~~	~~$ 739.83~~			~~$ 739.83~~
Customer Charge per Month per Meter	$ 734.69			$ 734.69	$ 734.69			$ 734.69
All therms over the first block per month at	$ 0.2620	$ 1.1341	$ 0.0878	$ 1.4839	$ 0.1198	$ 0.5593	$ 0.0878	$ 0.7669
	~~$ 0.2633~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.8740~~	~~$ 0.1204~~	~~$ 0.4868~~	~~$ 0.0555~~	~~$ 0.6627~~
Commercial/Industrial - G-51	~~$ 57.46~~			~~$ 57.46~~	~~$ 57.46~~			~~$ 57.46~~
Customer Charge per Month per Meter	$ 57.06			$ 57.06	$ 57.06			$ 57.06
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.2819	$ 1.1324	$ 0.0878	$ 1.5021	$ 0.2819	$ 0.5580	$ 0.0878	$ 0.9277
	~~$ 0.2839~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9054~~	~~$ 0.2839~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.8379~~
All therms over the first block per month at	$ 0.1833	$ 1.1324	$ 0.0878	$ 1.4035	$ 0.1833	$ 0.5580	$ 0.0878	$ 0.8291
	~~$ 0.1846~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8061~~	~~$ 0.1846~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.7386~~
Commercial/Industrial - G-52	~~$ 172.39~~			~~$ 172.39~~	~~$ 172.39~~			~~$ 172.39~~
Customer Charge per Month per Meter	$ 171.19			$ 171.19	$ 171.19			$ 171.19
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2428	$ 1.1324	$ 0.0878	$ 1.4630	$ 0.1759	$ 0.5580	$ 0.0878	$ 0.8217
	~~$ 0.2439~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8654~~	~~$ 0.1767~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.7307~~
All therms over the first block per month at	$ 0.1617	$ 1.1324	$ 0.0878	$ 1.3819	$ 0.1000	$ 0.5580	$ 0.0878	$ 0.7458
	~~$ 0.1624~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7839~~	~~$ 0.1004~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.6544~~
Commercial/Industrial - G-53	~~$ 761.39~~			~~$ 761.39~~	~~$ 761.39~~			~~$ 761.39~~
Customer Charge per Month per Meter	$ 756.10			$ 756.10	$ 756.10			$ 756.10
All therms over the first block per month at	$ 0.1697	$ 1.1324	$ 0.0878	$ 1.3899	$ 0.0814	$ 0.5580	$ 0.0878	$ 0.7272
	~~$ 0.1705~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7920~~	~~$ 0.0818~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.6358~~
Commercial/Industrial - G-54	~~$ 761.39~~			~~$ 761.39~~	~~$ 761.39~~			~~$ 761.39~~
Customer Charge per Month per Meter	$ 756.10			$ 756.10	$ 756.10			$ 756.10
All therms over the first block per month at	$ 0.0648	$ 1.1324	$ 0.0878	$ 1.2850	$ 0.0352	$ 0.5580	$ 0.0878	$ 0.6810
	~~$ 0.0650~~	~~$ 1.1324~~	~~$ 0.0878~~	~~$ 1.2852~~	~~$ 0.0353~~	~~$ 0.4985~~	~~$ 0.0555~~	~~$ 0.5893~~

Issued: ~~October xx, 2020~~ October xx, 2021

Effective: ~~November 1, 2020~~ November 1, 2021

Issued by: Neil Proudman

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	Delivery Charge	**Cost of Gas Rate Page 92**	**LDAC Charge**	**Total Rate**	**Delivery Charge**	**Cost of Gas Rate Page 89**	**LDAC Page 97**	**Total Rate**
Residential Non Heating - R-5	~~$ 20.15~~			~~$ 20.15~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
All therms	$ 0.4997	$ 1.1339	$ 0.1444	$ 1.7780	$ 0.4997	$ 0.5587	$ 0.1444	$ 1.2028
	~~$ 0.5018~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.1178~~	~~$ 0.5018~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 0.8755~~
Residential Heating - R-6	~~$ 20.15~~			~~$ 20.15~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 20.01			$ 20.01	$ 20.01			$ 20.01
All therms	$ 0.7322	$ 1.1339	$ 0.1444	$ 2.0105	$ 0.7322	$ 0.5587	$ 0.1444	$ 1.4353
	~~$ 0.7381~~	~~$ 0.5571~~	~~$ 0.0589~~	~~$ 1.3541~~	~~$ 0.7381~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 1.1118~~
Residential Heating - R-7	~~$ 11.08~~			~~$ 11.08~~	~~$ 20.15~~			~~$ 20.15~~
Customer Charge per Month per Meter	$ 11.01			$ 11.01	$ 11.01			$ 11.01
All therms	$ 0.4027	$ 0.6236	$ 0.1444	$ 1.1707	$ 0.4027	$ 0.5587	$ 0.1444	$ 1.1058
	~~$ 0.4060~~	~~$ 0.3064~~	~~$ 0.0589~~	~~$ 0.7713~~	~~$ 0.7381~~	~~$ 0.3148~~	~~$ 0.0589~~	~~$ 1.1118~~
Commercial/Industrial - G-44	~~$ 74.69~~			~~$ 74.69~~	~~$ 74.69~~			~~$ 74.69~~
Customer Charge per Month per Meter	$ 74.18			$ 74.18	$ 74.18			$ 74.18
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6094	$ 1.1341	$ 0.0878	$ 1.8313	$ 0.5539	$ 0.5593	$ 0.0878	$ 1.2010
	~~$ 0.6126~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.2233~~	~~$ 0.6126~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.9790~~
All therms over the first block per month a	$ 0.4094	$ 1.1341	$ 0.0878	$ 1.6313	$ 0.3691	$ 0.5593	$ 0.0878	$ 1.0162
	~~$ 0.4114~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.0221~~	~~$ 0.4114~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7778~~
Commercial/Industrial - G-45	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
Customer Charge per Month per Meter	$ 222.55			$ 222.55	$ 222.55			$ 222.55
Size of the first block	1000 therms				400 therms		~~$~~	
Therms in the first block per month at	$ 0.5539	$ 1.1341	$ 0.0878	$ 1.7758	$ 0.5539	$ 0.5593	$ 0.0878	$ 1.2010
	~~$ 0.5569~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 1.1676~~	~~$ 0.5569~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.9233~~
All therms over the first block per month a	$ 0.3691	$ 1.1341	$ 0.0878	$ 1.5910	$ 0.3691	$ 0.5593	$ 0.0878	$ 1.0162
	~~$ 0.3711~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9818~~	~~$ 0.3711~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.7375~~
							~~$~~	
Commercial/Industrial - G-46	~~$ 961.78~~			~~$ 961.78~~	~~$ 961.78~~			~~$ 961.78~~
Customer Charge per Month per Meter	$ 955.10			$ 955.10	$ 955.10		~~$~~	$ 955.10
All therms over the first block per month a	$ 0.3406	$ 1.1341	$ 0.0878	$ 1.5625	$ 0.1557	$ 0.5593	$ 0.0878	$ 0.8028
	~~$ 0.3423~~	~~$ 0.5552~~	~~$ 0.0555~~	~~$ 0.9530~~	~~$ 0.1565~~	~~$ 0.3109~~	~~$ 0.0555~~	~~$ 0.5229~~
Commercial/Industrial - G-55	~~$ 74.69~~			~~$ 74.69~~	~~$ 74.69~~			~~$ 74.69~~
Customer Charge per Month per Meter	$ 74.18			$ 74.18	$ 74.18			$ 74.18
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3665	$ 1.1324	$ 0.0878	$ 1.5867	$ 0.3665	$ 0.5580	$ 0.0878	$ 1.0123
	~~$ 0.3691~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9906~~	~~$ 0.3691~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.7445~~
All therms over the first block per month a	$ 0.2383	$ 1.1324	$ 0.0878	$ 1.4585	$ 0.2383	$ 0.5580	$ 0.0878	$ 0.8841
	~~$ 0.2400~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8615~~	~~$ 0.2400~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6154~~
Commercial/Industrial - G-56	~~$ 224.11~~			~~$ 224.11~~	~~$ 224.11~~			~~$ 224.11~~
Customer Charge per Month per Meter	$ 222.55			$ 222.55	$ 222.55			$ 222.55
Size of the first block	1000 therms				1000 therms		~~$~~	
Therms in the first block per month at	$ 0.3157	$ 1.1324	$ 0.0878	$ 1.5359	$ 0.2287	$ 0.5580	$ 0.0878	$ 0.8745
	~~$ 0.3171~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.9386~~	~~$ 0.2297~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.6051~~
All therms over the first block per month a	$ 0.2102	$ 1.1324	$ 0.0878	$ 1.4304	$ 0.1300	$ 0.5580	$ 0.0878	$ 0.7758
	~~$ 0.2111~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8326~~	~~$ 0.1304~~	~~$ 0.3199~~	~~$ 0.0555~~	
Commercial/Industrial - G-57	~~$ 989.80~~			~~$ 989.80~~	~~$ 989.80~~			~~$ 989.80~~
Customer Charge per Month per Meter	$ 982.93			$ 982.93	$ 982.93			$ 982.93
All therms over the first block per month a	$ 0.2207	$ 1.1324	$ 0.0878	$ 1.4409	$ 0.1059	$ 0.5580	$ 0.0878	$ 0.7517
	~~$ 0.2216~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.8431~~	~~$ 0.1063~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4817~~
Commercial/Industrial - G-58	~~$ 989.80~~			~~$ 989.80~~	~~$ 989.80~~			~~$ 989.80~~
Customer Charge per Month per Meter	$ 982.93			$ 982.93	$ 970.84		~~$~~	$ 970.84
All therms over the first block per month a	$ 0.0842	$ 1.1324	$ 0.0878	$ 1.3044	$ 0.0457	$ 0.5580	$ 0.0878	$ 0.6915
	~~$ 0.0846~~	~~$ 0.5660~~	~~$ 0.0555~~	~~$ 0.7061~~	~~$ 0.0459~~	~~$ 0.3199~~	~~$ 0.0555~~	~~$ 0.4213~~

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NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Third Revised Page 91
Superseding Proposed First Revised Page 91

Anticipated Cost of Gas
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2022 THROUGH OCTOBER 31, 2022
~~**PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021**~~
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS				
Purchased Gas:				
Demand Costs:	~~$ 2,919,324~~		$ 3,276,842	
Supply Costs:	~~2,202,631~~		6,971,475	
Storage Gas:				
Demand, Capacity:	~~-~~		-	
Commodity Costs:	~~-~~		-	
Produced Gas:	~~22,682~~		82,504	
Hedged Contract Savings	~~-~~		-	
			-	
Unadjusted Anticipated Cost of Gas		~~$ 5,144,637~~		$ 10,330,821
Adjustments:				
Prior Period (Over)/Under Recovery as o ~~April 30, 2018~~ September 01, 2019 (monthly adjustment filing	~~$ 1,885,446~~		$ 4,472,186	
Interest	~~51,144~~		222,837	
Prior Period Adjustments	~~-~~		-	
Broker Revenues	~~-~~		-	
Refunds from Suppliers	~~-~~		-	
Fuel Financing	-		-	
Transportation CGA Revenues	~~-~~		-	
Interruptible Sales Margin	~~-~~		-	
Capacity Release and Off System Sales Margin	~~-~~		-	
Hedging Costs	~~-~~		-	
Fixed Price Option Administrative Costs	~~-~~		-	
Total Adjustments		~~1,936,590~~		4,695,023
Total Anticipated Direct Cost of Gas		~~$ 7,081,227~~		$ 15,025,844
Anticipated Indirect Cost of Gas				
Working Capital:				
Total anticipated Direct Cost of Gas ~~(05/01/2018 - 10/31/2018)~~ (05/01/19 - 10/31/19)	~~$ 5,144,637~~		$ 10,330,821	
Working Capital Rate	~~0.0391~~		-	
Prime Rate	~~3.25%~~		3.25%	
Working Capital Percentage	~~0.127%~~		0.01%	
Working Capital	~~6,538~~		$ 769	
Plus: Working Capital Reconciliation ~~(Acct 142.20)~~ (Acct 1163-1424)	~~(18,982)~~		4,555	
Total Working Capital Allowance		~~$ (12,443)~~		$ 5,324
Bad Debt:				
Total anticipated Direct Cost of Gas ~~(05/01/2018 - 10/31/2018)~~ (05/01/19 - 10/31/19)	~~$ 5,144,637~~		$ 10,330,821	
Less: Refunds	-		-	
Plus: Total Working Capital	~~(12,443)~~		5,324	
Plus: Prior Period (Over)/Under Recovery	~~1,885,446~~		4,472,186	
Subtotal	~~$ 7,017,640~~		$ 14,808,331	
Bad Debt Percentage	~~1.11%~~		0.70%	
Bad Debt Allowance	~~77,896~~		103,658	
Plus: Bad Debt Reconciliation ~~(Acct 175.52)~~ (Acct 1163-1754)	~~(280,167)~~		23,159	
Total Bad Debt Allowance		~~(202,272)~~		126,817
Production and Storage Capacity				-
Miscellaneous Overhead ~~(05/01/2018 - 10/31/2018)~~ (05/01/19 - 10/31/19)	~~$ 13,170~~		$ -	
Times Summer ~~Winter~~ Sales	~~20,973~~		23,366	
Divided by Total Sales	~~109,299~~		115,043	
Miscellaneous Overhead		~~2,527~~		-
Total Anticipated Indirect Cost of Gas		~~$ (212,188)~~		$ 132,141
Total Cost of Gas		~~$ 6,869,039~~		$ 15,157,985

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Title: President

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NHPUC NO. 11 - GAS | **Proposed Third Revised Page 92**
LIBERTY UTILITIES | **Superseding Proposed First Revised Page 92**

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: SUMMER PERIOD, MAY 1, 2022 THROUGH OCTOBER 31, 2022
~~PERIOD COVERED: SUMMER PERIOD, MAY 1, 2021 THROUGH OCTOBER 31, 2021~~
(Refer to Text in Section 17 Cost of Gas Clause)

(Col 1)	~~(Col 2)~~	~~(Col 3)~~	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	~~$ 9,653,380~~		$ 15,025,844		
Projected Prorated Sales (05/01/22 - 10/31/22) ~~(05/01/21 - 10/31/21)~~	~~20,973,031~~		27,125,444		
Direct Cost of Gas Rate		~~$ 0.4603~~		$ 0.5539	per therm
Demand Cost of Gas Rate	~~$ 4,548,346~~	~~$ 0.2169~~	$ 3,276,842	$ 0.1208	
Commodity Cost of Gas Rate	~~3,136,847~~	~~$ 0.1496~~	7,053,979	$ 0.2601	
Adjustment Cost of Gas Rate	~~1,968,188~~	~~$ 0.0938~~	4,695,023	$ 0.1731	
Total Direct Cost of Gas Rate	~~$ 9,653,380~~	~~$ 0.4603~~	$ 15,025,844	$ 0.5539	
Total Anticipated Indirect Cost of Gas	~~$ (174,652)~~		$ 131,366		
Projected Prorated Sales (05/01/22 - 10/31/22) ~~(05/01/21 - 10/31/21)~~	~~20,973,031~~		27,125,444		
Indirect Cost of Gas		~~$ (0.0083)~~		$ 0.0048	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/22				$ 0.5587	per Therm
~~TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 05/01/21~~		~~$ 0.4520~~			

RESIDENTIAL COST OF GAS RATE - 05/01/2022		**COGsr**	**$ 0.5587**	**/therm**
~~RESIDENTIAL COST OF GAS RATE - 5/01/21~~		**~~COGsr~~**	**~~$ 0.4520~~**	**~~/therm~~**
	Maximum	(COG + 25%)	~~$ 0.5650~~	$ 0.6984
COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2022		**COGsl**	**$ 0.5580**	**/therm**
~~COM/IND LOW WINTER USE COST OF GAS RATE - 05/01/2021~~		**~~COGsl~~**	**~~$ 0.4591~~**	**~~/therm~~**

Average Demand Cost of Gas Rate Effective ~~05/01/21~~ 05/01/2022	~~$ 0.2169~~	$ 0.1208	Maximum	(COG + 25%)	~~$ 0.5739~~	$ 0.6975
'Times: Low Winter Use Ratio (Summer)	~~1.0465~~	0.9910				
Times: Correction Factor	~~0.9867~~	1.0027				
Adjusted Demand Cost of Gas Rate	~~$ 0.2240~~	$ 0.1200				
Commodity Cost of Gas Rate	~~$ 0.1496~~	$ 0.2601				
Adjustment Cost of Gas Rate	~~0.0938~~	0.1731				
Indirect Cost of Gas Rate	~~(0.0083)~~	0.0048				
Adjusted Com/Ind Low Winter Use Cost of Gas Rate	~~$ 0.4591~~	$ 0.5580				

COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2021	**COGsh**	**$ 0.5593**	**/therm**
~~COM/IND HIGH WINTER USE COST OF GAS RATE - 05/01/2020~~	**~~COGsh~~**	**~~$ 0.4474~~**	**~~/therm~~**

Average Demand Cost of Gas Rate Effective ~~05/01/20~~ 05/01/2021	~~$ 0.2169~~	$ 0.1208	Maximum	(COG + 25%)	~~$ 0.5593~~	$ 0.6991
'Times: High Winter Use Ratio (Summer)	~~0.9918~~	1.0017				
Times: Correction Factor	~~0.9867~~	1.0027				
Adjusted Demand Cost of Gas Rate	~~$ 0.2123~~	$ 0.1213				
Commodity Cost of Gas Rate	~~$ 0.1496~~	$ 0.2601	Minimum			
Adjustment Cost of Gas Rate	~~0.0938~~	0.1731	Maximum			
Indirect Cost of Gas Rate	~~(0.0083)~~	0.0048				
Adjusted Com/Ind High Winter Use Cost of Gas Rate	~~$ 0.4474~~	$ 0.5593				

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Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing

Table of Contents

Ln	Description	Reference	Amount
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**		Updated Summary
2			Page 1 of 1
3	**Off Peak 2022 Summer Cost of Gas Filing**		
4	**Summary**		
5			OP 22
6		Reference	May - Oct
7	(a)	(b)	(c)
8			
9	**Anticipated Direct Cost of Gas**		
10	Purchased Gas:		
11	Demand Costs:	Sch. 5A, col (j), ln 46	$ 3,276,842
12	Supply Costs	Sch. 6, col (i), ln 45	6,971,475
13			
14	Storage Gas:		
15	Demand, Capacity:	Sch. 5A, col (j), ln 61	$ -
16	Commodity Costs:	Sch. 6, col (i), ln 48	-
17			
18	Produced Gas:	Sch. 6, col (i), ln 54	$ 82,504
19			
20	Hedge Contract (Savings)/Loss		$ -
21			
22			
23	**Total Unadjusted Cost of Gas**		$ 10,330,821
24			
25	**Adjustments:**		
26			
27	Prior Period (Over)/Under Recovery)	Sch. 3, col (c) ln 28	$ 4,472,186
28	Interest 11/01/19 - 10/31/20	Sch. 3, col (q) ln 193	222,837
29	Prior Period Adjustments	Sch. 4, ln 24 col (b)	-
30	Refunds from Suppliers	Sch. 4, ln 24 col (c)	-
31	Broker Revenue	Sch. 4, ln 24 col (d)	-
32	Fuel Financing	Sch. 4, ln 24 col (e)	-
33	Transportation CGA Revenues	Sch. 4, ln 24 col (f)	-
34	Interruptible Sales Margin	Sch. 4, ln 24 col (g)	-
35	Capacity Release and Off System Sales Margins	Sch. 4, ln 24 col (h) + col (i)	-
36	Hedging Costs	Sch. 4, ln 24 col (j)	-
37	FPO Premium - Collection		-
38	Fixed Price Option Administrative Costs	Sch. 4, ln 24 col (k)	-
39			
40	**Total Adjustments**		$ 4,695,023
41			
42	**Total Anticipated Direct Costs**	lns 23 + 40	$ 15,025,844
43			
44	**Anticipated Indirect Cost of Gas**		
45	**Working Capital**		
46	Total Unadjusted Anticipated Cost of Gas	Ln 23	$ 10,330,821
47	Lead Lag Days / 365	DG 10-017, 14.27 / 365	0.0000
48	Prime Rate		3.25%
49	Working Capital Percentage	ln 47 * ln 48	0.000%
50	Working Capital	ln 46 * ln 49	-
51	Plus: Working Capital Reconciliation	Sch. 3, col (c), ln 98	4,555
52			
53	**Total Working Capital Allowance**	lns 50 + 51	$ 4,555
54			
55	**Bad Debt**		
56	Total Unadjusted Anticipated Cost of Gas	ln 23	$ 10,330,821
57	Less Refunds	ln 30	-
58	Plus Working Capital	ln 53	4,555
59	Plus Prior Period (Over) Under Recovery	ln 27	4,472,186
60	Subtotal		$ 14,807,562
61	Bad Debt Percentage	per GTC 17(f)	0.70%
62			
63	Bad Debt Allowance	ln 60 * ln 61	$ 103,653
64	Prior Period Bad Debt Allowance	Sch. 3, col (c), ln 163	23,159
65			
66	**Total Bad Debt Allowance**	lns 63 + 64	$ 126,812
67			
68	**Production and Storage Capacity**	per GTC17(f)	$ -
69			
70	**Miscellaneous Overhead**	per GTC 17(f)	$ -
71	Sales Volume	Sch. 10B, ln 23/1000	23,366
72	Divided by Total Sales	Sch. 10B, ln 23/1000	115,043
73	Ratio		20.31%
74			
75	**Miscellaneous Overhead**	lns 70 * 73	$ -
76			
77	**Total Anticipated Indirect Cost of Gas**	lns 53 + 66 + 68 + 75	$ 131,366
78			
79	**Total Cost of Gas**	lns 42 + 77	$ 15,157,210
80			
81	**Projected Forecast Sales (Therms)**	Sch. 3, col (q), ln 52	27,125,444

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

2

3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **Summary of Supply and Demand Forecast**

Updated Schedule 1
Page 1 of 4

5										
6										Off Peak Period
7	For Month of:		May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	May - Oct
8	(a)	(b)	(c)	(d)	(e)	(d)	(e)	(f)	(g)	(h)
9	**I. Gas Volumes (Therms)**									
10										
11	**A. Firm Demand Volumes**		87,054	267,289	220,723	223,909	335,525	722,212	855,832	
12	Firm Gas Sales	Sch. 10B, ln 23	870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
13	Lost Gas (Unaccounted for)		53,988	29,666	24,501	25,149	36,419	78,230		247,952
14	Company Use		3,081	1,693	1,398	1,435	2,079	4,465		14,152
15	Unbilled Therms		4,069,607	41,684	34,671	62,109	(22,767)	(63,717)	(8,558,316)	(4,436,728)
16										
17	**Total Firm Volumes**	Sch. 6, ln 93	4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101		22,950,820
18										
19	**B. Supply Volumes (Therms)**									
20	Pipeline Gas:									
21	Dawn Supply	Sch. 6, ln 63	739,535	95,658	-	-	206,295	636,518		1,678,006
22	Niagara Supply	Sch. 6, ln 64	668,413	540,809	542,484	545,801	591,423	687,667		3,576,596
23	TGP Supply (Gulf)	Sch. 6, ln 65	13,120	-	-	-	-	384,326		397,446
24	Dracut Supply 1 - Baseload	Sch. 6, ln 66	-	-	-	-	-	-		-
25	Dracut Supply 2 - Swing	Sch. 6, ln 67	-	-	-	-	-	436,185		436,185
26	City Gate Delivered Supply	Sch. 6, ln 68	-	-	-	-	-	-		-
27	LNG Truck	Sch. 6, ln 69	44,883	18,131	-	-	55,566	20,602		139,181
28	Propane Truck	Sch. 6, ln 70	79,409	71,899	69,472	69,279	73,449	81,696		445,204
29	PNGTS	Sch. 6, ln 71	205,081	146,300	119,612	125,908	176,916	218,093		991,910
30	Portland Natural Gas	Sch. 6, ln 72	152,602	3,126	-	-	2,555	574,003		732,286
31	TGP Supply (Zone 4)	Sch. 6, ln 73	5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088		29,866,267
32	Subtotal Pipeline Volumes		7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177		38,263,081
33										
34	Storage Gas:									
35	TGP Storage	Sch. 6, ln 78	-	-	-	-	-	-		-
36										
37	Produced Gas:									
38	LNG Vapor	Sch. 6, ln 81	20,024.76	18,131.18	17,518.99	17,470.44	18,521.89	20,601.58		112,268.82
39	Propane	Sch. 6, ln 82	-	-	-	-	-	-		-
40	Subtotal Produced Gas		20,024.76	18,131.18	17,518.99	17,470.44	18,521.89	20,601.58		112,268.82
41										
42	Less - Gas Refill:									
43	LNG Truck	Sch. 6, ln 87	(44,883.07)	(18,131.18)	-	-	(55,565.66)	(20,601.58)		(139,181.49)
44	Propane	Sch. 6, ln 88	(79,408.52)	(71,899.50)	(69,471.84)	(69,279.32)	(73,448.86)	(81,695.93)		(445,203.96)
45	TGP Storage Refill	Sch. 6, ln 89	(2,188,222.48)	(2,766,567.68)	(3,120,795.80)	(3,057,928.82)	(2,444,250.24)	(1,262,379.73)		(14,840,144.76)
46	Subtotal Refills		(2,312,514.07)	(2,856,598.36)	(3,190,267.64)	(3,127,208.14)	(2,573,264.76)	(1,364,677.25)		(15,424,530.21)
47										
48	Total Firm Sendout Volumes	lns 32 + 35 + 40 + 46	4,997,212.39	2,745,935.65	2,267,802.45	2,327,785.06	3,370,983.22	7,241,101.08		22,950,819.85

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**									
2										
3	**Off Peak 2022 Summer Cost of Gas Filing**									
4	**Summary of Supply and Demand Forecast**									
49										**REDACTED**
50	**II. Gas Costs**									Updated Schedule 1
51										Page 2 of 4
52	**A. Demand Costs**									
53	Supply									
54	Niagara Supply	Sch.5A, ln 12	[redacted]							
55	Subtotal Supply Demand									
56	Less Capacity Credit									
57	Net Pipeline Demand Costs									
58										
59	Pipeline:									
60	Iroquois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]							
61	Tenn Gas Pipeline 95346 Z5-Z6	Sch.5A, ln 17								
62	Tenn Gas Pipeline 2302 Z5-Z6	Sch.5A, ln 18								
63	Tenn Gas Pipeline 8587 Z0-Z6	Sch.5A, ln 19								
64	Tenn Gas Pipeline 8587 Z1-Z6	Sch.5A, ln 20								
65	Tenn Gas Pipeline 8587 Z4-Z6	Sch.5A, ln 21								
66	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6	Sch.5A, ln 22								
67	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7	Sch.5A, ln 23								
68	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 24								
69	Portland Natural Gas Trans Service	Sch.5A, ln 25								
70	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 27								
71	Portland Natural Gas	Sch.5A, ln 25								
72	TransCanada via Union to Portland	Sch.5A, ln 27								
73	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 29								
74	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 30								
75	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 31								
76	National Fuel FST 2358	Sch.5A, ln 32								
77	Subtotal Pipeline Demand		$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 3,703,482	$ 4,954,402
78	Less Capacity Credit		(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(279,771)	(1,253,999)	(1,677,561)
79	Net Pipeline Demand Costs		$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 2,449,483	$ 3,276,842
80										
81	Peaking Supply:									
82	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 37	[redacted]							
83	Granite Ridge Demand	Sch.5A, ln 38								
84	DOMAC Demand NSB041	Sch.5A, ln 39								
85	Subtotal Peaking Demand									
86	Less Capacity Credit									
87	Net Peaking Supply Demand Costs									
88										
89	Storage:									
90	Dominion - Demand	Sch.5A, ln 49	[redacted]							
91	Dominion - Storage	Sch.5A, ln 50								
92	Honeoye - Demand	Sch.5A, ln 51								
93	National Fuel - Demand	Sch.5A, ln 52								
94	National Fuel - Capacity	Sch.5A, ln 53								
95	Tenn Gas Pipeline - Demand	Sch.5A, ln 54								
96	Tenn Gas Pipeline - Capacity	Sch.5A, ln 55								
97	Subtotal Storage Demand		$ -	$ -	$ -	$ -	$ -	$ -		$ -
98	Less Capacity Credit		-	-	-	-	-	-		-
99	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -		$ -
100										
101	Total Demand Charges	lns 55 + 77 + 85 + 97	$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 3,703,482	$ 4,954,402
102	Total Capacity Credit	lns 56 + 78 + 86 + 98	(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(279,771)	(1,253,999)	(1,677,561)
103	Net Demand Charges		$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 2,449,483	$ 3,276,842
104			**THIS PAGE HAS BEEN REDACTED**							

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**
2
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**

REDACTED
Updated Schedule 1
Page 3 of 4

Ln	Description	Reference							Total
105									
106									
107	**B. Commodity Costs**								
108	Pipeline:								
109	Dawn Supply	Sch. 6, ln 12	[redacted]						
110	Niagara Supply	Sch. 6, ln 13							
111	TGP Supply (Gulf)	Sch. 6, ln 14							
112	Dracut Supply 1 - Baseload	Sch. 6, ln 15							
113	Dracut Supply 2 - Swing	Sch. 6, ln 16							
114	Dracut Supply 3 - Swing	Sch. 6, ln							
115	City Gate Delivered Supply	Sch. 6, ln 17							
116	LNG Truck	Sch. 6, ln 18							
117	Portland Natural Gas	Sch. 6, ln 21							
118	PNGTS	Sch. 6, ln 20							
119	TGP Supply (Zone 4)	Sch. 6, ln 22							
120	Subtotal Pipeline Commodity Costs		$ 2,582,425	$ 1,948,176	$ 1,951,410	$ 1,908,418	$ 1,867,983	$ 2,854,727	$ 13,113,139
121									
122	Storage:								
123	TGP Storage - Withdrawals	Sch. 6, ln 48	$ -	$ -	$ -	$ -	$ -	$ -	$ -
124									
125	Produced Gas Costs:								
126	LNG Vapor	Sch. 6, ln 51	[redacted]						
127	Propane	Sch. 6, ln 52							
128	Subtotal Produced Gas Costs		$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
129									
130	Less Storage Refills:								
131	LNG Truck	Sch. 6, ln 38	[redacted]						
132	Propane	Sch. 6, ln 39							
133	TGP Storage Refill	Sch. 6, ln 40							
134	Storage Refill (Trans.)	Sch. 6, ln 41							
135	Subtotal Storage Refill		$ (960,246)	$ (1,223,872)	$ (1,393,945)	$ (1,367,756)	$ (1,088,979)	$ (566,192)	$ (6,600,989)
136									
137	Total Supply Commodity Costs		$ 1,636,172	$ 737,463	$ 570,378	$ 553,539	$ 792,656	$ 2,304,446	$ 6,594,655
138									
139	**C. Supply Volumetric Transportation Costs:**								
140	Dawn Supply	Sch. 6, ln 27	[redacted]						
141	Niagara Supply	Sch. 6, ln 28							
142	TGP Supply (Zone 4)	Sch. 6, ln 29							
143	Dracut Supply 1 - Baseload	Sch. 6, ln 30							
144	Dracut Supply 2 - Swing	Sch. 6, ln 31							
145	Dracut Supply 3 - Swing	Sch. 6, ln							
146	Subtotal Pipeline Volumetric Trans. Costs		$ 88,990	$ 71,093	$ 70,660	$ 70,003	$ 71,501	$ 87,078	$ 459,325
147									
148	TGP Storage - Withdrawals	Sch. 6, ln 33	$ -	$ -	$ -	$ -	$ -	$ -	$ -
149									
150	Total Supply Volumetric Trans. Costs	lns 146 + 148	$ 88,990	$ 71,093	$ 70,660	$ 70,003	$ 71,501	$ 87,078	$ 459,325
151									
152	Total Commodity Gas & Trans. Costs	lns 137 + 150	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
153									
154									
155									
156									

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Line	Description	Reference							Total
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**								
2									
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Summary of Supply and Demand Forecast**								
157	**D. Supply and Demand Costs by Source**								**REDACTED**
158									Updated Schedule 1
159									Page 4 of 4
160	Purchased Gas Demand Costs								
161	Pipeline Gas Demand Costs	lns 55 + 77	$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 4,954,402
162	Peaking Gas Demand Costs	ln 85	-	-	-	-	-	-	-
163	Subtotal Purchased Gas Demand Costs		$ 823,110	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 826,258	$ 4,954,402
164	Less Capacity Credit	lns 56 + 78 + 86	(278,705)	(279,771)	(279,771)	(279,771)	(279,771)	(279,771)	(1,677,561)
165	Net Purchased Gas Demand Costs		$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 3,276,842
166									
167	Storage Gas Demand Costs								
168	Storage Demand	ln 97	$ -	$ -	$ -	$ -	$ -	$ -	$ -
169	Less Capacity Credit	ln 98	-	-	-	-	-	-	-
170	Net Storage Demand Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
171									
172	**Total Demand Costs**	lns 165 + 170	$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 3,276,842
173									
174	Purchased Gas Supply								
175	Commodity Costs	ln 120	[redacted]						
176	Less Storage Inj.(TGP Storage)	ln 133							
177	Less Storage Transportation	ln 134							
178	Less LNG Truck	ln 131							
179	Less Propane Truck	ln 132							
180	Plus Transportation Costs	ln 146							
181	Subtotal Purchased Gas Supply		$ 1,711,170	$ 795,397	$ 628,125	$ 610,666	$ 850,505	$ 2,375,613	$ 6,971,475
182									
183	Storage Commodity Costs								
184	Commodity Costs	ln 123	$ -	$ -	$ -	$ -	$ -	$ -	$ -
185	Transportation Costs	ln 148	-	-	-	-	-	-	-
186	Subtotal Storage Commodity Costs		$ -	$ -	$ -	$ -	$ -	$ -	$ -
187									
188	Produced Gas Commodity Costs	ln 128	$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
189									
190	**Subtotal Commodity Costs**	lns 181 + 186 + 188	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
191									
192	Hedge Contract (Savings)/Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -
193									
194	**Total Commodity Costs**	lns 190 + 192	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
195									
196	**Total Demand Costs**	ln 103	$ 544,405	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 546,487	$ 3,276,842
197	**Total Supply Costs**	ln 194	1,725,162	808,556	641,038	623,542	864,157	2,391,524	7,053,979
198									
199	**Total Direct Gas Costs**	lns 196 + 197	$ 2,269,567	$ 1,355,043	$ 1,187,525	$ 1,170,030	$ 1,410,644	$ 2,938,011	$ 10,330,821
200									
201				**THIS PAGE HAS BEEN REDACTED**					

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

Updated Schedule 2

Off Peak 2022 Summer Cost of Gas Filing Page 1 of 1

Contracts Ranked on a per Unit Cost Basis

Supplier (a)	**Contract** (b)	**Contract Type** (c)	**Contract Unit** (d)	**Unit Dth (MDQ/ACQ)** (e)	**Off Peak Cost per Unit Dth** (f)
Demand Costs					
ANE (TransCanada via Union to Iroquois)	Dawn - Parkway to Iroquois	Transportation	MDQ	4,047	[redacted]
Dominion - Capacity Reservation	GSS 300076	Storage	ACQ	102,700	
Tenn Gas Pipeline - Cap. Reservations	FS-MA 523	Storage	ACQ	1,560,391	
National Fuel - Capacity Reservation	FSS-1 2357	Storage	ACQ	670,800	
Tenn Gas Pipeline - Demand	FS-MA 523	Storage	MDQ	21,844	
Dominion - Demand	GSS 300076	Storage	MDQ	934	
National Fuel - Demand	FSS-1 2357	Storage	MDQ	6,098	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	20,000	
Tenn Gas Pipeline	42076 FTA Z6-Z6	Transportation	MDQ	40,000	
National Fuel	FST N02358	Transportation	MDQ	6,098	
Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	5,077	
Portland Natural Gas Trans Service	FT-1999-001	Transportation	MDQ	1,000	
Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
Portland Natural Gas	FTN	Transportation	MDQ	5,000	
Supply Costs - Commodity					
LNG Truck		Pipeline	Dkt	13,918	[redacted]
TGP Supply (Zone 4)		Pipeline	Dkt	2,986,627	
Niagara Supply		Pipeline	Dkt	357,660	
Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
Dawn Supply		Pipeline	Dkt	167,801	
TGP Citygate Supply		Pipeline	Dkt	-	
PNGTS		Pipeline	Dkt	99,191	
Dracut Supply 1 - Baseload		Pipeline	Dkt	-	
TGP Supply (Gulf)		Pipeline	Dkt	39,745	
LNG Vapor		Produced	Dkt	11,227	
Propane		Pipeline	Dkt	-	
Supply Costs - Volumetric Transportation					
Dracut Supply 1 - Baseload		Pipeline	Dkt	-	[redacted]
TGP Supply (Zone 4)		Pipeline	Dkt	39,745	
Dracut Supply 2 - Swing		Pipeline	Dkt	43,619	
Dawn Supply		Storage	Dkt	167,801	
Niagara Supply		Pipeline	Dkt	357,660	

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

Off Peak 2022 Summer Cost of Gas Filing
COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

Ln			Prior Period Balance Plus Nov Collections	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period
9		Days in Month	October 31, 2021	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
10	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
11	**Account 8840-2-0000-10-1920-1741 (formerly, 175.40) COG (Over)/Under Balance - Interest Calculation**																
13	**Beginning Balance**	Account 1920-1741 1/	**$ 4,472,186**	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,589,886	$ 4,172,732	$ 4,108,398	$ 4,146,596	$ 4,133,544	$ 3,771,672	$ 2,753,139	$ 4,472,186
14	Forecast Direct Gas Costs		-	-	-	-	-	-	-	2,380,201	1,465,677	1,298,159	1,280,664	1,521,278	3,048,645	-	10,994,623
15	Production & Storage & Misc Overhead		-	-	-	-	-	-	-	-	-	-	-	-	-		-
16	Projected Revenues w/o Int.	In 54 * In 64	-	-	-	-	-	-	-	(496,376)	(1,524,072)	(1,258,554)	(1,276,721)	(1,913,150)	(4,118,023)	(4,879,914)	(15,466,809)
17	Projected Unbilled Revenue	In 58 * In 64	-	-	-	-	-	-	-	(2,320,472)	(2,344,240)	(2,364,010)	(2,399,424)	(2,386,442)	(2,350,111)		(14,164,699)
18	Reverse Prior Month Unbilled		-	-	-	-	-	-	-		2,320,472	2,344,240	2,364,010	2,399,424	2,386,442	2,350,111	14,164,699
19	Add Net Adjustments (with TGP Refund)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Gas Cost Billed	Account 1920-1741 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Monthly (Over)/Under Recovery		$ 4,472,186	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,153,239	$ 4,090,569	$ 4,128,233	$ 4,115,124	$ 3,754,653	$ 2,738,625	$ 223,336	$ 0
22	Average Monthly Balance	(In 13 + 21)/ 2	$ -	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,371,563	$ 4,131,650	$ 4,118,315	$ 4,130,860	$ 3,944,098	$ 3,255,148	$ 1,488,238	
24	Interest Rate	Prime Rate		5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
26	Interest Applied	In 22 * In 24 /365 *Days/Mo.	$ -	$ 19,298	$ 20,027	$ 20,116	$ 18,251	$ 20,287	$ 19,721	$ 19,492	$ 17,828	$ 18,363	$ 18,419	$ 17,019	$ 14,514	$ -	$ 223,336
28	**(Over)/Under Balance**	In 21 + In 26	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,589,886	$ 4,172,732	$ 4,108,398	$ 4,146,596	$ 4,133,544	$ 3,771,672	$ 2,753,139	$ 223,336	$ 223,336
31	**Calculation of COG with Interest**																
33	**Beginning Balance**	In 13	$ 4,472,186	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,589,886	$ 4,137,119	$ 4,053,078	$ 4,074,889	$ 4,044,949	$ 3,658,681	$ 2,588,011	$ 4,472,186
34	Forecast Direct Gas Costs	In 14	-	-	-	-	-	-	-	2,380,201	1,465,677	1,298,159	1,280,664	1,521,278	3,048,645	-	10,994,623
35	Prod Storage & Misc Overhead	In 15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Projected Revenues with int.	In 54 * 66	-	-	-	-	-	-	-	(502,645)	(1,543,321)	(1,274,450)	(1,292,846)	(1,937,313)	(4,170,033)	(4,941,547)	(15,662,155)
37	Projected Unbilled Revenue	In 58 * 66	-	-	-	-	-	-	-	(2,349,780)	(2,373,848)	(2,393,867)	(2,429,728)	(2,416,583)	(2,379,793)		(14,343,599)
38	Reverse Prior Month Unbilled		-	-	-	-	-	-	-		2,349,780	2,373,848	2,393,867	2,429,728	2,416,583	2,379,793	14,343,599
39	Add Net Adjustments	In 19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Gas Cost Billed	In 20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Gas Cost Unbilled																
42	Reverse Prior Month Unbilled																
43	Add Interest	In 26	-	-	-	-	-	-	-	19,492	17,828	18,363	18,419	17,019	14,514	-	105,636
44	**(Over)/Under Balance**		$ 4,472,186	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,137,155	$ 4,053,236	$ 4,075,131	$ 4,045,265	$ 3,659,078	$ 2,588,597	$ 26,256	$ (89,710)
46	Average Monthly Balance			$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,363,520	$ 4,095,177	$ 4,064,105	$ 4,060,077	$ 3,852,014	$ 3,123,639		
48	Interest Applied	In 24 * In 46 /365 *Days/Mo.		$ 19,298	$ 20,027	$ 20,116	$ 18,251	$ 20,287	$ 19,721	$ 19,457	$ 17,671	$ 18,121	$ 18,103	$ 16,622	$ 13,928	$ -	$ 221,602
50	**(Over)/Under Balance**	In 43 +In 44 + In 48	$ 4,472,186	$ 4,491,484	$ 4,511,511	$ 4,531,627	$ 4,549,878	$ 4,570,165	$ 4,589,886	$ 4,137,119	$ 4,053,078	$ 4,074,889	$ 4,044,949	$ 3,658,681	$ 2,588,011	$ 26,256	$ 26,256
53	Forecast Sendout Therms	Sch 1								4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101		22,950,820
54	Less 'Forecast Billing Therm Sales	Sch. 10B, In 23 May - Oct								870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
55	Less Forecast Unaccounted For	Sch 1								53,988	29,666	24,501	25,149	36,419	78,230		247,952
56	Less Forecast Company Use	Sch 1								3,081	1,693	1,398	1,435	2,079	4,465		14,152
57	Unbilled Volumes									4,069,607	41,684	34,671	62,109	(22,767)	(63,717)	(8,558,316)	(4,436,728)
58	Gross Unbilled									4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)	
60	Beg Balance									-	4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	
61	Incremental									4,069,607	41,684	34,671	62,109	(22,767)	(63,717)	(8,558,316)	
62	Ending Balance									4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)	
64	COG w/o Interest	Sch. 3, pg. 4, In 211 col. (c)								$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	
66	COG With Interest	Sch. 3, pg. 4, In 211 col. (d)								$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	

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

3 **Off Peak 2022 Summer Cost of Gas Filing**

4 **COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**

Line			Prior Period Balance	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period
72		Days in Month	Plus Nov Collections	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
73			October 31, 2021														
74	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
76	**Account 8840-2-0000-10-1163-1424 (formerly, 142.40) Working Capital (Over)/Under Balance - Interest Calculation**																
78	**Beginning Balance**	Account 1163-1424 1/	**$ 4,555**	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 4,675	$ 3,864	$ 3,424	$ 3,062	$ 2,688	$ 2,139	$ 944	$ 4,555
80	Days Lag									0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
81	Prime Rate									3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	3.25%	
82	Forecast Working Capital	ln 34 * ln 80 / 365 * ln 81		-	-	-	-	-	-	-	-	-	-	-	-	-	-
84	Projected Revenues w/o Int.	ln 123 * ln 126		-	-	-	-	-	-	(146)	(449)	(371)	(376)	(563)	(1,213)	(1,437)	(4,555)
85	Projected Unbilled Revenue	ln 124 * ln 126								(683)	(690)	(696)	(707)	(703)	(692)		(4,171)
86	Reverse Prior Month Unbilled										683	690	696	707	703	692	4,171
88	Add Net Adjustments			-	-		-	-	-	-	-	-	-	-	-	-	-
90	Working Capital Billed	Account 1163-1424 2/															-
92	Monthly (Over)/Under Recovery		$ 4,555	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 3,845	$ 3,408	$ 3,048	$ 2,676	$ 2,129	$ 937	$ 199	$ -
94	Average Monthly Balance	(ln 78 + 92)/ 2		$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 4,260	$ 3,636	$ 3,236	$ 2,869	$ 2,409	$ 1,538		
96	Interest Rate	Prime Rate		5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
98	Interest Applied	ln 94 * ln 96 / 365 * Days of Month		$ 20	$ 20	$ 20	$ 19	$ 21	$ 20	$ 19	$ 16	$ 14	$ 13	$ 10	$ 7		$ 199
100	**(Over)/Under Balance**	ln 92 + ln 98	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	**$ 4,675**	$ 3,864	$ 3,424	$ 3,062	$ 2,688	$ 2,139	$ 944	$ 199	199
103	**Calculation of Working Capital with Interest**																
105	**Beginning Balance**		$ 4,555	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 4,675	$ 3,829	$ 3,370	$ 2,992	$ 2,602	$ 2,029	$ 782	$ 4,555
106	Forecast Working Capital	ln 82		-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Projected Rev. with interest	ln 123 * ln 128		-	-	-	-	-	-	(152)	(468)	(386)	(392)	(587)	(1,264)	(1,497)	(4,746)
108	Projected Unbilled Revenue	ln 124 * ln 128								(712)	(719)	(725)	(736)	(732)	(721)		(4,346)
109	Reverse Prior Month Unbilled										712	719	725	736	732	721	4,346
110	Add Net Adjustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital Billed	ln 90	-			-											-
112	WC Unbilled									-	-	-	-	-	-	-	-
113	Reverse WC Unbilled										-	-	-	-	-	-	-
114	Add Interest	ln 98		-	-	-	-	-	-	19	16	14	13	10	7		79
115	Monthly (Over)/Under Recovery		$ 4,555	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 3,829	$ 3,370	$ 2,992	$ 2,602	$ 2,029	$ 783	$ 6	$ (112)
117	Average Monthly Balance			$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 4,252	$ 3,600	$ 3,181	$ 2,797	$ 2,315	$ 1,406		
119	Interest Applied	ln 96 * ln 117 / 365 * Days of Month		20	20	20	19	21	20	19	16	14	12	10	6	-	$ 197
121	**(Over)/Under Balance**	-ln 114 +ln 115 + ln 119	$ 4,555	$ 4,574	$ 4,595	$ 4,615	$ 4,634	$ 4,654	$ 4,675	$ 3,829	$ 3,370	$ 2,992	$ 2,602	$ 2,029	$ 782	$ 6	$ 6
123	Forecast Therm Sales	ln 53								870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
124	Unbilled Therm	ln 55								4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	(4,436,728)	
126	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 228 col. (c)								$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	
128	Working Capital Rate w/ Int.	Sch. 3, pg. 4, ln 228 col. (d)								$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	$0.0002	

Line																	
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty**																
2																	
3	**Off Peak 2022 Summer Cost of Gas Filing**																
4	**COG (Over)/Under Cumulative Recovery Balances and Interest Calculation**																
130																	Updated Schedule 3
131																	Page 3 of 3
132			Prior Period Balance														
133			Plus Nov Collections	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period
134		Days in Month	October 31, 2021	30	31	31	28	31	30	31	30	31	31	30	31	30	Total
135	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)
136																	
137	**Account 8840-2-0000-10-1163-1754 (formerly, 175.54) Bad Debt (Over)/Under Balance - Interest Calculation**																
138																	
139	Forecast Direct Gas Costs	ln 34		$ -	$ -	$ -	$ -	$ -	$ -	$ 2,380,201	$ 1,465,677	$ 1,298,159	$ 1,280,664	$ 1,521,278	$ 3,048,645	$ -	10,994,623
140	Forecast Working Capital	ln 106 + (May includes prior period)		-	-	-	-	-	-	4,555	-	-	-	-	-		4,555
141	Prior Period Balance (with Refund)	ln 21 / 6								745,364	745,364	745,364	745,364	745,364	745,364		4,472,186
142	Total Forecast Direct Gas Costs & Working Capital			-	-	-	-	-	-	3,130,120	2,211,041	2,043,523	2,026,028	2,266,642	3,794,009	-	10,999,178
143																	
144	**Beginning Balance**	Account 1163-1754 1/	**$ 23,159**	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768	$ 21,839	$ 24,161	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 23,159
145		**Oct Collections & Unbilled**															
146	Forecast Bad Debt	ln 142 * 0.007		-	-	-	-	-	-	21,911	15,477	14,305	14,182	15,866	26,558		108,300
147																	
148	Projected Revenues w/o int	ln 184 * ln 187		-	-	-	-	-	-	(4,219)	(12,954)	(10,697)	(10,851)	(16,261)	(35,001)	(41,476)	(131,458)
149	Projected Unbilled Revenue	ln 185 * ln 187								(19,723)	(19,925)	(20,093)	(20,394)	(20,283)	(19,974)		(120,391)
150	Reverse Prior Month Unbilled										19,723	19,925	20,093	20,394	20,283	19,974	120,391
151																	-
152	Bad Debt Billed	Account 1163-1754 2/			-		-	-	-								-
153	Add Net Adjustments	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-
154																	
155	Monthly (Over)/Under Recovery		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 21,738	$ 24,161	$ 27,600	$ 30,746	$ 30,592	$ 22,591	$ 1,208	$ -
156																	
157	Average Monthly Balance	(ln 144 + 155)/ 2		$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 22,753	$ 23,000	$ 25,881	$ 29,231	$ 30,734	$ 26,658	$ 11,959	
158																	
159	Interest Rate	Prime Rate		5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%	5.25%		
160																	
161	Interest Applied	ln 157 * ln 159 / 365 * Days of Mo.		$ 100	$ 104	$ 104	$ 95	$ 105	$ 102	$ 101	$ 99	$ 115	$ 130	$ 133	$ 119		$ 1,307
162																	
163	**(Over)/Under Balance**	ln 155 + ln 161	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	**$ 23,768**	$ 21,839	$ 24,260	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 11,959	1,307
164																	
165																	
166	**Calculation of Bad Debt with Interest**																
167																	
168	**Beginning Balance**		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768	$ 16,906	$ 16,596	$ 17,879	$ 18,697	$ 15,167	$ (65)	$ 23,159
169	Forecast Bad Debt	ln 146		-	-	-	-	-	-	21,911	15,477	14,305	14,182	15,866	26,558	-	108,300
170	Projected Revenues with int.	ln 184 * 189		-	-	-	-	-	-	(5,086)	(15,617)	(12,896)	(13,082)	(19,604)	(42,196)	(50,003)	(158,484)
171	Projected Unbilled Revenue	ln 185 * 189								(23,777)	(24,021)	(24,223)	(24,586)	(24,453)	(24,081)		(145,142)
172	Reverse Prior Month Unbilled										23,777	24,021	24,223	24,586	24,453	24,081	145,142
173	Bad Debt Billed	ln 152	-		-	-	-	-	-								-
174	Add Interest	ln 161		-	-	-	-	-	-	101	99	115	130	133	119		698
175	Add Net Adjustments	ln 153	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
176	Monthly (Over)/Under Recovery		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 16,917	$ 16,623	$ 17,917	$ 18,746	$ 15,226	$ 20	$ (25,988)	$ (26,328)
177																	
178	Average Monthly Balance	(ln 168 + 176)/ 2		$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 20,343	$ 16,765	$ 17,256	$ 18,312	$ 16,962	$ 7,593	$ (13,027)	
179																	
180	Interest Applied	ln 159 * ln 178 / 365 * Days of Month		100	104	104	95	105	102	91	72	77	82	73	34	-	$ 1,038
181																	
182	**(Over)/Under Balance**	-ln 174 +ln 176 + ln 180	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768	$ 16,906	$ 16,596	$ 17,879	$ 18,697	$ 15,167	$ (65)	$ (25,988)	$ (25,988)
183																	
184	Forecast Therm Sales	ln 53								870,536	2,672,893	2,207,233	2,239,093	3,355,253	7,222,123	8,558,316	27,125,444
185	Unbilled Therm	ln 55								4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587		
186																	
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. (c)								$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	
188																	
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. (d)								$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	
190																	
191																	
192																	
193	**Total Interest**	lns 48 + 119 + 180		$ 19,417	$ 20,151	$ 20,241	$ 18,364	$ 20,413	$ 19,843	$ 19,566	$ 17,759	$ 18,213	$ 18,198	$ 16,705	$ 13,968	$ -	$ 222,837

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty** — Updated Schedule 4
2 — Page 1 of 1
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

Line	**<u>Adjustments</u>**	**Prior Period Adjustments**	**Refunds from Suppliers / Pipelines**	**Broker Revenue**	**Fuel Financing**	**Transportation CGA Revenues**	**Interruptible Sales Margin**	**Off System Sales Margin**	**Capacity Release Margin**	**Net Option Premiums**	**Fixed Price Option Administrative Costs**	**Total Adjustments**
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8												
9	Nov-19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Dec-19	-	-	-	-	-	-	-	-	-	-	-
11	Jan-20	-	-	-	-	-	-	-	-	-	-	-
12	Feb-20	-	-	-	-	-	-	-	-	-	-	-
13	Mar-20	-	-	-	-	-	-	-	-	-	-	-
14	Apr-20	-	-	-	-	-	-	-	-	-	-	-
15	May-20	-	-	-	-	-	-	-	(149,464)	-	-	(149,464)
16	Jun-20	-	-	-	-	-	-	-	(141,180)	-	-	(141,180)
17	Jul-20	-	-	-	-	-	-	-	(211,505)	-	-	(211,505)
18	Aug-20	-	-	-	-	-	-	-	(224,684)	-	-	(224,684)
19	Sep-20	-	-	-	-	-	-	-	(162,433)	-	-	(162,433)
20	Oct-20	-	-	-	-	-	-	-	(191,448)	-	-	(191,448)
21												
22	Total Off Peak Period	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,080,715)	$ -	$ -	$ (1,080,715)

Ln												
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**											**REDACTED**
2												Updated Schedule 5A
3	**Off Peak 2022 Summer Cost of Gas Filing**											Page 1 of 2
4	**Demand Costs**											
5												
6											Off Peak	Peak
7											May - Oct	May - Oct
8		Peak	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22		Total	Total
9	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)		(j)	(k)
10												
11	**Supply**											
12	Niagara Supply		Sch 5B, ln 9 * Sch 5C ln 9 x days	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
13	Subtotal Supply Demand & Reservation Charges			$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
14												
15	**Pipeline**											
16	Iroquois Gas Trans Service RTS 470-0		Sch 5B, ln 12 * Sch 5C ln 12 x days	[redacted]								
17	Tenn Gas Pipeline 95346 Z5-Z6		Sch 5B, ln 13 * Sch 5C ln 14 x days									
18	Tenn Gas Pipeline 2302 Z5-Z6		Sch 5B, ln 14 * Sch 5C ln 16 x days									
19	Tenn Gas Pipeline 8587 Z0-Z6		Sch 5B, ln 15 * Sch 5C ln 18 x days									
20	Tenn Gas Pipeline 8587 Z1-Z6		Sch 5B, ln 16 * Sch 5C ln 20 x days									
21	Tenn Gas Pipeline 8587 Z4-Z6		Sch 5B, ln 17 * Sch 5C ln 22 x days									
22	Tenn Gas Pipeline (Dracut) 42076 Z6-Z6		Sch 5B, ln 18 * Sch 5C ln 24 x days									
23	Tenn Gas Pipeline (Dracut) 358905 Z6-Z7		Sch 5B, ln * Sch 5C ln 25 x days									
24	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 28 x days									
25	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 30 x days									
26	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 31 x days									
27	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 48 x days									
28	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 49 x days									
29	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 34 x days									
30	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 36 x days									
31	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 38 x days									
32	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 40 x days									
33												
34	Subtotal Pipeline Demand Charges			$ 1,640,391	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539		$ 4,954,402	$ 4,903,685
35												
36	**Peaking Supply**											
37	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 28 x days	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
38	Granite Ridge Demand	peak	Sch 5B, ln 31 * Sch 5C ln 59 x days	-	-	-	-	-	-		-	-
39	DOMAC Demand NSB041	peak	Per Contract	-	-	-	-	-	-		-	
40	Subtotal Peaking Demand Charges			$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
41												
42	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 34 + ln 40	$ 1,640,391	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539	$ 1,643,539		$ 4,954,402	$ 4,903,685
43												
44	Less Transportation Capacity Credit			$ (555,436)	$ (556,502)	$ (556,502)	$ (556,502)	$ (556,502)	$ (556,502)		$ (1,677,561)	$ (1,660,388)
45												
46	**Total Supply, Pipeline & Peaking Demand**			$ 1,084,955	$ 1,087,037	$ 1,087,037	$ 1,087,037	$ 1,087,037	$ 1,087,037		$ 3,276,842	$ 3,243,297

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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2											Updated Schedule 5A
3	**Off Peak 2022 Summer Cost of Gas Filing**										Page 2 of 2
4	**<u>Demand Costs</u>**										
47											
48	**Storage**										
49	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 63 x days	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ 1,748	$ -	$ 10,488
50	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 64 x days	1,489	1,489	1,489	1,489	1,489	1,489	-	8,935
51	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 67 x days	8,351	8,351	8,351	8,351	8,351	8,351	-	50,105
52	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 69 x days	16,053	16,053	16,053	16,053	16,053	16,053	-	96,318
53	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 70 x days	31,930	31,930	31,930	31,930	31,930	31,930	-	191,580
54	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 41 * Sch 5C ln 73 x days	28,603	28,603	28,603	28,603	28,603	28,603	-	171,615
55	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 42 * Sch 5C ln 74 x days	27,931	27,931	27,931	27,931	27,931	27,931	-	167,586
56											
57	**Subtotal Storage Demand Costs**			$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ -	$ 696,628
58											
59	Less Transportation Capacity Credit			$ (39,313)	$ (39,313)	$ (39,313)	$ (39,313)	$ (39,313)	$ (39,313)	$ -	$ (235,878)
60											
61	**Total Storage Demand Costs**		ln 57 + ln 59	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ 76,792	$ -	$ 460,750
62											
63	**Total Demand Charges**		ln 42 + ln 57	$ 1,756,496	$ 1,759,644	$ 1,759,644	$ 1,759,644	$ 1,759,644	$ 1,759,644	$ 4,954,402	$ 5,600,313
64											
65	Total Transportation Capacity Credit		ln 44 + ln 59	$ (594,749)	$ (595,815)	$ (595,815)	$ (595,815)	$ (595,815)	$ (595,815)	$ (1,677,561)	$ (1,896,266)
66											
67	**Total Demand Charges less Cap. Cr.**		ln 63 + ln 65	$ 1,161,746	$ 1,163,829	$ 1,163,829	$ 1,163,829	$ 1,163,829	$ 1,163,829	$ 3,276,842	$ 3,704,047
68											
69											
70	Monthly Off Peak Demand			$ 990,382	$ 993,530	$ 993,530	$ 993,530	$ 993,530	$ 993,530	$ 4,954,402	$ -
71	Monthly Off Peak Transportation Cap Credit			(335,343)	(336,409)	(336,409)	(336,409)	(336,409)	(336,409)	(1,677,561)	-
72	**Total Off Peak Demand**			$ 655,039	$ 657,121	$ 657,121	$ 657,121	$ 657,121	$ 657,121	$ 3,276,842	$ -
73											
74	Monthly Peak Demand			$ 766,114	$ 766,114	$ 766,114	$ 766,114	$ 766,114	$ 766,114	$ -	$ 5,600,313
75	Monthly Peak Transportation Cap Credit			(259,406)	(259,406)	(259,406)	(259,406)	(259,406)	(259,406)	-	(1,896,266)
76	**Total Peak Demand**			$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ -	$ 3,704,047

Line		Peak	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								Updated Schedule 5B
2									Page 1 of 1
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Demand Volumes**								
5									
6		Peak	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**Supply**								
9	Niagara Supply			-	-	-	-	-	-
10									
11	**Pipeline**								
12	Iroquois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
13	Tenn Gas Pipeline		95346 Z5-Z6	4,000	4,000	4,000	4,000	4,000	4,000
14	Tenn Gas Pipeline		2302 Z5-Z6	3,122	3,122	3,122	3,122	3,122	3,122
15	Tenn Gas Pipeline (long haul)		8587 Z0-Z6	7,035	7,035	7,035	7,035	7,035	7,035
16	Tenn Gas Pipeline (long haul)		8587 Z1-Z6	14,561	14,561	14,561	14,561	14,561	14,561
17	Tenn Gas Pipeline (short haul)		8587 Z4-Z6	3,811	3,811	3,811	3,811	3,811	3,811
18	Tenn Gas Pipeline		42076 FTA Z6-Z6	20,000	20,000	20,000	20,000	20,000	20,000
	Tenn Gas Pipeline		358905 FTA Z6-Z6	40,000	40,000	40,000	40,000	40,000	40,000
19	Tenn Gas Pipeline (Concord Lateral)		Firm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
20	Portland Natural Gas Trans Service		FT-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
21	Portland Natural Gas		FTN	5,000	5,000	5,000	5,000	5,000	5,000
22	ANE (TransCanada via Union to Iroquois)		Dawn - Parkway to Iroquois	4,047	4,047	4,047	4,047	4,047	4,047
23	TransCanada via Union to Portland		Union Parkway to Portland	5,077	5,077	5,077	5,077	5,077	5,077
24	Tenn Gas Pipeline (short haul)	peak	632 Z4-Z6 (stg)	15,265	15,265	15,265	15,265	15,265	15,265
25	Tenn Gas Pipeline (short haul)	peak	11234 Z4-Z6(stg)	7,082	7,082	7,082	7,082	7,082	7,082
26	Tenn Gas Pipeline (short haul)	peak	11234 Z5-Z6(stg)	1,957	1,957	1,957	1,957	1,957	1,957
27	National Fuel	peak	FST N02358	6,098	6,098	6,098	6,098	6,098	6,098
28									
29	**Peaking**								
30	Tenn Gas Pipeline (Concord Lateral)	peak		-	-	-	-	-	-
31	Granite Ridge Demand	peak		-	-	-	-	-	-
32	DOMAC Liquid Demand Charge	peak	NSB041	-	-	-	-	-	-
33									
34	**Storage**								
35	Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
36	Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
37	Honeoye - Demand	peak	SS-NY	1,362	1,362	1,362	1,362	1,362	1,362
38	Honeoye - Capacity	peak	SS-NY	245,380	245,380	245,380	245,380	245,380	245,380
39	National Fuel - Demand	peak	FSS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
40	National Fuel - Capacity Reservation	peak	FSS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
41	Tenn Gas Pipeline - Demand	peak	FS-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
42	Tenn Gas Pipeline - Cap. Reservations	peak	FS-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Off Peak 2022 Summer Cost of Gas Filing
Demand Rates

Updated Schedule 5C
Page 1 of 1

				May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Nov-22	Dec-22	Jan-23	Feb-23	Mar-23	Apr-23
Tariff Rates				31	30	31	31	30	31	184	30	31	31	28	31	30
				Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate						
Supply																
Niagara Supply		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pipeline																
Iroquois Gas	RTS 470-01	$ 5.2357	Forth Revised Sheet No. 4	$ 0.1689	$ 0.1745	$ 0.1689	$ 0.1689	$ 0.1745	$ 0.1689	$ 0.1708	$ 0.1745	$ 0.1689	$ 0.1689	$ 0.1870	$ 0.1689	$ 0.1745
Tenn Gas Pipeline	95346 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.4746	$ 0.4904	$ 0.4746	$ 0.4746	$ 0.4904	$ 0.4746	$ 0.4799	$ 0.4904	$ 0.4746	$ 0.4746	$ 0.5254	$ 0.4746	$ 0.4904
Tenn Gas Pipeline	2302 Z5-Z6	$ 6.2957	17th Rev Sheet No. 14	$ 0.2031	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2099	$ 0.2031	$ 0.2053	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099
Tenn Gas Pipeline	8587 Z0-Z6	$ 20.3736	FT-A (Z0 - Z6)	$ 0.6572	$ 0.6791	$ 0.6572	$ 0.6572	$ 0.6791	$ 0.6572	$ 0.6645	$ 0.6791	$ 0.6572	$ 0.6572	$ 0.7276	$ 0.6572	$ 0.6791
Tenn Gas Pipeline	8587 Z1-Z6	$ 18.0875	FT-A (Z1 - Z6)	$ 0.5835	$ 0.6029	$ 0.5835	$ 0.5835	$ 0.6029	$ 0.5835	$ 0.5900	$ 0.6029	$ 0.5835	$ 0.5835	$ 0.6460	$ 0.5835	$ 0.6029
Tenn Gas Pipeline	8587 Z4-Z6	$ 7.1645	FT-A (Z4 - Z6)	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2337	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388
TGP Dracut	42076 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1349	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1394	$ 0.1349	$ 0.1364	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394
TGP Dracut	358905 FTA Z6-Z6	$ 4.1818	17th Rev Sheet No. 14	$ 0.1349	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1394	$ 0.1349	$ 0.0227	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394
TGP Concord Lateral	Firm Transportation	$ 12.2113	Per contract	$ 0.3939	$ 0.4070	$ 0.3939	$ 0.3939	$ 0.4070	$ 0.3939	$ 0.3983	$ 0.4070	$ 0.3939	$ 0.3939	$ 0.4361	$ 0.3939	$ 0.4070
Portland Natural Gas	FT-1999-001	$ 18.2633	Negot Dmd /CMDY=Part 4.1 V7	$ 0.5891	$ 0.6088	$ 0.5891	$ 0.5891	$ 0.6088	$ 0.5891	$ 0.5957	$ 0.6088	$ 0.5891	$ 0.5891	$ 0.6523	$ 0.5891	$ 0.6088
Portland Natural Gas	FTN	$ 22.8125	Negot Dmd /CMDY=Part 4.1 V7	$ 0.7359	$ 0.7604	$ 0.7359	$ 0.7359	$ 0.7604	$ 0.7359	$ 0.7441	$ 0.7604	$ 0.7359	$ 0.7359	$ 0.8147	$ 0.7359	$ 0.7604
Tenn Gas Pipeline	632 Z4-Z6 (stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2337	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388
Tenn Gas Pipeline	11234 Z4-Z6(stg)	$ 7.1645	17th Rev Sheet No. 14	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2388	$ 0.2311	$ 0.2337	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388
Tenn Gas Pipeline	11234 Z5-Z6(stg)	$ 6.2957	17th Rev Sheet No. 14	$ 0.2031	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2099	$ 0.2031	$ 0.2053	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099
National Fuel	FST N02358	$ 4.5274	4.010 Version 31.0.1 Pg 1	$ 0.1460	$ 0.1509	$ 0.1460	$ 0.1460	$ 0.1509	$ 0.1460	$ 0.1477	$ 0.1509	$ 0.1460	$ 0.1460	$ 0.1617	$ 0.1460	$ 0.1509
ANE Union Gas		$ 3.6665														
TransCanada Pipelines Limited		$ 11.9842	Union Parkway to Iroquois													
Delivery Pressure Demand Charge		0.6083	Union Parkway to Iroquois													
Sub Total Demand Charges		16.2590														
Conversion rate GJ to MMBTU		1.0551														
Conversion rate to US$		1.2589	1/0/1900													
Demand Rate/US$		$ 13.6260		$ 0.4395	$ 0.4542	$ 0.4395	$ 0.4395	$ 0.4542	$ 0.4395	$ 0.4444	$ 0.4542	$ 0.4395	$ 0.4395	$ 0.4866	$ 0.4395	$ 0.4542
Union Gas		$ 3.6665														
TransCanada Pipelines Limited		$ 20.4218														
Delivery Pressure Demand Charge		$ 0.6083														
Sub Total Demand Charges		$ 24.6966														
Conversion rate GJ to MMBTU		$ 1.0551														
Conversion rate to US$		$ 1.2589	$0.0000													
Demand Rate/US$		$ 20.6972		$ 0.6677	$ 0.6899	$ 0.6677	$ 0.6677	$ 0.6899	$ 0.6677	$ 0.6751	$ 0.6899	$ 0.6677	$ 0.6677	$ 0.7392	$ 0.6677	$ 0.6899
Peaking																
Granite Ridge Demand		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
DOMAC Demand NSB041		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -						
Storage																
Dominion - Demand	GSS 300076	$ 1.8716	GSS Settled,Tariff Rec #10.30 V	$ 0.0604	$ 0.0624	$ 0.0604	$ 0.0604	$ 0.0624	$ 0.0604	$ 0.0612	$ 0.0624	$ 0.0604	$ 0.0604	$ 0.0668	$ 0.0604	$ 0.0624
Dominion - Capacity	GSS 300076	$ 0.0145	GSS Settled,Tariff Rec #10.30 V	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005
		$ 1.8861		$ 0.0608	$ 0.0629	$ 0.0608	$ 0.0608	$ 0.0629	$ 0.0608	$ 0.0617	$ 0.0629	$ 0.0608	$ 0.0608	$ 0.0674	$ 0.0608	$ 0.0629
Honeoye - Demand	SS-NY	$ 6.1299	Sub 1st Rev Sheet No. 5	$ 0.1977	$ 0.2043	$ 0.1977	$ 0.1977	$ 0.2043	$ 0.1977	$ 0.2004	$ 0.2043	$ 0.1977	$ 0.1977	$ 0.2189	$ 0.1977	$ 0.2043
National Fuel - Demand	FSS-1 2357	$ 2.6325	4.020 Version 26.0.0 Pg 1	$ 0.0849	$ 0.0878	$ 0.0849	$ 0.0849	$ 0.0878	$ 0.0849	$ 0.0861	$ 0.0878	$ 0.0849	$ 0.0849	$ 0.0940	$ 0.0849	$ 0.0878
National Fuel - Capacity	FSS-1 2357	$ 0.0476	4.020 Version 26.0.0 Pg 1	$ 0.0015	$ 0.0016	$ 0.0015	$ 0.0015	$ 0.0016	$ 0.0015	$ 0.0016	$ 0.0016	$ 0.0015	$ 0.0015	$ 0.0017	$ 0.0015	$ 0.0016
		$ 2.6801		$ 0.0865	$ 0.0893	$ 0.0865	$ 0.0865	$ 0.0893	$ 0.0865	$ 0.0876	$ 0.0893	$ 0.0865	$ 0.0865	$ 0.0957	$ 0.0865	$ 0.0893
Tenn Gas Pipeline	FS-MA 523	$ 1.3094	20th Rev Sheet No.61	$ 0.0422	$ 0.0436	$ 0.0422	$ 0.0422	$ 0.0436	$ 0.0422	$ 0.0428	$ 0.0436	$ 0.0422	$ 0.0422	$ 0.0468	$ 0.0422	$ 0.0436

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2									
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
									REDACTED Updated Schedule 6 Page 1 of 5
5									Off-Peak
6	For Month of:	Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	May - Oct
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8									
9	**Supply and Commodity Costs**								
10									
11	**Pipeline Gas:**								
12	Dawn Supply	ln 63 * ln 104	[redacted]						
13	Niagara Supply	ln 64 * ln 109							
14	TGP Supply (Gulf)	ln 65 * ln 129							
15	Dracut Supply 1 - Baseload	ln 66 * ln 114							
16	Dracut Supply 2 - Swing	ln 67 * ln 119							
	Dracut Supply 3 - Swing								
17	City Gate Delivered Supply	ln 68 * ln 135							
18	LNG Truck	ln 69 * ln 137							
19	Propane Truck	ln 70 * ln 139							
20	PNGTS	ln 71 * ln 144							
21	Portland Natural Gas								
22	TGP Supply (Zone 4)	ln 73 * ln 154							
23									
24	Subtotal Pipeline Gas Costs		$ 2,582,425	$ 1,948,176	$ 1,951,410	$ 1,908,418	$ 1,867,983	$ 2,854,727	$ 13,129,445
25									
26	**Volumetric Transportation Costs**								
27	Dawn Supply	ln 63 * ln 202	[redacted]						
28	Niagara Supply	ln 64 * ln 213							
29	TGP Supply (Zone 4)	ln 73 * ln 251							
30	Dracut Supply 1 - Baseload	ln 66 * ln 262							
31	Dracut Supply 2 - Swing	ln 67 * ln 262							
	Dracut Supply 3 - Swing								
32	City Gate Delivered Supply	ln 68 * ln 262							
33	TGP Storage - Withdrawals	ln 78 * ln 177							
34									
35	**Total Volumetric Transportation Costs**		$ 88,990	$ 71,093	$ 70,660	$ 70,003	$ 71,501	$ 87,078	$ 459,325
36									
37	**Less - Gas Refill:**								
38	LNG Truck	ln 87 * ln 161	[redacted]						
39	Propane	ln 88 * ln 162							
40	TGP Storage Refill	ln 89 * ln 127							
41	Storage Refill (Trans.)	ln 89 * ln 241							
42									
43	Subtotal Refills		$ (960,246)	$ (1,223,872)	$ (1,393,945)	$ (1,367,756)	$ (1,088,979)	$ (566,192)	$ (6,600,989)
44									
45	**Total Supply & Pipeline Commodity Costs**	ln 24 + ln 35 + ln 43	$ 1,711,170	$ 795,397	$ 628,125	$ 610,666	$ 850,505	$ 2,375,613	$ 6,971,475
46									
47	**Storage Gas:**								
48	TGP Storage - Withdrawals	ln 78 * ln 169	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49									
50	**Produced Gas:**								
51	LNG Vapor	ln 81 * ln 156	[redacted]						
52	Propane	ln 82 * ln 158							
53									
54	**Total Produced Gas**	ln 51 + ln 52	$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
55									
56									
57	**Total Commodity Gas & Trans. Costs**	ln 45 + ln 48 + ln 54	$ 1,725,162	$ 808,556	$ 641,038	$ 623,542	$ 864,157	$ 2,391,524	$ 7,053,979
58			**THIS PAGE HAS BEEN REDACTED**						

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**

59									
60	**Volumes (Therms)**								
61									
62	**Pipeline Gas:**	See Schedule 11A							
63	Dawn Supply		739,535	95,658	-	-	206,295	636,518	1,678,006
64	Niagara Supply		668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
65	TGP Supply (Gulf)		13,120	-	-	-	-	384,326	397,446
66	Dracut Supply 1 - Baseload		-	-	-	-	-	-	-
67	Dracut Supply 2 - Swing		-	-	-	-	-	436,185	436,185
	Dracut Supply 3 - Swing								
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	LNG Truck		44,883	18,131	-	-	55,566	20,602	139,181
70	Propane Truck		79,409	71,899	69,472	69,279	73,449	81,696	445,204
71	PNGTS		205,081	146,300	119,612	125,908	176,916	218,093	991,910
72	Portland Natural Gas		152,602	3,126	-	-	2,555	574,003	732,286
73	TGP Supply (Zone 4)		5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088	29,866,267
74									
75	Subtotal Pipeline Volumes		7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177	38,263,081
76									
77	**Storage Gas:**								
78	TGP Storage		-	-	-	-	-	-	-
79									
80	**Produced Gas:**								
81	LNG Vapor		20,025	18,131	17,519	17,470	18,522	20,602	112,269
82	Propane		-	-	-	-	-	-	-
83									
84	Subtotal Produced Gas		20,025	18,131	17,519	17,470	18,522	20,602	112,269
85									
86	**Less - Gas Refill:**								
87	LNG Truck		(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
88	Propane		(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
89	TGP Storage Refill		(2,188,222)	(2,766,568)	(3,120,796)	(3,057,929)	(2,444,250)	(1,262,380)	(14,840,145)
90									
91	Subtotal Refills		(2,312,514)	(2,856,598)	(3,190,268)	(3,127,208)	(2,573,265)	(1,364,677)	(15,424,530)
92									
93	**Total Sendout Volumes**		4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820
94									
95									
96									

Line	Description	Reference							Average Rate
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2									
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
97									**REDACTED**
98	**Gas Costs and Volumetric Transportation Rates**								Updated Schedule 6
99									Page 3 of 5
100	**Pipeline Gas:**								
101	**Dawn Supply**								Average Rate
102	NYMEX Price	Sch 7, In 10/10	[redacted]						
103	Basis Differential								
104	**Net Commodity Costs**								
105									
106	**Niagara Supply**								
107	NYMEX Price	Sch 7, In 10/10	[redacted]						
108	Basis Differential								
109	**Net Commodity Costs**								
110									
111	**Dracut Supply 1 - Baseload**								
112	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10	[redacted]						
113	Basis Differential								
114	**Net Commodity Costs**								
115									
116	**Dracut Supply 2 - Swing**								
117	Commodity Costs - NYMEX Price	Sch 7, In 10 / 10	[redacted]						
118	Basis Differential								
119	**Net Commodity Costs**								
120									
121	**Dracut Supply 3 - Swing**	Sch 7, In 10 / 10							
122	Commodity Costs - NYMEX Price		[redacted]						
123	Basis Differential								
124	**Net Commodity Costs**								
125									
126	**TGP Supply (Gulf)**								
127	NYMEX Price	Sch 7, In 10/10	[redacted]						
128	Basis Differential								
129	**Net Commodity Costs**								
130									
131									
132	**TGP Citygate Supply**								
133	NYMEX Price	Sch 7, In 10/10	[redacted]						
134	Basis Differential								
135	**Net Commodity Costs**								
136									
137	**LNG Truck**	Sch 7, In 10/10	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
138									
139	**Propane Truck**	NYMEX - Propane	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
140									
141	**PNGTS**								
142	NYMEX Price	Sch 7, In 10/10	[redacted]						
143	Additional Cost								
144	**Net Commodity Cost**								
145									
146	**PNGTS EXP**								
147	NYMEX Price	Sch 7, In 10/10	[redacted]						
148	Basis Differential								
149	**Net Commodity Cost**								
150									
151	**TGP Supply (Zone 4)**								
152	NYMEX Price	Sch 7, In 10/10	[redacted]						
153	Basis Differential								
154	**Net Commodity Cost**		**$0.3562**	**$0.3524**	**$0.3620**	**$0.3531**	**$0.3135**	**$0.3150**	**$0.3420**
155									
156	**LNG Vapor (Storage)**	Sch 13, In 97 /10	**$0.6988**	**$0.7258**	**$0.7371**	**$0.7371**	**$0.7371**	**$0.7723**	**$0.7347**
157									
158	**Propane**	Sch 13, In 67 /10	**$1.1475**	**$1.0155**	**$0.9197**	**$0.8429**	**$0.7781**	**$0.7194**	**$0.9038**
159									
160	**Storage Refill:**								
161	**LNG Truck**	In 137	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
162	**Propane**	In 139	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**	**$0.0000**
163									
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1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2									
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
165									**REDACTED**
166									Updated Schedule 6
167									Page 4 of 5
182	**Per Unit Volumetric Transportation Rates**								
183	**Dawn Supply Volumetric Transportation Charge**								Average Rate
184	**Commodity Costs**	In 104	[redacted]						
185									
186	TransCanada - Commodity Rate/GJ	Dawn - Parkway to Iroquois	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
187	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
188	Conversion Rate to US$	1/0/1900	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589	1.2589
189	Commodity Rate/US$	In 186 x In 187 x In 188	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040	$0.00040
190	TransCanada Fuel %	Dawn - Parkway to Iroquois	0.74%	0.67%	0.00%	0.00%	0.00%	0.00%	0.23%
191	TransCanada Fuel * Percentage	In 184 x In 190	$0.00283	$0.00256	$0.00000	$0.00000	$0.00000	$0.00000	$0.00090
192	Subtotal TransCanada		**$0.00323**	**$0.00296**	**$0.00040**	**$0.00040**	**$0.00040**	**$0.00040**	**$0.00130**
193	IGTS - Z1 RTS Commodity	Forth Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
194	IGTS - Z1 RTS ACA Rate Commodity	Forth Revised Sheet No. 4	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
195	IGTS - Z1 RTS Deferred Asset Surcharge	Forth Revised Sheet No. 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
196	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**	**$0.00046**
197	TGP NET-NE - Comm. Segments 3 & 4	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
198	IGTS -Fuel Use Factor - Percentage	Forth Revised Sheet No. 4	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
199	IGTS -Fuel Use Factor - Fuel * Percentage	In 184 x In 198	**$0.00382**	**$0.00384**	**$0.00387**	**$0.00385**	**$0.00384**	**$0.00385**	**$0.00385**
200	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
201	TGP FTA Fuel * Percentage	In 184 x In 200	**$0.00329**	**$0.00330**	**$0.00333**	**$0.00331**	**$0.00330**	**$0.00331**	**$0.00331**
202	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01092**	**$0.01068**	**$0.00818**	**$0.00814**	**$0.00812**	**$0.00814**	**$0.00903**
203									
204									
205	**Niagara Supply Volumetric Transportation Charge**								
206	**Commodity Costs**	Ln 109	[redacted]						
207									
208	TGP FTA - FTA Z 5-6 Comm. Rate	19th Rev Sheet No. 15	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705	$0.00705
209	TGP FTA - FTA Z 5-6 - ACA Rate	19th Rev Sheet No. 15	$0.00012	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
210	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00717**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**	**$0.0072**
211	TGP FTA Fuel Charge % Z 5-6	17th Rev Sheet No. 32	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%	0.86%
212	TGP FTA Fuel * Percentage	In 206 x In 211	**$0.00311**	**$0.00313**	**$0.00316**	**$0.00314**	**$0.00313**	**$0.00314**	**$0.00314**
213	**Total Volumetric Transportation Rate - Niagara Supply**		**$0.01028**	**$0.01030**	**$0.01033**	**$0.01031**	**$0.01030**	**$0.01031**	**$0.01031**
214									
215									
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1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Supply and Commodity Costs, Volumes and Rates**
217 **REDACTED**
218 Updated Schedule 6
219 Page 5 of 5
220 **TGP Direct Volumetric Transportation Charge** Average Rate

221	**Commodity Costs**	Ln 127	[redacted]						
222									
223	TGP - Max Comm. Base Rate - Z 0-6	19th Rev Sheet No. 15	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672	$0.02672
224	TGP - Max Commodity ACA Rate - Z 0-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
225	Subtotal TGP - Max Comm. Rate Z 0-6		$0.02684	$0.02684	$0.02684	$0.02684	$0.02684	$0.02684	$0.02684
226	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
227	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**	**$0.00875**
228	TGP - Max Comm. Base Rate - Z 1-6	19th Rev Sheet No. 15	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331	$0.02331
229	TGP - Max Commodity ACA Rate - Z 1-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
230	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02343	$0.02343	$0.02343	$0.02343	$0.02343	$0.02343	$0.02343
231	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
232	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**	**$0.01579**
233	TGP - Fuel Charge % - Z 0 -6	17th Rev Sheet No. 32	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%	4.66%
234	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
235	Prorated TGP Fuel Charge % - Z 0-6		1.52%	1.52%	1.52%	1.52%	1.52%	1.52%	1.52%
236	TGP - Fuel Charge % - Z 1 -6	17th Rev Sheet No. 32	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%	4.06%
237	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
238	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.74%	2.74%	2.74%	2.74%	2.74%	2.74%	2.74%
239	TGP - Fuel Charge % - Z 0-6	ln 221 x ln 235	**$0.00592**	**$0.00597**	**$0.00604**	**$0.00605**	**$0.00599**	**$0.00599**	**$0.00599**
240	TGP - Fuel Charge % - Z 1-6	ln 221 x ln 238	**$0.01066**	**$0.01076**	**$0.01088**	**$0.01089**	**$0.01079**	**$0.01078**	**$0.01080**
241	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.04112**	**$0.04128**	**$0.04146**	**$0.04148**	**$0.04133**	**$0.04131**	**$0.04133**
242									
243	**TGP (Zone 4 Purchase) Volumetric Transportation Charge**								
244	**Commodity Costs**	Ln 127	[redacted]						
245									
246	TGP - Max Comm. Base Rate - Z 4-6	19th Rev Sheet No. 15	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928	$0.00928
247	TGP - Max Commodity ACA Rate - Z 4-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
248	Subtotal TGP - Max Commodity Rate - Z 4-6		**$0.00940**	**$0.00940**	**$0.00940**	**$0.00940**	**$0.00940**	**$0.00940**	**$0.00940**
249	TGP - Fuel Charge % - Z 4-6	17th Rev Sheet No. 32	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%	1.22%
250	TGP - Fuel Charge	ln 244 x ln 249	**$0.00435**	**$0.00430**	**$0.00442**	**$0.00431**	**$0.00382**	**$0.00384**	**$0.00417**
251	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.01375**	**$0.01370**	**$0.01382**	**$0.01371**	**$0.01322**	**$0.01324**	**$0.01357**
252									
253									
254	**TGP Dracut**								
255	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
256									
257	TGP - Trans Charge - Comm. - Z 6-6	19th Rev Sheet No. 15	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300	$0.00300
258	TGP - Trans Charge - ACA Rate - Z6-6	19th Rev Sheet No. 15	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
259	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
260	TGP - Fuel Charge % - Z 6-6	17th Rev Sheet No. 32	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
261	TGP - Fuel Charge	ln 255 x ln 260	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**	**$0.00000**
262	**Total Volumetric Transportation Rate - TGP Dracut**		**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**	**$0.00312**
263									
264			**THIS PAGE HAS BEEN REDACTED**						

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 7
2 Page 1 of 1
3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **NYMEX Futures @ Henry Hub**

4										May - Oct
5										Off Peak
6	For Month of:		Reference	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Strip Average
7		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**I. NYMEX Opening Prices as of:**									
9		Opening Prices	Line 206	$3.9770	$4.0110	$4.0520	$4.0580	$4.0420	$4.0720	$ 4.0353
10				$3.9770	$4.0110	$4.0520	$4.0580	$4.0420	$4.0720	$ 4.0353

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3

November 1, 2021 - April 30, 2022
Residential Heating (R3)

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
Typical Usage (Therms)		62	110	123	148	132	92	667
	8/1/2021 - Current							
Winter:								
Cust. Chg	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34
Headblock	$ 0.5632	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5632	$ 34.92	$ 61.95	$ 69.27	$ 83.35	$ 74.34	$ 51.81	$ 375.65
HB Threshold	-							
Summer:	8/1/2021 - Current							
Cust. Chg	$ 15.39							
Headblock	$ 0.5632							
Tailblock	$ 0.5632							
HB Threshold	-							
Total Base Rate Amount		$ 50.31	$ 77.34	$ 84.66	$ 98.74	$ 89.73	$ 67.20	$ 467.99
COG Rate - (Seasonal)		$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339
COG amount		$ 70.30	$ 124.73	$ 139.47	$ 167.82	$ 149.67	$ 104.32	$ 756.31
LDAC		$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
LDAC amount		$ 8.95	$ 15.89	$ 17.76	$ 21.37	$ 19.06	$ 13.29	$ 96.33
Total Bill		**$ 129.56**	**$ 217.96**	**$ 241.90**	**$ 287.94**	**$ 258.47**	**$ 184.81**	**$ 1,320.63**

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	51	28	16	14	14	21	144	811
Cust. Chg	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34	$ 184.68
Headblock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 28.72	$ 15.77	$ 9.01	$ 7.88	$ 7.88	$ 11.83	$ 81.10	$ 456.76
Total Base Rate Amount	$ 44.11	$ 31.16	$ 24.40	$ 23.27	$ 23.27	$ 27.22	$ 173.44	$ 641.44
COG Rate - (Seasonal)	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 1.0318
COG amount	$ 28.49	$ 15.64	$ 8.94	$ 7.82	$ 7.82	$ 11.73	$ 80.45	$ 836.76
LDAC	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
LDAC amount	$ 7.37	$ 4.04	$ 2.31	$ 2.02	$ 2.02	$ 3.03	$ 20.80	$ 117.13
Total Bill	**$ 79.97**	**$ 50.85**	**$ 35.65**	**$ 33.12**	**$ 33.12**	**$ 41.98**	**$ 274.69**	**$ 1,595.32**

November 1, 2020 - April 30, 2021
Residential Heating (R3)

			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
Typical Usage (Therms)			62	110	123	148	132	92	667
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 15.50	$ 15.39	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 15.50	$ 93.00
Headblock	$ 0.5678	$ 0.5632	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 0.5678	$ 0.5632	$ 35.20	$ 62.46	$ 69.84	$ 84.03	$ 74.95	$ 52.24	$ 378.72
HB Threshold	-	-	$ 34.53						
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 15.50	$ 15.39							
Headblock	$ 0.5678	$ 0.5632							
Tailblock	$ 0.5678	$ 0.5632							
HB Threshold	-	-							
Total Base Rate Amount			$ 50.70	$ 77.96	$ 85.34	$ 99.53	$ 90.45	$ 67.74	$ 471.72
COG Rate - (Seasonal)			$ 0.5571	$ 0.5571	$ 0.4664	$ 0.4276	$ 0.5156	$ 0.6050	$ 0.5100
COG amount			$ 34.54	$ 61.28	$ 57.37	$ 63.28	$ 68.06	$ 55.66	$ 340.19
LDAC			$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
LDAC amount			$ 3.65	$ 6.48	$ 7.24	$ 8.72	$ 7.77	$ 5.42	$ 39.29
Total Bill			**$ 88.90**	**$ 145.72**	**$ 149.95**	**$ 171.54**	**$ 166.28**	**$ 128.82**	**$ 851.20**
DIFFERENCE:									
Total Bill			**$ 40.67**	**$ 72.24**	**$ 91.95**	**$ 116.40**	**$ 92.19**	**$ 55.99**	**$ 469.43**
% Change			**45.75%**	**49.57%**	**61.32%**	**67.86%**	**55.44%**	**43.47%**	**55.15%**
Base Rate			$ (0.40)	$ (0.62)	$ (0.68)	$ (0.79)	$ (0.72)	$ (0.53)	$ (3.73)
% Change			-0.78%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%	-0.79%
COG & LDAC			$ 41.06	$ 72.86	$ 92.62	$ 117.19	$ 92.90	$ 56.53	$ 473.16
% Change			107.52%	107.52%	143.35%	162.76%	122.51%	92.55%	124.69%
check			$ -	$ -	$ -	$ -	$ -	$ -	$ -

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	51	28	16	14	14	21	144	811
Cust. Chg	$15.50	$15.50	$15.50	$15.39	$15.39	$15.39	$ 92.67	$ 185.67
Headblock	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Tailblock	$ 28.96	$ 15.90	$ 9.08	$ 7.88	$ 7.88	$ 11.83	$ 81.54	$ 460.26
Total Base Rate Amount	$ 44.46	$ 31.40	$ 24.58	$ 23.27	$ 23.27	$ 27.22	$ 174.21	$ 645.93
COG Rate - (Seasonal)	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.4893
COG amount	$ 20.07	$ 11.02	$ 6.30	$ 5.51	$ 5.51	$ 8.26	$ 56.66	$ 396.86
LDAC	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
LDAC amount	$ 3.00	$ 1.65	$ 0.94	$ 0.82	$ 0.82	$ 1.24	$ 8.48	$ 47.77
Total Bill	**$ 67.53**	**$ 44.07**	**$ 31.82**	**$ 29.61**	**$ 29.61**	**$ 36.72**	**$ 239.35**	**$ 1,090.55**
DIFFERENCE: Total Bill	**$ 12.44**	**$ 6.78**	**$ 3.83**	**$ 3.51**	**$ 3.51**	**$ 5.27**	**$ 35.34**	**$ 504.77**
% Change	**18.42%**	**15.39%**	**12.03%**	**11.86%**	**11.86%**	**14.34%**	**14.76%**	**46.29%**
Base Rate	$ (0.34)	$ (0.24)	$ (0.18)	$ -	$ -	$ -	$ (0.77)	$ (4.50)
% Change	-0.78%	-0.76%	-0.75%	0.00%	0.00%	0.00%	-0.44%	-0.70%
COG & LDAC	$ 12.79	$ 7.02	$ 4.01	$ 3.51	$ 3.51	$ 5.27	$ 36.10	$ 509.26
% Change	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	55.42%	114.54%
check	$ -	$ (0.00)	$ -	$ -	$ -	$ -	$ -	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41

November 1, 2021 - April 30, 2022 / **May 1, 2022 - October 31, 2022**
Commercial Rate (G-41)

	Rate	Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)		89	277	504	457	331	297	1,955	153	39	26	34	25	29	306	2,261
Winter:	8/1/2021 - Current															
Cust. Chg	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 342.36								
Headblock	$ 0.4688	$ 41.72	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 46.88	$ 276.12								
Tailblock	$ 0.3149	$ -	$ 55.74	$ 127.22	$ 112.42	$ 72.74	$ 62.04	$ 430.15								
HB Threshold	100	$41.93	$46.88	$46.88	$46.88	$46.88	$46.88									
Summer:	8/1/2021 - Current															
Cust. Chg	$ 57.06								$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 57.06	$ 342.36	$ 684.72
Headblock	$ 0.4688								$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 9.38	$ 56.26	$ 332.38
Tailblock	$ 0.3149								$ 41.88	$ 5.98	$ 1.89	$ 4.41	$ 1.57	$ 2.83	$ 58.57	$ 488.72
HB Threshold	20															
Total Base Rate Amount		$ 98.78	$ 159.68	$ 231.16	$ 216.36	$ 176.68	$ 165.98	$ 1,048.64	$ 108.32	$ 72.42	$ 68.33	$ 70.84	$ 68.01	$ 69.27	$ 457.19	$ 1,505.82
COG Rate - (Seasonal)		$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 1.0563
COG amount		$ 100.93	$ 314.15	$ 571.59	$ 518.28	$ 375.39	$ 336.83	$ 2,217.17	$ 85.57	$ 21.81	$ 14.54	$ 19.02	$ 13.98	$ 16.22	$ 171.15	$ 2,388.31
LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount		$ 7.81	$ 24.32	$ 44.25	$ 40.13	$ 29.06	$ 26.08	$ 171.66	$ 13.43	$ 3.42	$ 2.28	$ 2.99	$ 2.20	$ 2.55	$ 26.87	$ 198.53
Total Bill		**$ 207.53**	**$ 498.15**	**$ 847.00**	**$ 774.77**	**$ 581.13**	**$ 528.88**	**$ 3,437.46**	**$ 207.33**	**$ 97.66**	**$ 85.15**	**$ 92.85**	**$ 84.19**	**$ 88.04**	**$ 655.20**	**$ 4,092.67**

November 1, 2020 - April 30, 2021 / **May 1, 2021 - October 31, 2021**
Commercial Rate (G-41)

	Rate	Rate	Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)			89	277	504	457	331	297	1,955	153	39	26	34	25	29	306	2,261
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 57.46	$ 57.06	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 57.46	$ 344.76								
Headblock	$ 0.4711	$ 0.4688	$ 41.93	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 47.11	$ 277.48								
Tailblock	$ 0.3165	$ 0.3149	$ -	$ 56.02	$ 127.87	$ 112.99	$ 73.11	$ 62.35	$ 432.34								
HB Threshold	100	100															
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current															
Cust. Chg	$ 57.46	$ 57.06								$57.46	$ 57.46	$ 57.46	$ 57.06	$ 57.06	$ 57.06	$ 343.56	$ 688.32
Headblock	$ 0.4711	$ 0.4688								$ 9.42	$ 9.42	$ 9.42	$ 9.38	$ 9.38	$ 9.38	$ 56.39	$ 333.87
Tailblock	$ 0.3165	$ 0.3149								$ 42.09	$ 6.01	$ 1.90	$ 4.41	$ 1.57	$ 2.83	$ 58.82	$ 491.16
HB Threshold	20	20															
Total Base Rate Amount			$ 99.39	$ 160.59	$ 232.44	$ 217.56	$ 177.68	$ 166.92	$ 1,054.58	$ 108.98	$ 72.90	$ 68.78	$ 70.84	$ 68.01	$ 69.27	$ 458.78	$ 1,513.36
COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5018	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.4865
COG amount			$ 49.41	$ 153.79	$ 234.11	$ 194.54	$ 170.03	$ 179.12	$ 981.01	$ 59.46	$ 15.16	$ 10.10	$ 13.21	$ 9.72	$ 11.27	$ 118.91	$ 1,099.92
LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount			$ 4.94	$ 15.37	$ 27.97	$ 25.36	$ 18.37	$ 16.48	$ 108.50	$ 8.49	$ 2.16	$ 1.44	$ 1.89	$ 1.39	$ 1.61	$ 16.98	$ 125.49
Total Bill			**$ 153.74**	**$ 329.75**	**$ 494.52**	**$ 437.47**	**$ 366.09**	**$ 362.52**	**$ 2,144.09**	**$ 176.92**	**$ 90.22**	**$ 80.33**	**$ 85.94**	**$ 79.11**	**$ 82.15**	**$ 594.67**	**$ 2,738.76**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ 53.79**	**$ 168.39**	**$ 352.48**	**$ 337.30**	**$ 215.05**	**$ 166.36**	**$ 1,293.37**	**$ 30.40**	**$ 7.44**	**$ 4.82**	**$ 6.90**	**$ 5.08**	**$ 5.89**	**$ 60.53**	**$ 1,353.90**
% Change	**34.99%**	**51.07%**	**71.28%**	**77.10%**	**58.74%**	**45.89%**	**60.32%**	**17.18%**	**8.25%**	**6.00%**	**8.03%**	**6.42%**	**7.17%**	**10.18%**	**49.43%**
Base Rate	$ (0.60)	$ (0.91)	$ (1.28)	$ (1.20)	$ (1.00)	$ (0.95)	$ (5.94)	$ (0.66)	$ (0.48)	$ (0.46)	$ -	$ -	$ -	$ (1.59)	$ (7.53)
% Change	-0.61%	-0.57%	-0.55%	-0.55%	-0.56%	-0.57%	-0.56%	-0.60%	-0.65%	-0.66%	0.00%	0.00%	0.00%	-0.35%	-0.50%
COG & LDAC	$ 54.40	$ 169.30	$ 353.76	$ 338.50	$ 216.05	$ 167.30	$ 1,299.31	$ 31.06	$ 7.92	$ 5.28	$ 6.90	$ 5.08	$ 5.89	$ 62.12	$ 1,361.43
% Change	100.08%	100.08%	134.98%	153.93%	114.67%	85.53%	119.26%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	111.10%
check	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 0.00	$ 0.00	$ (0.00)	$ (0.00)	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42

November 1, 2021 - April 30, 2022
C&I High Winter Use Medium G-42

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
Typical Usage (Therms)		830	2,189	3,708	3,406	2,603	2,395	15,131
Winter:	8/1/2021 - Current							
Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
Headblock	$ 0.4261	$ 353.66	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 2,484.16
Tailblock	$ 0.2839	$ -	$ 337.56	$ 768.80	$ 683.06	$ 455.09	$ 396.04	$ 2,640.55
HB Threshold	1,000							
Summer:	8/1/2021 - Current							
Cust. Chg	$ 171.19							
Headblock	$ 0.4261							
Tailblock	$ 0.2839							
HB Threshold	400							
Total Base Rate Amount		$ 524.85	$ 934.85	$ 1,366.09	$ 1,280.35	$ 1,052.38	$ 993.33	$ 6,151.86
COG Rate - (Seasonal)		$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341	$ 1.1341
COG amount		$ 941.30	$ 2,482.54	$ 4,205.24	$ 3,862.74	$ 2,952.06	$ 2,716.17	$ 17,160.07
LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount		$ 72.88	$ 192.21	$ 325.59	$ 299.07	$ 228.56	$ 210.30	$ 1,328.61
Total Bill		**$ 1,539.04**	**$ 3,609.60**	**$ 5,896.92**	**$ 5,442.17**	**$ 4,233.01**	**$ 3,919.80**	**$ 24,640.53**

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,319	484	285	247	269	340	2,944	18,075
Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
Headblock	$ 170.44	$ 170.44	$ 121.44	$ 105.25	$ 114.62	$ 144.87	$ 827.06	$ 3,311.22
Tailblock	$ 260.90	$ 23.85	$ -	$ -	$ -	$ -	$ 284.75	$ 2,925.31
Total Base Rate Amount	$ 602.53	$ 365.48	$ 292.63	$ 276.44	$ 285.81	$ 316.06	$ 2,138.95	$ 8,290.81
COG Rate - (Seasonal)	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 0.5593	$ 1.0405
COG amount	$ 737.72	$ 270.70	$ 159.40	$ 138.15	$ 150.45	$ 190.16	$ 1,646.58	$ 18,806.65
LDAC	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount	$ 115.82	$ 42.50	$ 25.02	$ 21.69	$ 23.62	$ 29.85	$ 258.50	$ 1,587.11
Total Bill	**$ 1,456.07**	**$ 678.68**	**$ 477.05**	**$ 436.27**	**$ 459.88**	**$ 536.08**	**$ 4,044.03**	**$ 28,684.57**

November 1, 2020 - April 30, 2021
C&I High Winter Use Medium G-42

			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
Typical Usage (Therms)			830	2,189	3,708	3,406	2,603	2,395	15,131
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
Headblock	$ 0.4284	$ 0.4261	$ 355.57	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 2,497.57
Tailblock	$ 0.2855	$ 0.2839	$ -	$ 339.46	$ 773.13	$ 686.91	$ 457.66	$ 398.27	$ 2,655.44
HB Threshold	1,000	1,000							
	-	-							
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 172.39	$ 171.19							
Headblock	$ 0.4284	$ 0.4261							
Tailblock	$ 0.2855	$ 0.2839							
HB Threshold	400	400							
Total Base Rate Amount			$ 527.96	$ 940.25	$ 1,373.92	$ 1,287.70	$ 1,058.45	$ 999.06	$ 6,187.35
COG Rate - (Seasonal)			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5043
COG amount			$ 460.82	$ 1,215.33	$ 1,722.37	$ 1,449.93	$ 1,337.16	$ 1,444.42	$ 7,630.03
LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount			$ 46.07	$ 121.49	$ 205.79	$ 189.03	$ 144.47	$ 132.92	$ 839.77
Total Bill			**$ 1,034.84**	**$ 2,277.07**	**$ 3,302.08**	**$ 2,926.67**	**$ 2,540.07**	**$ 2,576.41**	**$ 14,657.15**

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,319	484	285	247	269	340	2,944	18,075
Cust. Chg	$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
Headblock	$ 171.36	$ 171.36	$ 122.09	$ 105.25	$ 114.62	$ 144.87	$ 829.56	$ 3,327.13
Tailblock	$ 262.37	$ 23.98	$ -	$ -	$ -	$ -	$ 286.36	$ 2,941.79
Total Base Rate Amount	$ 606.12	$ 367.73	$ 294.48	$ 276.44	$ 285.81	$ 316.06	$ 2,146.65	$ 8,334.00
COG Rate - (Seasonal)	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.4854
COG amount	$ 512.56	$ 188.08	$ 110.75	$ 95.98	$ 104.53	$ 132.12	$ 1,144.04	$ 8,774.07
LDAC	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount	$ 73.20	$ 26.86	$ 15.82	$ 13.71	$ 14.93	$ 18.87	$ 163.39	$ 1,003.16
Total Bill	**$ 1,191.89**	**$ 582.68**	**$ 421.05**	**$ 386.13**	**$ 405.27**	**$ 467.06**	**$ 3,454.08**	**$ 18,111.24**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$ 504.19**	**$ 1,332.53**	**$ 2,594.84**	**$ 2,515.50**	**$ 1,692.93**	**$ 1,343.39**	**$ 9,983.38**	**$ 264.18**	**$ 96.00**	**$ 56.00**	**$ 50.14**	**$ 54.61**	**$ 69.02**	**$ 589.95**	**$ 10,573.33**
% Change	**48.72%**	**58.52%**	**78.58%**	**85.95%**	**66.65%**	**52.14%**	**68.11%**	**22.16%**	**16.48%**	**13.30%**	**12.99%**	**13.47%**	**14.78%**	**17.08%**	**58.38%**
Base Rate	$ (3.11)	$ (5.40)	$ (7.83)	$ (7.35)	$ (6.06)	$ (5.73)	$ (35.49)	$ (3.59)	$ (2.25)	$ (1.86)	$ -	$ -	$ -	$ (7.70)	$ (43.19)
% Change	-0.59%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.57%	-0.59%	-0.61%	-0.63%	0.00%	0.00%	0.00%	-0.36%	-0.52%
COG & LDAC	$ 507.30	$ 1,337.93	$ 2,602.67	$ 2,522.85	$ 1,699.00	$ 1,349.12	$ 10,018.87	$ 267.77	$ 98.26	$ 57.86	$ 50.14	$ 54.61	$ 69.02	$ 597.65	$ 10,616.52
% Change	100.08%	100.08%	134.98%	153.93%	114.67%	85.53%	118.29%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	45.71%	108.58%
check	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Annual Bill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-52

November 1, 2021 - April 30, 2022
Commercial Rate (G-52)

		Nov-21	Dec-21	Jan-22	Feb-22	Mar-22	Apr-22	Winter Nov-Apr
Typical Usage (Therms)		1,352	1,866	2,284	2,160	1,886	1,760	11,308
Winter:	8/1/2021 - Current							
Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14
Headblock	$ 0.2428	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 1,456.80
Tailblock	$ 0.1617	$ 56.92	$ 140.03	$ 207.62	$ 187.57	$ 143.27	$ 122.89	$ 858.30
HB Threshold	1,000							
Summer:	8/1/2021 - Current							
Cust. Chg	$ 171.19							
Headblock	$ 0.1749							
Tailblock	$ 0.1000							
HB Threshold	1,000							
Total Base Rate Amount		$ 470.91	$ 554.02	$ 621.61	$ 601.56	$ 557.26	$ 536.88	$ 3,342.24
COG Rate - (Seasonal)		$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324
COG amount		$ 1,531.00	$ 2,113.06	$ 2,586.40	$ 2,445.98	$ 2,135.71	$ 1,993.02	$ 12,805.18
LDAC		$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount		$ 118.72	$ 163.85	$ 200.55	$ 189.66	$ 165.60	$ 154.54	$ 992.92
Total Bill		**$ 2,120.63**	**$ 2,830.93**	**$ 3,408.57**	**$ 3,237.21**	**$ 2,858.57**	**$ 2,684.45**	**$ 17,140.34**

May 1, 2022 - October 31, 2022

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
Headblock	$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 156.89	$ 1,031.39	$ 2,488.19
Tailblock	$ 49.70	$ 12.80	$ 3.20	$ 2.50	$ 5.00	$ -	$ 73.20	$ 931.50
Total Base Rate Amount	$ 395.79	$ 358.89	$ 349.29	$ 348.59	$ 351.09	$ 328.08	$ 2,131.73	$ 5,473.97
COG Rate - (Seasonal)	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.9201
COG amount	$ 835.33	$ 629.42	$ 575.86	$ 571.95	$ 585.90	$ 500.53	$ 3,698.98	$ 16,504.16
LDAC	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
LDAC amount	$ 131.45	$ 99.05	$ 90.62	$ 90.00	$ 92.20	$ 78.76	$ 582.07	$ 1,574.99
Total Bill	**$ 1,362.56**	**$ 1,087.36**	**$ 1,015.76**	**$ 1,010.54**	**$ 1,029.19**	**$ 907.36**	**$ 6,412.78**	**$ 23,553.12**

November 1, 2020 - April 30, 2021
Commercial Rate (G-52)

			Nov-20	Dec-20	Jan-21	Feb-21	Mar-21	Apr-21	Winter Nov-Apr
Typical Usage (Therms)			1,352	1,866	2,284	2,160	1,886	1,760	11,308
Winter:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34
Headblock	$ 0.2439	$ 0.2428	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 1,463.40
Tailblock	$ 0.1624	$ 0.1617	$ 57.16	$ 140.64	$ 208.52	$ 188.38	$ 143.89	$ 123.42	$ 862.02
HB Threshold	1,000	1,000							
	-	-							
Summer:	7/1/20 - 7/31/21	8/1/2021 - Current							
Cust. Chg	$ 172.39	$ 171.19							
Headblock	$ 0.1767	$ 0.1749							
Tailblock	$ 0.1004	$ 0.1000							
HB Threshold	1,000	1,000							
Total Base Rate Amount			$ 473.45	$ 556.93	$ 624.81	$ 604.67	$ 560.18	$ 539.71	$ 3,359.76
COG Rate - (Seasonal)			$ 0.5660	$ 0.5660	$ 0.4753	$ 0.4365	$ 0.5245	$ 0.6139	$ 0.5235
COG amount			$ 765.23	$ 1,056.16	$ 1,085.59	$ 942.84	$ 989.21	$ 1,080.46	$ 5,919.48
LDAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount			$ 75.04	$ 103.56	$ 126.76	$ 119.88	$ 104.67	$ 97.68	$ 627.59
Total Bill			**$ 1,313.72**	**$ 1,716.65**	**$ 1,837.16**	**$ 1,667.39**	**$ 1,654.06**	**$ 1,717.86**	**$ 9,906.84**
DIFFERENCE:									
Total Bill			**$ 806.91**	**$ 1,114.28**	**$ 1,571.41**	**$ 1,569.82**	**$ 1,204.51**	**$ 966.59**	**$ 7,233.51**
% Change			**61.42%**	**64.91%**	**85.53%**	**94.15%**	**72.82%**	**56.27%**	**73.02%**
Base Rate			$ (2.55)	$ (2.91)	$ (3.20)	$ (3.11)	$ (2.92)	$ (2.83)	$ (17.52)
% Change			-0.54%	-0.52%	-0.51%	-0.51%	-0.52%	-0.52%	-0.52%
COG & LDAC			$ 809.45	$ 1,117.19	$ 1,574.61	$ 1,572.93	$ 1,207.43	$ 969.42	$ 7,251.02
% Change			96.33%	96.33%	129.88%	148.01%	110.38%	82.28%	110.75%
check			$ -	$ -	$ -	$ -	$ -	$ -	$ -

May 1, 2021 - October 31, 2021

	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
Typical Usage (Therms)	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
Cust. Chg	$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
Headblock	$ 176.70	$ 176.70	$ 176.70	$ 174.90	$ 174.90	$ 156.89	$ 1,036.79	$ 2,500.19
Tailblock	$ 49.90	$ 12.85	$ 3.21	$ 2.50	$ 5.00	$ -	$ 73.46	$ 935.48
Total Base Rate Amount	$ 398.99	$ 361.94	$ 352.30	$ 348.59	$ 351.09	$ 328.08	$ 2,140.99	$ 5,500.75
COG Rate - (Seasonal)	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.4778
COG amount	$ 598.65	$ 451.09	$ 412.70	$ 409.90	$ 419.90	$ 358.71	$ 2,650.94	$ 8,570.42
LDAC	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
LDAC amount	$ 83.08	$ 62.60	$ 57.28	$ 56.89	$ 58.28	$ 49.78	$ 367.91	$ 995.50
Total Bill	**$ 1,080.72**	**$ 875.63**	**$ 822.28**	**$ 815.38**	**$ 829.26**	**$ 736.57**	**$ 5,159.83**	**$ 15,066.67**
DIFFERENCE:								
Total Bill	**$ 281.84**	**$ 211.73**	**$ 193.49**	**$ 195.17**	**$ 199.93**	**$ 170.80**	**$ 1,252.95**	**$ 8,486.45**
% Change	**26.08%**	**24.18%**	**23.53%**	**23.94%**	**24.11%**	**23.19%**	**24.28%**	**56.33%**
Base Rate	$ (3.20)	$ (3.05)	$ (3.01)	$ -	$ -	$ -	$ (9.26)	$ (26.78)
% Change	-0.80%	-0.84%	-0.86%	0.00%	0.00%	0.00%	-0.43%	-0.49%
COG & LDAC	$ 285.04	$ 214.78	$ 196.50	$ 195.17	$ 199.93	$ 170.80	$ 1,262.21	$ 8,513.23
% Change	41.81%	41.81%	41.81%	41.81%	41.81%	41.81%	41.81%	89.00%
check	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Off Peak 2022 Summer Cost of Gas Filing
Residential Heating

	Summer 2021	Summer 2022
Customer Charge	$ 15.50	$ 15.39
First 20 Therms	$ 0.5678	$ 0.5632
Excess 20 Therms	$ 0.5678	$ 0.5632
LDAC	$ 0.0589	$ 0.1444
COG	$ 0.5587	$ 0.5587
Total Adjust	$ 0.6176	$ 0.7031

		Summer 2021 COG @	Summer 2022 Cog @	Total		Base Rate		COG		LDAC	
				$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
		$ 0.6176	$ 0.7031	$ 0.09	14%						
Cooking alone	5	$ 21.43	$ 21.72	$ 0.29	1%	$ (0.13)	-1%	$ -	0%	$ 0.43	2%
	10	$ 27.35	$ 28.05	$ 0.70	3%	$ (0.16)	-1%	$ -	0%	$ 0.86	3%
	20	$ 39.21	$ 40.72	$ 1.51	4%	$ (0.20)	-1%	$ -	0%	$ 1.71	4%
Water Heating alone	30	$ 51.06	$ 53.38	$ 2.32	5%	$ (0.25)	0%	$ -	0%	$ 2.57	5%
	45	$ 68.84	$ 72.37	$ 3.53	5%	$ (0.32)	0%	$ -	0%	$ 3.85	6%
	50	$ 74.77	$ 78.71	$ 3.94	5%	$ (0.34)	0%	$ -	0%	$ 4.28	6%
Heating Alone	80	$ 104.41	$ 110.36	$ 5.96	6%	$ (0.45)	0%	$ -	0%	$ 6.41	6%
	125	$ 173.16	$ 183.81	$ 10.65	6%	$ (0.72)	0%	$ -	0%	$ 11.37	7%
	150	$ 193.31	$ 205.34	$ 12.03	6%	$ (0.80)	0%	$ -	0%	$ 12.83	7%
	200	$ 252.58	$ 268.65	$ 16.07	6%	$ (1.03)	0%	$ -	0%	$ 17.10	7%

Liberty Utilities (EnergyNorth Natural Gas) Corp.

2022 Summer Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
<u>Derivation of Class Assignments and Weightings</u>

Basic assumptions:
1 Residential class pays average seasonal gas cost rate (using MBA method to allocate costs to seasons)
2 Residual gas costs are allocated to C&I HLF and LLF classes based on MBA method
3 The MBA method allocates capacity costs based on design day demands in two pieces:
a The base use portion of the class design day demand based on base use
b The remaining portion of design day demand based on remaining design day demand
4 Base demand is composed solely of pipeline supplies
5 Remaining demand consists of a portion of pipeline and all storage and peaking supplies

Line				Column A	Column B	Column C	Column D	Column E	Column F
				Design Day Demand. Dekatherm	Adjusted Design Day Demand, Dt	Percent of Total		Avg Daily Base Use Load, Dt	Remaining Design Day Demand
1	RATE R-1-Resi Non-Htg			659	715	0.4%		103	613
2	RATE R-3-Resi Htg			66,114	72,399	42.2%		3,617	68,783
3	RATE G-41 (T)			28,689	31,499	18.4%		750	30,749
4	RATE G-51 (S)			2,361	2,534	1.5%		641	1,893
5	RATE G-42 (V)			36,728	40,301	23.5%		1,198	39,104
6	RATE G-52			5,125	5,490	3.2%		1,498	3,992
7	RATE G-43			9,793	10,710	6.2%		678	10,031
8	RATE G-53			5,922	6,346	3.7%		1,715	4,631
9	RATE G-54			1,495	1,608	0.9%		378	1,230
10									
11	Total			156,887	171,602	100.0%		10,577	161,025
12									-
13	Residential Total			66,773	73,115	**42.607%**		3,719	69,396
14	LLF Total			75,211	82,510	**48.083%**		2,626	79,885
15	HLF Total			14,903	15,977	**9.310%**		4,232	11,745
16	Total			156,887	171,602	100.0%		10,577	161,025
17									
18	C&I Breakdown								
19	LLF Total							2,626	79,885
20	HLF Total							4,232	11,745
21	Total							6,858	91,630
22									
23	C&I Breakdown Percentage								
24	LLF Total							38.291%	87.182%
25	HLF Total							61.709%	12.818%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$16,344,325	119,718	$11.3770			
30	Storage			$4,121,310	28,115	$12.2156			
31									
32	Peaking			$4,119,000					
33	Peaking Additional Costs (Concord Lateral Peaking x Differential)			$0					
34	Subtotal Peaking Costs			$4,119,000	23,769	$14.4412			
35	Total			$24,584,635	171,602	$11.9388			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,443,958	10,577	$11.3770			
39	Pipeline - Remaining			14,900,367	109,141	$11.3770			
40	Storage			4,121,310	28,115	$12.2156			
41	Peaking			4,119,000	23,769	$14.4412			
42	Total			24,584,635	171,602	$11.9388			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**42.607%**	615,228	4,506	$11.3770			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**42.607%**	6,348,623	46,502	$11.3770			
48	Storage	Line 40 * Line 13 Col C	**42.607%**	1,755,962	11,979	$12.2156			
49	Peaking	Line 41 * Line 13 Col C	**42.607%**	1,754,952	10,127	$14.4412			
50	Total		**42.607%**	10,474,751	73,114	$11.9388			
51									

Line	Description	Reference	%				Ratios for COG
52	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**						Updated Schedule 10A
53							Page 2 of 3
54	**2022 Summer Cost of Gas Filing**						
55	**Capacity Assignment Calculations 2020-2021**						
56	**Derivation of Class Assignments and Weightings**						
57							
58							**Ratios for COG**
59	C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
60	Pipeline - Base	Line 38 - Line 46		828,730	6,070	$11.3770	
61	Pipeline - Remaining	Line 39 - Line 47		8,551,745	62,640	$11.3769	
62	Storage	Line 40 - Line 48		2,365,348	16,136	$12.2157	
63	Peaking	Line 41 - Line 49		2,364,048	13,642	$14.4410	
64	Total		**57.393%**	14,109,870	98,488	$11.9388	**1.0000**
65							
66							
67	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
68	Pipeline - Base	Line 60 * Line 24 Col E		317,329	2,324	$11.3787	
69	Pipeline - Remaining	Line 61 * Line 24 Col F		7,455,589	54,610	$11.3770	
70	Storage	Line 62 * Line 24 Col F		2,062,160	14,068	$12.2154	
71	Peaking	Line 63 * Line 24 Col F		2,061,026	11,893	$14.4415	
72	Total		**48.3884%**	11,896,104	82,895	$11.9590	**1.0017**
73			38.291%	84%			(Line 72 / Line 64)
74							
75	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
76	Pipeline - Base	Line 60 - Line 68		511,401	3,746	$11.3766	
77	Pipeline - Remaining	Line 61 - Line 69		1,096,156	8,030	$11.3756	
78	Storage	Line 62 - Line 70		303,188	2,068	$12.2174	
79	Peaking	Line 63 - Line 71		303,022	1,749	$14.4379	
80	Total		**9.0047%**	2,213,767	15,593	$11.8310	**0.9910**
81							(Line 80 / Line 64)
82							
83	Unit Cost			Residential	LLF C&I	HLF C&I	
84							
85	Pipeline			$ 11.3770	$ 11.3770	$ 11.3770	
86	Storage			$ 12.2156	$ 12.2156	$ 12.2156	
87	Peaking			$ -	$ -	$ -	
88	Total			$ 11.9388	$ 11.9590	$ 11.8310	
89							
90							
91	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
92							
93	Pipeline			69.77%	**68.68%**	**75.52%**	
94	Storage			16.38%	**16.97%**	**13.26%**	
95	Peaking			13.85%	**14.35%**	**11.22%**	
96	Total			100.00%	**100.00%**	**100.00%**	
97							
98							
99	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
100							
101	Pipeline			42.61%	47.56%	9.84%	100.00%
102	Storage			42.61%	50.04%	7.36%	100.00%
103	Peaking			42.61%	50.04%	7.36%	100.00%

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 10A
2 Page 3 of 3
3 **2022 Summer Cost of Gas Filing**
4 **Correction Factor Calculation**
5
6

Ln		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		May	June	July	Aug	Sep	Oct	Sales
10								
11	G-41	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160
12	G-42	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140
13	G-43	179,740	73,660	58,680	59,440	100,920	204,000	676,440
14	High Winter Use	1,604,790	648,870	483,600	494,780	862,550	2,014,150	6,108,740
15								
16	G-51	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890
17	G-52	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290
18	G-53	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370
19	G-54	15,120	18,750	22,560	24,140	22,080	24,180	126,830
21	Low Winter Use	746,920	668,900	687,150	685,210	694,570	850,630	4,333,380
22								
23	Gross Total	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120

24
25

Ln			
26	Total Sales	10,442,120	
27	Low Winter Use	4,333,380	
28	Summer Ratio for Low Winter Use	**0.9910**	**Schedule 10A p 2, ln 80**
29	High Winter Use	6,108,740	
30	Summer Ratio for High Winter Use	**1.0017**	**Schedule 10A p 2, ln 72**

31
32 Correction Factor = Total Sales/((Low Winter Use x Winter Ratio for Low Winter Use)+(High Winter Use x Winter Ratio for High Winter Use
33 Correction Factor = **100.2748%**
34
35
36 **Allocation Calculation for Miscellaneous Overhead**
37

Ln		Period	Volume	Source
38	Projected Winter Sales Volume	11/1/21- 4/30/22	91,676,680	Sch.10B, ln 23
39	Projected Annual Sales Volume	11/1/21 - 10/31/22	115,042,810	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales		79.69%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. U[dated Schedule 10B
d/b/a Liberty Utilities Page 1 of 1
Off Peak 2022 Summer Cost of Gas Filing
2022 Summer Cost of Gas Filing

	Dry Therms														
Firm Sales							**Subtotal**							**Subtotal**	
	Nov-21	**Dec-21**	**Jan-22**	**Feb-22**	**Mar-22**	**Apr-22**	**PK 21-22**	**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**OP 22**	**Total**
R-1	68,340	87,950	100,820	86,060	85,740	64,450	493,360	51,360	38,850	33,950	34,160	38,040	51,620	247,980	741,340
R-3	6,259,770	9,415,520	10,967,410	9,270,440	7,794,900	4,711,810	48,419,850	2,667,890	1,294,670	1,005,090	1,028,340	1,719,640	4,100,280	11,815,910	60,235,760
R-4	454,380	670,430	779,980	661,890	559,780	360,860	3,487,320	203,890	100,540	76,380	75,540	119,390	284,380	860,120	4,347,440
Total Residential.	6,782,490	10,173,900	11,848,210	10,018,390	8,440,420	5,137,120	52,400,530	2,923,140	1,434,060	1,115,420	1,138,040	1,877,070	4,436,280	12,924,010	65,324,540
G-41	1,993,710	3,256,330	3,928,840	3,309,510	2,686,900	1,577,780	16,753,070	735,770	276,570	203,130	205,140	361,450	944,100	2,726,160	19,479,230
G-42	1,614,090	2,539,420	3,002,840	2,538,570	2,173,870	1,204,090	13,072,880	689,280	298,640	221,790	230,200	400,180	866,050	2,706,140	15,779,020
G-43	351,200	532,700	648,170	538,750	488,120	288,000	2,846,940	179,740	73,660	58,680	59,440	100,920	204,000	676,440	3,523,380
G-51	269,320	351,810	388,860	324,250	336,580	212,980	1,883,800	201,180	178,670	180,600	181,250	187,340	243,850	1,172,890	3,056,690
G-52	317,340	408,180	446,890	364,850	374,660	242,020	2,153,940	222,310	202,670	214,620	214,540	214,530	259,620	1,328,290	3,482,230
G-53	360,520	440,110	480,670	393,940	408,840	343,630	2,427,710	308,310	268,810	269,370	265,280	270,620	322,980	1,705,370	4,133,080
G-54	35,050	39,900	17,030	15,360	16,670	13,800	137,810	15,120	18,750	22,560	24,140	22,080	24,180	126,830	264,640
Total C/I	4,941,230	7,568,450	8,913,300	7,485,230	6,485,640	3,882,300	39,276,150	2,351,710	1,317,770	1,170,750	1,179,990	1,557,120	2,864,780	10,442,120	49,718,270
Sales Volume	**11,723,720**	**17,742,350**	**20,761,510**	**17,503,620**	**14,926,060**	**9,019,420**	**91,676,680**	**5,274,850**	**2,751,830**	**2,286,170**	**2,318,030**	**3,434,190**	**7,301,060**	**23,366,130**	**115,042,810**
Transportation Sales															
G-41	574,020	867,030	1,039,180	856,480	763,130	450,870	4,550,710	261,840	140,990	106,460	95,760	156,800	326,870	1,088,720	5,639,430
G-42	1,968,530	2,914,590	3,391,170	2,830,750	2,515,270	1,523,590	15,143,900	906,300	496,460	395,030	398,340	659,800	1,261,210	4,117,140	19,261,040
G-43	771,060	1,044,290	1,235,960	1,039,110	971,040	538,960	5,600,420	365,460	237,030	213,480	240,670	339,080	530,620	1,926,340	7,526,760
G-51	84,590	105,400	113,700	94,860	99,260	81,810	579,620	77,390	64,770	61,300	61,170	63,740	76,000	404,370	983,990
G-52	497,790	617,920	679,580	565,210	579,610	430,990	3,371,100	389,470	360,850	367,700	363,660	373,650	442,840	2,298,170	5,669,270
G-53	855,560	987,600	1,082,920	916,680	934,740	840,440	5,617,940	724,650	621,190	623,930	659,410	675,470	791,330	4,095,980	9,713,920
G-54	1,585,390	1,292,050	1,269,400	1,054,210	1,161,320	1,357,730	7,720,100	1,561,020	1,567,000	1,631,330	1,739,250	1,682,640	1,755,260	9,936,500	17,656,600
Total Trans. Sales	**6,336,940**	**7,828,880**	**8,811,910**	**7,357,300**	**7,024,370**	**5,224,390**	**42,583,790**	**4,286,130**	**3,488,290**	**3,399,230**	**3,558,260**	**3,951,180**	**5,184,130**	**23,867,220**	**66,451,010**
Total All Sales	**18,060,660**	**25,571,230**	**29,573,420**	**24,860,920**	**21,950,430**	**14,243,810**	**134,260,470**	**9,560,980**	**6,240,120**	**5,685,400**	**5,876,290**	**7,385,370**	**12,485,190**	**47,233,350**	**181,493,820**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Updated Schedule 11A
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Off Peak 2022 Summer Cost of Gas Filing
Normal and Design Year Volumes

Volumes (Therms) **Normal Year**

For the Months of May 22 -October 22

	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Off Peak May - Oct
Pipeline Gas:							
Dawn Supply	739,535	95,658	-	-	206,295	636,518	1,678,006
Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
TGP Supply (Gulf)	13,120	-	-	-	-	384,326	397,446
Dracut Supply 1 - Baseload	-	-	-	-	-	-	0
Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
Dracut Supply 3 - Swing	-	-	-	-	-	-	-
Constellation Combo	-	-	-	-	-	-	0
LNG Truck	44,883	18,131	-	-	55,566	20,602	139,181
Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
Portland Natural Gas	152,602	3,126	-	-	2,555	574,003	732,286
TGP Supply (Z4)	5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088	29,866,267
	7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177	38,263,081
Storage Gas:							
	-	-	-	-	-	-	0
Produced Gas:							
LNG Vapor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
Propane	-	-	-	-	-	-	0
	20,025	18,131	17,519	17,470	18,522	20,602	112,269
Less - Gas Refills:							
LNG Truck	(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
Propane	(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
TGP Storage Refill	(2,188,222)	(2,766,568)	(3,120,796)	(3,057,929)	(2,444,250)	(1,262,380)	(14,840,145)
	(2,312,514)	(2,856,598)	(3,190,268)	(3,127,208)	(2,573,265)	(1,364,677)	(15,424,530)
Total Sendout Volumes	4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** **Updated Schedule 11B**
2 **Page 1 of 1**
3 **Off Peak 2022 Summer Cost of Gas Filing**

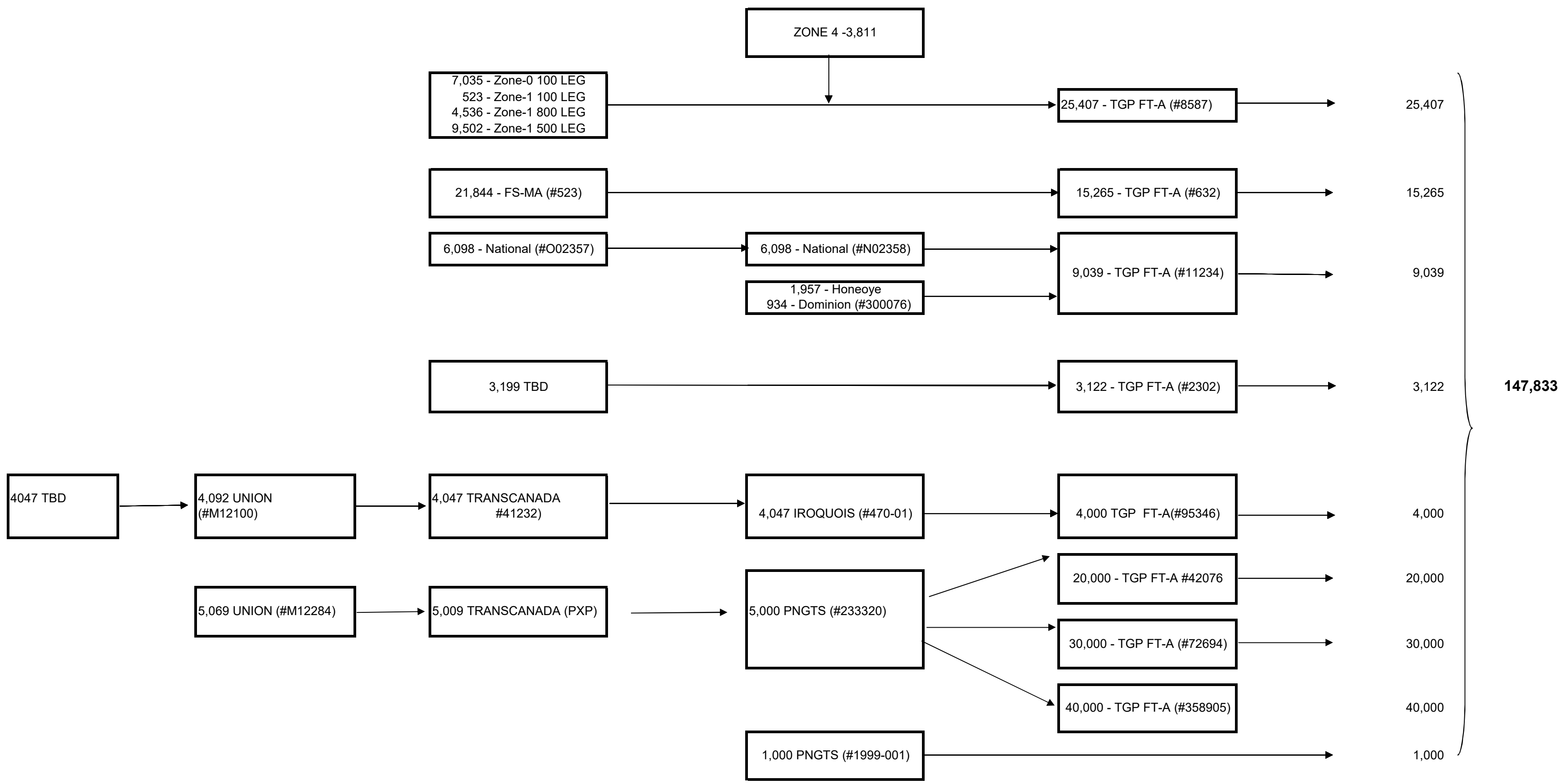
44 **Normal and Design Year Volumes**
45
46
47 **Volumes (Therms)** **Design Year**
48
49 **For the Months of May 22 -October 22**
50

51								**Off Peak**
52		**May-22**	**Jun-22**	**Jul-22**	**Aug-22**	**Sep-22**	**Oct-22**	**May - Oct**
53	Pipeline Gas:							
54	Dawn Supply	738,844	49,392	-	-	102,190	658,540	1,548,966
55	Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
56	TGP Supply (Gulf)	12,429	-	-	-	-	384,326	396,755
57	Dracut Supply 1 - Baseload	-	-	-	-	-	-	0
58	Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
	Dracut Supply 3 - Swing	-	-	-	-	-	-	-
59	Constellation Combo	-	-	-	-	-	-	0
60	LNG Truck	44,883	18,131	-	-	55,566	20,602	139,181
61	Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
62	PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
63	Portland Natural Gas	133,959	3,126	-	-	2,555	574,003	713,642
64	TGP Supply (Z4)	5,536,500	4,925,428	4,951,832	4,939,917	5,049,449	5,697,403	31,100,529
65	Subtotal Pipeline Volumes	7,419,517	5,755,086	5,683,400	5,680,904	6,051,547	8,758,514	39,348,969
66								
67	Storage Gas:							
68	TGP Storage	-	-	-	-	-	-	0
69								
70	Produced Gas:							
71	LNG Vapor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
72	Propane	-	-	-	-	-	-	-
73	Subtotal Produced Gas	20,025	18,131	17,519	17,470	18,522	20,602	112,269
74								
75	Less - Gas Refills:							
76	LNG Truck	(44,883)	(18,131)	-	-	(55,566)	(20,602)	(139,181)
77	Propane	(79,409)	(71,899)	(69,472)	(69,279)	(73,449)	(81,696)	(445,204)
78	TGP Storage Refill	(2,340,825)	(2,937,251)	(3,363,645)	(3,301,310)	(2,570,071)	(1,435,717)	(15,948,820)
79	Subtotal Refills	(2,465,117)	(3,027,282)	(3,433,117)	(3,370,589)	(2,699,086)	(1,538,015)	(16,533,205)
80								
81	Total Sendout Volumes	4,974,426	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,928,033

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								Updated Schedule 11C
2									Page 1 of 1
3	**Off Peak 2022 Summer Cost of Gas Filing**								
4	**Capacity Utilization**								
5	**Volumes (Therms)**								
6									
7		Off-Peak Period				Off-Peak Period			
8		Normal Year		Seasonal		Design Year		Seasonal	
9		Use	MDQ	Quantity	Utilization	Use	MDQ	Quantity	Utilization
10		(Therms)	(MMBtu/day)	(Therms)	Rate	(Therms)	(MMBtu/day)	(Therms)	Rate
11	**Pipeline Gas:**								
12	Dawn Supply	1,678,006	4,000	7,360,000	23%	1,548,966	4,000	7,360,000	21%
13	Niagara Supply	3,576,596	3,122	5,744,480	62%	3,576,596	3,122	5,744,480	62%
14	TGP Supply (Gulf)	397,446	21,596	39,736,640	1%	396,755	21,596	39,736,640	1%
15	Dracut Supply 1 & 2 & 3	436,185	50,000	92,000,000	0%	436,185	50,000	92,000,000	0%
16	LNG Truck	139,181	-	-	-	139,181	-	-	-
17	Propane Truck	445,204	-	-	-	445,204	-	-	-
18	PNGTS	991,910	1,000	1,840,000	54%	991,910	1,000	1,840,000	54%
	Portland Natural Gas	732,286	1,784	3,282,560	22%	713,642	1,784	3,282,560	22%
19	TGP Supply (Z4)	29,866,267	21,596	39,736,640	75%	31,100,529	21,596	39,736,640	78%
20	Other Purchased Resources	-		-		-		-	
21									
22	Subtotal Pipeline Volumes	38,263,081				39,348,969			
23									
24	**Storage Gas:**								
25	0	0		25,792,710	0%	-		25,792,710	0%
26									
27	**Produced Gas:**								
28	LNG Vapor	112,269				112,269			
29	Propane	-				-			
30									
31	Subtotal Produced Gas	112,269				112,269			
32									
33	**Less - Gas Refills:**								
34	LNG Truck	(139,181)				(139,181)			
35	Propane	(445,204)				(445,204)			
36	TGP Storage Refill	(14,840,145)				(15,948,820)			
37									
38	Subtotal Refills	(15,424,530)				(16,533,205)			
39									
40	Total Sendout Volumes	22,950,820				22,928,033			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing
Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MDQ MMBTU	MAQ * MMBTU	EXPIRATION DATE	NOTIFICATION DATE	RENEWAL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
Constellation	FCS		Firm Combination Liquid and Vapor Svc	Up to 7 trucks	630,000	3/31/2022 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2022	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2022	N/A	Terminates
Northern Transport	NA	NA	Trucking	28,500 Gallons	900,000 Gallons		N/A	Terminates
Dominion Transmission Incorporated	GSS	300076	Storage	934	102,700	3/31/2024	3/31/2022	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2023	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2023	3/31/2022	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2023	3/31/2022	Evergreen Provision
Iroquois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11/1/2022	11/1/2021	Evergreen Provision
Portland Natural Gas Transmission System	FT 1999-01	1999-001	Transportation	1,000	365,000	11/30/2032	11/31/2031	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	4,432	1,617,680	10/31/2040	10/31/2039	Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2028	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2022	11/30/2021	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2025	10/31/2024	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	358905	Transportation	40,000	14,600,000	10/31/2041	10/31/2040	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2026	10/31/2024	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	4,432	1,617,680	10/31/2040		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2023	10/31/2021	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	4,432	1,617,680	10/31/2040		Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** — Updated Schedule 13
2 Page 1 of 3

3 **Off Peak 2022 Summer Cost of Gas Filing**
4 **Storage Inventory**
5
6 **Underground Storage Gas**

Ln			May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Total
8			(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
9	Beginning Balance (MMBtu)		1,895,479	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	1,951,935
10									
11	Injections (MMBtu)	Sch 11A ln 39 /10	11,436	27,746	-	-	184,117	184,117	1,961,830
12									
13	Subtotal		1,906,915	1,929,391	1,929,241	1,929,241	2,113,358	2,297,475	
14									
15	Storage Sale		-	-	-	-	-	-	
16									
17	Withdrawals (MMBtu)	Sch 11A ln 29 /10	(5,270)	(150)	-	-	-	-	(1,368,064)
18									
19	Ending Balance (MMBtu)		1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,545,701
20									
21									
22	Beginning Balance		$ 9,092,272	$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 3,609,668
23									
24	Injections	ln 11 * ln 36	18,859	78,943	-	-	608,069	612,500	6,786,402
25									
26	Subtotal		$ 9,111,130	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 10,385,463	
27									
28	Storage Sale		$ -	$ -	$ -	$ -	$ -	$ -	
29									
30	Withdrawals	ln 17 * ln 34	$ (25,180)	$ -	$ -	$ -	$ -	$ -	$ (2,634,626)
31									
32	Ending Balance		$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 10,385,463	$ 7,761,444
33									
34	Average Rate For Withdrawals	ln 22 /ln 9	$ 4.7779	$ 4.7501	$ 4.7505	$ 4.7505	$ 4.6244	$ 4.5204	
35									
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$ 1.6490	$ 2.8452	$ -	$ -	$ 3.3026	$ 3.3267	

37 **Liberty Utilities (EnergyNorth Natural Gas) Corp.** Updated Schedule 13
38 Page 2 of 3
39 **Off Peak 2022 Summer Cost of Gas Filing**
40
41 **Liquid Propane Gas (LPG)**

Ln	Description	Reference	May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
44	Beginning Balance		93,824	93,828	94,844	94,844	94,844	94,844	96,655
45									
46	Injections	Sch 11A ln 38 /10	72	1,016	-	-	-	-	49,431
47									
48	Subtotal		93,896	94,844	94,844	94,844	94,844	94,844	
49									
50	Withdrawals	Sch 11A ln 33 /10	(68)	-	-	-	-	-	(61,632)
51									
52	Adjustment for change in temperature		-	-	-	-	-	-	-
53	Adjustment for Transfer		-	-	-	-	-	-	-
54	Ending Balance		93,828	94,844	94,844	94,844	94,844	94,844	84,454
55									
56									
57	Beginning Balance		$ 1,382,938	$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,193,497
58									
59	Injections	ln 46 * ln 69	1,061	13,101	-	-	-	-	168,840
60									
61	Subtotal		$ 1,384,000	$ 1,396,098	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	
62									
63	Withdrawals	ln 52 * ln 67	(1,002)	-	10,676	-	-	-	(763,126)
64									
65	Ending Balance		$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 599,211
66									
67	Average Rate For Withdrawals		$ 14.7397	$ 14.7199	$ 14.7199	$ 14.8325	$ 14.8325	$ 14.8325	
68									
69	Propane Rate for Injections	Actual or Sch. 6, ln 162 * 10	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Off Peak 2022 Summer Cost of Gas Filing

Ln	Liquid Natural Gas (LNG)		May-21 (Actual)	Jun-21 (Actual)	Jul-21 (Estimate)	Aug-21 (Estimate)	Sep-21 (Estimate)	Oct-21 (Estimate)	Total
76	Beginning Balance		7,885	5,928	10,583	10,583	10,583	10,583	12,057
78	Injections	Sch 11A ln 37 /10	797	6,395	-	-	-	-	136,806
80	Subtotal		8,682	12,323	10,583	10,583	10,583	10,583	
82	Withdrawals	Sch 11A ln 32 /10	(2,754)	(1,740)	-	-	-	-	(132,648)
84	Ending Balance		5,928	10,583	10,583	10,583	10,583	10,583	16,216
87	Beginning Balance		$ 34,430	$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 135,659
89	Injections	ln 78 * ln 99	3,480	24,011	-	-	-	-	653,097
91	Subtotal		$ 37,910	$ 49,896	$ 42,850	$ 42,850	$ 42,850	$ 42,850	
93	Withdrawals	ln 82 * ln 97	(12,025)	(7,045)	-	-	-	-	(825,208)
95	Ending Balance		$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ (36,451)
97	Average Rate For Withdrawals		$ 4.3665	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	
99	LNG Rate for Injections	Actual or Sch. 6, ln 161 * 10	$ 4.3665	$ 3.7546	$ 11.2630	$ 11.1000	$ -	$ -	

EnergyNorth Winter 2021/2022 Cost of Gas and Summer 2022 Cost of Gas
Summary of Changes from the Original filing to the Updated Filing

	WINTER RATE	WINTER IMPACT	SUMMER RATE	SUMMER IMPACT
Original Filing Residential COG Rates excluding GAP – R-4	**$ 0.9056**		**$ 0.5002**	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of $208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	$ 0.9034	$ (0.0022)	$ -	$ -
Pricing Update	$ 1.1339	$ 0.2305	$ 0.5587	$ 0.5587
Total Rate Change		**$ 0.2283**		**$ 0.5587**
Original Filing Residential GAP COG Rates – R-4	**$ 0.4981**		**$ 0.5002**	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of $208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	$ 0.4968	$ (0.0013)	$ -	$ -
Pricing Update	$ 0.6236	$ 0.1268	$ 0.5887	$ 0.5887
Total Rate Change		**$ 0.1255**		**$ 0.5887**
Original Filing G-4 rates	**$ 0.9058**		**$ 0.5007**	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of $208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	$ 0.9034	$ (0.0024)	$ -	$ -
Pricing Update	$ 1.1341	$ 0.2307	$ 0.5593	$ 0.5593
Total Rate Change		**$ 0.2283**		**$ 0.5593**
Original Filing G-5 rates	**$ 0.9041**		**$ 0.4994**	
Update Production & Storage Capacity Tab Pk Info and Rates Cell B29 to remove the portion that is attributable to Keene of $208,129. Found in the Settlement Agreement for DG 20-105 Exhibit 49, Bates page 005	$ 0.9017	$ (0.0024)	$ -	$ -
Pricing Update	$ 1.1324	$ 0.2307	$ 0.5580	$ 0.5580
Total Rate Change		**$ 0.2283**		**$ 0.5580**

*The Company has not changed the FPO Rate, as letters were issued prior to the market changes.

LDAC Adjustments				
Original Filing Total LDAC Rate	$	0.1733		
Updated Filing Total LDAC Rate	$	0.1444	$	(0.0289)
Removed the prior year decoupling adjustment				
1. Removed lines relating to the RDAF adjustment on Tab 'Pk Tab 19 RDAF Page 1'				
2. Removed tab 'Pk Tab 19 RDAF Page 4' as it was sole related to the RDAF Adjustment				
3. Renumbered Schedules to indicate 'page n of 3' instead of 'pg. n of 4'				
Updated the environmental rate calculation to exclude the Blue Chip invoice identified in the Environmental Audit.	$	0.1444	$	-
Total LDAC Rate Change			**$**	**(0.0289)**
Original Filing RDAF component of the Residential LDAC Rate	$	0.0459		
Updated Filing RDAF component of the LDAC Rate, this impacts residential only	$	0.0152	$	(0.0307)
Removed the RDAF Adjustments				
1. Removed lines relating to the RDAF adjustment on Tab 'Pk Tab 19 RDAF Page 1'				
2. Removed tab 'Pk Tab 19 RDAF Page 4' as it was sole related to the RDAF Adjustment				
3. Renumbered Schedules to indicate 'page n of 3' instead of 'pg. n of 4'				
Total LDAC Rate Change			**$**	**(0.0307)**
*This change resulted in a $0.0307 reduction in the LDAC rate and the RDAF Component of the LDAC rate				
Original Filing Environmental component of the LDAC Rate	$	0.0155		
Updated Filing Environmental component of the LDAC Rate, this impacts both Residential and Commercial	$	0.0155	$	-
Updated the environmental rate calculation to exclude the Blue Chip invoice for $1,062 identified in the Environmental Audit.				
Total Environmental Component Rate Change			**$**	**-**
*This change resulted in no change in the LDAC rate and the RDAF Component of the LDAC rate				
Original Filing GAP component of the LDAC Rate	$	0.0138		
Updated Filing GAP component of the LDAC Rate	$	0.0156	$	0.0018
This component changed due to the changes in COG rates				
Total GAP component Rate Change			**$**	**0.0018**
*This change resulted a $0.0018 increase in the LDAC rate and the RDAF Component of the LDAC rate				
Updated the environmental rate calculation to exclude the Blue Chip invoice identified in the Environmental Audit.				
Ties to total rate change for LDAC				