STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 22-___

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

Revenue Decoupling Adjustment Factor

DIRECT TESTIMONY

OF

ERICA L. MENARD

July 5, 2022

Liberty™

TABLE OF CONTENTS

I. INTRODUCTION 1
II. PURPOSE OF THE TESTIMONY AND SUMMARY OF REQUEST 2
III. OPERATION OF THE REVENUE DECOUPLING MECHANISM 12
IV. LOW-INCOME DISCOUNT RATE 16
V. REGULATORY PROCESSES AND APPROVALS FOR THE RDM 23
A. Intended Operation of the RDM 25
B. Initial RDM Tariff Provisions 28
C. First Compliance Tariff (June 11, 2018) 36
D. First RDAF Reconciliation (Docket No. DG 19-145) 43
E. Independent RDM Review 64
F. Second RDM Reconciliation (Docket No. DG 20-141) 66
G. Liberty Rate Case (Docket No. DG 20-105) 67
VI. REQUEST FOR RECOVERY OF THE UNDER-COLLECTION 69
VII. SUMMARY AND CONCLUSIONS 80

I. INTRODUCTION

Q. Please state your full name and business address.

A. My name is Erica L. Menard. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

Q. Please state by whom you are employed.

A. I am employed by Liberty Utilities Service Corp. ("LUSC") as Director, Rates and Regulatory Affairs. LUSC provides local utility management, shared services, and support to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or "the Company") and its regulated water, wastewater, natural gas, and electric utility affiliates.

Q. Please describe your professional and educational background.

A. I joined LUSC in March 2022. Prior to joining LUSC, I held various positions at Eversource Energy from 2003 to 2022. Most recently, I was the Manager of Revenue Requirements for New Hampshire responsible for the rate and regulatory filings presented to this Commission. I also held various positions at Eversource responsible for financial planning and analysis of operational and capital expenditures, business planning functions, sales forecasting, and performance management. Prior to my employment at Eversource, I was employed by ICF Consulting in Fairfax, Virginia, from 1997 to 2003 with responsibilities for implementing load profiling and load settlement software for various utilities worldwide. I hold a Bachelor of Arts in Economics and Business Administration from the University of Maine and a Master of Business Administration from the University of New Hampshire.

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

A. Yes, I have.

II. <u>PURPOSE OF THE TESTIMONY AND SUMMARY OF REQUEST</u>

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain that the Company has experienced a revenue under-collection of $4,023,830 through the Revenue Decoupling Mechanism ("RDM") approved in Order No. 26,122 (Apr. 27, 2018), as part of the Company's 2017 rate case, Docket No. DG 17-048. The revenue under-collection relates to the implementation of the RDM tariff that became effective November 1, 2018, and the interaction of the low-income discount rates made available to customers through the R-4 rate tariff and the rates for residential customers taking service under R-3 (without a low-income discount). Inadvertently, the tariff implementing the RDM gave conflicting directions for reconciling revenue targets with actual revenue collections for R-3 and R-4 customer classes for the annual decoupling cycle. These conflicting directives were sorted out and corrected in the Company's 2020 rate case, Docket No. DG 20-105. However, for the first two decoupling cycles -- 2018/2019 and 2019/2020 -- this internal conflict resulted in the inadvertent refund of $4,023,830 to customers through the RDM.

To unravel the circumstances that led to the revenue under-collection of $4,023,830, this testimony accomplishes three key objectives, which are: (1) to explain the sequence and chronology of the regulatory processes and approvals that caused the Company to under-collect revenues associated with the low-income discount provided to customers under the R-4 rate tariff; (2) to demonstrate that the Company is owed the amount of $4,023,830 from customers as a result of those regulatory processes and approvals; and (3) to explain the reasons that the Commission can and should allow the Company to collect the amounts due from customers over a reasonable time period.

This testimony concludes that, by operation of the approved RDM tariff language, revenues associated with the Company's low-income program were refunded to customers as part of the first two annual decoupling cycles of 2018–2019 and 2019–2020, although no refund was actually due. Although the low-income discount is meant to be provided to customers on a revenue neutral basis to the Company, the inadvertent interaction of the newly implemented RDM with the R-4 discount disrupted that revenue neutrality. Therefore, it is reasonable and appropriate for the Company to recover the amounts inadvertently and erroneously returned to customers during the annual decoupling cycles of 2018–2019 and 2019–2020, thus restoring revenue neutrality of the low-income program.

Q. Would you please summarize the circumstances that led to the revenue under-collection?

A. Yes. As my testimony explains, Liberty proposed a revenue decoupling mechanism in Docket No. DG 17-048. The RDM ultimately approved by the Commission differed from what the Company initially proposed and arose from a settlement reached between the Company and the Office of the Consumer Advocate ("OCA"). The Commission approved the RDM as described in the settlement and directed the Company to submit a compliance tariff to implement the RDM beginning November 1, 2018.

The purpose of the RDM is essentially to assure that the Company collects the base revenue requirement approved by the Commission in the Docket No. DG 17-048 rate proceeding, no more and no less, regardless of actual sales volumes. Because the RDM functions to collect the authorized revenue requirement independent of the amount of gas sold, the utility's ability to recover that revenue requirement between rate cases is preserved despite sales declines caused by energy conservation and energy efficiency initiatives. The Company's RDM operates in accordance with approved tariff provisions included as a component of the Company's Local Distribution Adjustment Clause ("LDAC").

From a simplified perspective, Liberty's RDM establishes revenue per-customer ("RPC") targets for each rate class, which are referred to as the "allowed" revenue targets. In the annual RDM reconciliation, the allowed revenue target for each rate class is compared to the actual revenues collected from customers in each respective rate class. The difference between allowed revenue targets and actual revenues collected is refunded to, or collected from, customers through the annual reconciliation process. Through this process, the Commission ensures that Company obtains recovery of the total authorized revenue, no more and no less.[1]

[1] This assumes Liberty's customer count does not change. Because Liberty's RDM is based on revenue-per-customer, Liberty's allowed revenue may increase if Liberty's customer count increases, and conversely, may decrease if the customer count falls. Accordingly, Liberty's revenues are "decoupled" from the quantity of gas sold, except that new customers will generate new revenues and a decrease in customers will cause a drop in revenues. Therefore, as part of the reconciliation process, attention is paid to the number of customers taking service in each rate class.

In this construct, it is imperative that the allowed revenue targets and the actual revenues collected are stated on a comparative basis for each rate class, e.g., R-3 revenue targets are compared to R-3 actual revenues, so that the differential between the allowed revenue target and actual revenues collected is truly the amount that should be refunded to customers, or recovered back from customers, as part of the annual RDM reconciliation. Assuring that this differential is correctly identified is necessary to assure that the Company is collecting the authorized revenue requirement, no less and no more.

This important goal was not achieved under the initially approved RDM tariff, NHPUC No. 10 Gas.[2] It was discovered that the reconciliation of revenues for the R-4 low-income class suffered from a mismatch embedded in the tariff between the allowed revenue target (which was based on the discounted rates) and the actual revenues collected (which was based on non-discounted rates). This improper comparison of the allowed revenue targets

[2] To avoid confusion, NHPUC No. 8 was the tariff in place at the time the Company filed its rate case in Docket No. DG 17-048; the Commission had NHPUC No. 8 in Docket No. DG 14-180. NHPUC No. 9 was the proposed tariff that accompanied the initial rate case filing in Docket No. DG 17-048, which the Commission suspended at the outset of that docket by Order No. 26,015 (May 8, 2017). After the Commission approved the DG 17-048 Settlement Agreement in Order No. 26,122 (Apr. 27, 2018), the Company's subsequent compliance filing was labelled NHPUC No. 10, *not* NHPUC No. 9, as would have been the custom. The Company essentially skipped NHPUC No. 9 due to the substantial changes in the tariff language that occurred during the course of the DG 17-048 rate case from the proposed and suspended, NHPUC No. 9 to the compliance tariff, labelled NHPUC No. 10. Note that the cover page of the compliance tariff filed on May 18, 2018, acknowledged this sequence:

NHPUC NO. 10 – GAS
LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
D/B/A
LIBERTY UTILITIES
SUPERSEDING NHPUC No. 8 AND IN LIEU OF NHPUC No. 9

NHPUC No. 9 was thus never in effect. Its relevance here is that NHPUC No. 9 contained the Company's initial RDM proposal, which, as described below, was substantially modified prior to being approved and included in NHPUC No. 10. The Commission approved NHPUC No. 11, the tariff currently in effect, in the Company's most recent rate case, Docket No. DG 20-105. NHPUC No. 11 contains adjustments to the RDM language that eliminated the issue addressed in this filing.

(discounted) to the actual revenues collected (non-discounted) yielded a refund to customers although no refund was due. This happened because the *discounted* revenue targets were naturally lower than the *non-discounted* revenues collected for the R-4 rate class, indicating that a refund was due to customers when – in fact – the allowed revenue targets were fundamentally out of alignment with the computation of actual revenues collected due to the mis-matched rates used in the calculation (discounted or non-discounted).

The RDM tariff should have directed the comparison of *non-discounted* target revenues to *non-discounted* actual revenues (or vice versa, discounted target revenues to discounted actual revenues), so that both sides of the comparison would have treated the R-4 rate discount in the same fashion. Instead, the mismatch made it appear that the actual revenues collected exceeded the allowed revenue target, therefore spurring the refunds to customers when reconciled in those cost of gas ("COG") dockets. For various reasons described below, the mismatch was not easily identified or remedied despite ongoing review and discussion among the parties through the two COG proceedings in 2019 and 2020 where the first two RDM reconciliations occurred.

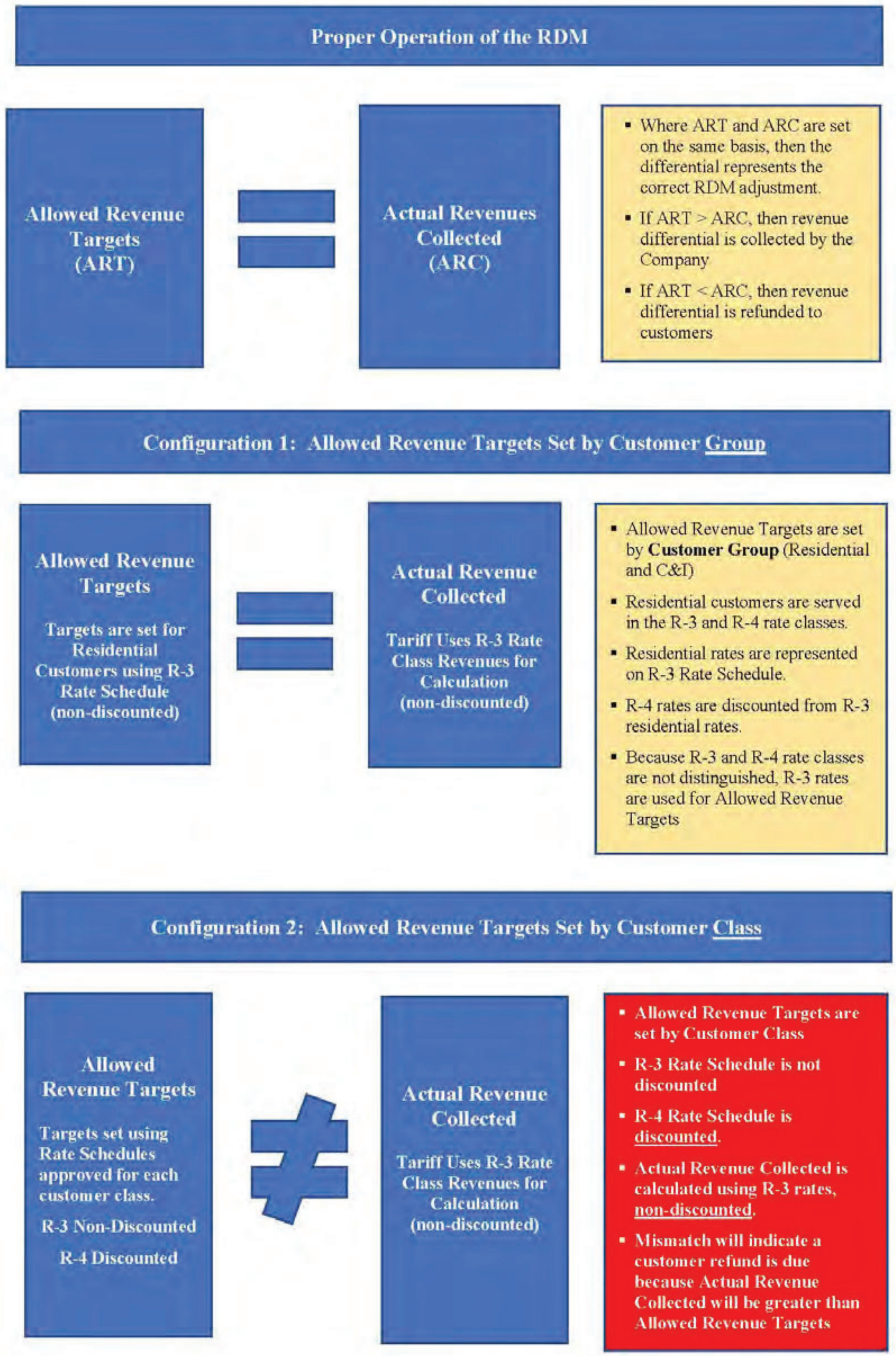
Q. What are the "conflicting directives" that were inadvertently established in the RDM tariff regarding the allowed revenue targets and actual revenues collected?

A. Again, the important factor is that the allowed revenue targets and actual revenue collections may be based either on non-discounted or discounted distribution rates, but the rates ***must be the same*** for both (i.e., one cannot be discounted while the other is non-discounted, or a mismatch occurs). Through the chain of events that occurred in relation to the Company's RDM tariff, an inadvertent mismatch arose involving *discounted* target revenues and *non-discounted* actual revenues. The mismatch arose from how the tariff language evolved as to whether: (1) the RDM tariff provisions *aggregated* R-3 (non-low-income) customers and R-4 (low-income) customers into a single category for purposes of developing the "allowed revenue target;" or, (2) the RDM tariff provisions created *separate* groups for R-3 and R-4 customers so that they would have separate allowed revenue targets. Where the tariff provisions *separate* these two rate classes, then the low-income discount applies to the allowed target revenues for the R-4 rate class, but not to the R-3 rate class. However, if these two customer groups are treated as *an aggregated whole*, i.e., as a combined residential customer group, then the R-3 and R-4 customers are treated exactly the same for purposes of setting the allowed revenue target. This difference matters because the RDM tariff very explicitly establishes that actual revenues collected are calculated based on the R-3 Rate Class, which are non-discounted revenues. Thus, to maintain comparability, the allowed revenue targets used in the RDM reconciliation should have been likewise *non-discounted*. However, this was not the case. Iterations of the RDM tariff provisions varied between the two approaches and, under the initially approved version of the tariff, the mismatch existed where the R-3 and R-4 rate classes are maintained in separate groups.

During the time the mismatch was unresolved, the Company, following the then-approved tariff language, issued refunds to customers as indicated by the RDM reconciliation process, totaling $4,023,830 over a two-year period. The RDM tariff provisions were revised in the Company's 2020 rate case, Docket No. DG 20-105, and the mismatch was eliminated on a going forward basis. However, the amount of $4,023,830 remains owed to the Company as an under-collection in the RDM. At bottom, the Company provided a low-income discount to the R-4 customer class in the 2018–2019 and 2019–2020 decoupling cycles but was prevented from recovering the matching discount revenues from all customers to maintain revenue neutrality. Instead, those revenues were inadvertently, and erroneously, refunded to all customers by operation of the then in effect RDM.

Q. Is it possible to provide a simplified illustration of the mismatch that occurred in the tariff provisions?

A. Yes. It is confusing and it has taken the Company some time to run this all to ground. However, the diagram presented below as Figure 1 depicts the mismatch. Figure 1 is also provided in Attachment ELM-1 at Bates 0087, which accompanies this testimony. As this testimony will explain, the approved RDM tariff implementing the RDM as of November 1, 2018, encompassed terms that drove a reconciliation consistent with the second scenario shown in Figure 1, below, embedding the mismatch in the computation of the annual reconciliation.


Proper Operation of the RDM
Allowed Revenue Targets (ART)
Actual Revenues Collected (ARC)
Where ART and ARC are set on the same basis, then the differential represents the correct RDM adjustment.
If ART > ARC, then revenue differential is collected by the Company
If ART < ARC, then revenue differential is refunded to customers
Configuration 1: Allowed Revenue Targets Set by Customer Group
Allowed Revenue Targets
Targets are set for Residential Customers using R-3 Rate Schedule (non-discounted)
Actual Revenue Collected
Tariff Uses R-3 Rate Class Revenues for Calculation (non-discounted)
Allowed Revenue Targets are set by Customer Group (Residential and C&I)
Residential customers are served in the R-3 and R-4 rate classes.
Residential rates are represented on R-3 Rate Schedule.
R-4 rates are discounted from R-3 residential rates.
Because R-3 and R-4 rate classes are not distinguished, R-3 rates are used for Allowed Revenue Targets
Configuration 2: Allowed Revenue Targets Set by Customer Class
Allowed Revenue Targets
Targets set using Rate Schedules approved for each customer class.
R-3 Non-Discounted
R-4 Discounted
Actual Revenue Collected
Tariff Uses R-3 Rate Class Revenues for Calculation (non-discounted)
Allowed Revenue Targets are set by Customer Class
R-3 Rate Schedule is not discounted
R-4 Rate Schedule is discounted.
Actual Revenue Collected is calculated using R-3 rates, non-discounted.
Mismatch will indicate a customer refund is due because Actual Revenue Collected will be greater than Allowed Revenue Targets

Q. What conclusions are demonstrated by this testimony?

A. My testimony supports the following conclusions:

- First, the mismatch between "allowed revenues" and "actual revenues" in the annual reconciliation process was the root cause of the inadvertent customer refund. The mismatch was not easily or immediately discernible as part of the initial implementation of the RDM in the first two decoupling cycles. For example, testimony submitted in the first of those COG proceedings by Commission Staff ("Staff")[3] advised a calculation change focusing on the *actual revenues collected*, whereas the mismatch lay in the *allowed revenue target*. The Company made Staff's recommended change in agreement with the parties in that docket, but the change did not correct the underlying, undiscovered mismatch.
- Second, it was the approved RDM tariff that directed the flawed method for calculating the allowed revenue target for the R-4 rate class. In performing the reconciliation, the Company followed the tariff provisions precisely; however, reliance on those tariff provisions created the undiscovered and inadvertent mismatch in revenues. Until the tariff terms were revised in the 2020 base-rate proceeding, the mismatch continued to occur.
- Third, both the RDM and the low-income discount rate are intended to maintain "revenue neutrality" in terms of recovering the Company's authorized revenue requirement. Specifically, the RDM operates to provide the Company recovery of

[3] Most of the Commission Staff members became part of the new Department of Energy as of July 1, 2021.

the authorized revenue requirement (no more and no less), even though sales units may be declining due to conservation and energy efficiency measures. Similarly, the low-income rate mechanism operates to, first, discount the distribution rate for R-4 customers and, second, collect the revenues associated with the discount from all other customers classes, again holding the Company neutral in relation to collecting the authorized revenue. As my testimony explains, the *simultaneous operation* of these two mechanisms inadvertently disrupted revenue neutrality when the approved tariff terms for each of these mechanisms were implemented in tandem for the first time.

- Fourth, there are precedents in New Hampshire in which similar numerical errors were resolved once the error was discovered. There is no legal or regulatory principle that allows the Commission to deprive the Company of revenues that are due for collection from customers under an approved set of rates and rate tariffs.
- Fifth, revenues collected through reconciling mechanisms are not subject to the prohibition on retroactive ratemaking. By their very nature, reconciling mechanisms are designed to allow for the going forward recovery of prior-period over- and under-collections, which is exactly what has occurred here.

Q. What is the Company's request in this proceeding?

A. Based on the information presented in this testimony, Liberty respectfully requests that the Commission authorize the Company to recover the RDM under-collection associated with the low-income discount totaling $4,023,830 over a two-year period through the Revenue

Decoupling Adjustment Factor ("RDAF"), which is commensurate with the timeframe of the under-collection itself.

Q. How is the remainder of your testimony organized?

A. Section I above was the Introduction. Section III describes the operation of the RDM in more detail. Section IV describes the operation of the Company's low-income discount rate mechanism for customers eligible to take service under the R-4 rate tariff. Section V explains the sequence and chronology of the regulatory processes and approvals that resulted in the tariff language which caused the Company to under-collect revenues associated with the low-income discount provided to R-4 customers due to operation of the approved RDM. Section VI demonstrates that the Company is owed the amount of $4,023,830 from customers as a result of those regulatory processes and approvals and the implementation of the RDM. Section VII discusses the reasons that the Commission can and should allow the Company to recover the amounts due over a reasonable amortization period. Section VIII summarizes the key elements of this testimony and the Company's request for authorization to recover the existing under-collection.

III. <u>OPERATION OF THE REVENUE DECOUPLING MECHANISM</u>

Q. Please summarize this section of your testimony.

A. In this section, I provide a brief overview of the intended operation of the Company's Revenue Decoupling Mechanism.

Q. What is revenue decoupling?

A. Revenue decoupling is a ratemaking mechanism that is designed to eliminate the dependence of a utility's revenues on system throughput (sales). Historically, a utility's revenues were a function of its sales. When customers consumed more, revenues increased, and when customers consumed less, revenues decreased. Consumption may be affected by a number of factors including weather, conservation, economic cycles, and other causes. The impetus for implementing revenue decoupling across the country is the drive to reduce energy consumption through energy efficiency initiatives and conservation measures to – in turn – reduce greenhouse gas emissions. In the 2005 through 2010 timeframe, energy conservation efforts ramped up significantly due to concerns about global warming and climate change. As a result, utility industry participants focused on the link between revenues and energy consumption and the fact that this linkage had the potential (if not the inevitability) to serve as a disincentive for utilities to invest in energy efficiency and demand management. Revenue decoupling was devised to eliminate those disincentives by allowing a utility to recover the base revenue requirement approved in its most recent base-rate proceeding – no more and no less – despite fluctuations or reductions in sales due to conservation.

Q. How does the implementation of revenue decoupling benefit customers?

A. Revenue decoupling benefits customers because it breaks the link between a utility's sales and revenues and thus removes the utilities' disincentives to invest in energy efficiency. Historically, if a utility invested in energy efficiency or encouraged its customers to do so, it was at its own financial risk because rates are traditionally set per unit of sales to recover the approved revenue requirement over an expected level of sales volumes. If sales volumes fall below the level expected in the design of base rates, the utility does not recover its authorized revenue requirement, regardless of any actions that it may take to manage costs. Therefore, utilities would be naturally disinclined to undertake initiatives like energy efficiency that would have a direct, negative impact on sales volumes. Revenue decoupling eliminates this disincentive and creates a situation in which utilities can support energy efficiency investments without experiencing a detrimental financial impact. "Decoupling eliminates certain perverse incentives for the Company to encourage usage of gas by its customers, by adjusting rates to ensure a certain level of recovery by Liberty." Order No. 26,122 at 54 (Apr. 27, 2018) (Order approving Liberty's decoupling mechanism in Docket No. DG 17-048).

Q. What support did Liberty present for its proposal to implement revenue decoupling in the 2017 distribution rate case?

A. In its initial filing in Docket No. DG 17-048, the Company submitted the pre-filed, direct testimony of Greg H. Therrien, Assistant Vice President with Concentric Energy Advisors, describing the status of revenue decoupling across the U.S. and presenting the design of the Company's proposed RDM and associated tariff provisions. Specifically, the Company proposed to add tariff provisions that would implement the RDM through Section 17(C.1) of the Local Distribution Adjustment Clause ("LDAC") tariff. The proposed language described the manner in which the Company would annually reconcile Actual Revenues to Target Revenues and then recover or return any difference through the Revenue Decoupling Adjustment Factor ("RDAF") in rates. Proposed Section 17(C.1) also described the documentation that the Company would provide with its annual RDAF filings. The new decoupling language was designed to replace the "Lost Revenue Adjustment Mechanism" or "LRAM" provisions in the LDAC tariff in its entirety. *See*, Exhibit 8 in Docket No. DG 17-048, the Direct Testimony of Gregg H. Therrien, at Bates 331 (Attachment ELM-1, Bates 0144). As I will document below, the Commission did not approve the Company's initially proposed RDM design and associated tariff provisions in that proceeding.

Q. Did the Company also submit evidence in its most recent rate case demonstrating the benefit of implementing revenue decoupling?

A. Yes. In the Company's most recent distribution rate case, Docket No. DG 20-105, the Company engaged a consultant to study the interrelation between revenue decoupling and energy efficiency penetration. The results indicated that, with surprising consistency, a utility's investment in energy efficiency increased by a significant amount immediately following the implementation of revenue decoupling. The study indicated that this was the case for selected utilities located throughout New England. The study also found that Liberty experienced similar increases in energy efficiency levels after the Commission approved its RDM in 2018. *See*, Exhibit 34 at Bates II-241 in Docket No. DG 20-105, FTI Consulting's July 31, 2020, "Evaluation of the Effects of Revenue Decoupling on Energy Efficiency Program Achievement" (Attachment ELM-1, Bates 0214).

IV. LOW-INCOME DISCOUNT RATE

Q. Please summarize the operation of the low-income discount rate mechanism.

A. The Company's qualifying residential low-income customers take service as part of the R-4 rate class and its applicable tariff provisions ("R-4 customers"). R-4 customers are for all relevant purposes the same as R-3 customers (the company's standard residential rate class) except that R-4 customers have the benefit of paying a distribution rate that is *discounted* as compared to R-3 customers. Prior to November 1, 2020, the low-income program was known as the Residential Low Income Assistance Program ("RLIAP"), which provided a discount of 60% on distribution rates for each month of the year, as compared to R-3 rates. Beginning November 1, 2020, the RLIAP was replaced by the Gas Assistance Program ("GAP"), which functions similarly to the RLIAP but provides for a 45% discount to both R-3 distribution rates and to gas supply rates, instead of the 60% RLIAP discount,[4] but only for the winter months of November through April. Under either the RLIAP or GAP, the revenues equal to the discount are not collected from R-4 customers (because those customers enjoy the benefit of the discount) but are instead collected from customers in all other rate classes to maintain revenue neutrality for the Company. The RLIAP and GAP were both designed to fully reimburse the Company for providing the R-4 discount so that, in the end, the Company received the same distribution revenue from R-3 and R-4 customers.

[4] *See*, DG 21-130, Exhibit 2, at Bates 015–016 (Updated Testimony of Simek/McNamara) (Attachment ELM-1, Bates 0271–0272).

In this case, the period during which the RDM under-collection occurred ended on October 31, 2019, while the RLIAP was in effect. Therefore, the discussion in this testimony focuses on the RLIAP structure for recovery of the discount provided to the R-4 customers.

Q. How many low-income customers does the Company serve?

A. As of April 2021, the Company estimates that there were 5,320 R-4 customers.[5] The number of R-4 customers fluctuates over time.

Q. Please describe the R-4 rate design.

A. The design for R-4 distribution rates is the same as for R-3 rates insofar as it includes a monthly customer charge and a single volumetric distribution charge that applies to all of a customer's usage in any given month.[6] The R-4 rates are identical to the R-3 rates; the R-4 rates are simply adjusted to apply the low-income discount.

Q. Who pays for the discount provided to the R-4 customers?

A. As I noted above, the low-income discount is socialized among all of the Company's customers, meaning that the revenues associated with the discount are *not* collected from R-4 customers, but are collected from all other customers through the RLIAP component of the LDAC. Each time the Company makes a COG filing, the Company calculates the value of the discount to be provided to R-4 customers during the upcoming period, then calculates an adjustment, or rate factor, that is applied to all other customers that enables the Company to recover the revenues equivalent to the value of the discount over the course

5 *See*, DG 21-130, Exhibit 2, at Bates 135 (Updated Testimony of Simek/McNamara, Schedule 19) (Attachment ELM-1, Bates 0391). As of May 2022, there were 6,195 R-4 customers.

6 R-3 and R-4 customers paid the same, non-discounted, cost-of-gas rate under the RLIAP.

of the year. In recent COG filings, that calculation has been included as Schedule 19 in the Company's submission.

Q. Please explain how the R-4 discount is recovered.

A. The LDAC is a reconciling mechanism that operates by tariff and is designed to enable the Company to recover certain costs and revenues outside of base distribution rates on a reconciling basis. Costs recovered through the LDAC include costs associated with the Company's energy efficiency programs, allowed rate-case expenses, and environmental costs related to the remediation of the Company's manufactured gas sites. Revenues collected through the LDAC also include the revenues equivalent to the discount provided to R-4 customers (to make the R-4 discount revenue neutral) and collections or refunds of revenue associated with the RDM reconciliation through the Revenue Decoupling Adjustment Factor ("RDAF").

Q. Please provide an example of how the RLIAP discount is recovered through the LDAC.

A. Table 1 below shows the Company's calculation of the rate at which the RLIAP was to be recovered for the period November 2018–October 2019, as shown in the Company's September 4, 2018, COG filing.[7] As indicated, the R-4 customer charge is reduced by $9.02 per month, a 60% discount, and the volumetric distribution charge is reduced by $0.3379/therm, which is also a 60% discount. Based on the Company's determination that the average annual usage for this customer class is 771 therms, the expected value of the

[7] *See,* Exhibit 2 in Docket No. DG 18-137, Schedule 19, at Bates 123 (Attachment ELM-1, Bates 0571).

annual discount to be provided to each R-4 customer is $368.69. It is this amount that the Company must recover through the LDAC for each R-4 customer. That is, the Company discounts each R-4 customer's bill by $368.69 through the discounted R-4 rate, then collects that same amount through the low-income component of the LDAC that is charged to all other customers.

At the time these calculations were submitted to the Commission there were 5,056 RLIAP customers, meaning that the total revenues due to the Company to neutralize the impact of providing the R-4 discount was $1,864,087 (5,056 x $368.69). Annual sales were forecasted to be 184,654,874 therms. Therefore, the rate required to recover the value of the R-4 discount from all other customers was $0.0130/therm ($1,864,087 / 184,654,874 therms).

Table 1. Calculation of RLIAP Discount Component of LDAC for November 2018 – October 2019

	Customer Charges	**Volumetric Charges**
R-3 Rates	$15.02/month	$0.5631/therm
Low-Income Discount	60%	60%
R-4 Rates	$6.00/month	$0.2252/therm
Discount Value in Dollars	$9.02/month	$0.3379/therm
Estimated Annual Usage*		771 therms
Discount Value (annually)	$108.24	$260.45
Total Discount Value (per customer, per year, on average)	$368.69	
Number of R-4 Customers	5,056	
Annual Cost of Discount	**$1,864,087**	
Total Annual Sales	184,654,874	
Recovery Rate	$0.0101/therm[4]	
*rounded		

Note: Numbers may not foot due to rounding.

This recovery rate was approved by the Commission in Docket No. DG 18-137 in its Order No. 26,188 (Nov. 1, 2018) (Attachment ELM-1, Bates 0641–0651) and was included in the LDAC rate beginning November 1, 2018.[8]

[8] Because the recovery of discounts to low-income customers in this manner relies on forecasted billing determinants, it is necessary to reconcile the value of the discounts actually provided to customers to the value of the discounts recovered through the LDAC on an ongoing basis. For purposes of simplicity, Table 1 intentionally omits the recovery that Liberty obtained during this period of $545,077, which was an un-collected balance from a prior period. Inclusion of that amount increases the rate by $0.0029/therm, to $0.0130/therm, which is the actual rate that was approved by the Commission in Order No. 26,188 and subsequently incorporated in the LDAC factor.

Q. Under the base-rate design and tariff provisions approved by the Commission in Docket No. DG 17-048, was the Company allowed to collect the same revenue from an R-4 customer as it did from an R-3 customer?

A. Yes. As stated above, R-3 customers and R-4 customers are the same for these purposes. Since R-3 and R-4 customers are treated the same for all purposes except for the R-4 discount, and since the usage of an R-4 customer is the same as the usage of an R-3 customer, then the same distribution revenue is to ultimately be collected from each of these customers. The difference is that a portion of the distribution revenue that the Company would otherwise collect from the R-4 customers instead flows through the LDAC because it is to be collected from all other customers as described above, which is not the case for any part of the revenue collected from R-3 customers. But again, the total revenue that the Company collects from an R-3 customer and an R-4 customer with identical usage should be the same.

Q. Would you please provide an example?

A. Yes. Using the same rates and volume assumptions shown in Table 1 above, I determined that an R-3 customer would generate revenues of $614.27 per year, which the Company would collect entirely through distribution rates. If the same customer took service under the R-4 tariff, the customer would generate only $245.58 in revenue annually, based on application of the R-4 rates which had been discounted by 60%. However, as I explained above, the Company would collect the difference between those amounts ($614.27 - $245.58 = $368.69, in this example) from all customers through the RLIAP portion of the

LDAC. When the RLIAP revenues from the LDAC are accounted for, the total revenues for R-3 and R-4 customers should match exactly.

Table 2. Revenue Collection from R-3 and R-4 Customers

	R-3	**R-4**	
Customer Rate	$15.02	$6.00	*a*
Volumetric Rate	$0.5631	$0.2252	*b*
Annual Usage*	771	771	*c*
Annual Customer	$180.24	$72.00	*d = a*12*
Annual Volumetric	$434.03	$173.58	*e = b*c*
Recovered through Base Rates	$614.27	$245.58	*f = d+e*
Recovery through LDAC	-	$368.69	*g (see, Table 1)*
Total Revenues	$614.27	$614.27	*h = f+g*
*rounded			

Note: Numbers may not foot due to rounding

Q. Why is this example important?

A. This example is important because it illustrates the central assumption embedded in the RDM reconciliation calculations that Liberty performed in accordance with the approved, albeit flawed, tariff. This presumption is that an R-3 customer and an R-4 customer *should be expected to generate different* levels of distribution revenue due to the R-4 customer paying only the discounted R-4 rate. This expectation of differing actual distribution revenue levels contributed to the root cause of the under-collection at issue in this proceeding. This difference in revenue is made up through the separate RLIAP provisions of the LDAC tariff, operating separately from distribution rates and separate from the

RDM. Thus, the RDM tariff provisions incorporated the expectation of *differing levels of distribution revenues* in setting the allowed revenue target for R-3 and R-4 customers. This presumption of expecting different revenue levels from R-3 and R-4 customers obscured the tariff's mismatched interaction of the lower R-4 allowed revenue targets and later use of non-discounted R-3 rates to calculate the actual revenues collected from all R-3 *and* R-4 customers.

V. <u>REGULATORY PROCESSES AND APPROVALS FOR THE RDM</u>

Q. Did the Company perform its calculations of the RDM in accordance with approved tariff provisions in both the 2018–2019 and 2019–2020 decoupling cycles?

A. Yes, the Company conducted its reconciliation in strict compliance with the approved tariff provisions in both proceedings. As shown below, the Company's clear adherence to the tariff provisions and collaboration with parties to the COG proceedings were all undertaken with the expectation that implementation of the RDM would result in the Company recovering its authorized revenue requirement each year thereafter and that the proposals, statements, and agreements by or among the parties clearly reflected the same expectation. Despite those efforts and intentions, and as discussed in this testimony, the result was the inadvertent and improper return of approximately $4 million to customers.

Q. Did the Company propose the RDM in the context of a base-rate proceeding resulting in the approval of governing tariffs?

A. Yes. As I previously noted in Section III above, the Company submitted a distribution-rate petition with the Commission on April 28, 2017, commencing Docket No. DG 17-048.

In that case, the Company submitted the Direct Testimony of Gregg H. Therrien proposing the design for a new revenue decoupling mechanism as a replacement for the LRAM. The Direct Testimony of David B. Simek presented the proposed NHPUC No. 9 tariff, which included language within the LDAC tariff that set forth the terms of the proposed RDM (at Part 17, Section C.1, Original Pages 35–39) (Docket No. DG 17-048, Exhibit 12) (Attachment ELM-1, Bates 0652–0657 and Bates 0961-0966).

Q. What was the LRAM?

A. The LRAM was a mechanism that allowed the Company to recover distribution revenue that was lost between rate cases as a result of the Company's authorized energy efficiency programs. The LRAM did not enable recovery to account for distribution revenue lost due other factors such as societal energy conservation, weather variations, or changes in economic conditions. In decoupling the Company's distribution revenues from its distribution sales, the RDM is designed to address the impact of conservation and other influences on sales volumes much more broadly than addressed by the LRAM, beyond that directly associated with the Company's energy efficiency programs. Thus, the RDM is a more comprehensive rate mechanism than the LRAM.[9]

[9] In the Energy Efficiency Resource Standard docket, DE 15-137, the Commission required utilities to propose decoupling, or another replacement for the LRAM: "the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before." Order No. 25,932 at 60 (Aug. 2, 2016) (Attachment ELM-1, Bates 0717). Liberty elected to propose its decoupling the following year.

A. Intended Operation of the RDM

Q. How is the RDM intended to operate?

A. At its core, the RDM is broadly designed to recover the total revenue requirement authorized by the Commission in a distribution rate proceeding. To accomplish this objective, the RDM measures the difference between the revenue requirement authorized for collection through distribution rates in the most recent rate proceeding and the revenue level actually collected in a given decoupling cycle. Any differences in the revenues allowed and revenues collected, positive or negative, would be reconciled through an "adjustment factor," the RDAF, so that the Company does not collect any more or less revenue than the total revenue requirement authorized by the Commission.

Q. Is a target set for recovery of the authorized revenues through the RDM?

A. Yes. To assure the Company recovers no more and no less than the authorized revenue requirement, a target level of revenues must be set based on the revenue requirement authorized by the Commission. With respect to Liberty's RDM, the target for authorized revenues was set *by customer class* using a Revenue Per Customer ("RPC") approach. Specifically, the number of customers then existing in each rate class was identified, along with the amount of revenue that needed to be collected from each customer (i.e., the revenue per customer, or "RPC") in the class to produce the class contribution to the overall, total authorized revenue requirement. The RPC remains fixed following the conclusion of the rate case and does not change unless or until the Commission authorizes a change in the authorized revenue requirement, which would normally occur in a step adjustment or subsequent distribution rate case.

Q. How is the RPC used in subsequent periods to operate the RDM?

A. In subsequent periods, the RPC remains fixed (unless or until the Company's revenue authorization changes) but the number of customers the Company serves typically changes from time to time. Under traditional ratemaking, the Company is allowed to keep the revenue produced by new customers taking service under the approved rate tariffs because adding customers inures to the benefit of all customers in future rate cases where fixed costs are spread over a larger base. The RDM is similarly designed to allow the Company to retain the benefits of new customers between rate cases. Under the RPC method, changes in the number of customers increases the Company's revenue but *do not* cause an over- or under-collection in relation to the revenue requirement authorized in the most recent rate proceeding.

Q. Would you please provide an example to illustrate this concept?

A. Yes. Assume that at the conclusion of a rate case, the Commission has determined that a utility's residential class included 10,000 customers and the class contribution to the authorized revenue requirement is $470,000. This would indicate an RPC of $47 per customer (i.e., $470,000 divided by 10,000 customers). In some future period, assume that the residential class has grown to 11,000 customers. The total amount the utility would be *allowed* to collect from that rate class would be the product of the RPC and the updated customer count, or $517,000 (i.e., $47 per customer times 11,000 customers).[10]

---

[10] The converse is also true. If the number of customers decreases, the Company's authorized revenue requirement would decrease.

In this way, the increase in revenue of $47,000 (or 1,000 times $47 per customer), does not count as an "over-collection" that would then be refunded to customers by operation of the RDM. Instead, the $47,000 becomes part of the "allowed revenue" in the computation of the reconciliation and the Company is able to keep that incremental revenue to offset the costs of adding the new customer until rates are reset in a distribution rate proceeding. In a future rate case, the new customers become part of the customer base and both the costs and revenues flowing from those customers will be counted in the authorized revenue requirement in setting new distribution rates.

Q. Are there alternatives to using the RPC method in establishing the RDM?

A. Yes, the primary alternative is to establish the allowed revenue target on a *company-wide basis*, whereby the overall authorized revenue requirement is set for the utility and the RDM operates to collect that total revenue amount regardless of whether the number of customers served by the utility has increased or decreased from the time rates were last set. In this model, the utility gets no credit for adding customers between rate cases. From an industry perspective, this total revenue-requirement method has generally (and widely) been implemented for electric companies, while the RPC method has generally (and widely) been implemented for gas companies. This is because gas utilities are in the business of adding new customers to the distribution system, either through conversion from an alternative fuel within its existing system footprint, or from expanding the system to reach new customers. Total Revenue RDMs do not encourage growth (and, in fact, discourage growth) because revenues received from new customer additions are in effect "refunded" to existing customers through the RDM.[11]

Q. Please explain how the RDM reconciliation is designed to work.

A. The RDM is designed to enable a comparison of allowed, or target, revenues with actual revenues *on a monthly basis*, identifying the differential for each month. At the end of each year, the monthly over- or under-collections are aggregated resulting in a total, net revenue adjustment that is either refunded to customers or collected from customers through the RDAF starting November 1 of the following year.

Q. Would you provide an example to illustrate this concept?

A. Yes. For November 1, 2018, the Company's target revenue from the R-3 rate class, based on the revenue requirement the Commission had just authorized in the recently concluded rate case, was $4,145,546. The customer count for the R-3 customer class at the time of the rate case was 71,747, so that the RPC was computed to be $57.78 per customer ($4,145,546 divided by 71,747).[12] This amount of $4,145,546 represented the contribution of the R-3 rate class to the total revenue requirement authorized in Docket No. DG 17-048.

B. Initial RDM Tariff Provisions

Q. Now that more experience with the RDM exists, what is the key clarification that determined whether the RDM tariff provisions created a mismatch between the

---

[11] *See*, Exhibit 27A in Docket No. DG 17-048 (Rebuttal Testimony of Gregg H. Therrien), at Bates 196 (Attachment ELM-1, Bates 0752).

[12] *See*, Exhibit 3 in Docket No. DG 19-145 (Revised Pages of Simek/McNamara Testimony w/Atts.) (Attachment ELM-1, Bates 1525).

allowed revenue target and actual revenue collections for the R-4, low-income eligible rate class?

A. As discussed at the outset of this testimony, the key clarification that is necessary to avoid the inadvertent mismatch is whether: (1) the RDM tariff provisions *aggregate* R-3 customers and R-4 customers into a single category for purposes of developing the "allowed revenue target;" or, (2) the RDM tariff provisions create *separate* groups for R-3 and R-4 customers so that they would have separate allowed revenue targets. If the tariff *separates* these two groups, then the low-income discount should apply to the allowed target revenues for the R-4 rate class, but not to the R-3 rate class. However, if these two customer groups are treated as *an aggregated whole*, i.e., as a combined residential customer group, then the R-3 and R-4 customers should be treated exactly the same for purposes of setting the allowed revenue target. Since this distinction was not identified until the Company's most recent rate case, Docket No. DG 20-105, the iterations of the tariff provisions varied between these two models without understanding the ramifications.

Q. Please describe the Company's proposed RDM, as submitted in the Company's initial rate filing in Docket No. DG 17-048.

A. In its initial filing in Docket No. DG 17-048, the Company submitted Mr. Therrien's pre-filed direct testimony to present the design of the Company's proposed RDM and associated tariff provisions. Specifically, the Company included language in proposed NHPUC No. 9 implementing the RDM through Section 17(C.1) of the LDAC tariff ("Initial Proposed RDM Tariff"). The Initial Proposed RDM Tariff described the manner in which the Company would annually true up "Actual Base Revenue" versus "Target Revenues," and recover or return the resulting difference through the RDAF in rates. Section 17(C.1) also described the documentation that the Company would provide with its annual RDAF filings.

Q. How did the Company's Initial Proposed RDM Tariff language in Section 17(C.1) define the manner in which the allowed revenue target and actual revenue collection would be established and reconciled?

A. The Initial Proposed RDM Tariff established the following definitions in Section 17(C.1.4):

a. **Actual Base Revenue per Customer** is the actual revenue derived from the Company's base rates divided by the Actual Number of Customers for a given season for a Customer Class Group.

b. **Actual Number of Customers** is the actual number of customers for the applicable Customer Class Group for the most recently completed Winter Season or Summer Season. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for bills for a given season for a Customer Class Group and dividing by the number of months in each Season.

c. **Customer Class** is the group of all customers taking service pursuant to the same Rate Schedule.

d. **Customer Class Group** is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment amounts. The three Customer Class Groups are as follows: (1) The Residential Non-Heating Customer Class Group (CG1) shall consist of all customers taking service pursuant to the Company's residential non-heating rate schedule R-1. (2) The Residential Heating Customer Class Group (CG2) shall consist of all customers taking service pursuant to the Company's residential heating rate schedules R-3, and R-4. (3) The Commercial and Industrial Customer Class Group (CG3) shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-51, G-52, G-53 and G-54.

Sections (e) and (f), omitted

g. **Benchmark Base Revenue per Customer** is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

See, DG 17-048, NHPUC No. 9, Attachment DBS-TARIFF-2, dated 4/28/2017, Original Page 36 (highlighting added) (Attachment ELM-1, Bates 0962).

As indicated by the plain language of these provisions, rate classes R-3 and R-4 were clearly and unambiguously ***combined*** as a "Customer Class Group." Further, the Benchmark Base Revenues (or "allowed" or "target" revenues) were set for the "Customer Class Group" on an aggregated basis. This treatment precluded any application of the low-income discount rate in setting the allowed revenue target because the low-income discount rate applies only to the R-4 customer class and would not be applied where the R-3 and R-4 customer classes are aggregated into a single "Customer Class Group."

Q. Did the Revenue Decoupling Adjustment Formulas included in the Initial Proposed RDM Tariff also contemplate that the reconciliation would be calculated on the basis of the "Customer Class Group?"

A. Yes. The RDAF formulas set forth in proposed DG 17-048, NHPUC No. 9, Attachment DBS-TARIFF-2, dated 4/28/2017, Original Page 37–38 (Attachment ELM-1, Bates 0963–0964) consistently use the term "applicable Customer Class Group" as the basis for each component of the equation, as follows:

$ACUSTS^{CG}_{T-1}$: The Actual Number of Customers for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1). Actual number of customers for each Winter or Summer Season shall be the average number monthly customers in that season, calculated by summing the number of equivalent bills in each month of the most recently completed Winter or Summer Season, and dividing by the number of months in the Season.

$ARPC^{CG}_{T-1}$: The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1), as defined in Section 4.0. For purposes of calculating the Actual Base Revenue per Customer, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.

$BRPC^{CG}_{T-1}$: The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section 4.0(A) for the most recently completed Winter or Summer Season (T-1).

This language precluded any application of the low-income discount rate in setting the allowed revenue target because the low-income discount rate applies only to the R-4 customer class and would not be applied where the R-3 and R-4 customer classes are aggregated into a single "Customer Class Group."[13]

See, DG 17-048, NHPUC No. 9, Attachment DBS-TARIFF-2, dated 4/28/2017, Original Page 36 (highlighting added) (Attachment ELM-1, Bates 0962).

Q. How did the Initial Proposed RDM Tariff describe the operation of the Revenue Decoupling Adjustment?

A. The Initial Proposed RDM Tariff described the operation of the annual Revenue Decoupling Adjustment, as follows:

> Revenue Decoupling Adjustment shall be determined by calculating the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer, and multiplying that difference by the Actual Number of Customers for the applicable Customer Class Group. The Revenue Decoupling Adjustment shall equal the sum of the

[13] Note that this language would have avoided the issue raised in this testimony because it specifically precluded use of the R-4 discount when calculating both the benchmark, or allowed, revenue and the actual revenue because it required both sides of the equation to use the non-discounted R-3 rate for R-4 customers.

> adjustments calculated for each of the three Customer Class Groups and shall include a reconciliation component.

See, DG 17-048, NHPUC No. 9, Attachment DBS-TARIFF-2, dated 4/28/2017, Original Page 36 (highlighting added) (Attachment ELM-1, Bates 0962).

Q. Was a settlement ultimately reached in Docket No. DG 17-048 on a proposed RDM mechanism?

A. Yes. Following the Company's initial filing, substantial discussion occurred in the docket in relation to a range of issues, including the Company's revenue decoupling proposal. In February 2018, the Company reached a settlement with the Office of the Consumer Advocate ("OCA"), a party to the proceeding, which was submitted to the Commission for approval on March 2, 2018 (the "Revised Agreement").[14] Among resolutions to other issues raised in the proceeding, the Settlement Agreement proposed a full decoupling mechanism using the RPC method. Commission Staff did not join the Settlement Agreement.

Q. Did the Revised Agreement adopt the Company's Initial Proposed RDM Tariff, as filed, or were changes contemplated in relation to the implementation of the RDM?

A. The Revised Agreement did not adopt the Company's Initial Proposed RDM Tariff provisions, as filed. However, Section II.F of the Revised Agreement did contemplate that the Company would implement a full decoupling mechanism comprised of the following elements: (1) real-time weather normalization, calculated at the individual customer level;

[14] Exhibit 29 in Docket No. DG 17-048, titled *Revised Agreement Regarding Permanent Rates* at Bates 010 (Section II.F) (Attachment ELM-1, Bates 1088). The revised agreement contained minor changes to the original agreement that had been filed a few days earlier.

(2) a revenue per customer design, with accrual calculations at the rate class level and billing rates *aggregated into two rates – Residential and Commercial & Industrial ("C&I)*; (3) Managed Expansion Program customers would be subject to decoupling, but the expansion surcharge dollars (i.e., the 30% distribution premium) would be excluded from the decoupling calculation; and (4) special contract customers will be excluded entirely from the decoupling calculation.

Thus, the Revised Agreement expressly contemplated that the RDM would take the form of an RPC model, with R-3 and R-4 customers *aggregated* into the "Residential" customer group.

More specifically, with respect to the details of applying the RPC method, Section II.F of the Revised Agreement stated that:

> [T]he annual revenue per customer adjustment will be determined by calculating the difference between actual annual distribution revenue per customer and approved annual distribution revenue per customer for two groups of customers: (a) the residential classes and (b) the commercial and industrial classes. Approved annual distribution revenue per customer for each of these two groups will be based on the approved distribution revenues and test year average customer counts for each group. The difference in total distribution revenues is calculated using this revenue per customer variance multiplied times the actual average annual customer count. This amount will be recovered from or refunded to each group over the subsequent 12-month period through a uniform charge per therm for each group

Exhibit 29 in Docket No. DG 17-048, at 11 (highlighting added) (Attachment ELM-1, Bates 1089).

Further, the Revised Agreement stated that the new decoupling mechanism would take effect beginning on November 1, 2018. On that date, the RDM would replace the LRAM and the Company would cease any and all recovery of lost revenues attributable to energy efficiency programs outside of the RDM. *Id.* at 11–12.

Q. Did the Commission approve the Revised Agreement?

A. No, not in its entirety. On April 27, 2018, the Commission issued Order No. 26,122, largely rejecting the Revised Agreement and instead authorizing a rate increase based on the Commission's own resolution of the underlying revenue-requirement issues. The Commission's decision on the proposed Revised Agreement also addressed other issues, such as rate design and revenue decoupling. Order No. 26,122, at 8 (Attachment ELM-1, Bates 1125).

With respect to revenue decoupling, the Commission approved the revenue decoupling proposal "in concept," subject to certain modifications "for clarity and to facilitate implementation." *Id.* at 45. Noting that the RDM was "slated for November 1 [implementation]," the Commission directed Liberty to file illustrative tariffs demonstrating the rates, terms, and conditions required to implement decoupling "in conformance with existing law," within 45 days of the date of the Order. *Id.* at 45–46. The due date for this compliance filing was June 11, 2018.

None of the modifications made by the Commission altered the RPC method outlined in Section II.F of the Revised Agreement for implementation of the RDM. *Id.*

C. First Compliance Tariff (June 11, 2018)

Q. Did the Company comply with Order No. 26,122 in relation to the revenue decoupling directives?

A. Yes. On June 11, 2018, the Company submitted a compliance tariff for the Commission's review to implement the RDM (the "First Compliance Tariff") (Attachment ELM-1, Bates 1200-1213). Specifically, the Company submitted "Attachment A," which presented revised tariff provisions for Section 17 of the Company's LDAC tariff. The revised LDAC tariff provisions in the First Compliance Tariff established the RDM and introduced the Revenue Decoupling Adjustment Clause ("RDAC") in Section 17(D), comprising the mechanism by which the Company's actual, collected revenues would be reconciled to its authorized, target revenues.

Q. What was the purpose of the RDAC, as stated in the First Compliance Tariff?

A. As indicated in the LDAC tariff submitted in the First Compliance Tariff (June 11, 2018), the purpose of the RDAC was to:

> [A]llow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its rates for firm gas sales and firm transportation in order to reconcile Actual Base Revenue per Customer with Benchmarked Base Revenue per Customer."[15]

[15] First Compliance Tariff, submitted June 11, 2018, at 2 (Attachment ELM-1, Bates 1200-1213).

Q. Did the specific tariff terms of the RDM carry over from the Company's initial tariff filed in Docket No. DG 17-048, to the First Compliance Tariff?

A. No. As stated earlier, the decoupling mechanism described in the Revised Agreement made certain changes to the Company's initial decoupling proposal and, thus, those changes had to be incorporated into the language in the First Compliance Tariff.

Q. How were the terms "Actual Base Revenue" and "Customer Class" defined in the First Compliance Tariff?

A. In the First Compliance Tariff, the use of the term "Customer Class Group" was maintained, but slight modifications were made to the definitions of "Actual Base Revenue" and "Benchmark Base Revenue Per Customer," in order to address a separate issue under discussion regarding customer counts. These wording changes inadvertently changed the basis of the RPC targets from "Customer Class Groups" to "Customer Class." Specifically, the definitions used in the First Compliance Tariff were as follows:

a. **Actual Base Revenue** is the actual revenue derived from the Company's distribution rates for a given Decoupling Year for a Customer Class. The Company will use monthly distribution revenues and Actual Number of Customers to determine the Monthly Actual Base Revenue per Customer.

> *As compared to the <u>Initial Proposed RDM Tariff</u>:*
>
> **Actual Base Revenue per Customer** is the actual revenue derived from the Company's base rates divided by the Actual Number of Customers for a given season for a Customer Class Group.

b. Actual Number of Customers is the actual number of Equivalent Bills for the applicable Customer Class for the applicable month of the Decoupling Year.

c. Billing Year is the 12-months commencing November 1 immediately following the completion of the Decoupling Year.

d. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

e. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment billing rates. The two Customer Class Groups are as follows:

Residential Customer Class Group (CG1): defined as both Residential Non-Heating Customer Class and Residential Heating Customer Class, shall consist of all customers taking service pursuant to the Company's residential rate schedules. CG1 shall include customers taking service under rate schedules R-1, R-3, R-4, R-5, R-6 and R-7.

Commercial and Industrial Customer Class Group (CG2): shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-44, G-45, G-46, G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

Sections f, g, and h, omitted

i. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

> *As compared to the <u>Initial Proposed RDM Tariff</u>:*
>
> **Benchmark Base Revenue per Customer** is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

As demonstrated by the highlighted text above, the precise wording of the First Compliance Tariff called for the Benchmark Base Revenue per Customer to be set by *Customer Class* rather than by *Customer Class Group*, thereby separating the R-3 and R-4 customer classes for purposes of setting the allowed revenue target. This change in language inadvertently required the allowed revenue target (or Benchmark Base Revenue per Customer) to be set individually for the R-3 and R-4 customer classes, which thus caused the low-income discount to be included in the target R-4 revenues.

Q. Did the Revenue Decoupling Adjustment Formulas included in the First Compliance Tariff follow the changes that were made to the definitions, as compared to the Initial Proposed RDM Tariff?

A. Yes. The Revenue Decoupling Adjustment Formulas set forth in the First Compliance Tariff consistently utilize the term "applicable Customer Class" as the basis for each component of the equation, as follows:

$ACUSTS_{T-1}^{CG}$: The Actual Number of Equivalent Bills for the applicable Customer Class for the most recently completed Decoupling Year (T-1)

AR_{T-1}^{CG}: The Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year, (T-1), as defined in Section 4(D). For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.

PC_{T-1}^{CG}: The Benchmark Base Revenue Per Equivalent Bill for the applicable Customer Class as determined in accordance with Section 4 (D) for the most recently completed Decoupling Year, stated on a monthly basis (T-1).

Moreover, as shown in the highlighted language, the definition of Actual Base Revenue specifically states that base revenues for the low-income R-4 customer class will be determined on the basis of *non-discounted* R-3 rates.

Although this language regarding the interplay of R-3 and R-4 revenue was included in the formula definition of Actual Base Revenue in both the Initial Proposed RDM Tariff and the First Compliance Tariff, there was no indication or recognition at this time that there was an embedded mismatch with the "Customer Class" language used in defining the Benchmark Base Revenue target in the First Compliance Tariff. The changes made between the Company's Initial Proposed RDM Tariff and the First Compliance Tariff were made to solve issues unrelated to the low-income discount rate or the specifics of computing revenue decoupling true-ups for the R-3 and R-4 customer classes. Therefore, the mismatch was not identified until it was time to put these definitions into use in the course of performing the first annual reconciliation the following year.

Q. What happened next, after the filing of the First Compliance Tariff on June 11, 2018?

A. As noted above, the Company submitted the First Compliance Tariff on June 11, 2018. Liberty contacted Commission Staff a week after the filing to arrange a meeting to discuss the compliance filing and obtain Staff's comments, as directed by the Commission. After the first agreed meeting date had to be cancelled, Staff did not provide Liberty with additional dates on which it could meet. Over the succeeding months, Liberty asked Staff for status updates on Staff's review of the compliance filing but received no substantive responses.[16]

On September 24, 2018, the Commission issued a letter stating it "has reviewed the illustrative tariff and believes additional information is needed concerning three issues." All three stated issues related to the Company's proposed "real-time weather normalization" proposal.

On October 1, 2018, the Company submitted a response to the Commission relating exclusively to the three issues raised on "real-time weather normalization" (Liberty Response to September 24 Secretarial Letter) (Attachment ELM-1, Bates 1214–1229).

Q. Did the Company submit revisions to the First Compliance Tariff before its implementation on November 1, 2018?

A. Yes. On October 1, 2018, in addition to submitting a response to the September 24

---

[16] Source: *Liberty Response to September 24 Secretarial Letter*, October 1, 2018, at paragraph 6 (Attachment ELM-1, Bates 1216).

Secretarial Letter, the Company submitted a "Revised Proposed Section 17" of the Company's tariff in clean and redlined form. None of the changes made to the First Compliance Tariff in this filing pertained to the definitions or formula section specific to the treatment of the R-4 Customer Class for purposes of determining Benchmark or Actual Base Revenue.

The Commission conducted a hearing on the proposed "Revised Proposed Section 17" RDM tariff provisions and related matters on October 19, 2018.

On October 22, 2018, the Company submitted a second "Revised Proposed Section 17," to incorporate edits proposed by Commission Staff (Attachment ELM-1, Bates 1230–1265). Again, none of the changes made to the First Compliance Tariff pertained to the definitions or formula section specific to the treatment of the R-4 Customer Class for purposes of determining Benchmark or Actual Base Revenue.

On October 31, 2018, the Commission issued a Secretarial Letter approving the Company's "Second Revised Proposed Section 17" as the RDM Tariff (Attachment ELM-1, Bates 1266–1267).

On November 2, 2018, the Commission issued Order No. 26,187 (Attachment ELM-1, Bates 1268–1283), formally approving the Second Revised Proposed Section 17. I will hereinafter refer to this as the "Approved RDM Tariff." In Order No. 26,187, at page 5, the Commission reviewed the history of changes to the proposed RDM tariff provisions, stating that:

> On June 11, 2018, Liberty submitted an illustrative tariff to implement decoupling, including real-time weather normalization, as directed in the April Order at 45-46. Liberty submitted an updated version on October 22, after receiving input from Staff and the OCA. At the October 19 hearing, Liberty agreed to make additional changes suggested by the Commission.

Further, the Commission approved the proposed RDM tariff provisions, stating:

> We reviewed Liberty's illustrative tariff filed on June 11 as well as the revised version filed October 22. We find that the October 22 tariff adequately describes the decoupling mechanism, including the real-time weather adjustment, **and we approve it.** We require Liberty to file a compliance version of this tariff within 15 days of this order.

Order No. 26,187, at 10 (emphasis added).

The Company submitted the Approved Decoupling Tariff on November 16, 2018 (Attachment ELM-1, Bates 1284–1329), in accordance with Order No. 26,187. The Company did not propose or make any changes to the RDM tariff provisions in the Approved Decoupling Tariff and the Approved Decoupling Tariff became the operative set of terms and conditions governing the RDM and RDAC computations.

D. First RDAF Reconciliation (Docket No. DG 19-145)

Q. What is a "Decoupling Year" and what period was covered in the first "Decoupling Year"?

A. The "Decoupling Year" is the 12-month period for reconciliation of target revenues and actual revenues collected (per the tariff, from September through August annually). As stipulated to in the Settlement Agreement, and as approved by the Commission, the first

Decoupling Year ran from November 2018 to August 2019.[17] The first reconciliation was performed on the basis of actual data ending August 31, 2019, and projected data for September and October 2019. Actual data for September and October 2019 was included in the reconciliation for the subsequent Decoupling Year.

Q. When did the Company reconcile the first Decoupling Year?

A. In September 2019, the Company submitted its annual Cost of Gas filing to set gas factors for the 2019–2020 COG year. The Company included the 2018–2019 RDM reconciliation in this COG filing. The Commission docketed the filing as Docket No. DG 19-145. Including the reconciliation with the COG proceedings made sense because any revenues recovered or refunded through the RDAF would become part of the LDAC, which has long been adjusted as part of the fall COG filing.

Q. What are the key comparative elements of the annual revenue adjustment calculation that drive the results of the RDM reconciliation?

A. There are two key comparative elements driving the results of the RDM reconciliation. First, the "Benchmark Base Revenue" is the revenue-per-customer or "RPC" target authorized by the Commission for each rate class in the distribution rate proceeding. In Section 4(a) of this testimony, I provided an example that illustrates how this value is calculated.

17 *See*, Order No, 26,122 (April 27, 2018) (Attachment ELM-1, Bates 1118-1199); Order No. 26,187 (November 2, 2018) (Attachment ELM-1, Bates 1268–1283); and original and revised settlement agreements as filed on February 27, 2018, and March 2, 2018, in DG 17-048 (Attachment ELM-1, Bates 1079–1117). The RDM took effect on November 1, 2018. In the Approved Decoupling Tariff, NHPUC No, 10 Gas Tariff, First Revised Page 35, at Section D.4.f, the ***first*** "Decoupling Year" is defined as November 1, 2018, through August 31, 2019, and each subsequent Decoupling Year is the 12 months commencing September 1 through August 31 of the next year.

Second, is Actual Base Revenue per Customer ("Actual Base Revenue"). The Actual Base Revenue constitutes the Company's actual revenue collections, which, according to the tariff, would be determined using "the actual revenue derived from the Company's distribution rates for a given Decoupling Year," as well as the actual number of customers that the Company served in a year.[18] Put another way, the Actual Base Revenue was designed to equal the Company's actual revenues for a given class during a year, divided by the actual number of customers served in the rate class during the same year.

Q. Does Actual Base Revenue include revenues from components charged to customers as part of the LDAC?

A. No. LDAC charges are not "distribution rates" and the tariff language specifically established that the revenue comprising the Actual Base Revenue would be generated exclusively by distribution rates.

Q. Earlier in your testimony, you explained that the Company is reimbursed for the revenues associated with extending the low-income discount to the R-4 rate class through the LDAC. That being the case, is the RDM designed to count the R-4 reimbursement revenues collected through the LDAC in the RDM?

A. No, the Approved Decoupling Tariff specifically states that "[f]or purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3."[19] As a result, the revenues associated with

---

18 *Id.*

19 Second Revised p. 37.

extension of the low-income discount rate to the R-4 customer class are already accounted for by virtue of the fact that the formula equation states that, for purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R-4 shall be determined based on non-discounted rate R-3.

Q. When did the Company first calculate the Benchmark Base Revenue?

A. The Benchmark Base Revenue targets were submitted to the Commission in September 2018, in advance of the implementation of the RDM on November 1, 2018, as part of the Company's COG filing in Docket No. DG 18-137.[20] The filed Benchmark Base Revenue targets for the R-3 and R-4 classes are shown below in Table 3.

Table 3. Benchmark Base Revenue Targets Submitted in Docket No. DG 18-137

	R-3				R-4		
	Customers	Target Revenue	Benchmark RPC		Customers	Target Revenue	Benchmark RPC
January	76,501	$6,925,912	**$90.53**		5,629	$191,604	**$34.04**
February	70,269	$6,006,068	**$85.47**		5,175	$163,736	**$31.64**
March	71,991	$5,267,976	**$73.18**		5,301	$153,105	**$28.88**
April	75,178	$3,465,023	**$46.09**		5,515	$109,479	**$19.85**
May	68,613	$2,308,483	**$33.65**		5,072	$66,579	**$13.13**
June	73,366	$1,894,274	**$25.82**		5,405	$56,646	**$10.48**
July	74,096	$1,686,231	**$22.76**		5,462	$50,195	**$9.19**
August	70,010	$1,601,723	**$22.88**		5,162	$48,023	**$9.30**
September	70,749	$1,797,279	**$25.40**		5,214	$51,492	**$9.88**
October	71,998	$2,621,900	**$36.42**		5,293	$74,427	**$14.06**
November	68,057	$4,000,612	**$58.78**		5,032	$112,783	**$22.42**
December	74,878	$5,910,427	**$78.93**		5,519	$166,171	**$30.11**

[20] *See*, September 4, 2018, Initial Filing of Winter 2018/2019 Cost of Gas and Summer 2019 Cost of Gas, Docket No. DG 18-137, Testimony of Simek/McNamara, Schedule 19, Bates 122 (Attachment ELM-1, Bates 1412).

Q. Why were the R-4 Benchmark Base Revenue targets lower than the R-3 Benchmark Base Revenue targets?

A. The Benchmark Base Revenue targets were developed in strict accordance with the definitions set forth in the Approved Decoupling Tariff, following these three steps:

1. LDAC Tariff, Section 17, Paragraph D.4.i, states that:

   Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

2. LDAC Tariff, Section 17, Paragraph D.4.d, states that:

   Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

3. The "distribution rates in effect at the start of the Decoupling Year" for the R-4 customer class are set forth in the R-4 Rate Schedule. The R-4 Rate Schedule establishes the distribution rates applicable to the low-income customer class. The R-4 Rate Schedule states that customers are subject to "Delivery Charge" for all therms used, which is discounted by 60% from the "Delivery Charge" for the R-3 Rate Schedule (i.e., all therms sold at $0.2201 rather than $0.5502).

The R-4 Rate Schedule for the R-4 customer class reflects discounted "delivery charges," set in the Company's most recent distribution rate proceeding. Thus, by definition of the Approved Decoupling Tariff, the R-4 Benchmark Base Revenues were to be set on a discounted basis.

Q. Did the Company's approach adhere to the RDM tariff provisions in the Approved Decoupling Tariff?

A. Yes. Strictly adhering to the approved tariff provisions produced Benchmark Base Revenue targets for the R-4 class that were 60% lower than the R-3 revenue target for the same month.[21] This is because the Approved Decoupling Tariff required the Company to set the Benchmark Base Revenue target for the R-4 rate class, reflecting the "distribution revenue level and approved equivalent bills" associated with the Company's most recent rate case. These rates are <u>discounted</u> for the R-4 class, as expressly shown in the R-4 Rate Schedule. Thus, the Company established the Benchmark Base Revenue for the R-4 customer class at the 60% discount to the R-3 customer class level.

Q. In preparing the first reconciliation in September 2019, did the Company recognize that there was a potential mismatch between the Benchmark Base Revenue target and the Actual Base Revenue?

A. Yes. As the Company was preparing the filing according to the tariff provisions, the results showed a relatively large over-collection of base revenues, which was not expected and appeared unusual. As the Company examined what could be causing the unusual differential, the Company identified that there was a mismatch occurring between the Benchmark Base Revenue targets and the Actual Base Revenue computation, which would make it appear that a refund was due to customers when it was not. Therefore, as part of the Company's initial filing in Docket No. DG 19-145, the Company explained that a

---

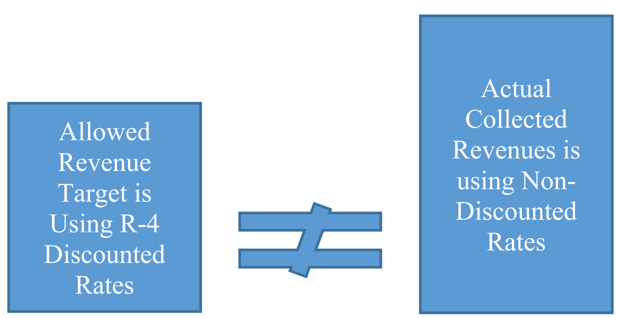
[21] Because of differences in consumption between R-3 and R-4 customers, the R-4 revenue targets are close to, but not exactly, 60% less than the R-3 revenue targets for each same month.

mismatch of revenues was occurring.[22] Specifically, Company Witnesses David Simek and Catherine McNamara explained as follows:

> The approved Benchmark Base Revenue per Customer calculation uses low-income residential heating revenue (rate R-4) in the calculation while the Actual Base Revenue per Customer calculation uses the residential heating rate (rate R-3) to calculate the rate R-4 revenue. In other words, the formulas in the tariff use the R-4 rate to calculate the benchmark R-4 revenue per customer and use the R-3 rate to calculate the actual R-4 revenue per customer.

<u>This statement summarized the issue succinctly and correctly</u>.

Illustratively, the Company attempted to alert the parties to the mismatch caused by the lack of a comparative basis between the Benchmark Base Revenue target and Actual Base Revenue, as defined in the tariff.



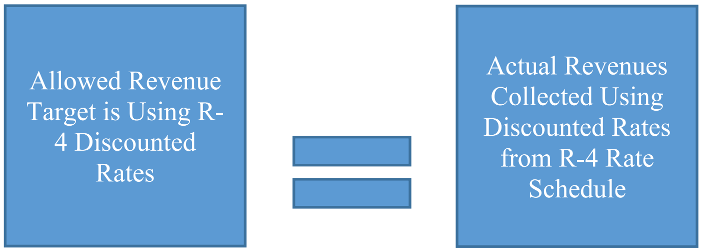
[22] Docket No. DG 19-145, Initial Filing of September 3, 2019, Initial Testimony of Simek/McNamara at 9–10, Bates 012 (Attachment ELM-1, Bates 1494).

Q. How did Company Witnesses Simek and McNamara address this situation in their testimony submitted in Docket No. DG 19-145?

A. In view of the relatively large revenue refund that resulted from strictly following the definitions and formulas in the Approved Decoupling Tariff, Company Witnesses Simek and McNamara developed an alternative RDAF calculation that would eliminate the mismatch by placing the Benchmark Base Revenue targets and Actual Base Revenue computation on the same, comparative basis. The Company then presented the two alternative computations in the reconciliation of the 2018–2019 Decoupling Year.

The first computation used the values derived from the definitions and formulas in the tariff, which meant that the R-4 discounted "delivery charge" was used to develop the Benchmark Base Revenue targets and the non-discounted R-3 rates were used to calculate the Actual Base Revenue collections for the R-4 customer class. This configuration is illustrated above and adhered strictly to the tariff provisions.

The second computation was developed to reflect the "intent" or proper operation of the RDM mechanism, meaning that they calculated both the Benchmark Base Revenue targets and the Actual Base Revenue collections *on a comparative basis*, using the R-4 customer class (discounted) delivery rates for the Benchmark Base Revenue targets and the actual R-4 revenues for the Actual Base Revenues. This computation reduced the refund due to customers for the first decoupling year to a level that would be more reasonably expected for an RDM reconciliation. Illustratively, this alternative configuration was:



Q. What were the specific results of the two alternative computations?

A. The results of the two computations showed that adhering to the tariff formula significantly overstated the size of the RDAF reconciliation, as shown in Table 4, below. When the Benchmark Base Revenue target is calculated using discounted R-4 rates and is reconciled against Actual Base Revenues calculated using the same discounted rate, the results indicate that the Company over-collected its authorized revenues for this class by only **18 percent**, or about $29,000, which would be returned to customers through the RDAF. Conversely, when the non-discounted R-3 rates are used to impute actual revenues and are compared to the discounted R-4 revenue targets as called for in the tariff equation, the calculation indicates that revenues were over-collected by **67 percent**, or about $268,000.

Table 4. Proposed Alternatives for RDAF Calculation for R-4[23]

	Comparative Inputs	Tariff Formula	
Customers	5,946	5,946	*a*
Benchmark RPC	$22.31	$22.31	*b*
Allowed revenue	$132,655	$132,655	*c = a*b*
Customer charge	$6.01	**$15.02**	*d*
Customer revenues	$35,735	$89,309	*e = a*d*

[23] The variation in the RPC figures between Table 3, the initially approved RPCs, and Table 4, the RPCs used the following year during the first reconciliation arises from the distribution rate adjustment that occurred as a result of the Cast Iron/Bare Steel filing earlier in 2018, Docket No. DG 19-054. *See,* Order No. 26,266 (June 28, 2019).

Sales volumes	566,467	566,467	*f*
Volumetric rate	$0.2228	**$0.5502**	*g*
Sales revenues	$126,209	$311,670	*h = f*g*
Actual base revenues	$161,944	$400,979	*i = e+h*
RDAF by dollars	($29,289)	($268,324)	*j = c-i*
RDAF by percent	18%	67%	*k = j/i*

Q. Did these alternative computations reveal a mismatch embedded in formula for the RDM reconciliation?

A. Yes. These alternative computations revealed, for the first time, that an inherent mismatch was created by the approved tariff language and that, by its operation, the tariff terms were effectively causing the Company *to provide the low-income discount twice*. However, at this juncture, the "mismatch" appeared to result from the fact that the delivery rates charged to customers by virtue of the approved R-4 rate schedule were discounted, but the formula for computation of the Actual Base Revenues in the Approved Decoupling Tariff expressly called for use of the non-discounted R-3 revenues to calculate the Actual Base Revenues for purposes of the RDM reconciliation. Thus, focus was centered on the use of the R-3 revenues for computation of the Actual Base Revenue collections, which appeared anomalistic given that the development of Benchmark Base Revenue targets is the first step of the sequence, and the targets were set on a discounted basis.

Therefore, with the alternative computation, Company Witnesses Simek and McNamara suggested that the actual (discounted) revenues for the R-4 customer class should be used to compute the Actual Base Revenues for the reconciliation rather than the actual (non-discounted) revenues for the R-3 customer class, which was not discounted.

Q. Did participants to the 2019 COG proceeding agree with the Company's recommendation to use the discounted R-4 rates to calculate the Actual Base Revenue collections for the RDM reconciliation?

A. No. During a technical session conducted on September 23, 2019, Commission Staff presented its opinion to the Company that the use of the (discounted) R-4 rates to calculate the Benchmark Base Revenue targets and the (non-discounted) R-3 rates to calculate Actual Base Revenue collections was correct, essentially because the tariff said so. Accordingly, Staff recommended that the Company use the "Tariff Formula" version of the calculations shown in Table 4, subject to a handful of additional minor updates.

Based on discussion with Commission Staff and other parties at the Technical Session, the Company agreed to revise and resubmit its initial filing, adjusting the schedules and testimonies to follow the Tariff Formula.[24] Although this approach appeared to perpetuate the mismatch between discounted allowed-revenue targets and non-discounted actual revenue collections, this approach did, in fact, follow the express provisions of the Approved Decoupling Tariff. Therefore, it became difficult for the Company to insist on a method that differed from the approved tariff provisions, despite the fact that the Benchmark Base Revenue targets and the Actual Base Revenue collections did not appear to be set on a comparative basis by the terms of the Approved Decoupling Tariff. However, Liberty submitted its revised filing on October 7, 2019.

[24] Docket No. DG 19-145, Revised Pages of Simek/McNamara at 8–9 (Attachment ELM-1, Bates 1504–1505).

On October 8, 2019, Commission Staff submitted pre-filed testimony presenting its "analysis of the [Revenue Decoupling Adjustment] related tariff issue the Company raised in its initial filing."[25] In relation to the mismatch suspected by the Company, Staff summarized its critique of the Company's initial filing, as follows:

- "Liberty believed that the calculations of actual revenue and allowed revenue for R-4 customers were not aligned with each other. Staff disagreed and explained the reasons to the company in a technical session."

Q. What reasoning did Staff provide for its recommendation?

A. Staff emphasized that the Company had erred in concluding that there was a mismatch embedded in the RDM reconciliation, stating:[26]

> Since the Company is already made whole for the discount offered to low-income (R-4) customers after revenue collected from the RLIAP charge is collected, Liberty's initial "adjustment" for R-4 customers overestimated compensation due to the Company by approximately 2.1 million dollars. Staff's analysis is consistent with the relevant tariff language which states that "For purposes of calculating the Actual Base Revenue, base revenues for Low Income rate class R4, shall be determined based on non-discounted rate R-3" when calculating the AR_{T-1} (Actual Base Revenue for the applicable Customer Class for the most recently completed Decoupling Year. See Tariff page 37). The intent of RDAF and tariff language match perfectly in this context.

Thus, Staff's conclusion was that the Company should not be making an "adjustment" to create a comparative basis for allowed revenue targets and actual revenue collections by discounting the Actual Base Revenue collections (AR_{T-1}) to match the discounted

---

[25] Testimony of Al-Azad Iqbal, Exhibit 5 in Docket No. DG 19-145 at 1 (Attachment ELM-1, Bates 1538).

[26] *Id.* at 3.

Benchmark Base Revenue target. Instead, Staff insisted that the Company should be following the Tariff Formula, which required the use of the R-3 rates when calculating the Actual Base Revenue collections for R-4 customers.[27]

Q. Was Staff's reasoning correct, arriving at the right resolution of the issue?

A. No, it was not. At the time, it was difficult for all parties involved to overcome the fact that the Company was operating in accordance with an Approved Decoupling Tariff and the "Tariff Formula" approach followed the approved tariff provisions precisely. In addition, perception of the mismatch was obscured by the fact that the Company was recovering the low-income discount through RLIAP, and these revenue collections were excluded from the RDM reconciliation. This fact is what appears to have obscured Staff's recognition of the apparent mismatch.

As shown in the statement quoted above from Staff testimony, it appeared to Staff that the Company's "adjustment" to place the Benchmark Base Revenue target and Actual Base Revenue collections on a comparative basis by discounting the R-3 revenues was resulting in "overestimated compensation" or double recovery of the low-income discount by $2.1 million. Stated another way, Staff's testimony indicates it viewed that, by discounting the R-3 revenues to calculate the Actual Base Revenue collections, the RDM was *erroneously giving the low-income discount amount back to the Company twice*, i.e., through the RDM reconciliation and through the RLIAP, thereby justifying the return of $2.1 million to customers. But, in fact, the $2.1 million revealed by using the "Comparative Inputs"

---

[27] *Id.* at 3.

belonged to the Company because the alternative analysis proved that the tariff provisions were compelling the Company *to give customers the low-income discount twice.*

Q. Is the Company contending that the provisions of the Approved Decoupling Tariff were flawed?

A. Yes. Adhering to the express language of the Approved Decoupling Tariff resulted in a miscalculation of the RDM reconciliation. The provisions of the Approved Decoupling Tariff inadvertently operated to require the Company to calculate the Benchmark Base Revenue target for R-4 customers using the discounted rate shown in the R-4 Rate Schedule, as approved in the most recent distribution rate case. These targets are lower than the targets for R-3 customers by the amount of the low-income discount, or 60%. Conversely, the provisions of the Approved Decoupling Tariff required the Company to use the non-discounted R-3 customer revenues to calculate the Actual Base Revenue collections, as succinctly described in Staff's testimony. As a result, discounted target revenues are compared to non-discounted actual revenues, falsely indicating the need for a refund to customers as part of the RDM reconciliation. Thus, the Company was effectively providing the same discount twice, once in the reduced rates charged to the R-4 customers per the R-4 Rate Schedule and a second time through the refund of revenues in the annual RDM reconciliation for 2018–2019 and 2019–2020.

Q. Would you provide examples that demonstrate these mechanics?

A. Yes, I have provided a series of simple calculations that demonstrate the problem with Staff's recommendation to adhere to the Tariff Formula. First, for reference, assume that in some month the Company serves 5,000 R-3 customers whose Benchmark RPC is $45/customer, meaning that the allowed revenue is $225,000. If the customer charge is $15/month, the volumetric charge is $0.50/therm, and monthly usage is 60 therms, the revenues for the class will be $225,000, meaning that there will be no RDAF adjustment.

Table 5. Indicative RDAF Calculations for R-3 Customers

Benchmark RPC	$45	*a*
Customers	5,000	*b*
Authorized revenues	$225,000	*c = a*b*
Customer charge	$15.00	*d*
Customer revenues	$75,000	*e = b*d*
Volumetric charge	$0.5000	*f*
Monthly use per customer	60	*g*
Volumetric revenues	$150,000	*h = f*g*
Actual base revenues	$225,000	*i = e+h*
RDAF adjustment	$0	*j = c-i*

Q. What does this result tell us about the R-4 customers?

A. When the calculations are expanded to recognize all of the Company’s actual revenues, including the recovery of the RLIAP discount through the LDAC, the result should be the same if Staff’s contention is correct. Recall that in Section IV, Table 2, I demonstrated how the Company’s revenue collections for an R-4 customer should be the same as the revenue for an R-3 customer with identical usage, once the LDAC revenues are considered.

Q. Would you provide an illustration of the perception that Staff held in relation to the first RDM reconciliation?

A. Staff's position, as I understand it, was that it is permissible to use the non-discounted Actual Base Revenue collections for these calculations because the revenues collected through the LDAC to recover the R-4 discount constitutes the "make whole" payment that is necessarily equal to the reduction in the authorized revenue from the lower Benchmark Base Revenue target. The example below reflects what I believe was Staff's perception. I have adjusted the calculation shown in Table 5 above by reducing the Benchmark Base Revenue target by 60% to make it applicable for reconciling the R-4 class, and also by calculating the value of the RLIAP payment from the LDAC.

Table 6. Indicative RDAF Calculations for R-4 Customers

Benchmark RPC	$27	*A*
Customers	5,000	*B*
Authorized revenues	135,000	*c = a*b*
Customer charge	$15.00	*D*
Customer revenues	$75,000	*e = b*d*
Volumetric charge	$0.5000	*F*
Monthly use per customer	60	*G*
Volumetric revenues	$150,000	*h = f*g*
Actual base revenues for ratemaking	$225,000	*i = e+h*
RDAF adjustment	($90,000)	*j = c-i*
<u>LDAC recovery</u>		
Value of customer charge	$6.00	*k = d*(1-60%)*
Customer revenues	$30,000	*l = b*k*
Value of volumetric charge	$0.20	*m = f * (1-60%)*

Volumetric revenues	$60,000	$n = g*m$
Total RLIAP recovery	$90,000	$o = l+n$
Total revenues	$225,000	$p = i+j+o$

Q. What is the result?

A. From these calculations, it appears that the 60-percent reduction in the Benchmark Base Revenue target creates a negative RDAF adjustment – a refund of revenues to customers – of $90,000, but that this amount is offset precisely by the Company's recovery of the RLIAP. If these calculations were accurate, the Company would collect $225,000, the same as was shown in the example for the R-3 customer.

Q. What is the inherent flaw in Staff's perceived solution?

A. The flaw is the assumption that the Company actually received all of the Actual Base Revenue. However, using the R-3 rates to calculate the Actual Base Revenue collections does not mean that the Company actually collected those revenues. In actuality, the Company collects only 40 percent of the revenues shown above at lines *e* and *h*. In Table 7 below, I have added a new line "p" to include an adjustment for the value of the discount that the Company provides to its R-4 customers.

Table 7. Indicative RDAF Calculations for R-4 Customers

Adjusted for Actual Revenues

Benchmark RPC	$27	*A*
Customers	5,000	*B*
Authorized revenues	135,000	*c = a*b*
Customer charge	$15.00	*D*
Customer revenues	$75,000	*e = b*d*
Volumetric charge	$0.5000	*F*
Monthly use per customer	60	*G*
Volumetric revenues	$150,000	*h = f*g*b*
ABRC revenues for ratemaking	$225,000	*i = e+h*
RDAF adjustment	($90,000)	*j = c-i*
<u>LDAC recovery</u>		
Value of customer charge	$6.00	*k = d*(1-60%)*
Customer revenues	$30,000	*l = b*k*
Value of volumetric charge	$0.20	*m = f * (1-60%)*
Volumetric revenues	$60,000	*n = g*m*b*
Total RLIAP recovery	$90,000	*o = l+n*
Adjustment for actual revenues	($90,000)	*p = -(e+h)*(1-60%)*
Total revenues	$135,000	*q = i+j+o+p*

Q. What is the result?

A. Tracking the Company's actual revenues through the various reconciliations in this manner reveals the source of the over-refund. Because of the mismatch in the rates used to calculate the Benchmark Base Revenue targets and the Actual Base Revenue collections, the Company will over-refund the R-4 class each month in an amount that is equal to the value of the discount that is provided to low-income customers.

Q. Is this what you meant earlier in your testimony when you indicated that calculations flowing from the terms of the Approved Decoupling Tariff effectively provided the R-4 discount twice?

A. Yes. The Company provides the low-income discount a first time in the form of the reduced rates at which it provides service to the R-4 customers. Then, the discount was essentially provided a second time through the RDM reconciliation because the Benchmark Base Revenue target includes a discount that is not reflected in the Actual Base Revenue collection, and therefore are set too low. The two discounts are offset by the RLIAP revenues the Company receives through the LDAC, but that revenue is received only once.

Q. Why did the Company agree to an incorrect solution in the 2018–2019 COG proceeding?

A. The Company did not know for sure at that time that the approach recommended by Commission Staff was, in fact, wrong. Again, the Company, Commission Staff, and other parties were attempting to construe the relevant provisions of the Approved Decoupling Tariff and it was difficult to come to the conclusion that the tariff provisions were just wrong. The Company and all other parties to the proceeding were dealing with a subtle flaw embedded deep within a new and complex mechanism. The Company was also engaging in good faith and with an open mind with the parties in an effort to identify compromises to disputed issues knowing that the RDM was of a reconciling nature and, thus, any necessary adjustments could be taken into account in future reconciliations.[28] At

[28] The Commission also recognized that the decoupling mechanism may need adjustments as the parties worked through its complexities. In approving the RDM, the Commission stated: "The settlement would have required Liberty

the time the Company revised its 2018–2019 COG filing, the Company had become convinced that following the provisions of the Approved Decoupling Tariff was appropriate and, certainly, that was the position of Commission Staff and other parties as well. When the Commission issued Order No. 26,306 approving the Company's revised filing, the Commission noted OCA's "appreciation" for Staff's effort in identifying the apparent "inaccuracies" in the Company's previous submission. All parties were acting in good faith to examine and resolve the first annual RDM reconciliation.[29]

Q. Is that to say that the Company has no responsibility for the accuracy of the filings it puts before the Commission?

A. No, it does not mean that. The Company is certainly responsible for each of its filings and neither the Commission nor any other party is responsible for validating the accuracy of any of the Company's submissions. In this instance, though, the circumstances around this filing are sufficiently unusual as to merit mention here. The mechanism is complex and there were several tariff iterations. As a result, the true nature of the mismatch was not identified by any party.

to file its next rate case using an historic test year no later than December 31, 2020, to reset test year revenues in light of the decoupling mechanism. 3/6/18 AM, Tr. at 57. We agree that such a reset is well advised and we adopt such a requirement in this order." Order No. 26,122 at 46.

[29] The Commission again recognized that the RDM may need further adjustment: "We also approve the Company's LDAC rates, including but not limited to the RDAF, as presented in the initial filing and revised in the October 8 filing, as just and reasonable. Because actual costs and revenues are reconciled every year, any adjustments needed as a result of further inquiry into the matters addressed in this order, including final audits, can be made in Liberty-EnergyNorth's COG filing for 2020-2021." Order No. 26,306 at 7.

Q. What was the total apparent overcollection caused by the mismatch embedded in the RDM reconciliation for the period November 2018–August 2019?

A. The total over-collection inadvertently returned to customers was $1,932,205.

Q. How is that amount calculated?

A. In its most recent COG filing with the 2020/2021 decoupling reconciliation, the Company submitted schedules with corrected calculations that provide the basis for comparison. Those schedules indicated that, for the period 2018–2019, the Company refunded a total of $7,016,791 through the RDM. Correction of the RDAF calculation to eliminate the mismatch I have discussed above indicates that the refund should have been $5,084,568.[30] The difference is $1,932,205.

Q. Aside from the calculations shown in those schedules, is there any way to validate the accuracy of the assertion that the amount of $1,932,205 was, in fact, an over-refund to customers?

A. Yes. As shown in the examples I have provided earlier in my testimony, particularly the example portrayed in Table 7, the error embedded in the RDM reconciliation mechanism will result in an over-refund equal to the value of the discount provided to the R-4 customers. This mathematical exercise demonstrates that the over-refund would be expected to be roughly 1.5 times the amount of the revenue from the R-4 customers at R-4 rates -- and this is exactly correct. The provided schedule indicates that, for this period,

[30] *See,* Docket No. DG 21-130, Exhibit 2 (Updated Testimony of Simek/McNamara, at Bates 014–015 and supporting attachments, Schedule 19, at Bates 128–131) (Attachment ELM-1 at Bates 0270–0271 and Bates 0384–0387, respectively).

the allowed base revenues for the R-4 class, calculated using R-4 rates, is $1,228,492. The over-collection of $1,932,205 is approximately 1.57 times that amount. Since some variation in the ratio is to be expected from the uncertainty of changes in month-to-month consumption that affect the relationship between Benchmark Base Revenue targets and the R-3 and R-4 rates, this result strongly supports my conclusion.

Q. Did the Company follow the specific terms of the Approved Decoupling Tariff during this entire period?

A. Yes, the Company adhered to the specific terms and formulas of the Approved Decoupling Tariff through the entire effort to develop and produce the 2018–2019 RDM reconciliation for examination by Commission Staff and other parties. As I explained earlier in my testimony, the Company calculated the RDM reconciliations in full compliance with every aspect of the tariff. However, a methodological flaw was inadvertently embedded in the terms of the Approved Decoupling Tariff, NHPUC No. 10, ultimately causing the results of the computations to be incorrect.

E. Independent RDM Review

Q. Was the Company taking other steps to evaluate the RDM around this time?

A. Yes. Liberty hired an outside consultant to conduct an audit of the RDM. Results of that audit were reported on August 8, 2019 (the "Audit Report").[31]

[31] The Audit Report was provided during the course of discovery and was attached to OCA witness Mr. Iqbal's direct testimony in Docket No. DG 20-105, marked as Exhibit 39, beginning at Bates 030 (Attachment ELM-1, Bates 1572).

Q. Why did the Company commission the audit?

A. The Company commissioned the audit because of unexpected financial results from the RDM. As the Audit Report explains, the Company experienced revenues that were $1.4 million lower than had been expected during the first seven months in which the RDM was in operation.[32] The revenue shortfall was attributable to several factors, including changes to customers counts arising, in part, from the reclassification of certain large customers after RDM was implemented; effects associated with an adjustment mechanism designed to account for changes in weather; and changes in customer consumption, among others factors.

Q. Did the advisors evaluate the Company's calculation of the Benchmark Base Revenue targets?

A. Yes. The advisors evaluated the Company's calculation of the Benchmark Base Revenue targets and determined that the Company's calculations were accurate.[33] The advisors did not make any reference to potential mismatches between the Benchmark Base Revenue targets and the computation of Actual Base Revenue collections. The reason for their omission is that the mismatch was a very subtle error, embedded within a new, complicated tariffed mechanism, which made it extremely difficult to identify and diagnose, even by experts. It was only in the course of actually preparing the RDM reconciliation that the nuances of the calculation began to emerge.

---

32 Audit Report, at 1.

33 Audit Report, at 4.

F. Second RDM Reconciliation (Docket No. DG 20-141)

Q. When did the Company next reconcile the RDM?

A. In September 2020, when the Company made its next COG filing in a proceeding docketed Docket No. DG 20-141, the Company presented its RDM reconciliation for the 2019–2020 RDM cycle (September 2019–August 2020). In this filing, the same mismatch existed between the Benchmark Base Revenue targets and the rates used to calculate the Actual Base Revenue collections and, again, the magnitude of the refund indicated a problem with the computations embedded in the tariff. However, several dynamics were occurring contemporaneously with this filing that precluded additional discussion in the 2020 COG docket on the anomaly existing within the Approved Decoupling Tariff.

For example, the COVID-19 pandemic caused distraction and disruption beginning in March 2020 and through the time of the Company's filing in September 2020. In addition, the Company was preparing to file a new base-rate case and the expectation of all parties involved was that the RDM tariff provisions would be revisited in that proceeding, which did ultimately occur. The Company's base-rate filing was submitted to the Commission on July 31, 2020.

On September 1, 2020, the Company submitted its Winter 2020–2021 and Summer 2021 Cost of Gas Filing to the Commission. The Commission approved the Company's requested COG, including the second reconciliation of the RDM, in Order No. 26,419 (Oct. 30, 2020) (Attachment ELM-1, Bates 1611–1621) without any discussion on the embedded tariff flaw.

Q. What was the total amount of the over-refund from the mismatch for the period September 2019 to August 2020?

A. The amount of the over-refund for the second Decoupling Year was $2,092,605, which was similar to the over-refund that occurred for the first RDM reconciliation in Docket No. DG 19-145. This would be expected because the value of the low-income discount would not be expected to vary materially from year to year, as it applies to base distribution rates.[34] This means that the total over-refund was $4,024,810 as of this time.

Q. Have you validated this result in the same manner in which you validated the estimate of the over-refund paid between November 2018 and August 2019?

A. Yes. During this period, the allowed revenue for the R-4 class, calculated using R-4 rates, was $1,329,427. The ratio of the over-refund to this amount is 1.57, exactly as it was for the prior year, thereby validating the nature of the error that occurred.

G. Liberty Rate Case (Docket No. DG 20-105)

Q. At what point did the Commission consider changes to the Company's tariff related to the operation of the RDM?

A. The provisions of the RDM were revisited during the course of the Company's most recent rate case, Docket No. DG 20-105, which was filed on July 31, 2020. There were at least two drivers that prompted this discussion in Docket No. DG 20-105. First, the Company recognized that an issue existed with the RDM, even if it was not yet definitively clear as

---

[34] *See*, Docket No. DG 21-130, Exhibit 2 (Updated Testimony of Simek/McNamara, at Bates 014–015 and supporting attachments, Schedule 19, at Bates 128–131) (Attachment ELM-1 at Bates 0270–0271 and Bates 0384–0387, respectively).

to what that issue was. By the time the rate case was concluded, the Company knew the refunds it was issuing were larger than should be expected and the Audit Report simultaneously identified a number of issues that Liberty was not aware of. At the same time, the financial impacts were continuing.

Second, the parties to the rate case agreed that the proceeding, which was the first rate case since the RDM was implemented, created a timely opportunity to consider refinements and improvements, as referenced by the Commission in the Order that approved the RDM in 2018, cited above. In particular, a settlement that was agreed to by the Company, Staff, and the OCA and filed with the Commission on June 30, 2021, indicated that clarifications of the sections of the Company's tariff that pertain to decoupling would be a priority (Attachment ELM-1, Bates 1622–1670).

Q. Did the Company subsequently file a Revised RDM Tariff in compliance with the Commission's directives in Docket No. DG 20-105?

A. Yes, on August 13, 2021, the Company filed an updated tariff in compliance with directives set forth by the Commission in Order No. 26,505 (Attachment ELM-1, Bates 1671–1829). The parties to the settlement in Docket No. DG 20-105 jointly developed the tariff changes for the specific purpose of alleviating the embedded mismatch discovered in relation to the reconciliation of the RDM. These directives were set forth in the Commission's final decision approving tariff changes in Order No. 26,505, issued on July 30, 2021 (Attachment ELM-1, Bates 1830–1846).

Q. Were any other changes made that related to ratemaking for the Company's low-income customers?

A. Yes. It was at this time that the Company replaced RLIAP with the GAP, a change that included a reduction in the twelve-month discount to distribution rates provided to low-income customers from 60% to a six-month winter period discount of 45% applied to distribution and gas supply rates.

VI. REQUEST FOR RECOVERY OF THE UNDER-COLLECTION

Q. Please summarize this section of your testimony.

A. In this section of my testimony, I explain why the Commission should approve the Company's recovery of the missing revenues. These reasons include the fact that the over-refund was the result of a good-faith error on a complex issue; that allowing for the recovery would be consistent with the clear intent of the decoupling mechanism to allow the Company to recover its authorized revenue requirement each year; and that there have been instances in New Hampshire in which errors of this sort have been corrected long after the fact.

Q. At what point did the Company determine it necessary to make a request to address the under-collection existing in the RDM?

A. As the Company approached preparations of the 2020–2021 COG filing in Docket No. DG 21-130, the Company finally had all the information necessary to ascertain that, in effect, there were "missing" revenues that should have been collected over the two-year period 2018 through 2020. The 2020–2021 COG filing was submitted on September 1, 2021, and the Company included a request for recovery of the $4 million in that proceeding because the COG process was the most appropriate venue for doing so. Further, because the RDM and other reconciliation mechanisms have generally been implemented through the LDAC, it made sense to recover this amount through the LDAC as well.

Q. In the course of updating the tariff and replacing RLIAP with GAP, did the Company also address the revenue mismatch?

A. Yes, as Company Witnesses Simek and McNamara explained in their Direct Testimony in the Company's most recent COG filing, the Company will no longer be using different rates to calculate the Benchmark Base Revenue targets and the Actual Base Revenue computation.[35]

Q. Did the Commission cite this heightened certainty as a factor in any of the other decisions reported in the order that approved the RDM in 2018?

A. Yes. In its order resolving the 2017 rate case, the Commission reviewed the positions of the parties regarding the Company's cost of capital and found that parties' consensus of a Return on Equity ("ROE") of 9.4% for ratemaking purposes was reasonable "with one important change." The Commission cited as evidence of that reasonableness the agreement of all parties that the 9.4% rate was appropriate, particularly given their sharp disagreements on other issues.[36] Notwithstanding this consensus among the parties, the

---

[35] *See*, Docket No. DG 21-130, Updated Testimony of Simek/McNamara, Exhibit 2, Bates 014–015 (Attachment ELM-1, Bates 0270–0271).

[36] Order No. 26,122, at 42 (Attachment ELM-1, Bates 1159).

Commission reduced the Company's ROE to 9.3% "to account for the decrease in risk [it] will experience under the approved decoupling mechanism."[37]

Q. Were there any other issues the Commission resolved in Order No. 26,122 that were based on its finding that the Company would recover its authorized revenue requirement with decoupling in place?

A. Yes. The Commission approved a proposed rate design that significantly reduced customer charges, seemingly based in large part on Staff's recommendation that "decoupling greatly increases the Company's ability to recover its fixed costs and therefore, we are comfortable with the significant decreases…."[38]

Q. Do these or other elements of the record in Docket No. DG 17-048 make clear the Commission's and the parties' expectations regarding decoupling as it relates to the Company's recovery of its authorized revenue each year?

A. Yes. The descriptions of the RDM and its design put forward by the parties repeatedly and consistently reflect their expectation that, with the RDM in place, the Company would earn its authorized revenue requirement each year.

Q. Would you cite some instances of statements made by the parties that support your conclusion?

A. The Company's original RDM proposal in Docket No. DG 17-048 indicated that authorized revenues should be reconciled on a per-customer basis via the RPC calculation

---

37 Id. at 43.

38 Id. at 48.

to ensure recovery of the authorized revenue amount, as I describe above. Staff's recommended modifications would have resulted in an RDM that accomplished the same objective, although Staff recommended an alternative to the RPC method and a few other modifications.[39] The OCA also initially recommended an alternative to the RPC method that would have again achieved the same objective, before later entering the Settlement Agreement with Liberty, which used the RPC calculations to recover the authorized amount.[40]

Q. Did Liberty collect its revenue requirement each year once decoupling was implemented in November 2018?

A. No. An error in the manner in which the RPC and reconciliation calculations were implemented prevented it from doing so, as I explain in the previous section of my testimony.

Q. Does it matter that the Company's decision to change its calculations in the 2019 COG docket, which first created the shortfall, was the recommendation of another party in that proceeding?

A. Yes, I think it does. It is not my position that the Company should be automatically granted recovery solely because the change in the calculation was recommended by another party, nor does the Company abdicate its responsibility for the accuracy of the work product it

[39] *See*, Exhibit 18 in Docket No. DG 17-048, Direct Testimony of Al-Azad Iqbal, at Bates 010 (Attachment ELM-1, Bates 1856).

[40] Exhibit 14 in Docket No. DG 17-048, Testimony of Ben Johnson, Ph.D., at Bates 14 (Attachment ELM-1, Bates 1937).

submits to this body, but I also think that the Commission should recognize that the manner in which the RDAF calculations were implemented is the result of a collaborative effort which, in this instance, resulted in an error, which I think justifies affording Liberty some flexibility. Moreover, it is my understanding that this Commission has a strong preference for engagement and collaboration by and among the parties that appear before it and denying recovery in this instance could have the effect of chilling collaboration in future proceedings.

Q. Is that to say that you think that fairness is an important consideration in this case?

A. I do. I am quite confident that fairness is a primary consideration in every decision this Commission renders – indeed, all decisions affecting rates are decided on the "just and reasonable" standard of RSA 378:7 – and so my assertion is not to suggest that the Commission's thinking about fairness as it considers Liberty's request would represent a major departure from the normal manner in which the Commission adjudicates cases. Rather, I make the observation because it seems to me that this case involves unusual circumstances and I think consideration of the fact that the Company seems to have acted correctly at every turn matters as does the fact that all the parties who have been involved in defining the RDM clearly intended for the Company to receive the money in dispute in this proceeding. Granting the Company's request is the only "just and reasonable" outcome here.

Q. Please explain your basis for that conclusion.

A. As I discuss at length earlier in my testimony, the records of the various proceedings in which the RDM was considered, approved, and subsequently reconciled are riddled with instances in which the parties clearly agree that the intent of the RDM is to allow the Company to recover the amount of revenue the Commission authorized. Now that the issue associated with the rates mismatch has been identified, evaluated, and fixed, it is beyond dispute that the calculations that were part of the prior RDAF tariff language, before it was fixed during the 2020 rate case, precluded that from happening. Those tariff changes, as well as the associated discussion during the recent rate cases, are themselves indicative of a clear consensus among the parties that the kind of mismatch that plagued early iterations of the RDM was neither intended nor desirable.

Q. Are you aware of any precedents for an after-the-fact correction to mitigate an unintended numerical error in New Hampshire that has resulted in the reconciliation of significant revenues?

A. Yes. I am aware of several instances in which that has happened. For instance, in the course of preparing its COG filing for Docket No. DG 18-137, the Company discovered that it had over-collected several years earlier, during Winter 2014/15, on Energy Efficiency-related costs that it had recovered through the LDAC.[41] The impact on rates when the Company returned the money was significant, lowering the LDAC by $0.0163/therm for Winter 2018/19, which resulted in savings to the average customer of

[41] *See,* Exhibit 3 in Docket No. DG 18-137, the Amended Technical Statement of David B. Simek and Catherine A. McNamara, at 1 (Attachment ELM-1, Bates 2032).

more than $10 per month. The Commission accepted and approved the correction years after-the-fact.

In two dockets of the Company's electric affiliate, Liberty Utilities (Granite State Electric) Corp. ("Granite State"), Granite State notified the Commission that it intended to investigate the beginning balances of several reconciling charges all the way back to the time Liberty acquired Granite State from National Grid in 2012. Granite State believed that the beginning balances that were being carried through these yearly reconciliation filings, and that were continuations of beginning balances inherited from National Grid, were inaccurate. The Commission encouraged the Company to pursue that investigation and to include the Commission's Audit Division in the work.

> Liberty plans to perform a complete audit of its over/under collected balance of transmission costs and stranded costs, starting with Liberty's acquisition of National Grid in 2012. According to Liberty, it will review revenues, expenses, and associated interest to determine an accurate over/under collected balance for use in next year's filing, including balances inherited from National Grid. Liberty testified that it had performed a similar review for its gas distribution affiliate, EnergyNorth Natural Gas, concerning over/under collections of gas costs.

Order No. 26,140 at 5 (May 1, 2018).

> Staff indicated full support of an audit of over/under collected balances by both Liberty and Commission Audit Staff, to achieve an accurate balance to be used in next year's filing.

Id. at 7.

> We support the goal of determining the correct over/under recovered balances for both transmission and stranded costs that the Company and Staff can agree on, to use as a starting point for next year's filing.

Id. at 9.

As a result of those investigations, Granite State discovered that the beginning balances related to reconciling energy service costs were off by $9 million, and the Commission approved the return of that $9 million to customers over a two-year period.

> Liberty testified that the ESAF and ESCRAF included several significant prior period adjustments which had been over-collected by more than $5 million. The adjustments were made to address issues that were discovered during an internal review of these accounts. Returning those over-collections to ratepayers serves to reduce the rates proposed in this case.
>
> ***
>
> Staff recommended that the Commission Audit Staff conduct an audit of the reconciliation accounts that feed into the ESAF and the ESCRAF, including a review of the various prior period adjustments that were made to these accounts, as described in this case.
>
> ***
>
> We authorize the Commission Audit Staff to conduct an independent audit of the ESAF and the ESCRAF and related accounts and balances in such timeframe as to allow the results of the audit to be reflected in next year's reconciliation filing.

Order No. 26,150 at 6, 7, and 8 (June 25, 2018).

> Liberty testified that in 2018, the Company had uncovered several prior period adjustments that amounted to a significant over-collection. Half of the over-collection, or approximately $4.6 million, is included in the reconciliation for the energy service period beginning August 1, 2019.
>
> ***
>
> … we approve the inclusion of the proposed reconciliation in rates, conditioned on Liberty further reconciling the results with Staff's audit.

Order No. 26,264 at 8 (June 24, 2019).

Granite State also discovered that the beginning balances related to the transmission and stranded costs were off by $900,000 in Granite State's favor, and the Commission approved Granite State's recovery of that $900,000.

> Q. And then Line 2 has a footnote that -- I'm sorry. Line 2 has a figure of another $901,710. That would be an additional under-collection; is that right?
>
> A. (Simek) Correct.
>
> Q. And the footnote references the accounting records and the audits. Could you just explain a little bit more what that means.
>
> A. (Simek) Yes. In last year's hearing, we were ordered to work with PUC Audit Staff to actually calculate what our beginning balances should be for this filing and going forward. And in doing so, the outcome of the audit shows that the May 18 beginning balance is consistent with what was audited and that it should have been adjusted by the 901,710.

Transcript of 5/9/19 hearing, at 21–22; *see* Schedule DBS-3, Bates 046;

> Liberty stated that, over the course of the past year, it completed an audit of its over/under collection balance of transmission costs (and stranded costs) starting with Liberty's acquisition of Granite State Electric Company from National Grid in 2012, as required by Order No. 26,140 (May 31, 2018). According to Liberty, the over/under collection balances for stranded costs and transmission costs presented in its filing reflect Liberty's books and records.

Order No. 26,243 (Apr. 30, 2019).

These investigations of Granite State's beginning balances back to the 2012 transition from National Grid followed similar work performed on several COG accounts for EnergyNorth:

> Q. And, were there any findings from that audit?

> A. (Simek) The major finding that came out of that audit is related to the beginning balances, the difference between the beginning balances that the Company shows on its General Ledger and the beginning balances that we had showed in our filings for the three regulatory accounts.
>
> This has been an issue that's been ongoing back to National Grid days. But I had committed to Audit Staff to have this issue resolved by the end of this month. So, going forward, we will be having the filings' beginning balances and the General Ledger will tie.

Transcript of April 23, 2015, hearing in Docket No. DG 15-091 (Summer 2015 COG) at 16–17.

Q. Are there instances involving other utilities that you are aware of?

A. Another probative example occurred in Re Northern Utilities, 80 NH PUC 721(Nov. 6, 1995), in which Northern Utilities made a retroactive billing adjustment: "The undercollection occurred because Northern's Rate Department had inadvertently failed to change billing rates on the January 1, 1995 effective date the Commission had authorized Northern to collect the Business Profits Tax in its rates." *Id.* at 721. The new rate should have been in effect for a six-month period of time. In response to learning of this adjustment, the Commission opened a docket "to consider utility authority to bill customers retroactively." *Id.* After receiving comment from many parties, the Commission ruled as follows:

> [U]tilities are entitled to collect their tariffed rates though they ought to collect them in a timely manner. When a utility erroneously fails to bill the tariffed rates on the effective date authorized, then, depending on the circumstances, corrective billing is the appropriate remedy in an amount and manner approved by the commission.

80 NH PUC at 723.

Q. In each of your examples, rates were changed to reconcile for events in some past period. Are these therefore instances of retroactive ratemaking?

A. No, there was no concern regarding "retroactive ratemaking" in these cases because the Commission was not retroactively changing rates, it was allowing the utility to collect the previously approved rates that were not timely collected in the normal course. The same is this case with Liberty's requested recovery of the existing RDM under-collection. Each of these instances involves an update that corrects an error or resolves and ambiguity in ways that result in outcomes that align with the intent of the original ratemaking order. Here, the parties all agreed that the RDM should facilitate the Company's ability to earn its authorized revenue each year and that reconciliation via the RDAF is the means to that end. The computation error that was unknowingly embedded in the RDAF mechanism was obviously contrary to that intent and the resolution that the Company is proposing aligns perfectly with that intent. Importantly, the ratemaking will not change. The only change is a correction to the process that allows the Company to collect the approved revenue through the approved rates.

Q. Over what period does the Company propose to recover these costs?

A. The Company proposes to recover the $4 million over two decoupling years, beginning with the 2022–2023 decoupling year.

VII. SUMMARY AND CONCLUSIONS

Q. Can you summarize your testimony in this proceeding?

A. Certainly. As noted throughout this testimony, the Company has experienced a revenue under-collection of $4,023,830 through the Revenue Decoupling Mechanism ("RDM") approved in Order No. 26,122 (Apr. 27, 2018), as part of the Company's 2017 rate case, Docket No. DG 17-048. The revenue under-collection relates to the implementation of the RDM tariff that became effective November 1, 2018, and the interaction of the low-income discount rates made available to customers through the R-4 rate tariff and the rates for residential customers taking service under R-3 (without a low-income discount). Inadvertently, the tariff implementing the RDM gave conflicting directions for reconciling revenue targets with actual revenue collections for R-3 and R-4 customer classes for the annual decoupling cycle. While these conflicting directives were sorted out and corrected in the Company's 2020 rate case, Docket No. DG 20-105, for the first two decoupling cycles -- 2018/2019 and 2019/2020 -- this internal conflict resulted in the inadvertent refund of $4,023,830 to customers through the RDM.

Further, my testimony concludes that, by operation of the approved RDM tariff language, revenues associated with the Company's low-income program were refunded to customers as part of the first two annual decoupling cycles of 2018–2019 and 2019–2020, although no refund was actually due to customers. Therefore, it is both reasonable and appropriate for the Company to recover the amounts inadvertently and erroneously returned to customers during the annual decoupling cycles of 2018–2019 and 2019–2020, thus restoring revenue neutrality of the low-income program.

My testimony, and the supporting materials that accompany it, explains at length the sequence and chronology of the regulatory processes and approvals that caused the Company to under-collect revenues associated with the low-income discount provided to customers under the R-4 rate tariff, while also demonstrating that the Company is owed the amount of $4,023,830 from customers as a result of those regulatory processes and approvals. The fact remains that the under-recovery was the result of a good-faith error on a highly complex issue, and that allowing for recovery now would be entirely consistent with the clear intent of the decoupling mechanism and the Commission's precedent in other instances in which errors of this sort have been corrected long after the fact. The Commission can and should allow the Company to collect the amounts due from customers over a reasonable time period, which the Company suggests would most appropriately be two decoupling years, consistent with the timeframe of the under-recovery.

Q. Does this conclude your testimony?

A. Yes.

THIS PAGE INTENTIONALLY LEFT BLANK

Docket No. DG 22-___
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty
Revenue Decoupling Adjustment Factor

APPENDIX

Bates Reference	Materials Presented	
0001–0086	Menard Testimony and Appendix	
0087	Figure 1 Schematic Presentation	
0088–0163	DG 17-048	Exhibit 8 – Therrien Testimony w/ Atts.
0164–0256	DG 20-105	Exhibit 34 – Mullen Testimony with FTI Report
0257–0507	DG 21-130	Exhibit 2 – Updated Testimony of Simek/McNamara
0508–0640	DG 18-137	Exhibit 2 – Peak Schedules with Sch. 19 RLIAP Calculations
0641–0651	DG 18-137	Order No. 26,188 approving LDAC (November 1, 2018)
0652–0657	DG 17-048	Exhibit – Simek RDAF Tariff
0658–0724	DE 15-137	Order No. 25,932 directing decoupling (August 2, 2016)
0725–0766	DG 17-048	Exhibit 27A - Therrien Rebuttal Testimony
0767–1078	DG 17-048	NHPUC No. 9, Att. DBS-Tariff-2 (April 28, 2017)
1079–1117	DG 17-048	Exhibit 29 – March 2, 2018, Settlement Agreement w/ Atts.
1118–1199	DG 17-048	Order No. 26,122 approving Settlement Agreement
1200–1213	DG 17-048	Liberty Compliance Filing w/ Atts. (June 11, 2018)
1214–1229	DG 17-048	Liberty Response to Secretarial Letter (October 1, 2018)
1230–1265	DG 17-048	Liberty 2nd Revised Proposed Sec. 17 Compliance
1266–1267	DG 17-048	Secretarial Letter Approving RDM Tariff (October 31, 2018)
1268–1283	DG 17-048	Order No. 26,187, Order on Rehearing (November 2, 2018)
1284–1329	DG 17-048	Liberty Compliance Tariff (November 16, 2018)
1330–1482	DG 18-137	Initial Testimony of Simek/McNamara w/ Schedules
1483–1502	DG 19-145	Initial Testimony of Simek/McNamara
1503–1536	DG 19-145	Revised Pages of Simek/McNamara Testimony w/ Atts.
1537–1542	DG 19-145	Exhibit 5 – Staff Testimony of Iqbal (October 8, 2019)
1543–1610	DG 20-105	Exhibit 39 – Iqbal Testimony with Audit Report Attached
1611–1621	DG 20-141	Order No. 26,419 approving COG 2020/2021 (October 30, 2020)
1622–1670	DG 20-105	Settlement Agreement w/ Atts. (June 30, 20121)
1671–1829	DG 20-105	Liberty Compliance Tariff (August 13, 2021)
1830–1846	DG 20-105	Order No. 26,505 for Settlement Agreement (July 30, 2021)
1847–1923	DG 17-048	Exhibit 18 – Iqbal Staff Testimony w/ Atts
1924–2031	DG 17-048	Exhibit 14 – Johnson OCA Testimony
2032–2035	DG 18-137	Exhibit 3 – Amended Technical Statement of Simek/McNamara (October 9, 2019)

THIS PAGE INTENTIONALLY LEFT BLANK

Proper peration of the RDM

Allo ed Revenue argets (AR)

Actual Revenues Collected (ARC)

- here ART and ARC are set on the same basis, then the differential represents the correct RDM ad ustment.
- If ART ARC, then revenue differential is collected by the Company
- If ART ARC, then revenue differential is refunded to customers

Configuration Allo ed Revenue argets et by Customer Group

Allo ed Revenue argets

argets are set for Residential Customers using R- Rate chedule (non-discounted)

Actual Revenue Collected

ariff Uses R- Rate Class Revenues for Calculation (non-discounted)

- Allowed Revenue Targets are set by **Customer Group** (Residential and C I)
- Residential customers are served in the R-3 and R-4 rate classes.
- Residential rates are represented on R-3 Rate Schedule.
- R-4 rates are discounted from R-3 residential rates.
- Because R-3 and R-4 rate classes are not distinguished, R-3 rates are used for Allowed Revenue Targets

Configuration 2 Allo ed Revenue argets et by Customer Class

Allo ed Revenue argets

argets set using Rate chedules approved for each customer class.

R- Non-Discounted

R- Discounted

Actual Revenue Collected

ariff Uses R- Rate Class Revenues for Calculation (non-discounted)

- **Allo ed Revenue argets are set by Customer Class**
- **R- Rate chedule is not discounted**
- **R- Rate chedule is discounted.**
- **Actual Revenue Collected is calculated using R- rates non-discounted.**
- **Mismatch ill indicate a customer refund is due because Actual Revenue Collected ill be greater than Allo ed Revenue argets**

EXHIBIT
tabbies
8
DG 17-048

Liberty Utilities

**STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION**

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

GREGG H. THERRIEN

April 28, 2017

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

I. Introduction 1

II. Scope of Decoupling Testimony 1

III. Overview of Decoupling 5

A. Introduction 5

B. Support for Decoupling: Energy Efficiency Programs 9

C. Support for Decoupling: Ratemaking 10

D. LDC Experience with Decoupling 12

1. Decoupling in the U.S. 12
2. Summary and Conclusion to Decoupling Overview 17

IV. EnergyNorth's Experience 18

A. Introduction 18

B. EnergyNorth's Energy Efficiency programs 19

C. The EERS Settlement Agreement 21

D. Impact of Customer Consumption Trends on EnergyNorth 23

1. Introduction 23
2. Analysis of UPC and customer trends 24
3. Explanation for UPC and Customer trends 27
4. Summary and Conclusion 39

V. EnergyNorth'S Decoupling Proposal 40

A. Details of EnergyNorth's Proposed Decoupling Mechanism 40

1. Introduction 40
2. Basis for the true up calculation 41
3. Rate classes to be included in the RDM 41
4. True up Customer Groups 42
5. Frequency and timing of RDM rate adjustment filing 43
6. Adjustments to Target and Actual revenues 44
7. Treatment of new customers 45
8. Customer impact protections 46
9. Summary 46
10. Additional RDM details 47

ATTACHMENTS

Attachment	Title
GHT/DECPL-1	U.S. LDCs with Decoupling Mechanisms
GHT/DECPL-2	EnergyNorth Annual Normalized Use per Customer, 2005 – 2016
GHT/DECPL-3	EnergyNorth Annual Customers, 2005 – 2016
GHT/DECPL-4	EnergyNorth 12-Month Rolling R-3 Unit Cost of Gas, 2006 – 2016
GHT/DECPL-5	EnergyNorth Year-to-Year C&I Revenue Per Customer
GHT/DECPL-6	Hypothetical RDM Target Revenue Per Customer: 2010 Base
GHT/DECPL-7	Simulated Decoupling Calculations: 2011 – 2016
GHT/DECPL-8	Decoupling Timeline
GHT/DECPL-9	Proposed RDM Target Revenue Per Customer (Rate Years 1 and 2)
GHT/DECPL-10	Resume and Experience of Gregg H. Therrien

TABLES

Table	Title
Table 1	Revenue Decoupling Mechanisms in Effect in the U.S.
Table 2	U.S. LDCs with Decoupling and a Cost Tracker
Table 3	EnergyNorth Energy Efficiency Program Savings (Annual Dth)
Table 4	Potential Energy Savings from Increased R-Value
Table 5	New Hampshire Building Code Change History
Table 6	Residential Delivered Cost of Heating Oil and Natural Gas
Table 7	30-Year Normal Degree Day History – Manchester, New Hampshire
Table 8	RDM Customer Groups
Table 9	RDM Class Accruals by Season by Year
Table 10	RDM Summary Analysis

CHARTS

Chart	Title
Chart 1	EnergyNorth Residential Heating (R-3) NUPC Snapshot
Chart 2a	Cumulative Effect of RDM – Summer
Chart 2b	Cumulative Effect of RDM – Winter

I. INTRODUCTION

Q. Please state your name, address and position.

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to this testimony.

Q. Have you testified previously before the New Hampshire Public Utilities Commission ("PUC" or the "Commission)?

A. No, I have not.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth", or "the Company").

II. SCOPE OF DECOUPLING TESTIMONY

Q. Please summarize the scope of your testimony concerning the Company's proposed Revenue Decoupling Mechanism ("RDM").

A. In this testimony, I will:

1) provide general background on RDMs, why they are necessary as part of a comprehensive energy efficiency program, and why traditional ratemaking is insufficient support for utility energy efficiency advocacy;

2) provide the results of our research on RDMs that have been implemented by gas Local Distribution Companies ("LDCs") throughout the U.S.;

3) describe the impact that EnergyNorth's Energy Efficiency ("EE") programs, customer self-funded conservation, and other external factors has had on the Company's throughput volumes and the effect on the Company's ability to earn a reasonable rate of return between rate cases;

4) describe my understanding of the recent energy efficiency settlement agreement in Docket No. DE 15-137, and how it recognizes the need to harmonize increased energy efficiency spending with appropriate changes in ratemaking; and

5) describe and explain the Company's proposed RDM, which will allow EnergyNorth to continue to be a forceful and active advocate for energy conservation efforts, without harming its ability to earn a reasonable return.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

In recent years, there has been a heightened focus on energy conservation efforts and policies that encourage conservation.[1] This interest in energy conservation has been attributed to environmental considerations and to a dramatic spike in energy prices that occurred in 2005 – 2006, and again in 2009. Although gas prices have dropped significantly since 2009, there has been price spikes in New Hampshire over the past three winters and the attention to gas conservation has continued.[2]

Since 2005, EnergyNorth has experienced a continuous decline in usage, as measured by Normalized Use per Customer ("NUPC"), in the Residential and Small Commercial and Industrial ("C&I") classes.[3] Continuing declines in the Residential Heating and Small C&I classes have been offset by increases in usage from the Large C&I customer classes. Despite EnergyNorth's overall customer usage remaining relatively flat over this time period, the Company has experienced significant year-to-year volatility in average use per customer.[4]

---

1 Heightened focus in New Hampshire on energy conservation efforts and enabling policies to encourage conservation are demonstrated in the following reports: (a) New Hampshire Independent Study of Energy Policy Issues (September 2011), prepared for the New Hampshire Public Utilities Commission by Vermont Energy Investment Corporation; (b) Increasing Energy Efficiency in New Hampshire: Realizing Our Potential, (November 2013), prepared for the New Hampshire Office of Energy and Planning by the Vermont Energy Investment Corporation; (c) New Hampshire 10-Year State Energy Strategy (September 2014), published by New Hampshire Office of Energy & Planning; and most recently (d) the Energy Efficiency Resource Standard Settlement Agreement (the "Settlement Agreement"), dated April 27, 2016, as approved in the New Hampshire Public Utilities Commission ("NHPUC") order in Docket No. DG 14-180 (dated August 2, 2016).

2 On an annual basis, the average Cost of Gas charged by EnergyNorth to firm sales customers has decreased from $1.18 per therm to $0.72 per therm between December 2009 and August 2013, a decrease of 40 percent. Since 2013 prices have trended even lower, despite increasing winter volatility. As of December 2016, EnergyNorth firm sales average annual customer average Cost of Gas is $0.50 per therm.

3 These classes account for approximately 66% of the Company's total firm throughput, based on 2016 normalized consumption.

4 The volatility in EnergyNorth's 12-month rolling Total firm NUPC is demonstrated by the following trend in standard deviation (in therms):
2006-2009 = 31.66

EnergyNorth is not alone - most US gas distribution companies have been experiencing similar patterns of declining use[5], and have responded by implementing RDMs in 29 different states.

EnergyNorth proposes to implement rate design measures[6] that will "decouple" the traditional connections between the volume of gas that EnergyNorth delivers to its customers and its revenues and earnings.

The decoupling rate design measures that the Company is proposing:

- Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
- Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [7]

2010-2013 = 14.95
2014-2016 = 21.48
These standard deviations indicate that volatility was highest during the 2006 – 2009 era of high gas prices, lowest post-shale supply influx, and increasing over the past three years as a result of the polar vortex and tight New England supplies. This is discussed in detail in Section IV. D. 3. of this testimony.

5 This trend was examined extensively by such organizations as the American Gas Association, which reported a trend in declining use per residential natural gas customer of 1 percent annually from 1980 to 2000, and accelerated thereafter. *See* An Economic Analysis of Consumer Response to Natural Gas Prices, by Frederick Joutz and Robert P. Trost, prepared for the AGA, March 2007.

6 Specifically, the Company's proposed RDM and the Company's rate design proposals, which increase the proportion of the Company's total distribution revenues that are derived from customer charge revenues.

7 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

– Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[8] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enables full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and

– Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

III. OVERVIEW OF DECOUPLING

A. Introduction

Q. Please describe a revenue decoupling mechanism.

A. In general terms, an RDM breaks the link between the quantities that a utility delivers to its customers and that utility's revenues. By eliminating the link between customer consumption and Company earnings, decoupling removes the disincentive for utilities to promote conservation and energy efficiency programs. Companies that have implemented decoupling are no longer caught between promoting conservation (that reduce sales) and growing revenues (by increasing sales). Breaking the link between

[8] The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff, Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire dba / Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way home; the Conservation Law foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development finance Authority; and TRC Energy Services.

utility sales and revenues is the best way to promote conservation activities fully and freely. Other mechanisms that only compensate the utility for the costs of conservation programs, such as a Lost Revenue Adjustment Mechanism ("LRAM"), fall short.

Q. Why is a LRAM insufficient in promoting conservation programs?

A. Mechanisms such as the recently approved LRAM in New Hampshire only compensate for energy efficiency measures installed as a result of utility programs, and alone do not promote conservation behaviors. The American Council for an Energy Efficient Economy ("ACEEE"), a nonprofit, 501(c)(3) organization, whose stated mission is to "act(s) as a catalyst to advance energy efficiency policies, programs, technologies, investments, and behaviors"[9] states:

> "An LRAM alone will not fully incentivize efficiency nor remove the throughput incentive. While the lost revenue adjustment can help make a utility whole by compensating it for reduced energy sales associated with efficiency programs, it will do little to encourage investment in energy efficiency unless combined with other policy levers. In fact, our analyses indicate that having an LRAM policy itself is not currently associated with higher levels of energy efficiency effort (program spending) or achievement (energy savings) than are found in states without an LRAM policy. Nor does LRAM reduce a utility's motivation to increase sales (although some states do have safety nets in place). To fully remove the throughput incentive, decoupling should be considered."[10]

---

[9] *See* http://aceee.org/about-us.

[10] "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms", June 2015, ACEEE Report U1503.

Q. How does a decoupling mechanism work?

A. RDMs generally adjust rates on a periodic basis (e.g. annually or seasonally) to "make up" the difference between a target revenue per customer, which would have been set in the most recent rate case, and actual revenue per customer. RDMs are symmetrical; the calculation can result in either a charge or credit depending on the actual revenue per customer. A rate adjustment credit will be included in customers' bills in a future period when actual revenue per customer is greater than the target revenue per customer in a recently-completed period. Conversely, a rate adjustment charge will be included in customers' bills when actual revenue per customer is less than the target revenue per customer.

Q. Why do utilities need decoupling?

A. Utilities are becoming increasingly responsible for managing and actively promoting customer conservation through the development and implementation of robust energy efficiency programs. All else being equal, these programs will result in lower NUPC. In addition, utility customers have become increasingly aware of energy use and have invested in energy efficiency measures with their own dollars. Further, appliance efficiency improvements and stricter building code requirements result in higher overall energy efficiencies when customer equipment and existing building stock are replaced. Lastly, other external factors such as economic factors, demographics, and weather trends can contribute to changes in consumption. While reduced energy usage is good for individual consumers and society as a whole, it does have a negative impact on a utility's ability to earn its allowed rate of return under traditional ratemaking.

Q. Please elaborate on the utility earnings dilemma.

A. The Company's financial performance, all else being equal, is negatively affected by declining NUPC. Decoupling is an appropriate and increasingly common component of a well-designed and implemented demand-side management ("DSM") program. Decoupling is appropriate whenever a utility's rates are designed such that a decrease in sales volumes adversely affects the ability of the utility to earn a reasonable return on investment. According to the Regulatory Assistance Project ("RAP"):

> "Utilities are interested in revenue stability, so that they have net income that can predictably provide a fair rate of return to investors, regardless of weather conditions, business cycles, or the energy conservation efforts of consumers."[11]

Q. Why should policy-makers and customers support decoupling?

A. As discussed above, decoupling unlocks the utility's ability to enthusiastically support energy efficiency policy goals. Over time, decoupling mechanisms provide rate stability that results from the mechanism's symmetrical design.[12] Further, decoupling can protect customers from a utility recovering excess revenues that may result from colder than normal weather or from favorable economic conditions.

[11] "Revenue Regulation and Decoupling: A Guide to Theory and Application", November 2016, page 26.

[12] RAP also recognizes this, stating, "Customers also have an interest in bill stability, because in extremely cold winters or hot summers, their bills can quickly become unmanageable." Ibid, page 26.

B. Support for Decoupling: Energy Efficiency Programs

Q. Why is decoupling important for regulated utilities that offer energy efficiency programs?

A. The ACEEE best summarized the importance of decoupling for regulated utilities in its June 2014 Policy Brief titled "Utility Initiatives: Alternative Business Models and Incentive Mechanisms" where it stated that:

> "Under traditional rate-of-return regulation, utilities have an economic disincentive to provide programs to help their customers be more energy efficient. Because a utility's earnings are based on the total amount of capital invested and the amount of electricity sold, increased energy sales generally increase utility profits. Experience suggests that enacting regulatory reforms such as decoupling…help overcome those inherent disincentives regarding energy efficiency.'

Further, in its June 2015 Report titled "Valuing Efficiency: A Review of Lost Revenue Adjustment Mechanisms" [13] they state:

> "Creating a regulatory environment that incentivizes utilities to invest in efficiency is critical for programs to be successful, impactful, and long lasting. Doing so requires a mix of policy tools. In addition to energy efficiency targets, utilities need a business model that aligns their financial interests with energy efficiency, including program cost recovery, performance incentives that encourage utilities to achieve high levels of savings, and some policy mechanism to neutralize the throughput incentive. It is our opinion that decoupling is the best third leg of this stool. However, it is also clear that decoupling is not always an option for states for a variety of reasons. In such scenarios, LRAM can be a temporary solution, offering a mechanism to address the

[13] Report U1503.

> concern over lost revenues and, possibly, help make parties more comfortable with the idea of full decoupling in the future.

These ACEEE policy excerpts clearly show the need for, and evolution of, utility ratemaking that supports energy efficiency goals.

C. <u>Support for Decoupling: Ratemaking</u>

Q. Please describe and explain the structure of decoupling mechanisms.

A. RDMs calculate a surplus or shortfall between actual and allowed revenues. There are two common RDM structures: (a) revenue per customer ("RPC") RDMs and (b) total revenue RDMs. The primary difference between these two structures is the revenue "true up" calculation and the treatment of new customers. The RPC RDM revenue true up determines the revenue shortfall or surplus by (a) calculating the difference between the target RPC and actual current period RPC by customer group or rate class and (b) multiplying the difference per customer ("RDM per Customer Adjustment") by the current period number of customers. The effect of a RPC RDM is that the sum of actual rate class/rate group revenues per customer plus the RPC RDM per customer adjustment will always equal the target RPC, and total actual revenues will change in direct proportion to the change in the number of customers between the test year and current period. New customer revenues are therefore preserved to fund new customer investment made by the utility.

The total revenue true up determines the revenue shortfall or surplus by calculating the difference between the target revenues and actual current period revenues by customer group or rate class. The effect of a Total Revenue RDM is that the sum of actual rate class/rate group revenues plus the Total Revenue RDM true up for each rate class/rate group will always equal the revenue target and total actual revenues will not change until the LDC's next rate case. There is no inherent recognition of new customer additions in this approach.

Q. Of these two types of RDM, which is most common for gas LDCs?

A. The application of a RPC RDM best suits utilities that add new customers to their system, and is the prevalent methodology among LDCs that have decoupling. Unlike electric distribution companies, gas LDCs typically do not have 100% market share in their service territories and are motivated to convert customers from alternate fuels, such as oil or propane. Adding new customers to the system involves incremental capital investment, which requires that the revenues from these new customers be necessarily retained by the Company to fund this new investment. Therefore, RPC RDMs are superior to Total Revenue RDMs for gas utilities, as new customer revenues are retained (at the system average RPC) to help cover the cost of the corresponding new investment. If a Total Revenue RDM is employed instead, then the LDCs incentive to add new customers is significantly diminished, as total revenues will remain unchanged while rate base grows.

Q. Does decoupling guarantee utility earnings?

A. No, it does not. The proposed RDM trues up revenues to the amount allowed on a per-customer basis. The utility remains at risk for managing its expenses commensurate with the level set for the test year base rates. This means the utility must manage its capital expenditure programs, its operations (e.g., salaries and wages, benefits, overtime, maintenance programs, uncollectibles, outside services, etc.), and pay taxes (including property taxes that are adjusted annually by most municipalities).

D. LDC Experience with Decoupling

1. Decoupling in the U.S.

Q. Please summarize your research on U.S. gas LDCs that have implemented RDMs.

A. I have identified 67 gas LDCs in 29 states that have implemented a RPC RDM or a Total Revenues RDM. This is summarized as follows:

Table 1: Revenue Decoupling Mechanisms in Effect in the U.S.

State	RPC RDM	Total Revenue RDM	Grand Total
AR	1	2	3
AZ	1		1
CA		4	4
CO	1		1
CT		1	1
GA		1	1
ID		1	1
IL	2	1	3
IN		3	3
LA		1	1
MA	6		6
MD	4	1	5
MI	1		1
MN	1	1	2
MS		1	1
NC	1	1	2
NJ	2		2
NV	1		1
NY	9	2	11
OR	2	1	3
RI	1		1
SC		1	1
TN	1		1
UT	1		1
VA	3		3
VT		1	1
WA	2	1	3
WI	1		1
WY	2		2
Grand Total	**43**	**24**	**67**

Q. Do any LDCs with RDMs also have other ratemaking adjustment mechanisms?

A. Yes, many LDCs with RDMs have also sought recovery of certain expenses and investments (plant / rate base additions) between general rate cases. Cost-related modifications to traditional ratemaking include several approaches to adjusting rates between rate cases to account for changes in (a) overall costs or (b) specific categories of costs. Rate plans that provide for allowed annual increases in a utility's allowed revenues[14] for a set number of years after the rate case is decided is an example of cost based departures that account for changes in overall costs. Step Adjustment increases are common practice in New Hampshire; step adjustments are a form of a rate plan.

Cost tracker mechanisms are another category of modifications to traditional gas LDC ratemaking. Cost trackers recover actual costs incurred on a timely basis. For example, capital cost trackers allow for periodic rate adjustments to recover the incremental revenue requirements associated with replacement and/or safety and reliability projects, while expense cost trackers recover certain specific expenses on a timely basis. New Hampshire has implemented some of these cost tracking measures, including the Cost of Gas Adjustment ("CGA"), indirect gas costs, EE/DSM program costs, environmental remediation costs, and the Cast Iron and Bare Steel ("CIBS") mechanism.

Common cost tracking mechanisms include:

a. Gas costs[15];
b. Pension and Post-Retirement Benefits Other than Pensions ("PBOP") expense;
c. Bad debt expense;
d. Environmental response costs;
e. EE program expense;
f. Property and/or franchise taxes;

---

[14] For example, the annual revenue increases may be (a) determined for each year of the rate plan in a rate case proceeding, or (b) calculated annually during the rate plan by a formula that accounts for changes in a price index.

[15] Recovery of gas costs through a rate adjustment mechanism is now so common that it is generally considered to be part of "traditional ratemaking."

g. Infrastructure replacement costs (e.g., CIBS);

h. System reinforcement costs, and

i. Integrity management costs.

The following table summarizes the prevalence of pairing an RDM with a cost tracker:

Table 2: LDCs With Decoupling and Cost Tracker

RDM Type	With a Tracker	No Tracker	Total
RPC	25	18	43
Total Revenue	20	4	24
Total	45	22	67

A complete listing of the 67 LDCs that currently have decoupling is included in Attachment GHT/DECPL-1.

Q. Have you identified any other common features in the structure of RDMs that you identified in your research?

A. Yes, I have. In Section III.A of this testimony, I explain that an RDM revenue true up calculation determines the difference between (a) Target RPC and Actual RPC or (b) Target Revenues and Actual Revenues. Both of these approaches to calculating the revenue true up account for differences in revenues that are the result of weather that is colder or warmer than normal in addition to accounting for differences due to conservation and related factors. For example, if weather in the current time period was colder than normal, the RDM would return to customers the revenue surplus associated with the colder weather in the following winter period, and if weather was warmer than normal, the RDM true up calculation would include a charge to recover the revenue deficiency associated with the warmer weather.

Alternatively, an RDM revenue true up calculation could determine the difference between (a) Target RPC and weather normalized RPC or (b) Target Revenues and weather normalized revenues. The true up calculation could be performed by determining the difference between target revenues and weather normalized actual revenues. Using this approach, the revenue true up calculation would not be affected by colder or warmer than normal weather.

Q. What does your research on RDMs indicate about the prevalence of RDMs that are based on actual revenues and RDMs that are based on weather normalized revenues?

A. I determined that 57 of the 67 LDCs have implemented RDMs that are based on actual revenues. Of the remaining 10 LDCs that have implemented RDMs based on normalized revenues, 7 have separate weather normalization adjustment mechanisms ("WNA").

Q. In your opinion, why are most RDMs – approximately 85 percent – based on actual revenues?

A. It is my belief that RDMs that are based on actual revenues, rather than weather normalized revenues, are more common because this RDM approach is easier to administer and oversee as the review process is straight-forward. RDMs that use actual revenues capture all sales-related variances, thus avoiding the need for a WNA (and explanation of its mechanics to customers) or a complicated normalization calculation and subsequent Commission review. Either (a) an RDM that is based on actual revenues or (b) an RDM that is based on weather normalized revenues together with a weather normalization adjustment mechanism have symmetrical, balanced effects that stabilize customers' bills and LDCs' revenues.

Q. What conclusions do you draw from the number of LDCs that have adopted revenue-related and cost-related modifications to traditional ratemaking?

A. Based on the widespread adoption of decoupling mechanisms (67 LDCs in 29 states; see Section III.D.1), of which 45 of these LDCs (two thirds) also have some form of cost tracker, I conclude that there is general understanding that (a) decoupling mechanisms are now viewed as an appropriate ratemaking approach that remove LDC disincentives to effectively promote EE programs and offset the overall effect of conservation on LDC revenues and earnings (b) cost tracking measures are now viewed as an appropriate approach to partially offsetting the effect of LDCs' capital spending plans on earnings between rate cases, and (c) the combination of a decoupling mechanism paired with an appropriate cost tracking measure may be necessary to provide a reasonable opportunity to earn a fair return.

2. Summary and Conclusion to Decoupling Overview

Q. Please summarize your findings about decoupling.

A. Over the past decade or longer, there has been considerable attention given to decoupling, which I believe is the result of a growing acceptance that decoupling is a balanced and administratively manageable ratemaking tool that will: (a) break the link between a utility's revenues and the amount of energy that the utility delivers or sells; and (b) address problems with traditional ratemaking that are caused by long term trends of declining customer energy usage.

I have found that, because LDCs in a number of states have adopted decoupling mechanisms over the last decade, there is now a rich source of data available concerning features of RDMs that have been implemented and issues related to the administration and implementation of RDMs, including, for example, RDM calculations and filing documentation.

IV. ENERGYNORTH'S EXPERIENCE

A. Introduction

Q. In Section III above, you provided a discussion of circumstances that would support the implementation of an RDM. Do those circumstances apply specifically to EnergyNorth?

A. Yes. As I will explain in the remainder of this section, EnergyNorth's circumstances demonstrate that an RDM is appropriate and justified for the Company. Specifically, I will:

- Describe EnergyNorth's current EE programs;
- Summarize the 2015 EERS Settlement Agreement;
- Describe and explain EnergyNorth's recent customer and revenue per customer trends; and
- Demonstrate that EnergyNorth's level of involvement in and support for EE

programs warrant the implementation of an RDM.

B. <u>EnergyNorth's Energy Efficiency programs</u>

Q. Please provide some background on EnergyNorth's EE programs.

A. EnergyNorth has been offering EE programs to its customers since 2003 that provide rebates and technical support for residential and commercial customers who seek to minimize their energy use.[16] Table 3 below provides a summary of the actual and planned direct energy savings that result from EnergyNorth's EE programs.

[16] Referred to as the "Core programs" in the EERS Settlement Agreement.

Table 3: EnergyNorth Energy Efficiency Program Savings (Annual Dth)

Year	Actual / Estimate	Residential	C&I	Total Energy Savings
2006	Actual	25,529	47,269	72,797
2007		27,151	104,730	131,881
2008		35,360	48,278	83,638
2009		32,414	88,174	120,588
2010		43,524	34,703	78,227
2011		29,281	46,466	75,747
2012		39,702	108,565	148,267
2013		40,509	74,831	115,340
2014		34,401	82,545	116,946
2015		63,685	80,069	143,754
2016	Plan[17]	57,226	65,118	122,344
2017	Proposed Savings Targets	57,791	65,762	123,553
2018		61,594	70,088	131,682
2019		66,158	75,280	141,438
2020		69,958	79,606	149,564

Q. Is the intent of the EE program incentive payment to compensate EnergyNorth for foregone EE revenues?

A. No, the incentive payment is intended to "incent the utilities to aggressively pursue achievement of the performance goals of their energy efficiency programs" and "to motivate the companies to achieve or exceed program goals".[18] It is not intended to offset EnergyNorth's foregone EE revenues.

---

[17] Settlement Agreement, Attachment B.

[18] *Energy Efficiency Programs for Gas and Electric Utilities,* Order No. 24,203 at 13 (September 5, 2003).

C. The EERS Settlement Agreement

Q. Please describe the EERS Settlement Agreement.

A. The Company, along with the Settling Parties, entered into a Settlement Agreement on April 27, 2016, more than a year after the inception of the Commission's investigation of Staff's proposed Energy Efficiency Resource Standard.[19] The Settlement Agreement represents the Parties' implementation of the approved EERS in New Hampshire,[20] and specifically:

1) Extends the Core programs;
2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);
3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;
4) Will implement the EERS commencing January 1, 2018;
5) Retains the Performance Incentive, with modifications;
6) Increases the low income share of the overall energy efficiency budget; and
7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).

---

[19] Docket No. IR 15-072, "Electric and Natural Gas Utilities - Energy Efficiency Investigation" dated March 13, 2015.
[20] Settlement Agreement, page 2.

Q. Please describe EnergyNorth's Implementation of the LRAM.

A. EnergyNorth implemented the LRAM effective January 1, 2017.[21] The Local Distribution Adjustment Charge ("LDAC") includes an embedded LRAM of $0.0016/therm and $0.0009 per therm for Residential and C&I customers, respectively. This LRAM will remain in effect (as part of the LDAC) until it is either recalculated for 2018 deliveries or replaced by the proposed decoupling mechanism described in Section V below.

Q. Does the Commission's Order approving the Settlement Agreement specifically require the Utilities, such as EnergyNorth, to implement decoupling?

A. Yes. The Commission approved the Settling Parties' proposed LRAM, and recognized that some parties prefer decoupling to an LRAM. Specifically, the Order states:

> "We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC)) are *required* to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before" (*emphasis added*).[22]

---

[21] Docket No. DG 16-814, "Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities -2016/2017 Cost of Gas", noticed on September 16, 2016. Approved by Commission Order No. 25,958 (October 26, 2016).
[22] Order No. 25,932 at 60.

Q. Is it the Company's position that proposing a decoupling mechanism in the instant proceeding comports with the Settlement Agreement and the Order?

A. Yes. The phrase "if not before" from the above caption clearly allows the Company to propose a decoupling mechanism prior to the end of the first EERS triennium, if desired.

D. Impact of Customer Consumption Trends on EnergyNorth

1. Introduction

Q. To set the stage for your discussion of the impacts of declining consumption on Energy North, please describe the analysis that you have prepared.

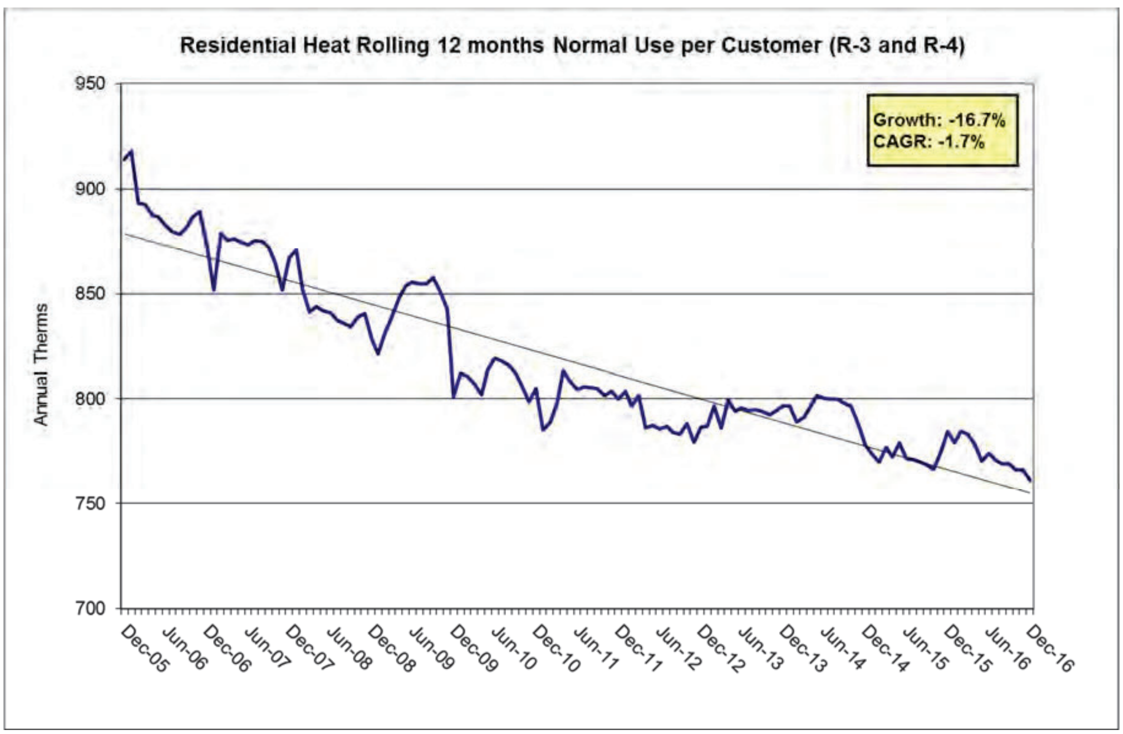
A. In this section, I discuss trends in EnergyNorth's NUPC and number of customers since 2005. I provide summary analyses that I prepared for the following customer groups: (a) Residential Non-Heating; (b) Residential Heating; (c) Low Load Factor C&I; (d) High Load Factor C&I; and (e) Total Company. I prepared separate analyses for the Residential and C&I Customer Groups because customers in these two groups have generally behaved very differently over the period of analysis, 2005 to 2016, particularly the High Load Factor C&I group. I also offer high level explanations for the changes in deliveries, customers and use per customer that EnergyNorth has experienced in the past several years.

2. Analysis of UPC and customer trends

Q. Please summarize the trends in EnergyNorth's weather NUPC that you have identified.

A. To identify trends in EnergyNorth's NUPC, I prepared Residential (Heating and Non-Heating), C&I (Low and High Load Factor) and Total Company NUPC graphs. These graphs are based on a 12-month rolling total NUPC, and are provided in Attachment GHT/DECPL-2. The first graph in Attachment GHT/DECPL-2 shows the NUPC for the Residential Heating Customer Class. A snapshot of this chart is as follows:

Chart 1: Residential Heating NUPC Snapshot



NUPC for the Residential Heating customer class declined 16.7% during the period of analysis, from 912 therms per customer in 2005 to 761 therms per customer in 2016, representing an average annual decline of 1.7%.[23] More recently, from 2013 to 2016 the Residential Heating class has declined at a similar rate of 1.5%.

The Residential Non-Heating NUPC in Attachment GHT/DECPL-2 shows a relatively level usage profile over time, with a 5.3% decline since 2005, or a -0.5% CAGR. Since 2013 NUPC for this class has decreased 12.4%, or 4.3%, primarily as a result of customer rate classification changes. At the conclusion of the last rate case in Docket No. DG 14-180 the Company discovered that 540 existing Rate R-1 customers should have been served under Rate R-3. Following that discovery, the Company initiated a program to convert these customers to Rate R-3.

The two C&I graphs in GHT/DECPL-2 show diverging trends depending on how customers in these classes use natural gas. Low Load Factor ("LLF") customers use gas predominantly for heating, while High Load Factor ("HLF") C&I customers tend to utilize natural gas for process loads, and are potentially subjected to multiple and unique usage drivers compared to LLFr C&I customers (and Residential Heating customers). As these two C&I graphs show, the LLF customer group had declining NUPC from 2005-2010, then rebounded back to 2005 levels by 2014. Their growth rate from 2005 to 2016 showed a slight decline at 0.2%, and a flat CAGR. Conversely, the HLF customer group exhibited rapid NUPC growth over the eleven-year historical period, growing 58.3%, or

[23] As calculated on the Compound Annual Growth Rate ("CAGR") formula.

4.3% annually. Since 2013 the LLF C&I group has remained flat (a 0.1% increase in NUPC) while the HLF C&I class' growth was comparatively lower (0.7% growth since 2013 compared to 4.3% CAGR since 2005).

The last graph in Attachment GHT/DECPL-2 shows that total company NUPC increased slightly by 2.3% percent, or 0.2% annually, which indicates that overall, the increasing HLF C&I NUPC offset much of the decreasing Residential and LLF C&I NUPC over the entire period. Of interest is the recent increase in volatility, including a declining overall NUPC trend since December 2013 of 2.0%. This is likely the result of recent winter period price spikes described further in Section IV.D.3 below.

Q. Please summarize the trends in EnergyNorth's number of customers that you have identified.

A. To identify trends in EnergyNorth's customer counts, I prepared graphs of the number of Residential, C&I and Total Company customers; these graphs are provided in Attachment GHT/DECPL-3. The first graph in Attachment GHT/DECPL-3 shows that the average number of Residential Non-Heating customers decreased by 2,285 (42.9%), or 5.0% annually. This is not surprising, as many low-use customers have converted their heating system to gas over the past decade, taking advantage of the favorable gas-to-oil price spread described in Section IV.D.3 and Table 6 below. The average Residential Heating customer class has increased by 9,914 customers (15.0%), or 1.3% annually. This increase is attributable to heating conversions and new customer attachments to the system (e.g., oil-to-gas conversions and new construction). This growth rate accelerated to 1.8% since 2013.

The next two graphs in Attachment GHT/DECPL-3 show that the number of LLF C&I average customers grew by 1,590 (18.6%), or 1.6% annually, while the HLF C&I class decreased by 86 customers on average, a 5.1% decrease (-0.5% annually).

The last graph in Attachment GHT/DECPL-3 demonstrates that the overall Company customer growth reflects an annual 1.0% growth in average firm customer count. Since the dramatic increase in the oil-to-gas price spread (using a 2013 base), the Residential Heating class has increased to a 1.8% annual growth rate.

3. Explanation for UPC and Customer trends

Q. What are the major contributors to declining NUPC?

A. Categorically, declining NUPC can be attributable to:

1) Utility-sponsored Energy Efficiency (EE)/DSM programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.

Q. Please explain each of these factors.

A. Utility-sponsored EE/DSM programs represent the Core programs, plus any additional programs contemplated in the EERS. These measures result in direct energy efficiency spending for EnergyNorth customers. Each program will have an avoided unit of energy and known levels of participation.

Customer self-funded conservation measures are the result of customers acting independently of utility-sponsored programs (e.g., when a customer installs insulation purchased at a home improvement store). Unlike company-funded conservation programs that track actual installed energy efficiency measures, the utility does not track customer-funded installations.

Appliance efficiencies and building code changes affect customer usage whenever an existing (less efficient) appliance is replaced by a new (more efficient) one, and new housing stock replaces old stock. There are known changes to building requirements and appliance efficiency standards that have been enacted over the past few decades. These include increased appliance efficiency requirements for furnaces and hot water heaters. Additionally, New Hampshire has passed a series of more stringent building codes consistent with national standards.

Price elasticity and economic impact on usage can be estimated using econometric modeling, but will have less of a degree of accuracy compared to known and measurable

EE/DSM installations. Although prices are low now[24], in the not so distant past, prices were high and customers responded by installing low cost permanent measures (weather stripping, water heater jackets, set back thermostats, etc.) and high cost permanent measures (insulated doors, added wall and attic insulation, efficient windows, etc.) as well as temporary measures (closing off rooms, turning down thermostats and wearing sweaters). The permanent measures reduce NUPC forever, long after the natural gas prices return to moderate levels. Further, changes in demographics (e.g., number of people per household, number of residents in a service territory or state) can also influence NUPC. Lastly, a significant downward trend in the 30-year normal weather standard also contributes to declining NUPC.

Q. What are the current and forecasted trends for each of these factors?

A. New Hampshire is clearly committed to EE, evidenced by the Settling Parties' commitment to implementing a comprehensive EERS in 2018. Customer-funded conservation measures are likely to continue, as low-cost weatherization options proliferate the home improvement marketplace. Even if the current appliance efficiencies and building codes do not change in the coming years, customer equipment and housing stock will be replaced resulting in net energy savings (e.g., replacing a failed gas furnace with a new gas furnace). Although the gas-to-oil pricing advantage has shrunk since

[24] The U.S. Energy Information Administration ("EIA") Annual Energy Outlook 2017 forecast of residential delivered cost of natural gas shows stable prices through 2025 (2017 forecast = $1.06 per therm compared to the forecasted 2025 delivered price of $1.14 per therm).

2012, the EIA is forecasting a return to a price spread where oil is twice the delivered price of natural gas.[25]

Q. Please elaborate on how customer-funded conservation contributes to declining NUPC.

A. Existing customers have chosen to invest in conservation measures using their own money without utilizing utility-sponsored EE programs. This occurs because of either a lack of understanding of the existence of utility programs or ineligibility based on program requirements. The quantification of energy savings for an individual, representative premise is easily obtainable for many conservation measures. The effectiveness of thermal resistance, for instance, is measured in “R-value” units. Increasing a surface’s R-value reduces heat loss. Therefore, when a consumer installs additional insulation in their home, thus increasing the surface’s R-value (e.g., attic floor, ceilings, walls, etc.) their natural gas usage (all else being equal) will decline. The following table demonstrates the impact of increasing R-values in a sample 1,000 square foot home in Concord, New Hampshire:

[25] EIA Annual Energy Outlook 2017.

Table 4: Potential Energy Savings from Increased R-Value [26]

Percentage Savings (therms)												
			OLD									
NEW	R-Value	Δ in R	R-10	R-11	R-12	R-13	R-14	R-15	R-16	R-17	R-18	R-19
	R-11	1	2.0%									
	R-12	2	3.7%	1.7%								
	R-13	3	5.1%	3.1%	1.4%							
	R-14	4	6.3%	4.3%	2.6%	1.2%						
	R-15	5	7.4%	5.4%	3.7%	2.3%	1.0%					
	R-16	6	8.3%	6.3%	4.6%	3.2%	2.0%	0.9%				
	R-17	7	9.1%	7.1%	5.4%	4.0%	2.8%	1.7%	0.8%			
	R-18	8	9.8%	7.8%	6.1%	4.7%	3.5%	2.5%	1.5%	0.7%		
	R-19	9	10.5%	8.5%	6.8%	5.4%	4.1%	3.1%	2.2%	1.4%	0.6%	
	R-20	10	11.0%	9.0%	7.4%	5.9%	4.7%	3.7%	2.8%	1.9%	1.2%	0.6%

As the above table indicates, an existing homeowner who upgrades their home with insulation, which increases the overall R-value of the dwelling, can decrease their natural gas usage significantly. For example, increasing the R-value from R-10 to R-16 would reduce annual usage from 682 to 626 therms, more than eight percent. Even a modest improvement in R-value can have a significant impact on declining usage.

Q. Please elaborate on how increased appliance efficiencies contribute to declining NUPC.

A. Appliance manufacturers have been improving the energy efficiencies of their gas equipment on both a mandated and voluntary basis. The U.S. Department of Energy ("DOE") regulates minimum efficiency standards for many appliances, including gas furnaces, boilers, and water heaters. In the early 1990s the DOE changed the standards on Annual Fuel Utilization Efficiency ("AFUE") factors. Under the new code, a gas furnace was required to meet at least an 80% AFUE while high efficient gas furnaces

[26] The average usage for a 1,000-square foot house in Concord, NH is estimated at 682 therms per year, using the estimator tool found at www.energydepot.com/residentialenergycalculator. The quantification of saved therms assumes EnergyNorth's normal annual heating degree days of 6,273 and utilizes the Insulation Investment Calculator found at www.chuck-wright.com/calculators/insulpb.html.

must achieve at least an 90% AFUE to meet the new standard. This is an increase from the 78% AFUE standard enacted in 1992.[27] Therefore, whenever an existing gas appliance (e.g., furnace, water heater, stove, dryer, grill, etc.) fails, its replacement will be more efficient and use less gas, resulting in lower NUPC.

Q. Have building codes changed as well?

A. Yes. New Hampshire has adopted the International Energy Conservation Code ("IECC"). Significant changes to New Hampshire's building code changes are as follows:

Table 5: New Hampshire Building Codes

	New Hampshire Building Code Change History
April 2010	2009 IECC adopted, with amendments
July 2007	2006 IECC adopted, with amendments
March 2002	Mandatory statewide building code is signed into law, using the 2000 IECC as reference, effective September 14th, 2002.

Q. How do these building code changes affect natural gas consumption?

A. Similar to the example provided in Table 4, changes in building codes has resulted in mandatory increases in R-value. Therefore, new buildings will be significantly more energy efficient. As old housing stock is replaced, average consumption (all else being equal) decreases.

[27] The National Appliance Energy Conservation Act of 1987, enacted March 17, 1987, and amended by the Energy Policy Act of 1992 and the Energy Policy Act of 2005.

Q. What are the economic and demographic effects on natural gas consumption?

A. I believe, based on preparing LDC demand forecasts, that the most significant economic factors that affected the Company's customer and NUPC trends include: (a) a dramatic spike in gas prices that started in 2005 caused by supply interruptions along the Gulf Coast; (b) equally dramatic decreases in gas prices since 2009, caused by a large increase in supply from shale formations in Pennsylvania and New York; (c) the economic recession that started in December 2007 and ended in June 2009[28]; and (d) the actual and forecasted long term price advantage that gas has over oil, caused by the large increase in gas supplies from shale formations. Some of these factors, such as the increased shale gas supply, have resulted in increased NUPC while other factors such as utility and customer-funded conservation, appliance efficiencies and building codes have contributed to declining NUPC.

To demonstrate the impact of gas prices on the Company's NUPC over the past several years, I have prepared Attachment GHT/DECPL-4, which shows the history of EnergyNorth's Residential Heating (Rate R-3) Cost of Gas ("COG") rates and the New York Mercantile Exchange ("NYMEX") futures settlement values. The significant decrease in COG rates since 2009 has likely had a positive effect on EnergyNorth's

---

[28] Recessions are determined by the Business Cycle Dating Committee of the National Bureau of Economic Research. The following is excerpted from a report issued September 20, 2010 by the Business Cycle Dating Committee:

> The Business Cycle Dating Committee of the National Bureau of Economic Research … determined that a trough in business activity occurred in the U.S. economy in June 2009. The trough marks the end of the recession that began in December 2007 and the beginning of an expansion. … In determining that a trough occurred in June 2009, the committee did not conclude that economic conditions since that month have been favorable or that the economy has returned to operating at normal capacity. … The trough marks the end of the declining phase and the start of the rising phase of the business cycle. Economic activity is typically below normal in the early stages of an expansion, and it sometimes remains so well into the expansion.

NUPC during the years immediately following this price change.[29] The polar vortex winter of 2013-2014 had a detrimental impact on national gas prices, coupled with increased concern over capacity constraints in the New England region. As a result, EnergyNorth appropriately responded with COG rate increases during this period. Although these price increases were significant, they were not as severe or long-lasting as the price increases between 2005 and 2009.

I believe that the decrease in Residential NUPC was caused by customer conservation efforts in response to (a) the high gas prices in 2005 – 2006 and again in 2009, and (b) the great recession of 2007-2009, which reduced customers' incomes and wealth.[30] In addition, I believe that more stable and slower declining Residential NUPC since 2010 indicates that the increase in usage that would be caused by the recovery from the recession and the decrease in gas costs has been largely offset by the continuing impact of energy conservation.

Customer NUPC trends during this period have also been impacted by the difference in oil and gas prices. Table 6, below, demonstrates the competitive price advantage that natural gas has had over oil in recent years.

[29] That is, if EnergyNorth COG rates had been constant or increasing during this period rather than decreasing by at least 40 percent, the NUPC growth rates would have been lower than the actual growth rates that are summarized in Attachment GHT/DECPL-2.

[30] In response to the high gas prices, customers installed long term irreversible conservation measures, such as high efficiency gas heating and water heating equipment, energy efficient windows and doors, and increased insulation. Customers also implemented short term reversible conservation efforts, such as reducing temperatures in heated living and working spaces, or closing off parts of homes and buildings. In response to the recession, customers would likely be limited to implementing low-cost, reversible conservation efforts.

Table 6: Residential Delivered Cost of Heating Oil and Natural Gas

Residential Delivered Cost per Therm			
Year	Distillate Fuel Oil	Natural Gas	Oil / gas ratio
2005	$1.42	$1.47	0.970
2006	$1.65	$1.61	1.028
2007	$1.84	$1.63	1.129
2008	$2.33	$1.61	1.445
2009	$1.73	$1.48	1.165
2010	$1.95	$1.40	1.390
2011	$2.36	$1.42	1.670
2012	$2.71	$1.33	2.033
2013	$2.65	$1.34	1.971
2014	$2.58	$1.58	1.638
2015	$1.96	$1.03	1.903
2016	$1.54	$0.99	1.556
2017	$1.85	$1.06	1.745
2018	$2.04	$1.06	1.925
2019	$2.16	$1.07	2.019
2020	$2.21	$1.09	2.028
2021	$2.26	$1.10	2.055
2022	$2.29	$1.10	2.082
2023	$2.33	$1.11	2.099
2024	$2.36	$1.13	2.088
2025	$2.41	$1.14	2.114

2005 – 2014 data from the U.S. EIA Residential Sector Energy Price and Expenditure Estimates, (Table ET3). 2015 - 2025 values from EIA's Annual Energy Outlook 2017.

Given the above natural gas price advantage, existing natural gas customers that use oil for other household needs (e.g., hot water) would be motivated to replace such equipment with gas-fired appliances. Low-use residential customers replacing their oil furnace with a natural gas furnace would increase overall system usage, but may contribute to declining NUPC once they become heating (Rate R-3) customers, as their usage (with a new, efficient furnace) would be lower than the Rate R-3 class average.

Q. How would this oil-to-gas price spread impact C&I customers?

A. I believe that the increases in C&I customers and NUPC have likely been driven by the impact of (a) existing EnergyNorth C&I customers converting from oil to gas equipment to take advantage of the competitive advantage of gas over oil, and (b) new C&I customers also converting to gas equipment, especially on-the-main energy users.

Finally, although overall NUPC has remained relatively flat since 2005, volatility has begun to increase. I believe this increased volatility is a reaction to shorter duration, less severe price spikes over the past three winters. If this trend continues and the price spikes become longer and more severe, NUPC will likely decline.

Q. Please describe how demographics can play a role in NUPC.

A. Demographics can influence NUPC at the individual premise level when more or fewer people occupy the premise. Additionally, premise vacancy rates caused by shifts in population also may affect use per customer[31]. The State of New Hampshire's August 2013 report[32] on the state's economic health recognizes the importance of demographics in the State's economic recovery. In the report, it was recognized that population growth in New Hampshire lags the nation:

> "Population changes may affect New Hampshire job growth and how job needs are met. From 2008 to 2012, the nation's population grew by 3.2 percent, compared to 0.4 percent for New Hampshire. This slower growth was primarily caused by domestic outmigration. A low rate of population growth

[31] Assuming that the premise retains an active gas account for minimal space heating, for example.
[32] "Measuring New Hampshire's Economic Health: A Workforce Perspective", published by the New Hampshire Employment Security, Economic and Labor Market Information Bureau, August 2013.

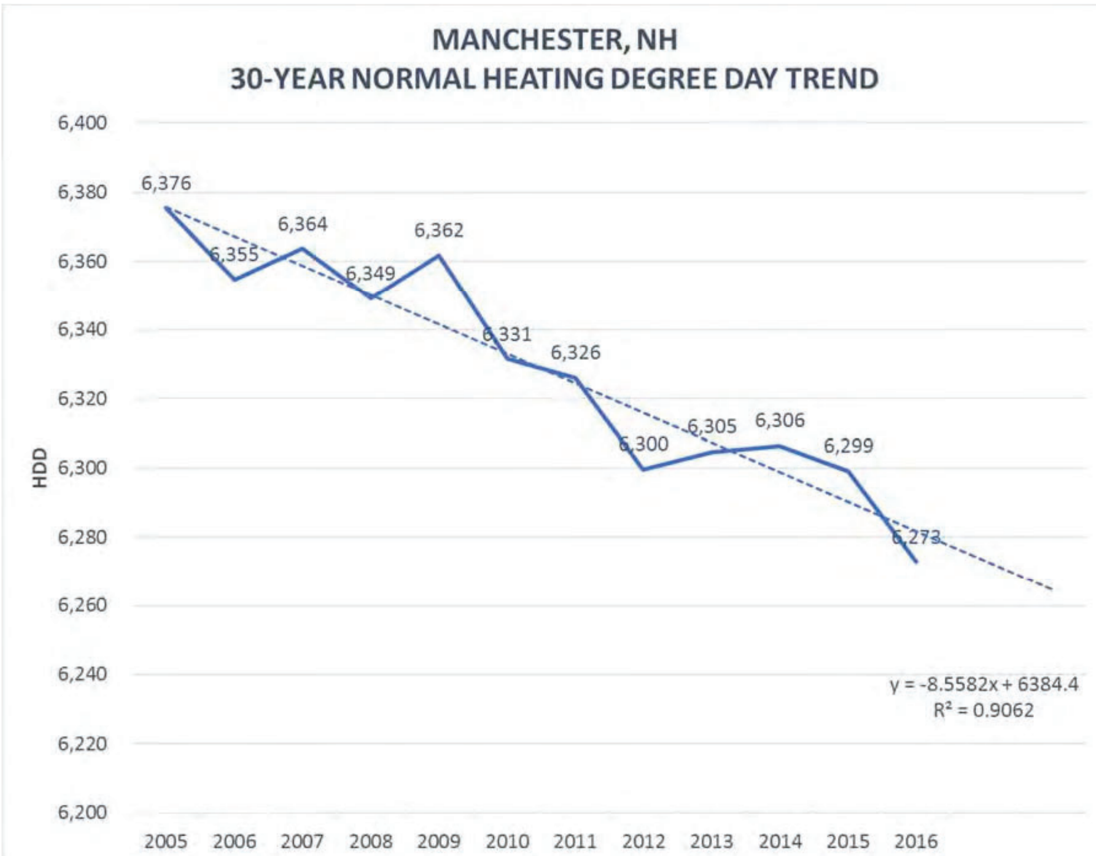
> will affect the rate of job growth in the future, as well as the distribution of jobs by industry and occupation."

Although the above quotation is addressing the issue of employment, it clearly speaks to the trend in New Hampshire's population growth, which can have a direct impact on NUPC, particularly in the Residential classes.

Q. The Company's proposed decoupling mechanism will symmetrically adjust for weather deviations from EnergyNorth's 30-year normal degree day standard. Are there other weather-related reasons to implement decoupling?

A. Yes. Normal temperature, defined in New Hampshire as the latest 30-year average heating degree days, has been declining. The trend over the past decade is for warmer years (most recent) to replace colder years (oldest of the 30-years). This is demonstrated as follows:

Table 7: 30-Year Normal Degree Day History



As the above graph shows, annual normal degree days has declined 103 heating degree-days ("HDD") since 2005. Even under "normal" weather conditions, it is reasonable to assume future year allowed revenues will be deficient if this warming trend continues.

4. Summary and Conclusion

Q. Please summarize why EnergyNorth is proposing, and should be granted, a decoupling mechanism.

A. The EERS Settlement Agreement states that each of the utilities in the state shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM. The Company's preferred solution is decoupling. Further, decoupling is now a mainstream ratemaking tool for gas LDCs across the country. 67 LDCs in 29 different states have a form of decoupling, with the clear majority utilizing actual revenues. EnergyNorth's proposed structure, detailed in Section V below, follows this nationally preferred and accepted design.

Decoupling further solves a long-standing ratemaking issue. There are clear declining NUPC trends in EnergyNorth's largest, most homogeneous customer classes (e.g., Residential Heating) that impact the Company's ability to earn its allowed rate of return. The factors contributing to this declining use reach well beyond utility-funded programs. The data and analysis presented in section IV.D above detail the main contributors to declining NUPC, including: customer-funded conservation; stricter appliance efficiency and building codes; economic and demographic drivers; and a warmer weather trend. None of these factors are within the control of the Company, and the Company should not be penalized between general rate cases for these exogenous events. Decoupling frees EnergyNorth from the negative effects of these causes of declining NUPC, and enables unfettered support and promotion of the State's energy efficiency goals.

V. ENERGYNORTH'S DECOUPLING PROPOSAL

A. Details of EnergyNorth's Proposed Decoupling Mechanism

1. Introduction

Q. Please provide a general description of the decoupling mechanism that EnergyNorth is proposing.

A. The Company is proposing a RPC decoupling mechanism that will be applied to all customers in all firm tariffed rate classes. The proposed RDM provides for separate winter and summer rate adjustments that correspond to the seasonality of the Company's distribution rates and Cost of Gas clause.

Q. Please list the RDM components that define EnergyNorth's proposed RDM.

A. EnergyNorth's proposed RDM is defined by the following RDM design components:

1) Basis for the true up calculation;
2) Rate classes to be included in the RDM;
3) Rate classes to be included in separate true-up customer groups;
4) Approach for returning RDM revenue surplus or recovering revenue shortfall from customers;
5) Frequency and timing of RDM rate adjustment filing;
6) Adjustments to Actual and Target revenues;
7) Treatment of new customers; and
8) Customer impact protections.

I will describe, explain and support these components of the Company's proposed RDM in the following sections of my testimony.

2. Basis for the true up calculation

Q. Please explain the approach that the Company is proposing for the true up calculation.

A. As described earlier in my testimony, the Company's proposed decoupling mechanism is a RPC RDM. A RPC RDM is critical to providing the Company with some opportunity to earn a reasonable return between rate cases, and retain revenues related to the growth in customers. Our RDM research indicates that RPC decoupling mechanisms are most common for gas LDCs because LDCs are experiencing significant customer growth that is related to the strong economic incentives for conversion from oil to gas. A RPC decoupling mechanism provides growth in revenues to partially offset the costs to connect the new customers.

3. Rate classes to be included in the RDM

Q. Which rate classes will be included in the Company's proposed RDM?

A. EnergyNorth proposes to include all firm tariffed customer classes in the RDM true up calculations, and to apply RDM rate adjustments to all firm rate classes.

It is appropriate to apply the RDM to all customers because (a) all EnergyNorth firm customers are eligible for the Company's EE programs and (b) Residential and C&I customers are likely to implement conservation efforts that are not directly associated with EnergyNorth's EE programs.

The RDM will not be applied to special contract customers because special contract customers are not eligible for EE programs, and special contract customers are not charged other rate adjustments, such as the LDAC.

4. True up Customer Groups

Q. How will the Company's customers be grouped for purposes of administering the proposed RDM?

A. The Company's firm rate classes will be combined into RDM Customer Groups as shown in Table 8 below:

Table 8: RDM Customer Groups

RDM Customer Group	Firm Rate Classes
Residential Non-Heating	R-1
Residential Heating	R-3, R-4
Commercial and Industrial	G-41, G-42, G-43, G-51, G-52, G-53, G-54

Q. Please explain why you are proposing to combine rate classes into the three rate groups that you have listed in Table 8, rather than keeping each C&I rate class separate?

A. I am not proposing to keep each rate class separate because C&I customers are assigned to the C&I rate classes based on their annual usage and percent of their annual usage that occurs in the Winter period. The potential shifting of C&I customers between rate classes may cause unintended results in the RDM calculations; these unintended results are avoided if all C&I customers are included in the same RDM customer group. In addition, I have prepared Attachment GHT/DECPL-5 to provide a summary of the variability in normal revenue per customer for each of the C&I rate classes[33]. Attachment GHT/DECPL-5 demonstrates that there is significant year-to-year variability in normal revenue per customer for several C&I rate classes, especially the large use classes G-42, G-43 and G-53. If the Company's RDM provided for separate revenue true ups and separate RDM rate adjustments for each C&I rate class, the calculation of the seasonal revenue shortfall/surplus would be significantly affected by whether the target RPC for that rate class had been determined in an "up" year or a "down" year. Separate RDM rate adjustments for each C&I rate class would likely result in noticeable rate volatility for some C&I rate classes.

This potential volatility is avoided with a single RDM true up calculation for all C&I rate classes combined. Attachment GHT/DECPL-5 also demonstrates that the normal revenue per customer for all C&I rate classes combined is relatively stable. Thus, the seasonal calculated revenue shortfall or surplus for the combined C&I RDM customer group will not be affected by the year (i.e. the rate case test year) that is used to determine the target RPC.

5. Frequency and timing of RDM rate adjustment filing

Q. Please explain how often and when the RDM rate adjustments will be made.

A. The Company will calculate separate Winter and Summer season RDM rate adjustments based on the prior winter or summer season RDM revenue shortfalls or surpluses, for

[33] This analysis is based on the same actual and weather normalized billing determinant data that was used to prepare Attachment GHT/DECPL-7; monthly revenues are based on 2016 rates, and R-4 revenues are calculated at R-3 rates. Additional discussion of the decoupling data base and analysis is provided in Section V.10.

each RDM customer group. Separate seasonal RDMs would reduce the shifting of charges or credits (associated with RDM revenue shortfalls or surpluses) between temperature sensitive and non-temperature sensitive customers.

6. Adjustments to Target and Actual revenues

Q. Please explain how the RDM Target Revenue per Customer will be determined.

A. The initial Winter and Summer RDM Target Revenue per Customer will be set in this proceeding; the target RPCs for each RDM customer group and for each season will be calculated in the Company's compliance filing by summing the allowed revenues by season for each RDM customer group, divided by the seasonal average number of RDM customer group customers.

For each seasonal RDM filing, the RDM target RPCs will be adjusted to account for the rates that were in effect during the recently-completed RDM season, because the Company's base distribution rates are adjusted annually, effective every July 1 to reflect the CIBS rate adjustment. The derivation of the Target Revenue per Customer by RDM Rate Group, based on the Company's proposed rates, is included as Attachment GHT/DECPL-9.

Q. Please explain how actual revenues per customer will be calculated.

A. Winter and Summer Actual Revenues per Customer, by RDM Rate Group, will be calculated directly from the actual booked base distribution revenues and actual booked number of average customers. The Company will calculate the RDM Actual Revenues per Customer and the RDM revenue shortfall/surplus monthly on a calendar month basis.

At the end of each season, the Company will sum all of the monthly data and will calculate RPC on a seasonal basis.

7. Treatment of new customers

Q. How will new customers be treated in the Company's proposed RDM?

A. The Company will include new, non-expansion rate customers in the RDM calculations. These customers will be charged the rate adjustments associated with the RDM and the calculations of actual revenues per customer will include the new customers. The Company proposes that expansion rate new customers be excluded from the RDM calculation and not be charged or credited the RDM rate. The reason for this proposed exclusion is that the expansion rates include a higher delivery rate than existing or new (non-expansion) customer rates. For example, expansion rate R-6 (Residential Heating - Expansion) delivery rates are 30% higher than existing R-3 Residential Heating rates. If R-3 and R-6 customers were included in the same RDM customer group, then the revenues associated with the 30% R-6 delivery premium, all else being equal, would be returned to all customers through the RDM. This defeats the purpose of the expansion rates, whereby the delivery premium revenue supports the incremental costs of the expansion investment.

An alternative treatment that creates a separate RDM customer group for expansion customers is not appropriate. Currently there are no expansion rate customers. Therefore, the near-term population of expansion rate customers will be small and would likely result in an unstable RDM calculation. For these reasons the Company proposes to exclude expansion rate customers from the RDM until they are migrated into the existing rate schedules once their expansion term expires.

8. Customer impact protections

Q. Is EnergyNorth proposing a customer impact cap on the annual RDM adjustments?

A. Yes. The Company's proposed RDM includes a plus or minus 5 percent cap on rate changes; that is, the RDM increase or decrease to rates will be limited to 5 percent of distribution revenues (revenues that exclude charges for COG and LDAC revenues, and all other related charges). Any excess over the 5 percent upper or lower limit will be deferred for recovery in the next period with carrying charges at the prime lending rate. The proposed 5 percent customer impact cap, based on distribution rates, is approximately equivalent to a 2.5 percent increase in total bills.[34]

Lastly, the proposed RDM includes a provision that the Company will file for a mid-period adjustment if the projected RDM end of season under or over collection exceeds 10 percent of total projected seasonal distribution revenues.

9. Summary

Q. To summarize, please describe how the Company's proposed RDM will be calculated and applied.

A. As a general summary of my testimony in this section, summer and winter RDM adjustments will be determined prior to the start of each season by (1) calculating Target

[34] The percent increase based on all charges, including COG and LDAC rates in addition to distribution rates, will depend on the level of the COG and LDAC rates at any time.

Revenue[35] per customer for that season for each RDM Rate Group; (2) calculating actual revenue per customer for that season (i.e. the most recently completed season) for each RDM Rate Group; (3) calculating the difference between Target and actual revenue per customer; (4) calculating RDM Rate Group revenue shortfalls or surpluses by multiplying the revenue per customer differences times actual average monthly customers for each rate group; (5) calculating the Company total revenue shortfall or surplus by summing the RDM Rate Group revenue shortfalls or surpluses; and lastly (6) calculating the RDM adjustment by dividing the Company total revenue shortfall or surplus by projected therm deliveries for the upcoming season.

This adjustment will also include a reconciliation of the same season prior period authorized Company total revenue shortfall or surplus to actual revenues recovered or returned in the same season prior period.

10. Additional RDM details

Q. Have you prepared a schedule to illustrate how the RDM calculations would be made?

A. Yes, I have prepared Attachments GHT/DECPL-6 and GHT/DECPL-7 for that purpose. To prepare this hypothetical illustration I used actual Company data for the period from January 2010 - 2016 to show:

[35] The summer and winter Target Revenue per customer for each rate group will be determined from the revenue requirement approved in this proceeding.

The calculation of the Target RPC for the three customer groups (Residential Heating, Residential Non-Heating, and C&I). I developed the Target RPC for a 2010 Test Year, which is shown in Attachment GHT/DECPL-6.

The calculation of actual RPCs, RDM revenue shortfalls or surpluses per customer, and total revenue shortfalls or surpluses for Summer 2011 through Summer 2016, which is shown in Attachment GHT/DECPL-7.

The hypothetical calculations for all years (2010-2016) utilize 2016 rates.

Q. Please summarize the results of the analysis that is provided in Attachment GHT/DECPL-9.

A. I have prepared Table 9,[36] below, to summarize the revenue shortfalls, by season, from Summer 2011 through Summer 2016:

[36] Please see Attachment GHT/DECPL-7 for supporting calculations. Also, Table 10 below provides further explanatory information regarding these hypothetical results.

Table 9: RDM Class Accrual Analysis

	Accrued Revenue Shortfall (Surplus) $			
	R-1	R-3, R-4	C&I	Total
Summer 2011	$763	$207,719	$15,778	$224,260
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815
Summer 2012	$1,846	$373,048	$71,814	$446,707
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005
Summer 2013	-$592	$288,368	-$124,816	$162,960
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131
Summer 2014	-$687	$175,820	-$500,720	-$325,587
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837
Summer 2015	$3,499	$356,979	-$421,197	-$60,720
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184
Summer 2016	$3,656	$381,248	-$299,262	$85,642

[1] Utilizing a 2010 base year and billing determinants and 2016 billing rates.

Q. How will the seasonal revenue shortfalls or surpluses be billed to customers?

A. As described above, a singular rate per therm will be calculated each season based on the sum of the accrued class RDMs, and billed the subsequent matching season. For example, the Summer 2011 total accrued shortfall of $224,260 will be collected over the 2012 summer period. The rate per therm will be calculated on a total system basis and applied to all firm rate classes.

These accrued seasonal totals must first pass the 5% test prior to calculating the billing rate per therm. If the RDM accrual is a shortfall and exceeds 5% of total distribution revenues for that season, then the dollars in excess of 5% will be deferred for recovery until the next applicable season. For example, the Winter 2011/2012 total RDM value exceeded 5%; therefore, the excess dollars would have been deferred until the following

2012/2013 winter period. The 5% test applies to the sum of the calculated RDM and deferred RDM for the applicable period. This may result in deferred dollars not being collected for multiple seasons, if the RDM continues to yield a surcharge in excess of the 5% limit. However, the Company's proposal includes a provision whereby if the calculated RDM exceeds 10%, the Company may petition the Commission for a more immediate recovery of the RDM dollars in excess of 10%.

Based on the sample data, the billing of the calculated seasonal RDMs is as follows:

Table 10: Seasonal RDM Accruals, Deferrals, and Billing Rates

Hypothetical RDM

	Accrued Revenue Shortfall (Surplus) $				+/- 5.0% Limit Test		Billable Amounts		
Season	R-1	R-3, R-4	C&I	Seasonal Accrued Total	klokoshjlzih	Deferral	Adjusted Total	Adjusted % of distribution revenues	Rate Per Therm
Summer 2011	$763	$207,719	$15,778	$224,260	1.0%	$0	Billing Lag		
Winter 2011 - 2012	$3,978	$2,233,390	$1,732,447	$3,969,815	9.8%	$1,937,300			
Summer 2012	$1,846	$373,048	$71,814	$446,707	2.1%	$0	$224,260	1.0%	$0.0061
Winter 2012 - 2013	-$15,033	$346,231	-$175,192	$156,005	0.3%	$0	$2,032,515	5.0%	$0.0178
Summer 2013	-$592	$288,368	-$124,816	$162,960	0.7%	$0	$446,707	2.1%	$0.0113
Winter 2013 - 2014	-$45,365	-$1,469,303	-$1,964,463	-$3,479,131	-7.1%	-$1,022,620	$2,093,305	4.7%	$0.0180
Summer 2014	-$687	$175,820	-$500,720	-$325,587	-1.4%	$0	$162,960	0.7%	$0.0042
Winter 2014 - 2015	-$3,697	-$910,895	-$1,847,245	-$2,761,837	-5.5%	-$1,261,730	-$2,456,511	-5.0%	($0.0207)
Summer 2015	$3,499	$356,979	-$421,197	-$60,720	-0.3%	$0	-$325,587	-1.4%	($0.0075)
Winter 2015 - 2016	$5,915	$2,509,631	$1,171,639	$3,687,184	8.4%	$240,762	-$2,522,728	-5.0%	($0.0211)
Summer 2016	$3,656	$381,248	-$299,262	$85,642	0.4%	$0	-$60,720	-0.3%	($0.0014)
Winter 2016 - 2017							$2,184,693	5.0%	$0.0180
Summer 2017							$85,642	0.4%	$0.0021
					Outstanding Deferrals	Winter	$240,762		
						Summer	$0		

Based on a 2010 base year and billing determinants, and 2016 billing rates.

The results of the above calculations are shown graphically below:

Chart 2a: Cumulative Effect of RDM - Summer

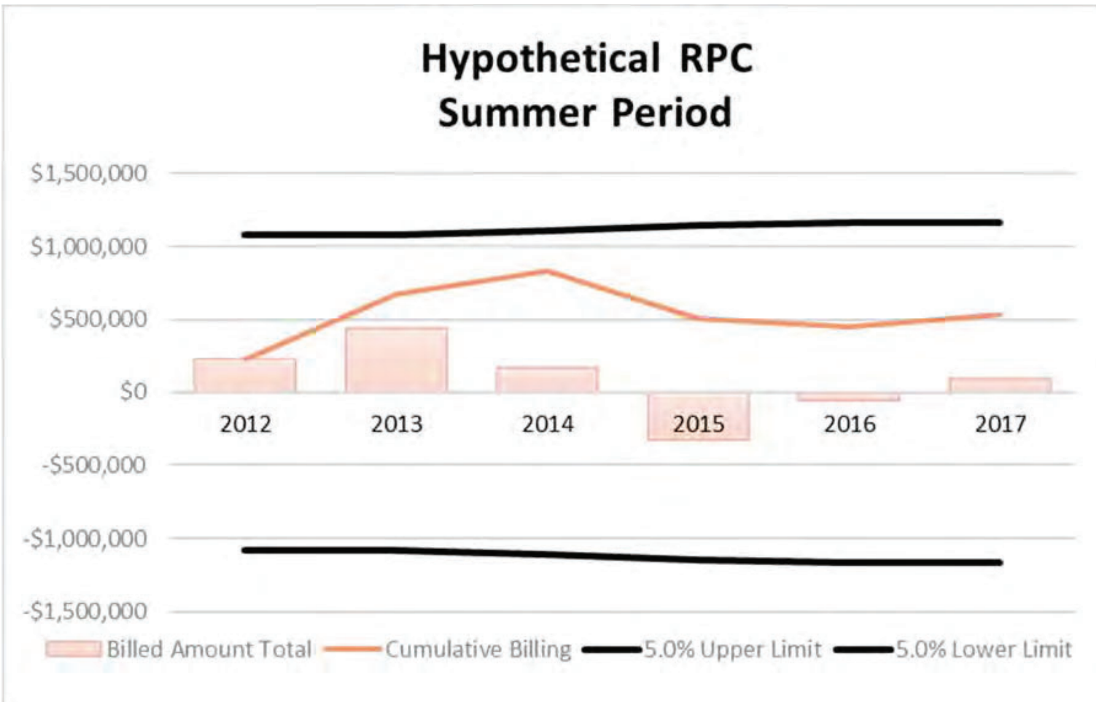
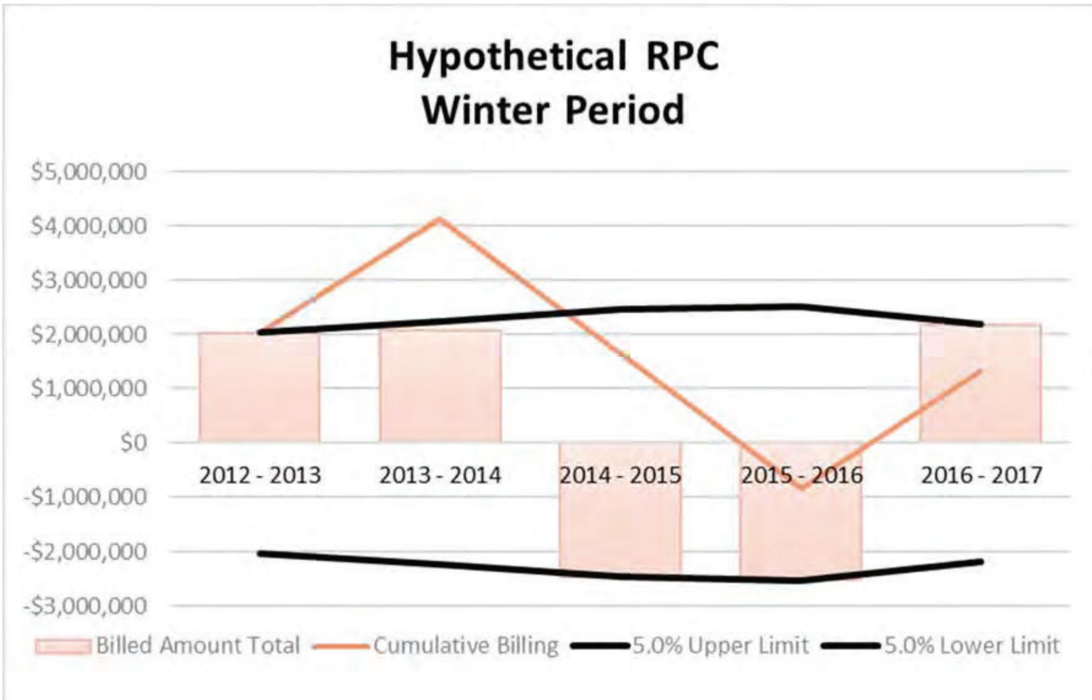


Chart 2b: Cumulative Effect of RDM - Winter



Tables 9 and 10 demonstrate that if an RDM had been in effect during this period, the RDM rate accrual would have been a debit (charge) in 5 seasons and a credit in the other 6 seasons. The largest shortfall is $3,969,815, or 9.8% of distribution revenues and the largest surplus is -$3,479,131, or 7.1% of distribution revenues. On a cumulative basis, the five-year cumulative RDM shortfall would have been $2,105,298; or 0.6% of total distribution revenues.

On a billed basis, the RDM rate adjustments would have been generally small. Seven of the seasons would have resulted in a charge to customer bills, and four seasons would have been credits. The 5 percent customer impact cap would have been applied in two of the five winter seasons, to be recovered in following winter periods. The 5 percent cap would not have been exceeded in any of the six summer periods. Lastly, there is a hypothetical shortfall to be collected in the Winter 2017 – 2018.

Q. Please describe the timing of RDM calculations, filings, and rate adjustments.

A. I have prepared Attachment GHT/DECPL-8 to illustrate the timing of RDM calculations, filings, and rate adjustments. Referring to Attachment GHT/DECPL-8, the Winter or Summer RDM Adjustment Factor will be based on the calculations related to the most recently completed corresponding Winter or Summer RDM prior period. The Company proposes to make its Winter RDM filing together with its annual LDAC filing, on or before September 1 of each year and each Summer RDM filing will be made on or before March 1 of each year. Each Winter and Summer RDM filing will also include a final reconciliation of actual and allowed RDM revenues for the prior same period.

Q. Has the Company prepared an RDM tariff provision?

A. Yes. The Company's proposed Local Distribution Adjustment Clause ("LDAC"), which includes provisions for the RDM in Section 18(C.1) of the LDAC, is included in the proposed tariff in this proceeding. Section 18(C.1) describes the manner in which the Company proposes to annually true up Actual Revenues versus Target Revenues, and to recover the RDM Adjustment Factors through rates. Section 18(C.1) also describes the documentation that the Company will provide with annual RDM filings. This new RDM language replaces the current "Lost Revenue Adjustment Mechanism Allowable for LDAC" provisions, as the proposed RDM replaces the LRAM in its entirety.

Q. Does this complete your testimony?

A. Yes, it does.

Liberty Utilities (EnergyNorth Natural Gas) Corp.
U.S. LDCs with Decoupling Mechanisms

Northeast

CT
- Connecticut Natural Gas Corporation

MA
- Bay State Gas Company
- Boston Gas Company
- Colonial Gas Company
- Fitchburg Gas & Electric
- Liberty Utilities (New England Natural Gas Company) Corp.
- NSTAR Gas Company

NJ
- New Jersey Natural Gas Company
- South Jersey Gas Company

NY
- Brooklyn Union Gas Company
- Central Hudson Gas & Electric Corporation
- Consolidated Edison Company of New York, Inc.
- Corning Natural Gas Corporation
- KeySpan Gas East Corporation
- National Fuel Gas Distribution Corporation
- New York State Electric & Gas Corporation
- Niagara Mohawk Power Corporation
- Orange and Rockland Utilities, Inc.
- Rochester Gas and Electric Corporation
- St. Lawrence Gas Company, Inc.

RI
- Rhode Island Gas & Electricity (National Grid-RI)

VT
- Vermont Gas Systems, Inc.

South

AR
- Arkansas Oklahoma Gas Corp.
- Black Hills Energy Arkansas, Inc.
- CenterPoint Arkansas

GA
- Atlanta Gas Light Company

LA
- Atmos - LA

MD
- Baltimore Gas and Electric Company
- Chesapeake Utilities - Maryland
- Columbia Gas of Maryland
- Sandpiper Energy
- Washington Gas Light (WGL)

MS
- Atmos - Mississippi

NC
- Piedmont Natural Gas Company, Inc.
- Public Service Company of North Carolina, Incorporated

SC
- Piedmont Natural Gas Company - SC

TN
- Chattanooga Gas Company

VA
- Columbia Gas of Virginia, Incorporated
- Virginia Natural Gas, Inc.
- Washington Gas Light

Midwest

IL
- Ameren Illinois Company
- North Shore Gas Company
- Peoples Gas Light and Coke Company

IN
- Citizens Energy Group
- Indiana Gas Company, Inc.
- Southern Indiana Gas and Electric Company, Inc.

MI
- Michigan Gas Utilities Corporation

MN
- CenterPoint Energy - MN
- Minnesota Energy Resources Corporation

WI
- Wisconsin Public Service Corporation

West

AZ
- Southwest Gas Corporation

CA
- Pacific Gas and Electric Company
- San Diego Gas & Electric Co.
- Southern California Gas Company
- Southwest Gas Corporation

CO
- Public Service Company of Colorado

ID
- Avista Gas

NV
- Southwest Gas Corporation

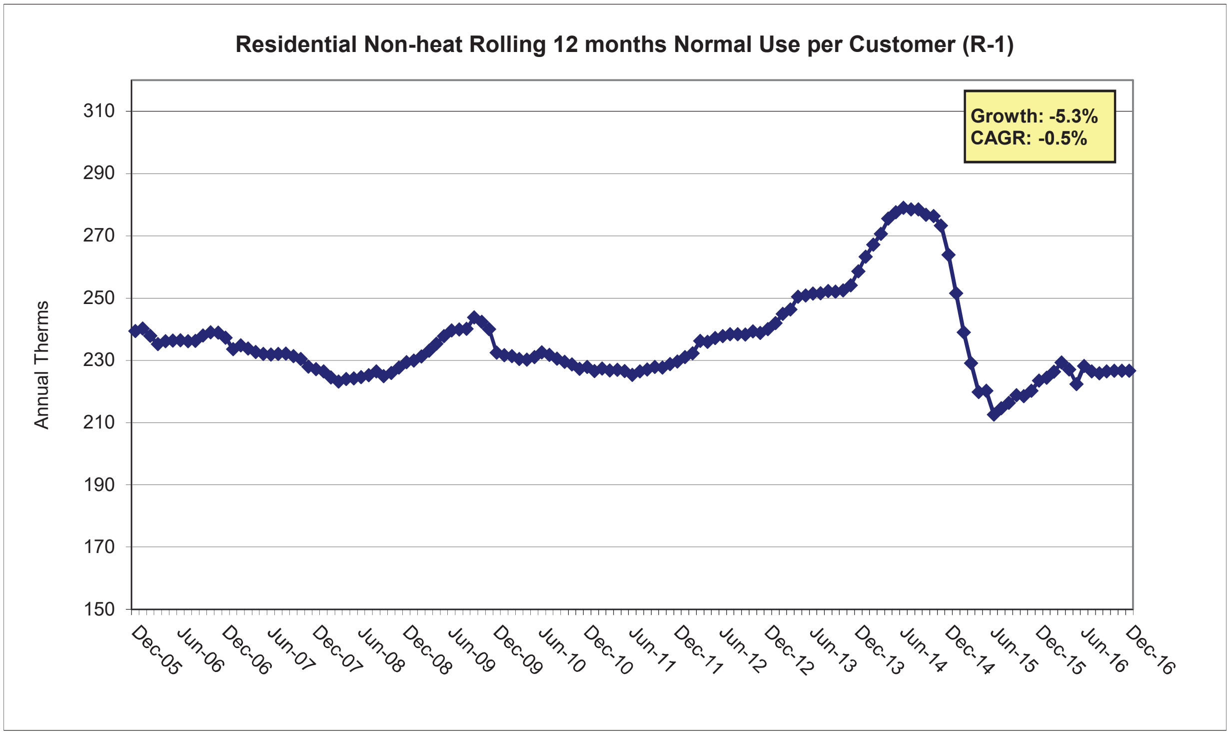
OR
- Avista Utilities
- Cascade Natural Gas Corporation
- Northwest Natural Gas Company

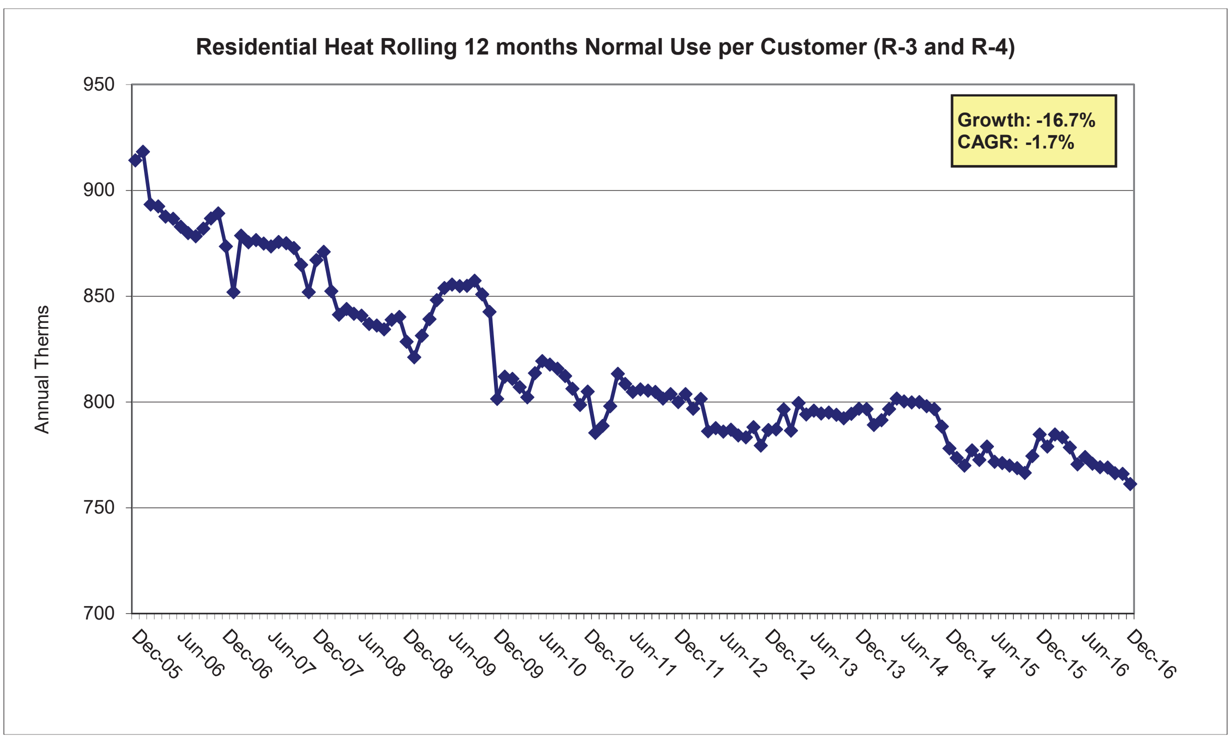
UT
- Questar Gas Company

WA
- Avista Corporation
- Cascade Natural Gas Corporation
- Puget Sound Energy, Inc.

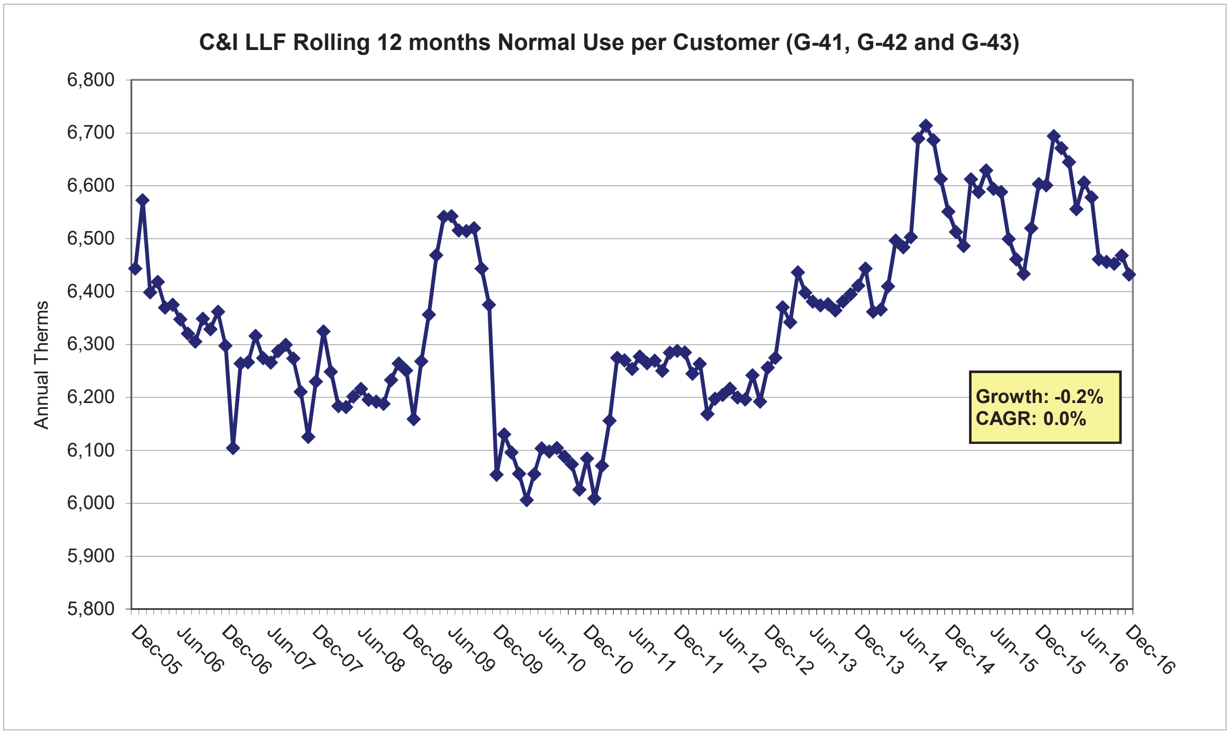
WY
- Black Hills Northwest Wyoming Gas Utility Company, LLC
- Questar Gas - WY

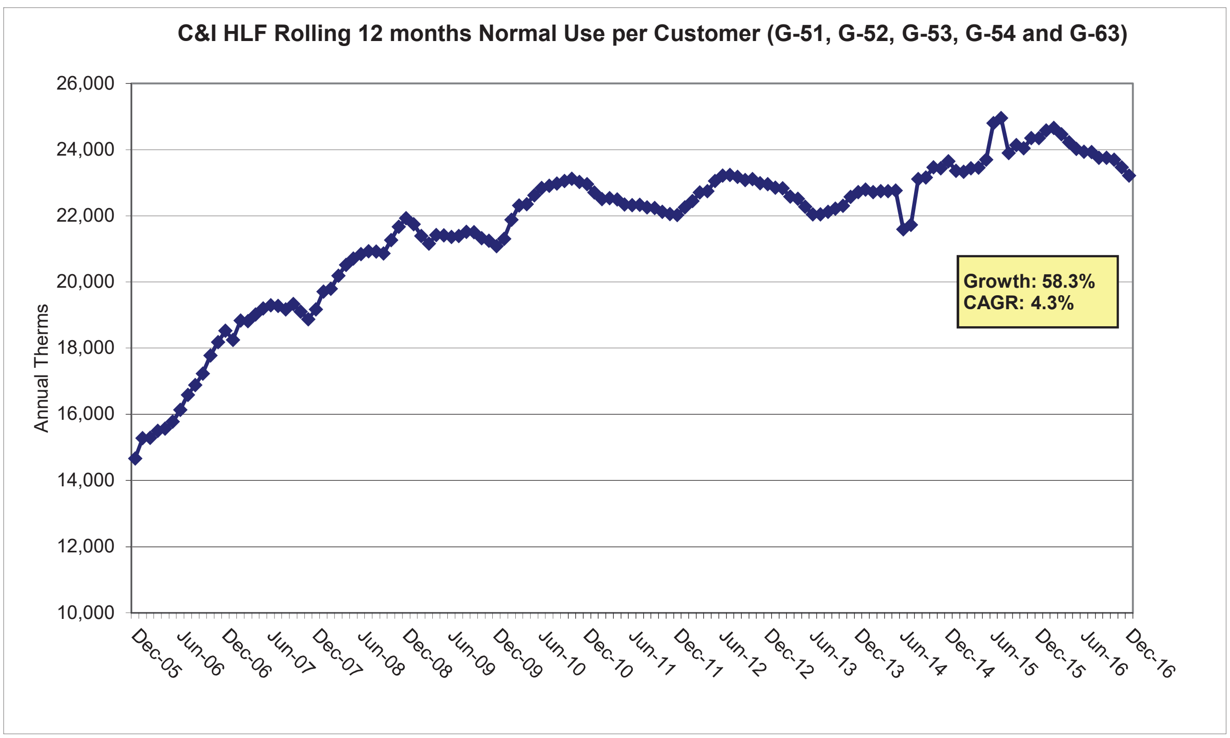
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016



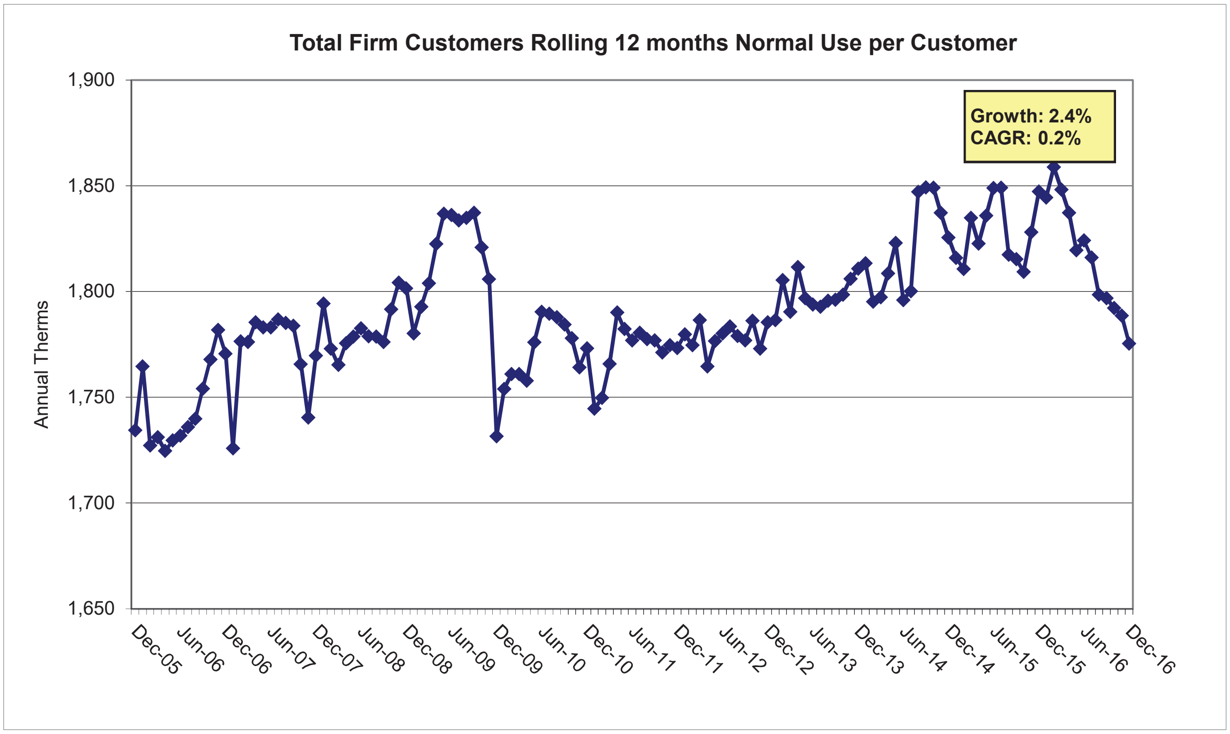


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016

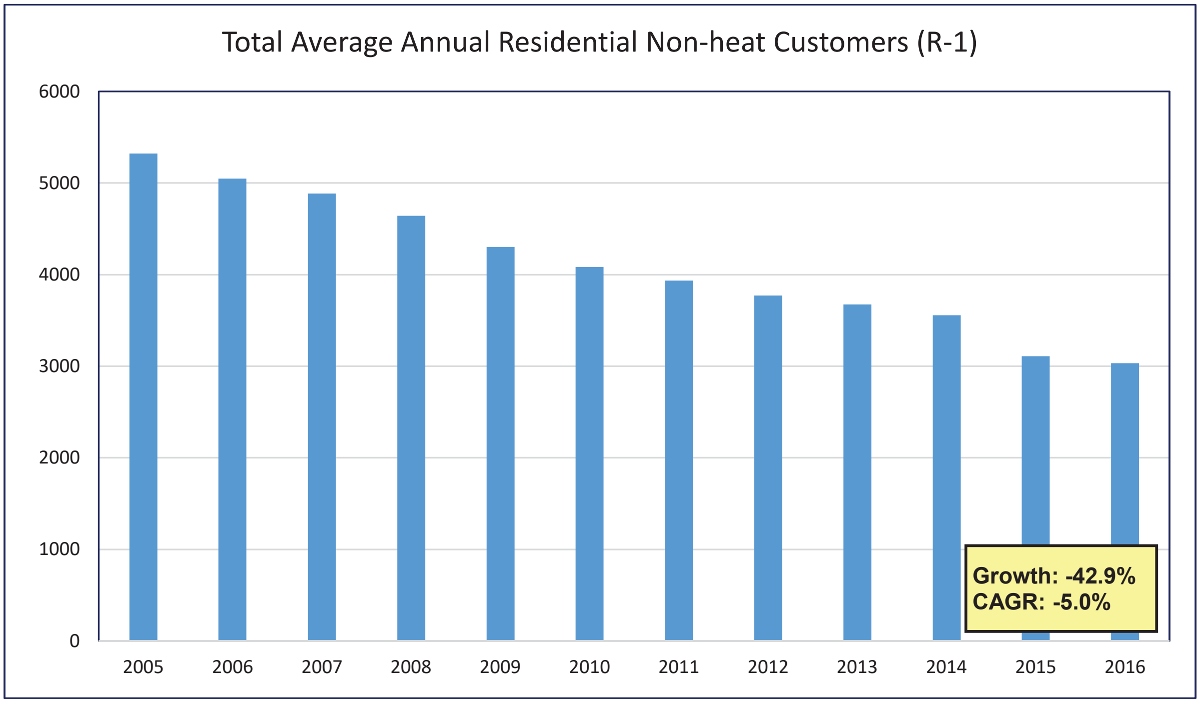


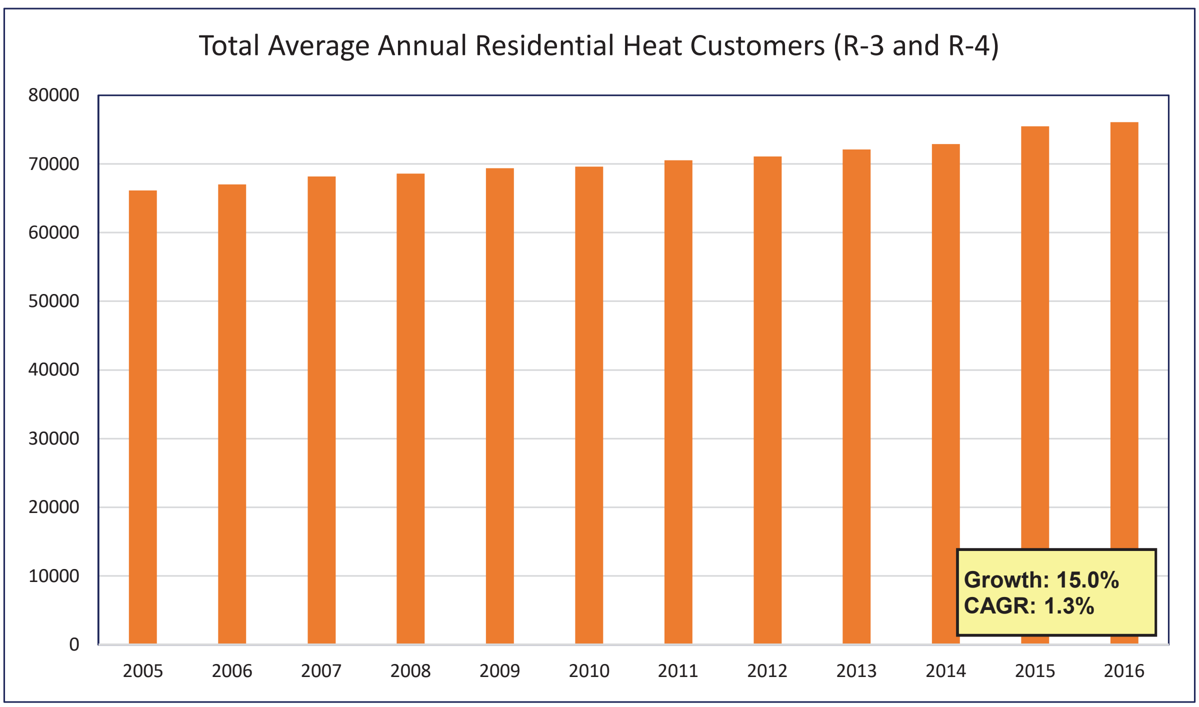


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Normalized Use per Customer, 2005 – 2016

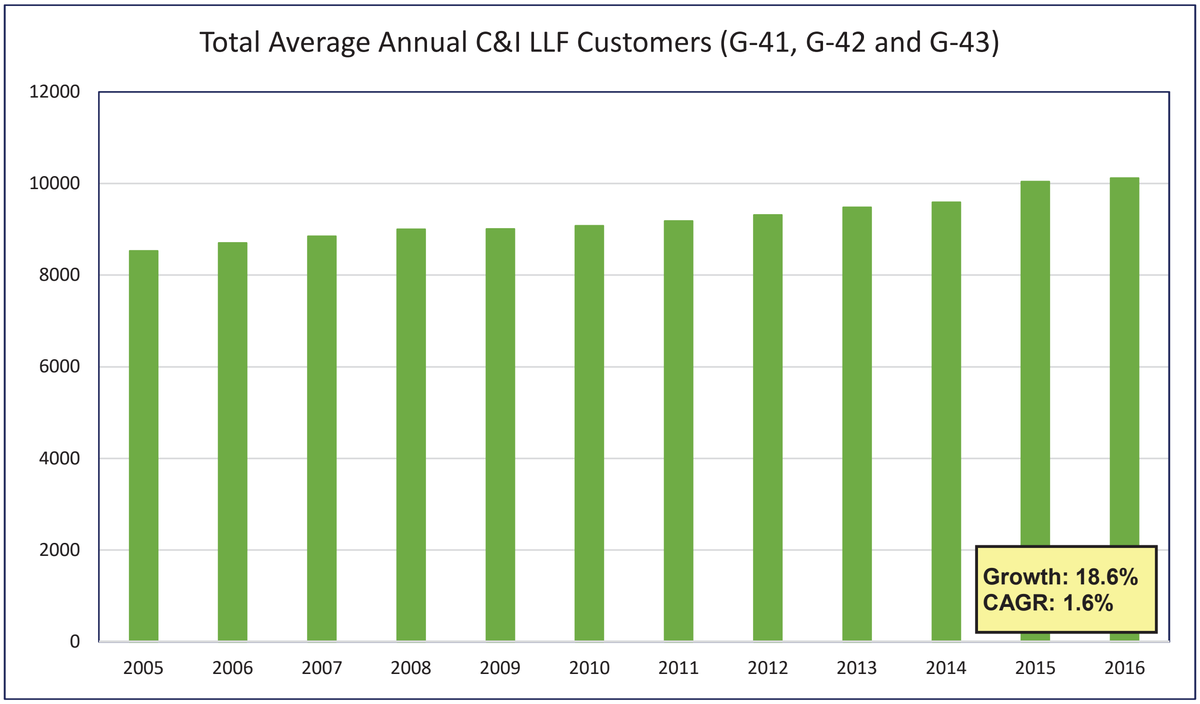


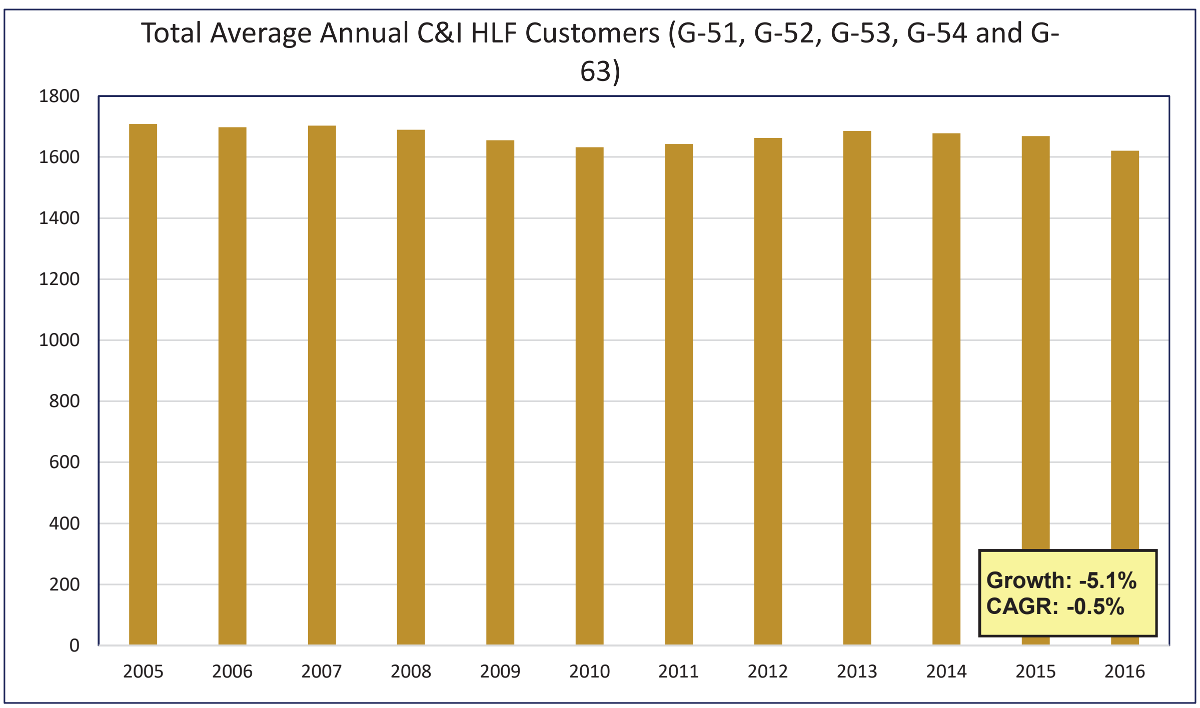
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016



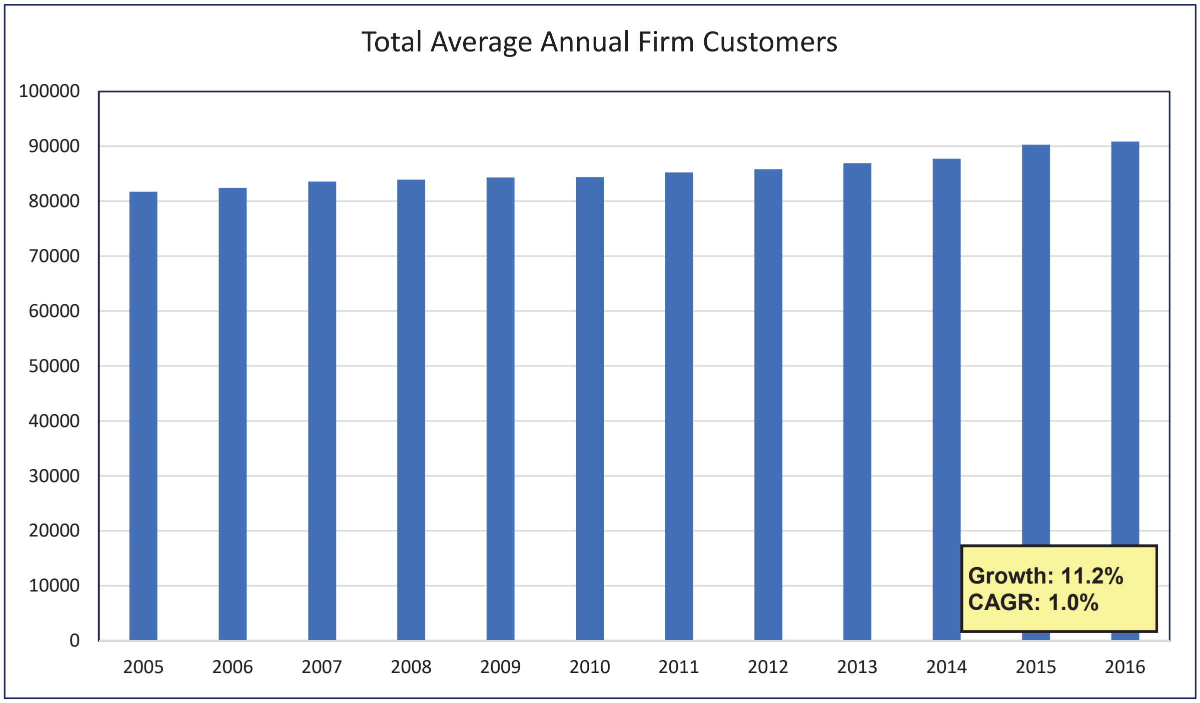


Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016

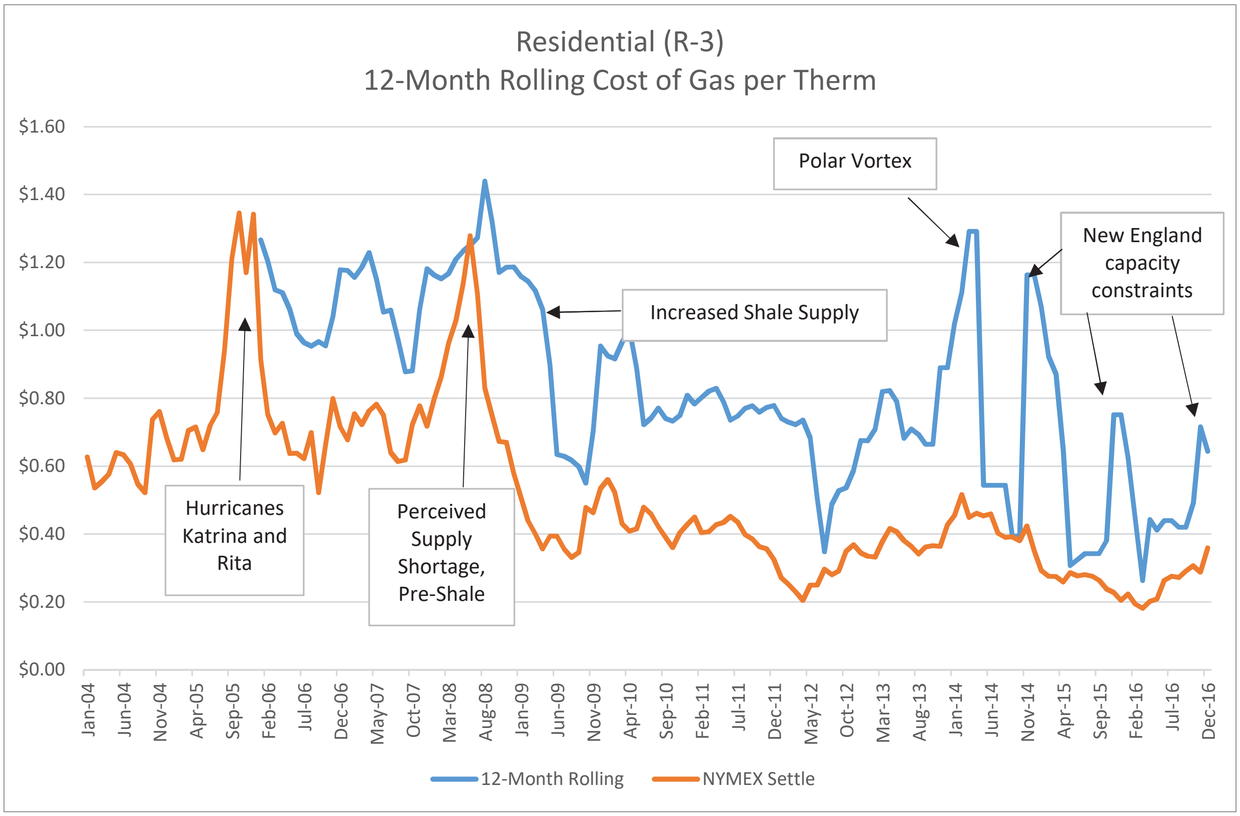




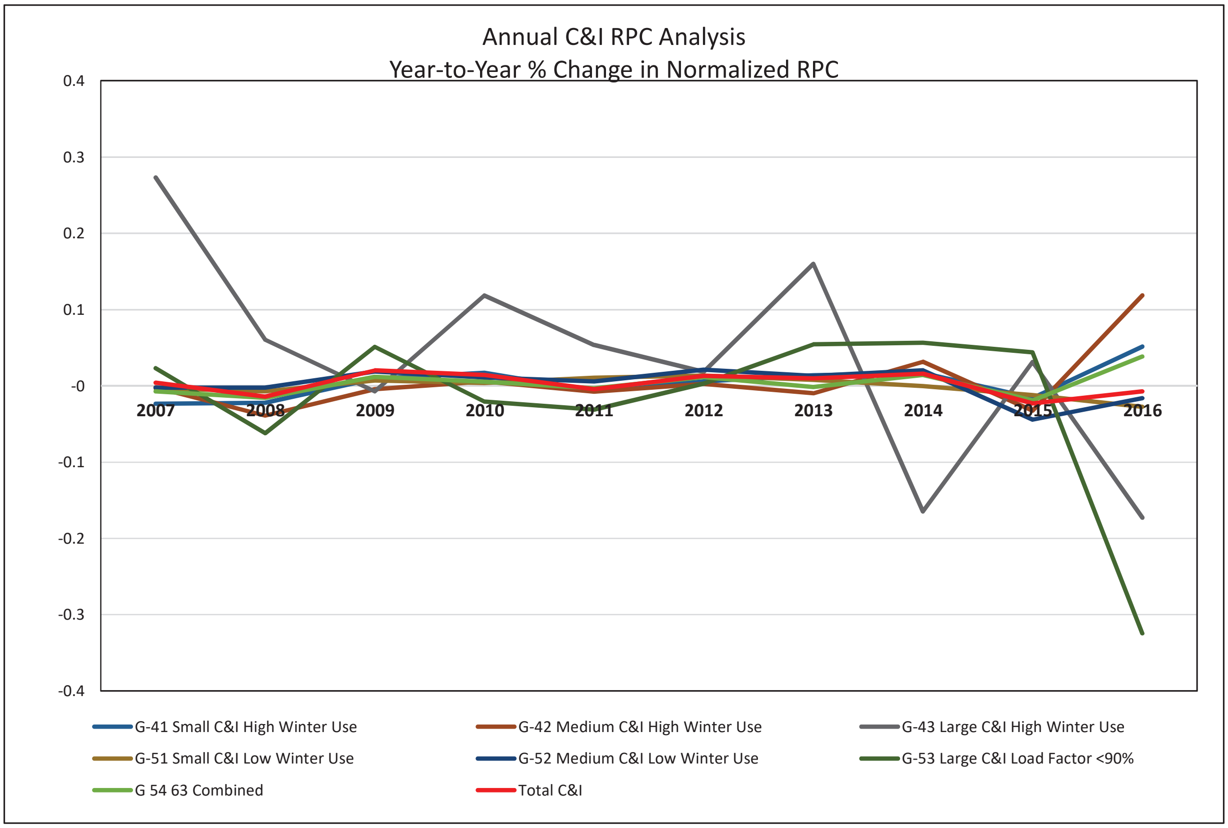
Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Annual Customers, 2005 – 2016



Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth 12-Month Rolling R-3 Unit Cost of Gas, 2006 – 2016



Liberty Utilities (EnergyNorth Natural Gas) Corp.
EnergyNorth Year-to-Year C Revenue Per Customer



Liberty Utilities (EnergyNorth Natural Gas) Corp.
Hypothetical RDM Target Revenues: 2010 Billing Determinants, 2016 rates

Line	Class		2010 Base Rate Revenues at 2016 rates		Average Customers		Target Revenue per Customer	
			Winter	Summer	Winter	Summer	Winter	Summer
1			(A)	(B)	(C)	(D)	(E)	(F)
2	Residential Non-heat	R-1	$499,480	$435,831	4,103	4,060	**$121.73**	**$107.34**
3	Residential Heat	R-3, R-4	$24,336,541	$12,789,369	70,111	69,146	**$347.12**	**$184.96**
4	Total Residential		$24,336,541	$12,789,369	70,111	69,146		
5	Small, High Winter Use	G-41	$6,836,739	$2,931,513	7,697	7,382		
6	Medium, High Winter Us	G-42	$8,189,424	$2,927,026	1,503	1,490		
7	Large High Winter Use	G-43	$1,077,990	$419,234	42	40		
8	Total High Winter Use		$ 16,104,153	$ 6,277,773	9,242	8,912		
9	Small, Low Winter Use	G-51	$791,325	$592,542	1,282	1,249		
10	Medium, Low Winter Us	G-52	$909,699	$597,965	311	309		
11	Large Low Winter Use	G-53	$745,035	$462,344	37	36		
12	Large Use, LF >90%	G-54	$456,463	$361,789	21	20		
13	Total Low Winter Use		$2,902,522	$2,014,640	1,651	1,615		
14	Total C&I		$19,006,674	$8,292,413	10,893	10,527	**$1,744.83**	**$787.74**
15	**TOTAL**		**$43,343,216**	**$21,081,782**	**81,004**	**79,673**		

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2011					Winter 2011 - 2012				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Residential Non-heat	R-1	$121.73	$107.34	$418,346	3,904	$107.15	$0.20	$763	$467,375	3,872	$120.70	$1.03	$3,978
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,793,077	70,289	$182.01	$2.96	$207,719	$22,566,735	71,446	$315.86	$31.26	$2,233,390
3	Total Residential				$12,793,077					$22,566,735				
4														
5	Small, High Winter	G-41			$2,959,325	7,483				$6,350,235	7,844			
6	Medium, High Winter	G-42			$2,954,098	1,526				$7,430,603	1,539			
7	Large High Winter	G-43			$438,949	41				$1,057,130	38			
8	Small, Low Winter	G-51			$597,278	1,265				$782,543	1,306			
9	Medium, Low Winter	G-52			$651,079	310				$861,902	305			
10	Large Low Winter	G-53			$452,023	38				$717,814	38			
11	Large LF > 90%	G-54			$346,494	19				$415,959	19			
12	Total C&I		$1,744.83	$787.74	$8,399,247	10,682	$786.27	$1.48	$15,778	$17,616,186	11,089	$1,588.60	$156.23	$1,732,447
13	TOTAL				$21,610,669	84,876			$224,260	$40,650,296	86,407			$3,969,815
14	Seasonal RDM Adjustment								$224,260					$3,969,815

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (C), (H)	Workpapers
Columns (D), (I)	Workpapers
Columns (E), (J)	Column (C) / Column (D); Column (H) / Column (I)
Columns (F), (K)	Column (B) - Column (E), Column (A) - Column (J)
Columns (G), (L)	Column (F) x Column (D), Column (I) x Column (K)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

			Target Revenue per Customer		Summer 2012					Winter 2012 - 2013				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
Line			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Residential Non-heat	R-1	$121.73	$107.34	$400,490	3,748	$106.85	$0.49	$1,846	$462,364	3,675	$125.82	($4.09)	($15,033)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,729,928	70,842	$179.70	$5.27	$373,048	$24,512,126	71,614	$342.28	$4.83	$346,231
3	Total Residential				$12,729,928					$24,512,126				
4														
5	Small, High Winter	G-41			$3,004,719	7,602				$7,165,823	7,940			
6	Medium, High Winter	G-42			$2,947,729	1,537				$8,320,931	1,566			
7	Large High Winter	G-43			$457,215	40				$1,357,501	42			
8	Small, Low Winter	G-51			$620,045	1,295				$836,321	1,310			
9	Medium, Low Winter	G-52			$656,952	312				$935,860	313			
10	Large Low Winter	G-53			$462,561	39				$728,336	39			
11	Large LF > 90%	G-54			$316,383	14				$422,583	19			
12	Total C&I		$1,744.83	$787.74	$8,465,605	10,838	$781.12	$6.63	$71,814	$19,767,356	11,229	$1,760.44	($15.60)	($175,192)
13	TOTAL				$21,596,022	85,428			$446,707	$44,741,847	86,517			$156,005
14	Seasonal RDM Adjustment								$446,707					$156,005

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (C), (H)	Workpapers
Columns (D), (I)	Workpapers
Columns (E), (J)	Column (C) / Column (D); Column (H) / Column (I)
Columns (F), (K)	Column (B) - Column (E), Column (A) - Column (J)
Columns (G), (L)	Column (F) x Column (D), Column (I) x Column (K)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2013					Winter 2013 - 2014				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)	(T)	(U)	(V)
1	Residential Non-heat	R-1	$121.73	$107.34	$394,169	3,667	$107.50	($0.16)	($592)	$493,821	3,684	$134.04	($12.31)	($45,365)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$12,953,149	71,591	$180.93	$4.03	$288,368	$26,877,471	73,198	$367.19	($20.07)	($1,469,303)
3	Total Residential				$12,953,149					$26,877,471				
4														
5	Small, High Winter	G-41			$3,003,894	7,699				$7,999,789	8,037			
6	Medium, High Winter	G-42			$3,119,974	1,575				$9,179,266	1,581			
7	Large High Winter	G-43			$518,306	45				$1,473,838	45			
8	Small, Low Winter	G-51			$623,216	1,305				$873,602	1,302			
9	Medium, Low Winter	G-52			$683,908	317				$1,000,744	315			
10	Large Low Winter	G-53			$471,235	38				$771,519	39			
11	Large LF > 90%	G-54			$371,274	23				$460,166	25			
12	Total C&I		$1,744.83	$787.74	$8,791,807	11,002	$799.09	($11.34)	($124,816)	$21,758,924	11,345	$1,918.00	($173.16)	($1,964,463)
13	TOTAL				$22,139,125	86,260			$162,960	$49,130,217	88,227			-$3,479,131
14	Seasonal RDM Adjustment								$162,960					($3,479,131)

Notes

Lines 1, 2, 12 Columns(A), (B)	Attachment GHT/DECPL-5
Columns (M), (R)	Workpapers
Columns (N), (S)	Workpapers
Columns (O), (T)	Column (M) / Column (N); Column (R) / Column (S)
Columns (P), (U)	Column (B) - Column (O), Column (A) - Column (T)
Columns (Q), (V)	Column (P) x Column (N), Column (S) x Column (U)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2014					Winter 2014 - 2015				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(W)	(X)	(Y)	(Z)	(AA)	(AB)	(AC)	(AD)	(AE)	(AF)
1	Residential Non-heat	R-1	$121.73	$107.34	$388,594	3,614	$107.53	($0.19)	($687)	$388,238	3,159	$122.90	($1.17)	($3,697)
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,245,331	72,562	$182.54	$2.42	$175,820	$27,385,331	76,270	$359.06	($11.94)	($910,895)
3	Total Residential				$13,245,331					$27,385,331				
4														
5	Small, High Winter	G-41			$3,192,573	7,800				$8,311,916	8,486			
6	Medium, High Winter	G-42			$3,234,255	1,590				$9,498,893	1,679			
7	Large High Winter	G-43			$643,606	40				$1,598,755	50			
8	Small, Low Winter	G-51			$627,080	1,302				$896,110	1,337			
9	Medium, Low Winter	G-52			$691,224	317				$1,040,248	321			
10	Large Low Winter	G-53			$463,789	35				$884,813	41			
11	Large LF > 90%	G-54			$394,871	20				$450,250	27			
12	Total C&I		$1,744.83	$787.74	$9,247,399	11,103	$832.84	($45.10)	($500,720)	$22,680,984	11,940	$1,899.54	($154.71)	($1,847,245)
13	TOTAL				$22,881,325	87,279			-$325,587	$50,454,553	91,369			-$2,761,837
14	Seasonal RDM Adjustment								($325,587)					($2,761,837)

Notes

Lines 1, 2, 12 Columns(K), (L)	Attachment GHT/DECPL-5
Columns (W), (AB)	Workpapers
Columns (X), (AC)	Workpapers
Columns (Y), (AD)	Column (W) / Column (X); Column (AB) / Column (AC)
Columns (Z), (AE)	Column (B) - Column (Y), Column (A) - Column (AD)
Columns (AA), (AF)	Column (Z) x Column (X), Column (AC) x Column (AE)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2015					Winter 2015 - 2016				
					Actual Summer Data			Shortfall (Surplus)		Actual Winter Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(AG)	(AH)	(AI)	(AJ)	(AK)	(AL)	(AM)	(AN)	(AO)	(AP)
1	Residential Non-heat	R-1	$121.73	$107.34	$329,373	3,101	$106.21	$1.13	$3,499	$368,107	3,073	$119.80	$1.93	$5,915
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,440,224	74,595	$180.18	$4.79	$356,979	$23,899,279	76,081	$314.13	$32.99	$2,509,631
3	Total Residential				$13,440,224					$23,899,279				
4														
5	Small, High Winter	G-41			$3,384,256	8,163				$7,115,946	8,445			
6	Medium, High Winter	G-42			$3,260,739	1,621				$8,015,245	1,664			
7	Large High Winter	G-43			$581,137	50				$1,415,144	50			
8	Small, Low Winter	G-51			$596,770	1,252				$776,716	1,274			
9	Medium, Low Winter	G-52			$681,154	311				$886,259	310			
10	Large Low Winter	G-53			$525,103	39				$753,469	36			
11	Large LF > 90%	G-54			$422,274	28				$463,685	27			
12	Total C&I		$1,744.83	$787.74	$9,451,432	11,463	$824.49	($36.74)	($421,197)	$19,426,465	11,805	$1,645.59	$99.25	$1,171,639
13	TOTAL				$23,221,030	89,159			-$60,720	$43,693,851	90,959			$3,687,184
14	Seasonal RDM Adjustment								($60,720)					$3,687,184

Notes

Lines 1, 2, 12 Columns(U), (V)	Attachment GHT/DECPL-5
Columns (AG), (AL)	Workpapers
Columns (AH), (AM)	Workpapers
Columns (AI), (AN)	Column (AG) / Column (AH); Column (AL) / Column (AM)
Columns (AJ), (AO)	Column (B) - Column (AI), Column (A) - Column (AN)
Columns (AK), (AP)	Column (AJ) x Column (AH), Column (AM) x Column (AO)

Actual Revenues are restated at 2016 rates

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Example RDM Calculations: Actual data

Line			Target Revenue per Customer		Summer 2016				
					Actual Summer Data			Shortfall (Surplus)	
			Winter	Summer	Revenues at 2016 rates	Customers	Revenue Per Customer	Per Customer	Total
			(A)	(B)	(AQ)	(AR)	(AS)	(AT)	(AT)
1	Residential Non-heat	R-1	$121.73	$107.34	$319,355	3,009	$106.13	$1.21	$3,656
2	Residential Heat	R-3, R-4	$347.12	$184.96	$13,592,320	75,548	$179.92	$5.05	$381,248
3	Total Residential				$13,592,320				
4									
5	Small, High Winter	G-41			$3,379,440	8,266			
6	Medium, High Winter	G-42			$3,368,966	1,670			
7	Large High Winter	G-43			$557,697	48			
8	Small, Low Winter	G-51			$594,855	1,237			
9	Medium, Low Winter	G-52			$661,495	307			
10	Large Low Winter	G-53			$463,563	32			
11	Large LF > 90%	G-54			$401,843	28			
12	Total C&I		$1,744.83	$787.74	$9,427,859	11,588	$813.57	($25.82)	($299,262)
13	TOTAL				$23,339,534	90,146			$85,642
14	Seasonal RDM Adjustment								$85,642

Notes

Liberty Utilities (EnergyNorth Natural Gas) Corp.
RDM Timeline

	Start	End
2017 Summer RDM True Up Period	5/1/2017	10/31/2017
Prepare Filing	2/2/2018	3/1/2018
Submit Filing	3/1/2018	3/1/2018
2017 Summer RDM Adjustment effective dates	5/1/2018	10/31/2018
2017-18 Winter RDM True Up Period	11/1/2017	4/30/2018
Prepare Filing	8/1/2018	8/31/2018
Submit Filing	9/1/2018	9/1/2018
2015-16 Winter RDM Adjustment effective dates	11/1/2018	4/30/2019
2018 Summer RDM True Up Period	5/1/2018	10/31/2018
Prepare Filing	2/1/2019	3/1/2019
Submit Filing	3/1/2019	3/1/2019
2018 Summer RDM Adjustment effective dates	5/1/2019	10/31/2019
2018-19 Winter RDM True Up Period	11/1/2018	4/30/2019
Prepare Filing	8/1/2019	8/31/2019
Submit Filing	9/1/2019	9/1/2019
2018-19 Winter RDM Adjustment effective dates	11/1/2019	4/30/2020

Liberty Utilities (EnergyNorth Natural Gas) Corp.
RDM Target Revenues: Permanent Rates

Line	Class		Rate Year 1 Pro-forma Base Rate Revenues		Rate Year 1 Average Customers		Rate Year 1 Target Revenue per Customer	
			Winter	Summer	Winter	Summer	Winter	Summer
1			(A)	(B)	(C)	(D)	(E)	(F)
2	Residential Non-heat	R-1	$577,648	$519,062	3,485	3,567	**$165.77**	**$145.53**
3	Residential Heat	R-3, R-4	$33,116,584	$16,129,504	76,309	76,479	**$433.98**	**$210.90**
4	Total Residential		$33,694,233	$16,648,566	79,794	80,045		
5	Small, High Winter Use	G-41	$9,797,494	$4,118,770	8,900	8,859		
6	Medium, High Winter Use	G-42	$11,032,480	$4,010,218	1,714	1,738		
7	Large High Winter Use	G-43	$2,207,715	$469,223	51	50		
8	Total High Winter Use		$ 23,037,690	$ 8,598,211	10,665	10,646		
9	Small, Low Winter Use	G-51	$1,064,357	$785,147	1,345	1,358		
10	Medium, Low Winter Use	G-52	$1,328,109	$779,591	318	320		
11	Large Low Winter Use	G-53	$1,161,177	$479,674	33	34		
12	Large Use, LF >90%	G-54	$668,388	$442,320	27	28		
13	Total Low Winter Use		$4,222,031	$2,486,733	1,723	1,740		
14	Total C&I		$27,259,721	$11,084,944	12,388	12,386	**$2,200.52**	**$894.95**
15	**TOTAL**		**$60,953,954**	**$27,733,510**	**92,182**	**92,431**		

A E F NE AMP IRE
BEF RE E
PUBLIC U ILI IE C MMI I N

Docket No. DG 20-105

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIREC E IM N

F

E EN E. MULLEN

July 31, 2020

THIS PAGE INTENTIONALL LEFT BLAN

ABLE F C N EN

I. IN R DUC I N AND BAC GR UND...
II. REA N F R RA E CA E FILING ....
III. RE UE F R EP AD U MEN ....
I . F LL -UP I EM FR M PRI R D C E ....
. DUE DA E F R RA E AND ER FILING 2
I. CU MER ER ICE INI IA I E...

A AC MEN

Attachment	itle
SEM-1	Compliance Checklist
SEM-2	Pelham Risk Sharing Analysis
SEM-3	Depreciation Reserve Analysis
SEM-4	Decoupling Impact on EE (Company)
SEM-5	Decoupling Impact on EE (FTI Consulting)
SEM-6	EE Marketing, Builder Education, and State/Local Meetings
SEM-7	Customer Feedback re Decoupling

I. IN R DUC I N AND BAC GR UND

. Please state your name and business address.

A. My name is Steven E. Mullen. My business address is 15 Buttrick Road, Londonderry, New Hampshire.

. By hom are you employed and in hat capacity

A. I am employed by Liberty Utilities Service Corp. (Liberty) as Director, Rates and Regulatory Affairs. I am responsible for rates and regulatory affairs for Liberty Utilities (EnergyNorth Natural Gas) Corp. (EnergyNorth or the Company) and Liberty Utilities (Granite State Electric) Corp. (Granite State) in New Hampshire, Liberty Utilities (Peach State Natural Gas) Corp. in Georgia, and Liberty Utilities (St. Lawrence Gas) Corp. in New ork.

. Please state your professional e perience and educational background.

A. In 2014, I was hired by Liberty as the Manager, Rates and Regulatory, and was promoted to Senior Manager in August 2017 and to my current position of Director in July 2018. In addition to managing the Rates and Regulatory Affairs department, I am responsible for the development of regulatory strategy, interacting with regulators and other parties on behalf of Liberty, reviewing and preparing testimony and other aspects of regulatory filings, and internal approval of rate changes for EnergyNorth and Granite State, among other duties.

From 1996 through 2014, I was employed by the New Hampshire Public Utilities Commission (Commission) in various roles. Through 2008, I held positions first as a

PUC Examiner, then as a Utility Analyst III and Utility Analyst I . In those roles, I had a variety of responsibilities that included field audits of regulated utilities books and records in the electric, telecommunications, water, sewer, and gas industries rate of return analysis review of a wide variety of utility filings and presenting testimony before the Commission. In 2008, I was promoted to Assistant Director of the Electric Division. orking with the Electric Division Director, I was responsible for the day-to-day management of the Electric Division, including decisions on matters of policy. In addition, I evaluated and made recommendations concerning rate, financing, accounting, and other general industry filings. In my roles at the Commission, I represented Commission Staff in meetings with utility officials, outside attorneys, accountants, and consultants relative to the Commission s policies, procedures, Uniform System of Accounts, rate cases, financing, and other industry and regulatory matters.

From 1989 through 1996, I was employed as an accountant with Chester C. Raymond, Public Accountant, in Manchester, New Hampshire. My duties involved preparation of financial statements and tax returns, as well as participation in year-end engagements.

I graduated from Plymouth State College with a Bachelor of Science degree in Accounting in 1989. I attended the NARUC Annual Regulatory Studies Program at Michigan State University in 1997. In 1999, I attended the Eastern Utility Rate School sponsored by Florida State University. I am a Certified Public Accountant and have obtained numerous continuing education credits in accounting, auditing, tax, finance, and utility related courses.

. hat is the purpose of your testimony

A. I am testifying on behalf of EnergyNorth in support of its request for an increase to distribution revenues, including its request for approval of step ad ustments to recover the revenue requirement associated with non-growth related capital additions placed in service after the test year. I also address certain issues related to the implementation of decoupling and other ratemaking impacts that depress earnings and have created financial pressures on the Company and contributed to its need to seek rate relief.

My testimony also describes the Company s request for approval of a property tax recovery mechanism, consistent with RSA 72 8-d and -e, to capture the impact of annual property tax increases that are beyond the Company s control.

In addition, I provide testimony to demonstrate the Company s compliance with the matters identified by the Commission in the February 28, 2020, secretarial letter in Docket No. DG 19-161, which was a rate case filing by EnergyNorth that was ultimately withdrawn. My testimony addresses each of these items, including and in addition to matters from Docket No. DG 17-048, EnergyNorth s prior rate case Docket No. DG 15-362, the docket wherein EnergyNorth received approval to expand its franchise area to the towns of Pelham and indham and Docket No. DG 17-035, the proceeding wherein Liberty was granted approval of a special contract with the New Hampshire Department of Administrative Services (NHDAS). I will describe how the Company has complied with the requirements from the various orders and secretarial letter issued in these dockets.

I also briefly discuss several regulatory matters involving due dates for certain rate and other filings, the examination and review of which would serve all parties well in terms of process improvements and possible workload reduction and efficiency gains.

Lastly, I describe an upcoming customer service initiative of the Company to switch its account payment services provider, which will involve migration of current payment options through Liberty s Interactive oice Response (I R) system and its website.

II. REA N F R RA E CA E FILING

. hat are the main factors that led to the Company s filing of this rate case

A. The ma or factors leading to this rate case filing are the lag on recovery for capital investments and increases in costs such as property taxes. These factors are described in more detail later in my testimony.

In addition to these factors, there are financial impacts related to the implementation of decoupling that have negatively impacted the Company. The decoupling impacts arose from an increase in use per customer since the 2016 test year in the prior rate case, as well as the February 2017 reclassification of 1,598 commercial and industrial customers to different rate classes based on a review of their usage. Because that reclassification happened after the test year, it was not reflected in the Docket No. DG 17-048 rate case billing determinants used to establish the revenue per customer (RPC) amounts established as part of the decoupling mechanism. Each rate class has a different RPC amount each month. The customer reclassification changed the results that would have otherwise occurred in the class specific RPC amounts determined in the rate case. In addition, as part of its decision in Docket No. DG 17-048, the Commission adopted a revenue ad ustment originally proposed by Staff based on the year-end customer count of EnergyNorth, rather than the average number of customers during the test year and using average revenues by customer class. Consequently, following the implementation of decoupling, the year-end customer count ad ustment significantly overstated the estimated number of new customers and thus overstated the amount of estimated annual revenue associated with those customers. The Company did not actually receive this revenue because those customers did not exist, so the Company experienced a detrimental financial impact due to the operation of the decoupling mechanism.

. ould you please e plain this impact in more detail

A. The revenue ad ustment was performed in a simplified manner, but the results of that ad ustment were found to vary significantly from the determination of revenues to be received from customers under the Company s decoupling structure that uses monthly RPC amounts that vary by class. Due to the significant variations in monthly RPC amounts, the simplified methodology in the year-end customer count ad ustment overstated the amount of revenue to be received from new customers. This had the effect of decreasing the amount of necessary distribution revenue increase in the prior rate case, which, in turn, lowered the RPC amounts calculated in that case. The longer the situation exists, the more the Company s revenues will be lower than they should be. In Order No. 26,122, the Commission recogni ed that a reset of the test year revenues would be necessary and directed that the next test year to be used in a rate case be no later than a twelve-month period ending December 31, 2020, so that such a reset could occur.

. as termination of the Cast Iron/Bare teel Replacement Program also a factor that led to this rate case filing

A. es. ith the termination of the accelerated recovery mechanism that was previously available as part of the Cast Iron/Bare Steel Replacement (CIBS) program, the Company needs to have an alternative method to obtain timely recovery of the costs involved with the replacement of leak-prone pipe on its distribution system. As described in the oint testimony of Company witnesses Brian Frost, Robert Mostone, and Heather Tebbetts, the Company is proposing an initial step ad ustment for certain capital investments made during calendar year 2020, including the replacement of leak-prone pipe. This proposal is consistent with the recommendation made by Staff in Docket No. DG 19-054 with respect to termination of the CIBS program.[1] In that docket, the Commission agreed with Staff and stated

> e encourage Liberty to seek recovery of 2019 CIBS spending through its anticipated general rate filing rather than a CIBS F 2020 filing. Recovery of 2019 CIBS spending through a general rate filing would be administratively efficient and recovery would commence at approximately the same time as provided for under the CIBS settlement agreement if a general rate case is filed by mid-year 2020.[2]

As described later in my testimony, the Company is also proposing step ad ustments to recover capital expenditures through 2022.

---

[1] https //www.puc.nh.gov/Regulatory/Docketbk/2019/19-054/INITIAL 20FILING 20- 20PETITION/19-054_2019-02-14_STAFF_RECOMMENDATION.PDF

[2] Order No. 26,266 at 7.

Given all of these factors described above, the Company found it necessary to file this rate case to avoid a prolonged period of continued detrimental financial impacts and to better position the Company to effectively and efficiently provide safe and reliable service to its customers going forward.

III. RE UE F R EP AD U MEN

. hat is the largest source of do n ard pressure on a utility s earnings bet een rate cases

A. The largest negative impact on a utility s earnings between rate cases is the regulatory lag between the time capital investments are made and the time that recovery of the revenue requirement associated with those capital investments begins, particularly when those investments are considered non-revenue producing or non-growth related. The revenue requirement includes a return on and of (*i.e.*, depreciation expense) the investment as well as associated costs, such as property taxes.

. Please demonstrate the impact of regulatory lag on a utility s earnings.

A. This can best be demonstrated by way of example. Assume a utility places 40,000,000 of non-growth related capital investments into service in a given year with no mechanism for rate recovery related to those investments. As a rule of thumb, the revenue requirement for utility capital investments can be roughly estimated by multiplying the capital investments by 15 percent, which provides for such items as depreciation, property taxes, and the impact of deferred taxes. For that 40,000,000 of non-growth related capital investments, the associated revenue requirement would be approximately

6,000,000. Therefore, all else being equal, those investments in a utility s plant and equipment would reduce earnings by 6,000,000. That reduction to earnings occurs each year there is no method for rate recovery, such as in the years between test years. This is the primary reason that utilities investing in their system and replacing existing infrastructure need to file frequent rate cases.

Applying this concept to EnergyNorth, and as described in the oint testimony of Messrs. Frost and Mostone and Ms. Tebbetts, EnergyNorth made significant capital investments that were placed in service during 2018 and 2019 for which there has been no cost recovery. These investments are a primary reason for the filing of this request for an increase in distribution revenues.

. Please describe more specifically ho the current regulatory structure for EnergyNorth impacts its earnings during the time interval bet een rate cases.

A. Since Liberty Utilities acquisition of EnergyNorth in mid-2012, EnergyNorth has had to file distribution rate cases approximately every three years -- in 2014, 2017, and now in 2020.[3] The 2014 and 2017 rate cases resulted in permanent rate increases based on historic test years, each accompanied by a step increase for plant placed in service during the year following the test year (*e.g.*, for Docket No. DG 17-048, the test year was 2016 and the step increase covered plant investments in 2017). This timing creates a lag in recovery for plant investments outside the test years and not covered by step increases. In addition, EnergyNorth historically was allowed annual recovery of investments made

[3] As noted, the Company also filed a rate case in 2019 that was subsequently withdrawn.

as part of its CIBS program. However, annual recovery through the CIBS program ceased as of March 31, 2020, which was the end of the most recent CIBS year, based on a decision by the Commission in Docket No. DG 19-054. As a result, investments placed in service after 2017 that were outside of the CIBS program have not been allowed for cost recovery, and this has negatively impacted the Company s earnings.

. ou mentioned property ta es as one of the cost items included in the revenue re uirement associated ith ne plant investments. ave property ta es increased on previously e isting plant investments

A. es. Property taxes are the primary funding source for municipal budgets, and for many municipalities utility property comprises a large portion of their tax base. Utility property taxes are also a significant funding source for the State of New Hampshire. As a result, even if no new capital investments are made, utilities often see their property tax bills increase.

. ave EnergyNorth s property ta es increased since its last rate case

A. es. The Company s prior rate case in Docket No. DG 17-048 had a 2016 test year and the property tax expense in that rate case was 9.3 million. For the test year in this case, the twelve months ended December 31, 2019, the total property tax expense was 12.4 million, which is an increase of 3.1 million, or 33 percent.

. as EnergyNorth granted a step adjustment for plant investments placed in service after the last rate case that provided recovery for additional property ta es

A. es. As part of Docket No. DG 17-048, the Commission approved a step ad ustment for plant placed in service during calendar year 2017, and the Company was also allowed annual ad ustments related to CIBS plant placed in service through March 31, 2020. However, the total amount of property tax recovery provided in those rate ad ustments totaled only approximately 1.15 million, leaving an additional increase of approximately 1.95 million for which there has not been any recovery to date. As compared to the amount of the Company s request in this proceeding for a temporary distribution revenue increase, property taxes alone account for a significant portion of the earnings shortfall.

. Based on these facts hat is the Company re uesting in its multi-year rate plan proposal

A. The Company is requesting approval of a multi-year rate plan that includes a provision for step ad ustments related to plant investments through 2022, along with a separate mechanism addressing changes in property taxes. As explained above, plant investments placed in service in the years outside of test years, particularly non-growth related capital investments, have a significant impact on EnergyNorth s earnings, as do uncontrollable increases in property taxes. Absent an alternative means of cost recovery, these costs end up causing frequent distribution rate case filings, which is administratively inefficient and costly for customers. Specifically, rate cases place significant demands on Company resources, as well as those of the Commission, its Staff, the Office of the Consumer Advocate (OCA), and other affected parties. Each rate case requires substantial costs to be incurred by the Company, Staff, and the OCA to prepare, review, and prosecute the case, and these costs are ultimately borne by EnergyNorth s customers. Thus, the step ad ustment approach, coupled with the proposed property tax mechanism, is a reasonable method to allow for more timely recovery of assets placed in service after the test year without the need for a full rate case, and would enable the Company to potentially lengthen the time between rate cases and have a reasonable opportunity to earn a reasonable rate of return. A multi-year plan that includes a provision for step ad ustments related to plant investments, along with addressing changes in property taxes, would be a step in the right direction. This would allow the Company to focus on operating the business while also reducing rate case expenses being incurred on a frequent basis.

. Is the Company s multi-year rate plan proposal limited solely to providing for step increases

A. No. Although step increases would be a necessary component of a multi-year plan for at least 2020 through 2022 capital investments, the Company is open to exploring other alternatives such as performance based ratemaking mechanisms, a program similar to National Grid s Gas Infrastructure, Safety, and Reliability Plan that is in place in Rhode Island, or other possible methodologies. The Company looks forward to having discussions with the Staff and the OCA to explore alternative approaches.

. ave there been any other developments related to property ta es that ould support approval for a rate mechanism for property ta es

A. es. On June 21, 2019, the Governor signed HB 700, which established a methodology for valuing utility distribution assets for property tax purposes, codified as RSA 72 8-d and -e. Part of that law established a new methodology for assessing utility property, and a five-year phase-in period to fully transition to that new methodology. The first property tax year of the phase-in period is the tax year beginning April 1, 2020.

The law also requires the Commission to establish by order a rate recovery mechanism for the property taxes paid by a public utility. Thus, the Company s proposal for a property tax recovery mechanism is supported by the recent law.

. o date has the Commission initiated any actions to develop a rate recovery mechanism for property ta es

A. To the Company s knowledge, no, it has not.

. Does the la re uire the rate recovery mechanism to be the same for all utilities

A. No. The law states as follows

> **2 -e Recovery of a es by Electric Gas and ater Utility Companies**. For the implementation period of the valuation of utility company assets under RSA 72 8-d, I and terminating with the property tax year effective April 1, 2024, the public utility commission shall by order establish a rate recovery mechanism for any public utility owning property that meets the definition of utility company assets under RSA 72 8-d, I. Such rate recovery mechanism shall either

> I. Ad ust annually to recover all property taxes paid by each such utility on such utility company assets based upon the methodology set forth in of RSA 72 8-d or
>
> II. Be established in an alternative manner acceptable to both the utility and the public utility commission.

. aking into account the last sentence uoted above does the Company have a proposed mechanism to capture the changes in property ta es that it ill e perience pursuant to R A 2 -d

A. es. As the Company has assets in many communities, and understanding that the law is new and requires changes to valuation methodologies previously used by those municipalities, it is likely there will be challenges over the first couple of years of implementation that will have to be worked through as the communities and Liberty understand the full effects of the new law and make sure it is applied appropriately. As an initial data point, many municipalities did not change the property valuations on their June 2020 tax bills, even though those bills are for the first property tax year impacted by the law. Given the likelihood of inconsistent treatment and timing of the property tax ad ustments among the municipalities, it is imperative that any recovery mechanism be simple to administer for all involved. ith that in mind, the Company proposes a full property tax recovery mechanism that each year compares the most recent municipal and state property tax bills to the amount currently collected in distribution rates. Such a mechanism would be simple to implement, administer, and verify, and would be consistent with the letter and spirit of the cost recovery contemplated in the law.

. ould the Company s proposed property ta mechanism cover all property ta es paid by the Company and not just the property that is considered utility company assets pursuant to R A 2 -d

A. es.

. hy is it reasonable to include certain assets beyond utility company assets in such a mechanism

A. To begin, recall that Liberty does not profit off property taxes they are simply a pass-through cost. In addition, utility company assets [4] encompass the vast ma ority of the Company s taxable property, so the inclusion of non- utility company assets is a relatively insignificant item, particularly since the valuation of those assets is not sub ect to the changes prescribed in RSA 72 8-d. It is possible, however, that the taxation of non- utility company assets may be increased as municipalities deal with changes to their operating budgets and revenues resulting from the property tax law. Thus, inclusion of the non- utility company assets, which are included in the Company s rate base, in the property tax mechanism would be appropriate to capture any such unintended consequences as they occur.

[4] "Utility company assets" as defined in RSA 72:8-d are: "For a gas company providing gas service to retail customers: distribution pipes, fittings, meters, pressure reducing stations, buildings, contributions in aid of construction (CIAC), construction works in progress (CWIP), and land rights including use of the public rights of way, easements on private land owned by third parties, and land owned in fee by the gas company."

. hat are some e amples of assets that are not encompassed in the definition of utility company assets for purposes of the valuation provisions of R A 2 -d and -e

A. Examples of such assets are transmission plant, production plant, and general plant such as office buildings.

. ould a deferral account need to be established ith respect to the property ta mechanism

A. es. A deferral account would be necessary to capture the increases and decreases that may occur as the property tax year progresses, and to capture the recoveries and timing differences between tax billing periods, the start of recovery, and timing of collections.

. Does the Company have a proposed implementation date for the property ta mechanism

A. Ideally, the effective date would occur soon after the Company receives its second tax bills of the property tax year in 2020, taking into consideration any ad ustments by municipalities dating back to the April 1, 2020, which was the effective date of this new law. Those bills are expected to be received during the fourth quarter of 2020. However, as this mechanism is being proposed as part of this rate case, the Company proposes that the ad ustment for the first property tax year of April 1, 2020, through March 31, 2021, take effect coincident with the August 1, 2021, implementation date of permanent rates at the conclusion of this proceeding. The effective date for subsequent property tax years could then be moved earlier in those calendar years.

I . F LL -UP I EM FR M PRI R D C E

. Does the Company s rate case filing address all of the directives of the Commission from prior dockets

A. es. In its February 28, 2020, secretarial letter in Docket No. DG 19-161, the Commission included a list of items it required the Company to address in this rate case filing. The letter summari ed the following requirements from prior dockets

1. Analysis comparing revenue requirement versus anticipated revenue from Pelham customers per Docket No. DG 15-362
2. From Docket No. DG 17-048
   a. An analysis of the depreciation reserve imbalance
   b. Information necessary to permit the Commission to evaluate the impact of decoupling
   c. An updated analysis similar to Exhibit 46 in that docket regarding the Company s investment in the iNATGAS facility
   d. A reduction to the proposed revenue requirement by 50 percent of any revenue shortfall for the first phase of the eene CNG/LNG conversion
3. Ad ustments to the revenue requirement for items such as the year-end customer count versus the average customer account, vacancies, and severance pay
4. Updated indirect gas costs [5]
5. An identification and explanation of all non-supply costs to be recovered through the eene Cost of Gas and

[5] The Company notes that, contrary to testimony from Staff during the January 10, 2020, prehearing conference in Docket No. DG 19-161, each EnergyNorth rate case filed subsequent to Liberty ownership has included an updated analysis of indirect gas costs as part of Functional Cost of Service Studies that were filed in each case. However, due to the particular circumstances of each case and how they were resolved, the indirect gas costs remained static, notwithstanding the fact that the Company did provide updated analyses of the costs.

6. If applicable, supporting information for the use of a test year other than a calendar year test year (*note: this item is not applicable to the current filing because the test year for this filing is calendar year 2019*).

The Company s filing presents the information necessary to address each of these directives, along with related requirements from Docket No. DG 15-362, Docket No. DG 17-035, and Docket No. DG 17-048. This section of my testimony describes how the Company has complied with the requirements from the various orders and secretarial letter issued in these dockets.

. ave you included an attachment that identifies the various re uirements from those dockets and here the Company is addressing them in the rate case filing

A. es. Attachment SEM-1 presents a list of the various requirements along with a reference to the Company s testimonies and attachments where the pertinent information is located.

. Please describe the follo -up information provided in the Company s filing ith respect to Docket No. DG - 2 the indham and Pelham franchise docket.

A. As discussed in that docket, the Company is serving customers in Pelham via a newly constructed take station on the Concord Lateral that is owned by Tennessee Gas Pipeline. Customers in Pelham are served under Managed Expansion Area rates in order to help pay the cost of the take station. In Docket No. DG 15-362, the Commission approved a settlement agreement that, in part, included a risk sharing mechanism whereby, as applicable to this rate case filing, the Company is required to prepare a discounted cash flow (DCF) analysis that compares the revenue requirement of the take station with the anticipated annual revenue from new Pelham customers. If there is a shortage in the average anticipated annual revenue over a three-year period following the date of implementation of permanent rates, as compared to the average annual revenue requirement over the same three-year period, the Company is required to absorb one-half of that shortfall.

. hen as the Pelham take station placed into service

A. It was placed into service on January 29, 2018.

. hat is the proposed implementation date for permanent rates

A. The proposed implementation date for permanent rates in this case is August 1, 2021.

. In accordance ith the settlement agreement in Docket No. DG - 2 hat is considered as anticipated revenue

A. The settlement agreement in that docket defines anticipated revenue as follows For purposes of this risk sharing section, anticipated revenue will include committed revenue plus Estimated Annual Margin as defined in EnergyNorth s main extension provision in its tariff.

. as the re uired analysis been prepared

A. es. Attachment SEM-2 presents the required analysis. As shown in Attachment SEM-2, the calculated average annual shortfall is approximately 129,165, with one-half of that amount being 64,583.

. ill this information be updated as the case proceeds

A. es. It is expected that during the course of this proceeding additional sales opportunities will materiali e, thus reducing the estimated shortfall.

. ave the results of the analysis been incorporated into the overall revenue re uirement schedules

A. es. The ad ustment is included on Schedule RR-EN-3-1 in the attachments to the permanent rates testimony of Company witnesses David Simek and enneth Sosnick.

. Please describe the follo -up items you are addressing from Docket No. DG - EnergyNorth s last rate case as identified in the secretarial letter.

A. The items I discuss are as follows (i) the status of the amorti ation of the depreciation reserve deficiency that was determined in that case and (ii) various items with respect to the topic of decoupling, including information to enable the Commission to evaluate the impact of decoupling. In addition, although not noted in the secretarial letter, I also provide a description of how various software-related items were assigned to the 3-, 5-, and 10-year amorti ation buckets.[6]

. ith respect to the depreciation reserve hat as re uired as part of the Commission s rder No. 2 22 in Docket No. DG -

A. A relatively large depreciation reserve deficiency of ust over 9.9 million was determined in that docket, and the order approved its amorti ation over a six-year period.

[6] Order No. 26,156 (July 10, 2018), at 7.

As part of its order, the Commission adopted the Company s position to perform a re-examination of the reserve variance in EnergyNorth s next rate case, rather than performing a full depreciation study.

. as that analysis been performed

A. es. The Company engaged the services of Management Applications Consulting, Inc. (MAC), which is the same consulting firm that prepared the depreciation study in Docket No. DG 17-048, in order to leverage the consultant s knowledge of the proceeding as well as its existing database of Company plant information. A copy of MAC s technical report is provided as Attachment SEM-3.

. hat ere the results of that analysis

A. As detailed in Attachment SEM-3, the results of the review were that the reserve deficiency had actually grown since the last rate case to 16.4 million. The result was not what was expected as the amorti ation of the 9.9 million deficiency, which began in May 2018, was expected to decrease. However, as described in the consultant s report, there are several factors that contributed to this result, including the regulatory lag between the period involved in the study (i.e., plant in service as of December 31, 2016) and the May 1, 2018, start of the amorti ation the fact that during that interim period a reserve surplus from an earlier case was still being amorti ed which, coupled with the fact that a deficiency actually existed, increased the amount of the deficiency by approximately 3.4 million and the Company s long-standing cost of removal estimate of 10 percent that is applied to certain capital pro ects that dates back to prior ownership of the Company.

. Did the consultant have any recommendations as to ho to address the reserve deficiency going for ard

A. es. Although MAC recommended the Company continue to use the 10 percent proxy for the cost of removal, MAC further recommended that the Company analy e obs of various si es and types to ascertain whether the 10 percent proxy currently being used for cost of removal should be ad usted downward. In addition, MAC recommended that the new depreciation study including calendar year 2020 plant data be performed during 2021 to determine if the life analyses support a longer service life for any accounts.

. Is the Company re uesting any adjustment to the depreciation reserve deficiency amorti ation that as approved by the Commission in Docket No. DG -

A. No. The Company has determined that the best course of action is to follow the recommendations of its consultant and perform additional analysis to determine if any internal policies need to be changed. Thus, the Company is not proposing any ad ustment to the approved six-year amorti ation of the reserve deficiency.

. Ne t hat are the decoupling items from Docket No. DG - that you are addressing

A. In Order No. 26,122, the Commission required EnergyNorth to file the following information in its next rate case as part of its approval of a decoupling mechanism

1) the amount of revenue collected or passed back through this mechanism, by year

2) an account of any measurable impacts decoupling had on Liberty s utility sponsored energy efficiency programs

3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes

4) an account of efforts taken to educate builders about energy efficiency

5) a detailed list of meetings with state and local officials and associations to promote energy efficiency

6) customer feedback resulting from decoupling as implemented through the rate design and

7) any changes in the Company s credit rating.

In addition to those items, the Commission required the Company to demonstrate that decoupling has allowed the Company to remain an effective champion of energy efficiency and has unlocked its ability to enthusiastically support energy efficiency policy goals. [7]

. **Please discuss each of the above items.**

A. ith respect to item (1), revenue collected or passed back to customers pursuant to the decoupling mechanism can happen in one of two ways. First, through the operation of the Normal eather Ad ustment (N A) that appears on each customer s monthly bill during the November through April winter period, a refund or charge is determined based on the difference between actual degree days over the billing period versus the normal heating degree days over the same historic period. Since the implementation of

[7] Order No. 26,122 (Apr. 27, 2018), at 46.

decoupling on November 1, 2018, the total revenue passed back to customers for the N A through the end of May 2020[8] was 2,413,206, with the totals by year shown in Table 1 below.

The second method by which revenue can be either collected or passed back to customers is through the Revenue Decoupling Ad ustment Factor (RDAF). The RDAF was addressed in Docket No. DG 19-145, in which the Company s Cost of Gas and its Local Delivery Ad ustment Charge (LDAC) were reviewed. The RDAF is one component of the LDAC. The RDAF provides an annual reconciliation of allowed revenues versus actual revenues, and beginning November 1, 2019, customers began receiving a credit of approximately 7 million, which is being returned over a twelve-month period. The yearly amounts of revenue collected or passed back through the N A and the RDAF are shown below in Table 1

Table 1

Period	NWA	RDAF	Total
11/2018 - 12/2018	$ (995,662)		$ (995,662)
01/2019 - 12/2019	$ 50,691	$ (986,682)	$ (935,991)
01/2020 - 05/2020	$ 3,358,177	$ (4,008,376)	$ (650,199)
	$ 2,413,206	$ (4,995,058)	$ (2,581,852)

[8] The NWA is in effect during the November through April winter period. In the months beyond April there are still amounts reflecting April usage billed in May as well as very minor adjustments in other months related to cancel/rebill transactions that may be necessary for individual customer bills.

In summary, through May 31, 2020, customers as a whole have received a positive financial benefit since the inception of decoupling of approximately 2.6 million.

Regarding item (2), please refer to Attachments SEM-4 and SEM-5 for information prepared by the Company and FTI Consulting (FTI), respectively, that provide assessments of the measurable impacts of decoupling on the Company s energy efficiency programs as well as the Company s ability to remain an effective champion of energy efficiency. FTI analy ed the Company s data as well as data of peer companies locally and in New England to gauge the impact decoupling has had on the Company s energy efficiency efforts. FTI reached several conclusions, as detailed in Attachment SEM-5, most notably that it is clear that the increased revenue certainty that came with decoupling either incented it to more ealously expand its EE program, or eliminated disincentives to do so, and that savings from its EE programs increased as a result. [9] The positive conclusions by FTI stand out even more when one considers factors that may have otherwise tempered energy efficiency efforts during the time following the implementation of decoupling. First, the relatively modest N A ad ustments provided in Table 1 above, especially when considered on an individual customer basis, would not be expected on their own to have much of an impact on customer behavior with respect to the energy efficiency programs. Second, it is important to keep in mind that decoupling only impacts the distribution portion of customers bills. Commodity prices have recently been lower than in the past, so when

9 Attachment SEM-5, page 25 of 25.

customers assess their overall bill, lower Cost of Gas prices also affect customer behavior and the demand for energy efficiency measures. Finally, as described above, customers are currently receiving the benefit of a si able credit through the RDAF. All of these factors working together, along with the infancy of the decoupling mechanism, make FTI s conclusions regarding the positive effects of decoupling on Liberty s energy efficiency efforts even more impressive.

EnergyNorth s activities and efforts through June 1, 2020, with respect to items (3), (4), and (5) above are summari ed and detailed in Attachment SEM-6. Page 1 summari es the total number of 2018, 2019, and 2020 activities through June 1, 2020, along with providing the total number of activities associated with requirements (3), (4), and (5). The remainder of Attachment SEM-6 is a detailed list of each activity including the date and details as to the type of activity, the audience, the market segment (e.g., residential, C I), and other relevant information.

ith respect to item (6), there has been very little customer feedback and few inquiries with respect to decoupling, with most of the inquiries occurring near the beginning of the implementation period. A list of the inquiries through June 1, 2020, is provided in Attachment SEM-7. The Company also refers the Commission to its report on the first 90 days of decoupling that was submitted to Staff on February 28, 2019, and was submitted to the Commission by Staff on March 4, 2019, as part of Docket No. DG 17-048.[10]

Lastly, with respect to item (7), through June 24, 2020, the Company has not experienced any changes to its credit rating as a result of the implementation of decoupling.

. hat did the Commission re uire in Docket No. DG - ith respect soft are classifications and amorti ation periods

A. Because the creation of separate classifications of software with varying amorti ation periods in the DG 17-048 matter was new for EnergyNorth, the Commission required that in the next rate case Liberty clearly describe how each piece of software is assigned an average service life.[11]

. Please describe ho various items of soft are are assigned to the - - and -year amorti ation buckets.

A. ith each item of software, the sub ect matter experts who use the software and are familiar with its features are consulted as to the appropriate life to apply to the software. Those sub ect matter experts reside in various departments, such as Information Technology, Engineering, Dispatch and Control, or other areas, depending on the particular nature and use of the software. The amorti ation period for cloud-based hosting arrangements will be the term of the service contract. The amorti ation period

10 The Company's 90-day report on decoupling can be accessed at: http://www.puc.nh.gov/Regulatory/Docketbk/2017/17-048/LETTERS-MEMOS-TARIFFS/17-048_2019-03-04_STAFF_FILING_LIBERTY_DECOUPLING_RPT.PDF

11 Order No. 26,156 at 6 (July 10, 2018).

for other software solutions will depend on the specifics of the software and may vary between contracts. In some cases, details from a business case document will provide details supporting the useful life. Regardless of the particular circumstances, the Company s Plant Accounting department will not issue the ob without having a clear direction on the appropriate useful life.

. Are there other follo -up items from Docket No. DG - identified in the secretarial letter that are addressed else here in the Company s filing

A. es. The following items are addressed elsewhere in the Company s rate case filing

- An analysis of the Company s investment in the iNATGAS compressed natural gas facility is included in the oint testimony of Messrs. Clark and Stevens
- Ad ustments to the revenue requirement for a year-end customer count, employment vacancies, and severance pay are included in the oint testimony of Messrs. Simek and Sosnick
- Information regarding production costs incurred by the eene Division as well as any non-supply costs to be recovered through the eene cost of gas are also included in the oint testimony of Messrs. Simek and Sosnick and,
- Indirect gas costs are addressed in the testimony of Mr. Sosnick on the Functional Cost of Service Study.

. In summary has the Company addressed all of the directives in the February 2 2 2 secretarial letter in Docket No. DG -

A. es, with one addition. Item 2(d) of the secretarial letter related to the eene CNG/LNG conversion. The conversion of the eene system from propane/air to CNG and LNG has not reached a phase where the concept of a revenue shortfall would come into effect. The only conversion that has happened to date is to the limited number of customers located at the Monadnock Marketplace and, consistent with Order No. 26,294,[12] no customer commitment requirement was required as part of the Commission s approval of the conversion of that limited portion of the system.

. Lastly please describe the follo -up item from Docket No. DG - ith respect to the special contract ith the Ne ampshire Department of Administrative ervices.

A. As stated above, Docket No. DG 17-035 involved a special contract with NHDAS related to its need for temporary boilers in order to ensure uninterrupted service for various State of New Hampshire buildings during the interim period between Concord Steam s cessation of service and NHDAS s completion of necessary retrofitting of natural gas equipment at those locations. A requirement of that special contract proceeding was that Liberty inform the Commission about the final costs associated with the contract. The Company has provided this information in the oint testimony of Company witnesses illiam Clark and Mark Stevens.

12 Docket No. DG 17-068, Order No. 26,294 (September 25, 2019) at 14.

Attachment SEM-1 provides a further summary of the Company s compliance with the Commission s directives.

. DUE DA E F R RA E AND ER FILING

. Please provide your general comments regarding due dates of rate-related and other re uired filings.

A. Over ust the past five years, the regulatory reporting requirements of EnergyNorth and eene have grown to where, on a combined basis, the weekly, monthly, quarterly, and annual required filings total slightly over 400 per year. That does not include other event-driven filings such as incident reports, interruptions of service, and similar filings that each year add to that total, depending on the occurrence of the relevant events. Those reporting requirements have been established by rules, laws, Commission orders, settlement agreements, and other measures over the years, which have for the most part included due dates either in mid-month or on the last day or first day of a month. In addition to the increase in the total number of reporting requirements, an increase in the number of reports due simultaneously has also occurred. Moreover, directives from the Commission, whether by order or secretarial letter, to file supplemental information in dockets, special reports, or other documents also typically include mid-month or end of month due dates. Although the use of overlapping due dates is most likely coincidental, it creates a significant burden on the utility.

Particularly with respect to rate-related filings, the overlapping due dates also create burdens for the Commission, its Staff, and the OCA to review and analy e those filings simultaneously, recogni ing that Liberty is not the only utility submitting filings at any particular time. It is important to note that many of the same Liberty personnel who are involved with filings for EnergyNorth are also involved with filings for Granite State that fall on the same due dates or otherwise overlap.

. aking your above comments into account hat do you recommend

A. Recogni ing the burden that overlapping filings can cause for those on both ends of the regulatory structure, and while recogni ing that some of the overlapping dates stem from laws or Commission rules, the Company recommends that a discussion take place among Liberty, Commission Staff, and the OCA to review existing reporting requirements and deadlines and determine if certain requirements (including due dates) can be revised in terms of content or frequency, and whether some may be combined or eliminated. Through such a meeting the Company is hopeful of developing reporting requirements and timelines that work well for all involved and spread the workload to allow everyone to work more efficiently, which is in everyone s best interest.

. Did you raise this same issue in Granite tate s recently concluded rate case Docket No. DG -

A. es. In that case a provision was included in the Settlement Agreement by which the Company, Staff, and the OCA would meet by a certain date to review Granite State s reporting requirements. Liberty would seek a similar agreement in this proceeding with respect to EnergyNorth s reporting requirements.

I. CU MER ER ICE INI IA I E

. Please describe the planned initiative to s itch the Company s payment services provider.

A. Liberty plans to change its payment services provider from Fiserv to ubra in January 2021. As part of that change, payment options that are currently available through the Company s I R system and website will be processed by ubra rather than Fiserv. Associated with change of providers, the current credit card fee payment structure will be modified.

. Please e plain the options the Company is evaluating to change the credit card fee payment structure

A. In response to feedback from customer satisfaction surveys, the Company is exploring two different credit card fee structures. One option is to continue the current practice of requiring the customer pay a separate transaction fee for using a credit or debit card to make their bill payment. The other option is to offer the credit card payment option without a transaction fee, with the cost of the service borne by the Company and included as part of operating costs. Customers frequently express dissatisfaction with the current structure that requires a transaction fee for credit card usage, so exploring a fee free model is important to addressing customer concerns.

. o ould this ork

A. Under the fee free model, EnergyNorth customers would be able to pay their bills by using a credit or debit card without incurring a separate transaction fee for using that payment method. This approach is consistent with customer expectations, which are changing in response to the growing availability of digital technology and a proliferation of methods to purchase and sell goods and services in an e-commerce environment. The Company s customer satisfaction surveys show that customers expect to be able to use their credit cards without incurring a separate fee, in large part because they now routinely make purchases and pay bills using these methods. In today s economy, customers rarely pay a separate transaction fee to use a credit or debit card to make payments. Consequently, requiring a transaction fee for utility payments causes a high level of dissatisfaction for customers. A fee free payment option would be a significant step in increasing customer satisfaction.

. **Does the Company have a specific proposal at this time**

A. No. The Company believes it would be appropriate to have discussions with Staff and the OCA to examine the pros and cons of the various alternative and keep the costs of either approach reasonable for customers. If the Company were to pursue a fee free model, it is likely that customer usage of the credit card payment option would increase substantially, and has the potential to become a relatively significant cost. For this reason, the Company will not implement the program without Commission approval.

. **Does this conclude your testimony**

A. es, it does.

Liberty ENNG Rate Case – Compliance Items

Docket	Compliance Requirement	Docket No. DG 20-105 Initial Filing Cross Reference
DG 19-161 2019 Rate Case	Secretarial Letter (2/28/2020) Item 1: "In Order No. 25,987 (concerning expansion of gas service in to Pelham and Windham) the Commission approved a risk sharing mechanism requiring Liberty to absorb one half of a Pelham revenue shortfall in its first rate case after commencing service, based on a comparison of the anticipated average annual revenue requirement and an updated actual average annual revenue requirement." • "Liberty must include in its initial filing of its next rate case all the information required to be filed by Order No. 25,987, including but not limited to, a revenue requirement calculation that includes an adjustment, if applicable, as outlined in the Settlement Agreement approved in that Order, and detailed supporting schedules as required by that Settlement Agreement."	• Mullen Testimony, Att. SEM-2 • Rev. Req. Schedule EN-RR-3-1
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • an analysis of Liberty's depreciation reserve imbalance (Order No. 26, 122 at 18).	• Mullen Testimony, Att. SEM-3
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • the information necessary to permit the Commission to evaluate the impact of decoupling (Order No. 26,122 at 46).	• Mullen Testimony • Atts. SEM-4, SEM-5, SEM-6, SEM-7
	Secretarial Letter (2/28/2020) Item 2: Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • an analysis of Liberty's investment in its iNATGAS facility similar to Exhibit 46 in DG 17-048, in sufficient detail, to allow the Commission to evaluate the investment and its impacts on firm customers.	• Clark/Stevens Testimony
	Secretarial Letter (2/28/2020) Item 2: "Consistent with Order No. 26,122, Liberty must also include in its next initial rate case filing: • a reduction to Liberty's proposed revenue requirement by 50 percent of any revenue shortfall for the first phase of the Keene CNG/LNG conversion.	• Mullen Testimony (project has not progressed to that point)

II-227

Docket	Compliance Requirement	Docket No. DG 20-105 Initial Filing Cross Reference
	Secretarial Letter (2/28/2020) Item 3: Order No 26, 122 also established a number of adjustments to be included in Liberty's revenue requirement calculations. In its next rate case filing, Liberty's revenue requirement calculation must include adjustments for each item specifically adopted in Order 26,122 (or an explanation as to the change in circumstance that obviates the need for specific adjustments). Those adjustments include: • Year-End Customer Count vs. Average Customer Count (Order No. 26, 122 at 1 O); • A payroll calculation that reflects a representative level of vacancies (Order No, 26, 122 at 11); and • Severance Pay (Order No. 26, 122 at 13).	• Simek/Sosnick Testimony (Perm)
	Secretarial Letter (2/28/2020) at 2: • "Liberty's next rate petition should also include in its initial filing updated indirect gas costs with supporting testimony and schedules." • "In addition, the initial filing should identify and explain all non-supply costs to be recovered through the Keene cost of gas."	• Sosnick Testimony (Functional Cost of Service Study) • Simek/Sosnick Testimony (Perm)
	Secretarial Letter (2/28/2020) at 2: "Finally, at the prehearing conference, Staff and the Office of the Consumer Advocate stated that a calendar year test year is preferable to a split-year test-year because it aligns with the Company's Annual Report to the PUC, Form F-16. The Commission found those statements persuasive and thus recommends Liberty use a calendar year in its next filed rate case. If it chooses not to do so, the Company must provide all supporting information in the format of a Form F-16 Annual Report."	• Not applicable: No split-year test year.

II-228

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-048 2017 Rate Case	Order No. 26,122 (Apr. 27, 2018): • Depreciation – Amortization of Reserve Deficiency: "Thus, we approve a six-year amortization period of the existing test year-end balance and direct the Company to prepare and present in its next rate case, a review of the reserve imbalance, a thorough explanation of the cause of any imbalance, and a proposal for amortizing that reserve imbalance." Id. at 18.	• Mullen Testimony • Att. SEM-3
	Order No. 26, 122 (Apr. 27, 2018): • Revenue Requirement Adjustments: ○ Customer count. Id. at 10 ○ Employee vacancies. Id. at 11 ○ Severance pay. Id. at 13.	• Simek/Sosnick Testimony (Perm)
	Order No. 26,122 (Apr. 27, 2018): • Rate Base – iNATGAS: "Nevertheless, the plant has been built and, for purposes of the base rates set in this case, we will allow recovery of the plant up to the level of costs presented in DG 14-091 ($2,245,000) plus related O&M expense. We will re-evaluate this investment in Liberty's next rate case and may consider putting more of the investment in rate base at that time. The remedy fashioned here will put ratepayers in the position they were in when this project was approved." Id. at 31-32.	• Clark/Stevens Testimony
	Order No. 26,122 (Apr. 27, 2018): • Keene: Commission permits the consolidation of Keene Division distribution rates with those of EnergyNorth subject to conditions, including: ○ "Liberty must reduce its revenue requirement by 50 percent of any revenue shortfall in the first distribution rate case filed within five years following construction of each Phase and by 100 percent of any revenue shortfall in the second distribution rate case filed within the five years following the construction of each Phase." Id. at 39. ○ Revenue requirement to include both production and distribution costs. Id. ○ Direct cost of Keene system shall be recovered in rates to all distribution customers. Id. ○ Customer commitment requirements. Id. ○ Liberty to file updated DCF analyses at the in-service date of each phase and annually. Id. at 40.	• Simek/Sosnick Testimony (Perm) • Sosnick Testimony (Functional Cost of Service Study) (Not all items are applicable at this time)

II-229

Docket	Compliance Requirement	Initial Filing Cross Reference
	Order No. 26,122 (Apr. 27, 2018): • Decoupling: "Further, to assist the Commission in evaluating Liberty's decoupling, we require the Company to report in its next rate case on the following: (1) the amount of revenue collected or passed back through this mechanism, by year; (2) an account of any measurable impacts decoupling had on Liberty's utility sponsored energy efficiency programs; (3) a detailed list of all efforts the Company made to promote its own energy efficiency programs, and to promote other energy efficiency measures such as lobbying for stricter building/energy codes; (4) an account of efforts taken to educate builders about energy efficiency; (5) a detailed list of meetings with state and local officials and associations to promote energy efficiency; (6) customer feedback resulting from decoupling as implemented through the rate design; and (7) any changes in the Company's credit rating. The above list is not intended to be exhaustive. In short, we require the Company to demonstrate that decoupling has allowed the Company to "remain an effective champion of energy efficiency" and has unlocked its "ability to enthusiastically support energy efficiency policy goals.'" Id. at 46.	• Mullen Testimony • Atts. SEM-4, SEM-5, SEM-6, SEM-7
	Order No. 26,122 (Apr. 27, 2018): • Test Year: Liberty shall file its next distribution rate case using a test year ending no later than December 31, 2020, and that rate case shall include a report on the effects of decoupling as detailed in the order. Id. at 56.	• Mullen Testimony
	Order No. 26,156 (July 10, 2018): • As suggested by Staff, we require that Liberty, in its next rate case, clearly explain how each piece of software is assigned an A[verage]S[ervice]L[ife]. Id. at 7	• Mullen Testimony

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-068 Keene Declaratory Ruling re CNG/LNG	Order No. 26,274 (July 26, 2019) (order on affirming/clarifying declaratory ruling): • "We note that Puc 503.04(a) requires gas utilities to 'provide certain services to its customers when service conditions such as change in pressure or composition of gas affect or would affect efficiency of operation or adjustment of appliances.' Puc 503.04(b) further requires that if any such change occurs, the 'utility shall, without undue delay and without charge, inspect the appliances of its customers and, if necessary, readjust those appliances for the new conditions.' Based on the Staff Assessment, it appears that these provisions will apply to the Keene system conversion, and we direct Liberty to address these rules when it seeks to recover Keene conversion costs from ratepayers." Id. at 11. • "In addition, in accordance with the directives set forth in Order No. 26,122, Liberty must provide updated discounted cash flows (DCFs) based on detailed engineering plans and customer commitments that will produce at least 50% of the revenue requirement associated with the new facilities prior to the initiation of construction of each conversion phase." Id. at 13.	• Not applicable at this time.
	Order No. 26,294 (Sept. 25, 2019) (order on rehearing): • "We clarify that before initiation of construction for each phase of the Keene system conversion/expansion, Order No. 26,122 requires Liberty to file a detailed report of its business plan. The business plan shall include all conversion/expansion project costs, as well as detailed projected cost estimates for all conversion/expansion projects to be included in the revenue requirement analysis required as part of the risk-sharing mechanism. The business plan must be supported by updated DCF analyses based on detailed engineering plans and customer commitments that will produce at least 50 percent of the revenue requirement associated with the new facilities. As established in DG 17-048, such DCF analyses are the first step in gaining approval for each phase of the conversion/expansion and will be used to demonstrate that Liberty's New Hampshire ratepayers are not burdened with unfair or unwarranted costs." Id. at 14.	• Not applicable at this time

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 17-035 NHDAS Special Contract	Order No. 26,018 (May 15, 2017), at 4: Liberty shall "notify the Commission if its costs related to this special contract exceed $2,725,000, and if a contract amendment is necessary and denied, an explanation of the Company's plans in light of the denial, and the expected impact on boiler operations, cost, and cost recovery."	• Clark/Stevens Testimony

II-232

Docket	Compliance Requirement	Initial Filing Cross Reference
DG 15-362 Franchise Approval in Pelham and Windham	<u>Order No. 25,987 (Feb. 8, 2017), at 4 (</u>Settlement Agreement Condition #4): "Liberty would recover the costs incurred to construct a take station off of the TGP Concord Lateral in Pelham through its distribution rates as part of a rate case. These costs would be amortized over 10 years, including a pre-tax return, based on the Commission-approved capital structure and cost of capital for Liberty."	• Mullen Testimony • Att. SEM-1 • Rev. Req. Schedules EN-RR-3-1
	<u>Order No. 25,987 (Feb. 8, 2017), at 4 (</u>Settlement Agreement Condition #5): "As a 'risk-sharing' provision Liberty would reduce its revenue deficiency in any rate case filed within five years of the in-service date of Phase 1 of the Pelham build-out as follows (as demonstrated in Appendix B of the Settlement Agreement): . . . a. In the first rate case any revenue deficiency between the anticipated average annual revenue from Pelham customers over the three years following implementation of permanent rates, and the average annual revenue requirement over the same period of the Pelham construction costs and amortization of the Pelham TGP take station, **would be reduced by one half**. If a second rate case is filed within the five year period, the amount of the reduction to the revenue deficiency **would be the full difference between** the anticipated Pelham revenue requirement and projected revenues. . . . b. For purposes of the risk-sharing provision, costs would include actual direct capital costs to date, the Pelham take station amortization expense, and projected direct capital costs for system reinforcement and customer growth to serve Pelham. . . . c. For purposes of the risk-sharing provision, anticipated revenue would include committed revenue plus Estimated Annual Margin as defined in Liberty's main extension provision in its tariff. . . . d. The risk-sharing provision would terminate if average annual revenue exceeds average annual revenue requirement. e. Liberty would file annual updated Pelham and Windham Discounted Cash Flow ("DCF") analyses in January of each year following the first full year of commencement of service until the projects achieve a positive annual return, but for no less than three years, and for no more than five years (as demonstrated in Appendix C of the Settlement Agreement). . . ."	• Mullen Testimony

Pelham DCF Analysis as of June 2020

Capital Cost w/o Take Station - Phases IA & IB & Pike	$1,612,698	Direct Costs
One time payment to TGP to build Take Station	$1,206,028.00	
Required Return (pre tax) Rate Base & Take Station	8.50%	
Take Station Annual Amortization (10 years)	($183,808)	
Net Present Value (Delta yrs 1-10 & 9.35% discount rate)	($859,770)	

Required Return (Requested Cost of Capital)

	Ratio	Rate	Pre-tax	Weighted Pre-tax
Equity	49.20%	9.30%	12.75%	6.27%
Debt	50.80%	4.38%	4.38%	2.23%
				8.50%

Year	IRS MACRS Rates	IRS MACRS Table	Book Depr	Delta Book less Tax	Tax Rate	Deferred Inc Tax	Accumulated Deferred Inc Tax	Rate Base	Required Return	Property Tax ($19.37)	Insurance	O&M	Take Station Amortization of Initial Payment	Revenue Requirement	Projected Revenues MEP Rates	Delta Rev Req less Revenue		Risk Sharing Calculation
								1,612,698										
1	5	80,635	40,317	(40,317)	27.08%	(10,918)	(10,918)	1,561,463	$134,902	$31,238	$2,761	$4,470	$183,808	$397,496	$242,261	($155,235)		
2	9.5	153,206	40,317	(112,889)	27.08%	(30,570)	(41,488)	1,490,575	$129,712	$30,246	$2,761	$4,582	$183,808	$391,425	$242,261	($149,164)		
3	8.55	137,886	40,317	(97,568)	27.08%	(26,421)	(67,910)	1,423,836	$123,862	$28,872	$2,761	$4,696	$183,808	$384,318	$242,261	($142,057)		
4	7.7	124,178	40,317	(83,860)	27.08%	(22,709)	(90,619)	1,360,809	$118,347	$27,580	$2,761	$4,814	$183,808	$377,627	$242,261	($135,366)		($135,366)
5	6.93	111,760	40,317	(71,443)	27.08%	(19,347)	(109,966)	1,301,145	$113,133	$26,359	$2,761	$4,934	$183,808	$371,312	$242,261	($129,051)		($129,051)
6	6.23	100,471	40,317	(60,154)	27.08%	(16,290)	(126,255)	1,244,538	$108,192	$25,203	$2,761	$5,057	$183,808	$365,339	$242,261	($123,078)		($123,078)
7	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(141,104)	1,189,372	$103,441	$24,107	$2,761	$5,184	$183,808	$359,618	$242,261	($117,357)	Total	($387,495)
8	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(155,952)	1,134,206	$98,752	$23,038	$2,761	$5,313	$183,808	$353,990	$242,261	($111,729)		
9	5.91	95,310	40,317	(54,993)	27.08%	(14,892)	(170,844)	1,078,997	$94,061	$21,970	$2,761	$5,446	$183,808	$348,363	$242,261	($106,102)	Average	($129,165)
10	5.9	95,149	40,317	(54,832)	27.08%	(14,848)	(185,693)	1,023,831	$89,370	$20,900	$2,761	$5,582	$183,808	$342,739	$242,261	($100,478)		
																	@ 50%	($64,583)

II-234

MANAGEMENT APPLICATIONS CONSULTING, INC.

1103 Rocky Drive • Suite 201 • Reading, PA 19609-1157 • 610/670-9199 • fax 610/670-9199 •www.manapp.com

MEMO

DATE: July 20, 2020
TO: Steve Mullen, Liberty Utilities
FROM: Paul Normand and Marcy Stefan
SUBJECT: Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant

At Liberty's request, MAC has reviewed the growth in the Company's plant as it relates to depreciable plant with the goal of quantifying the change in reserve imbalances since the Company's last depreciation study. In evaluating the change in plant balances as ordered in the last rate case, this creates a very complicated process of identifying any change by specific plant account. Since the 2016 period of time, many plant balances have been reclassified to comply with the New Hampshire Public Utility Commission's Staff audit, and we have derived the following detail comparisons by category with which to quantify the growth in the reserve imbalance:

TABLE 1

Historical Plant Balances and Net Salvage

					SCHEDULE A 2016		
ACCOUNT / DESCRIPTION	**PLANT BALANCE @12/31/2016**	**PLANT BALANCE @12/31/2019**	**DIFFERENCE (PLANT INCREASE)**	**% INCREASE IN PLANT**	**THEO. RSV WITH NET SALVAGE @12/31/2016**	**BOOK RSV @12/31/2016**	**RESERVE VARIANCE @12/31/2016**
367.00 Mains *(UNDER CURRENT 367 & 376)*	$234,672,697	316,221,089	81,548,392	34.75%	63,315,172	54,187,131	9,128,041
380.00 Services	$146,720,226	187,120,798	40,400,572	27.54%	68,883,816	66,714,617	2,169,199
TOTAL DEPREC GAS PLANT	477,852,305	631,074,215	153,221,910	32.06%	165,193,965	155,247,187	9,946,778

Note: Mains account was Account 367 @ 12/31/2016

	SCHEDULE A 2019 PRELIMINARY		
	THEO. RSV WITH NET SALVAGE @12/31/2019	**BOOK RSV @12/31/2019**	**RESERVE VARIANCE @12/31/2019**
367.00 Mains	3,904,396	404,274	3,500,122
376.00 Mains	72,758,459	60,928,702	11,829,757
380.00 Services	84,274,853	83,285,975	988,878
TOTAL DEPREC GAS PLANT	$205,106,324	188,750,655	$16,355,669

Note: Mains account split into 367 & 376 @ 12/31/2019
Note: See Attachments A (2016) and B (2019)

DATE: July 20, 2020
TO: Steve Mullen, Liberty Utilities
FROM: Paul Normand and Marcy Stefan
SUBJECT: Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant

TABLE 2

Historical Cost of Removal

DATE	$ COST OF REMOVAL	ACCUMULATED $ COST OF REMOVAL
@12/31/2012	573.53	573.53
@12/31/2013	1,502,866.45	1,503,439.98
@12/31/2014	1,604,008.61	3,107,448.59
@12/31/2015	1,504,536.59	4,611,985.18
@12/31/2016	1,736,434.75	6,348,419.93
@12/31/2017	2,527,346.53	8,866,047.53
@12/31/2018	2,843,715.44	11,709,762.97
@12/31/2019	3,738,897.19	15,448,660.16

Note: The Cost of Removal relates to the following work types:
1. Relay Main
2. Main Replacement
3. Relay service
4. Service Relocation
5. Service Replacement

Two key aspects of the Company's reserve variance growth are with respect to the replacement/retirement of large quantities of mains and services and the potential change in average service life (ASL) of depreciable assets. The first key element relating to ASL has to do with the potential increase to the life once new additions are factored into any life analyses. Based on experience and the Company's historical growth data, we would expect that a new study would derive longer service lives for both mains and services which would impact the resulting reserve variance. The second key element recognized annually is the cost of removal portion of the Company's plant replacement activities. It is this portion of costs that the Company has historically been estimating as a blanket 10% of investments in major plant accounts. In understanding this process, large growth in plant investments which has been occurring for many years, especially for key plant accounts related to mains and services, results in large amounts of unrecovered dollars being identified but not recovered in the short term.

Historically, we have observed that some utilities had periodically used a flat 10% estimate for cost of removal as a proxy to the more detailed and laborious efforts required to quantify these amounts which are primarily labor related. In the last ten years, the rapid increase in plant replacement/retirement requirements had, in many cases, resulted in a more detailed review of these costs (COR) which has resulted in being modified to reflect a much lower 3 to 5% range of costs to new plant investments. The cost areas typically considered are with respect to digging a trench, cutting and purging pipe, capping, resurfacing and flaggers/police. Again, the growth in

DATE: July 20, 2020
TO: Steve Mullen, Liberty Utilities
FROM: Paul Normand and Marcy Stefan
SUBJECT: Review of Reserve Variance Deficiency for Liberty Depreciable Gas Plant

these costs has been a direct result of a much higher frequency of retirement/replacement occurring for gas plant.

Based on our review of the available data (Tables 1 and 2), we offer the following recommendations to consider for the future plant activities of the Company's depreciable plant accounts:

1. Continue to record and document the Company's 10% COR by plant account.
2. In order to evaluate the current level of COR, a detailed effort coordinated between engineering (field) and accounting be undertaken for all major plant activity with respect to identifying/estimating activities relating solely to COR (plant and labor associated with activities). This should consider various types of projects where one can balance small and large projects to achieve an outcome to compare with the current 10% estimated level.
3. Once in place, consider maintaining this process going forwards to ensure that the new proposed levels are supportable.
4. The efforts surrounding the application of Items 1 – 3, above, should be undertaken as soon as possible such that the results will be available to influence the Company's next depreciation study.
5. Recommend that a new depreciation study be undertaken with the calendar year 2020 data included to ascertain if the life analyses support a longer average service life for any accounts. This should be prepared in early 2021 to provide you with immediate information as to the possible impact along with the technical support to possibly suspend the current allowed annual recovery of the shortfall.

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORPORATION
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/16
WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

FERC ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/16	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV.	ACCRUAL WITHOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV.	ACCRUAL WITH NET SALV.	THEO. RSV. WITHOUT NET SALV.	THEO. RSV. WITH NET SALV.	BOOK RSV. @12/31/16	RESERVE VARIANCE	COR RATE %
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
303.00	CAPITALIZED SOFTWARE	14,745,889	S 4.0	6.2	16.13	2,378,512	0	1.00	16.13	2,378,512	5,708,940	5,708,940	4,975,703	733,237	0.00
	PRODUCTION PLANT														
305.00	STRUCTURES AND IMPROVEMENTS	1,975,163	R 1.0	35.0	2.86	56,490	0	1.00	2.86	56,490	818,047	818,047	1,374,447	-556,400	0.00
311.00	LP GAS EQUIPMENT	258,481	R 1.0	35.0	2.86	7,393	0	1.00	2.86	7,393	59,141	59,141	63,766	-4,625	0.00
320.00	OTHER EQUIPMENT-LNG	2,556,209	R 1.0	35.0	2.86	73,108	0	1.00	2.86	73,108	357,489	357,489	364,891	-7,402	0.00
320.10	OTHER EQUIPMENT-PRODUCTION	8,777,306	R 1.0	35.0	2.86	251,031	0	1.00	2.86	251,031	4,967,873	4,967,873	7,765,237	-2,797,364	0.00
	TOTAL DEPREC. PRODUCTION PLANT	13,567,159		35.0	2.86	388,021			2.86	388,021	6,202,550	6,202,550	9,568,341	-3,365,791	
	STORAGE PLANT														
361.00	STRUCTURES AND IMPROVEMENTS-LNG	57,345	R 1.0	35.0	2.86	1,640	0	1.00	2.86	1,640	13,371	13,371	9,179	4,192	0.00
363.50	OTHER EQUIPMENT-LNG	7,646	R 1.0	35.0	2.86	219	0	1.00	2.86	219	1,783	1,783	1,560	223	0.00
	TOTAL DEPREC. STORAGE PLANT	64,991		35.0	2.86	1,859			2.86	1,859	15,154	15,154	10,739	4,415	
	TRANSMISSION PLANT														
366.20	STRUCTURES AND IMPROVEMENTS	269,809	R 1.0	35.0	2.86	7,717	0	1.00	2.86	7,717	119,856	119,856	177,630	-57,774	0.00
366.30	STRUCTURES AND IMPROVEMENTS-OTHER	353,851	R 1.0	35.0	2.86	10,120	0	1.00	2.86	10,120	192,816	192,816	278,219	-85,403	0.00
367.00	MAINS	234,672,697	R 3.0	60.0	1.67	3,919,034	-15	1.15	1.92	4,505,716	55,056,671	63,315,172	54,187,131	9,128,041	0.25
369.00	MEASURING AND REGULATING STATION EQUIP.	4,909,208	S 4.0	35.0	2.86	140,403	0	1.00	2.86	140,403	1,782,000	1,782,000	1,889,616	-107,616	0.00
	TOTAL DEPREC. TRANSMISSION PLANT	240,205,565		59.0	1.70	4,077,274			1.94	4,663,956	57,151,343	65,409,844	56,532,596	8,877,248	
	DISTRIBUTION PLANT														
380.00	SERVICES	146,720,226	R 4.0	45.0	2.22	3,257,189	-60	1.60	3.55	5,208,568	43,052,385	68,883,816	66,714,617	2,169,199	1.33
381.00	METERS	14,628,345	R 3.0	32.0	3.13	457,867	0	1.00	3.13	457,867	6,058,054	6,058,054	7,838,363	-1,780,309	0.00
381.10	METERS-INSTRUMENT	188,398	R 3.0	32.0	3.13	5,897	0	1.00	3.13	5,897	46,943	46,943	31,378	15,565	0.00
381.20	METERS-ERTS	5,647,769	SQ	15.0	6.67	376,706	0	1.00	6.67	376,706	4,689,816	4,689,816	2,073,245	2,616,571	0.00
382.00	METER INSTALLATIONS	14,360,005	R 3.0	32.0	3.13	449,468	0	1.00	3.13	449,468	3,013,872	3,013,872	2,510,354	503,518	0.00
387.00	OTHER EQUIPMENT	908,013	S 6.0	19.0	5.26	47,761	0	1.00	5.26	47,761	410,276	410,276	339,112	71,164	0.00
	TOTAL DEPREC. DISTRIBUTION PLANT	182,452,756		39.7	2.52	4,594,889			3.59	6,546,268	57,271,346	83,102,777	79,507,069	3,595,708	
	GENERAL PLANT														
390.00	STRUCTURES AND IMPROVEMENTS	22,070,702	R 1.0	35.0	2.86	631,222	0	1.00	2.86	631,222	2,218,786	2,218,786	3,314,051	-1,095,265	0.00
391.00	OFFICE FURNITURE AND EQUIP.	285,566	S 4.0	18.0	5.56	15,877	5	0.95	5.28	15,078	44,136	41,929	26,275	15,654	0.00
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	1,840,911	S 4.0	10.0	10.00	184,091	0	1.00	10.00	184,091	1,179,639	1,179,639	297,543	882,096	0.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	679,916	S 4.0	5.0	20.00	135,983	0	1.00	20.00	135,983	349,087	349,087	81,882	267,205	0.00
393.00	STORES EQUIPMENT	99,421	SQ	30.0	3.33	3,311	0	1.00	3.33	3,311	19,569	19,569	28,007	-8,438	0.00
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	825,963	S 6.0	19.0	5.26	43,446	0	1.00	5.26	43,446	270,641	270,641	347,637	-76,996	0.00
394.10	TOOLS, SHOP & GARAGE EQUIPMENT-CNG STATION	221,199	S 6.0	19.0	5.26	11,635	0	1.00	5.26	11,635	203,415	203,415	192,912	10,503	0.00
397.00	COMMUNICATION EQUIPMENT	443,965	SQ	10.0	10.00	44,397	0	1.00	10.00	44,397	343,778	343,778	212,912	130,866	0.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	348,302	S 5.0	15.0	6.67	23,232	0	1.00	6.67	23,232	127,856	127,856	151,520	-23,664	0.00
	TOTAL DEPREC. GENERAL PLANT	26,815,945		24.5	4.08	1,093,194			4.07	1,092,394	4,756,907	4,754,700	4,652,739	101,961	
	TOTAL DEPREC. GAS PLANT	477,852,305		38.1	2.62	12,533,748			3.15	15,071,009	131,106,240	165,193,965	155,247,187	9,946,778	
	AMORTIZED PLANT														
392	TRANSPORTATION EQUIPMENT	2,566,140		5.0	20.00	513,228	0	1.00	20.00	513,228			623,499		0.00
396	POWER OPERATED EQUIPMENT	491,943		5.0	20.00	98,389	0	1.00	20.00	98,389			430,651		0.00
	TOTAL AMORTIZED PLANT	3,058,083		5.0	20.00	611,617			20.00	611,617			1,054,150		
	TOTAL DEPREC. & AMORTIZED GAS PLANT	480,910,388		36.6	2.73	13,145,364			3.26	15,682,626			156,301,337		
1211	OPI-STRUCTURES-RETAINED												133,284		
304/365	LAND & LAND RIGHTS	592,018													
389.00	GNL LAND & LAND RIGHTS	16,806													
1012	ARO	139,286													
	DIFF. IN ACCOUNT 367 & 380 BAL. VS PUC ANNUAL REPORT	8,352													
	TOTAL GAS PLANT IN SERVICE	481,666,850											156,434,621		

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORPORATION
SCHEDULE OF DEPRECIATION ACCRUAL RATES @12/31/2019
WHOLE LIFE SCHEDULE WITH RESERVE VARIANCE

SCHEDULE A

FERC ACCOUNT NUMBER	DESCRIPTION	PLANT BALANCE @12/31/2019	DISP TYPE	ASL	ACCRUAL RATE W/O NET SALV.	ACCRUAL WITHOUT NET SALV.	NET SALV. %	SALV. FACTOR	ACCRUAL RATE W/ NET SALV.	ACCRUAL WITH NET SALV.	THEO. RSV. WITHOUT NET SALV.	THEO. RSV. WITH NET SALV.	BOOK RSV. @12/31/2019	RESERVE VARIANCE	COR RATE %
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	CAPITALIZED SOFTWARE														
303.10	CAPITALIZED SOFTWARE- 3 YEARS	899,372	S 4.0	3.0	33.33	299,761	0	1.00	33.33	299,761	566,269	566,269	522,934	43,335	0.00
303.20	CAPITALIZED SOFTWARE- 5 YEARS	13,147,962	S 4.0	5.0	20.00	2,629,592	0	1.00	20.00	2,629,592	10,900,573	10,900,573	10,760,273	140,300	0.00
303.40	CAPITALIZED SOFTWARE- 10 YEARS	3,539,569	S 4.0	10.0	10.00	353,957	0	1.00	10.00	353,957	1,900,188	1,900,188	2,318,763	-418,575	0.00
	TOTAL ACCOUNT 303	17,586,903		5.4		3,283,310				3,283,310	13,367,030	13,367,030	13,601,970	-234,940	
	PRODUCTION PLANT														
305.00	STRUCTURES AND IMPROVEMENTS	852,167	R 1.0	35.0	2.86	24,372	0	1.00	2.86	24,372	388,738	388,738	266,638	122,100	0.00
319.00	GAS MIXING EQUIPMENT	368,345	R 1.0	20.0	5.00	18,417	0	1.00	5.00	18,417	164,887	164,887	241,392	-76,505	0.00
320.00	OTHER EQUIPMENT-LNG	315,570	R 1.0	35.0	2.86	9,025	0	1.00	2.86	9,025	44,571	44,571	-57,148	101,719	0.00
320.10	OTHER EQUIPMENT	3,478,111	R 1.0	35.0	2.86	99,474	0	1.00	2.86	99,474	2,087,209	2,087,209	1,389,131	698,078	0.00
	TOTAL DEPREC. PRODUCTION PLANT	5,014,193		33.2	3.02	151,289			3.02	151,289	2,685,405	2,685,405	1,840,013	845,392	
	STORAGE PLANT														
361.00	STRUCTURES AND IMPROVEMENTS-LNG	96,980	R 1.0	35.0	2.86	2,774	0	1.00	2.86	2,774	19,586	19,586	17,233	2,353	0.00
363.50	OTHER EQUIPMENT-LNG	7,646	R 1.0	35.0	2.86	219	0	1.00	2.86	219	2,224	2,224	2,044	180	0.00
	TOTAL DEPREC. STORAGE PLANT	104,626		35.0	2.86	2,992			2.86	2,992	21,810	21,810	19,277	2,533	
	LNG GAS TERMINATING AND PROCESSING PLANT														
364.20	STRUCTURES AND IMPROVEMENTS-LNG	609,078	R 1.0	35.0	2.86	17,420	0	1.00	2.86	17,420	192,797	192,797	438,133	-245,336	0.00
364.80	OTHER EQUIPMENT	3,896,019	R 1.0	35.0	2.86	111,426	0	1.00	2.86	111,426	1,531,470	1,531,470	2,400,155	-868,685	0.00
	TOTAL DEPREC. LNG TERM. AND PROCESS. PLANT	4,505,097		35.0	2.86	128,846			2.86	128,846	1,724,267	1,724,267	2,838,288	-1,114,021	
	TRANSMISSION PLANT														
367.00	MAINS	11,740,462	R 3.0	60.0	1.67	196,066	-15	1.15	1.92	225,417	3,395,127	3,904,396	404,274	3,500,122	0.25
369.00	MEASURING AND REGULATING STATION EQUIP.	138,182	S 4.0	35.0	2.86	3,952	0	1.00	2.86	3,952	61,651	61,651	-44,894	106,545	0.00
	TOTAL DEPREC. TRANSMISSION PLANT	11,878,644		59.5	1.68	200,018			1.93	229,369	3,456,778	3,966,047	359,380	3,606,667	
	DISTRIBUTION PLANT														
375.00	STRUCTURES AND IMPROVEMENTS	1,689,296	R 1.0	35.0	2.86	48,314	0	1.00	2.86	48,314	147,159	147,159	211,302	-64,143	0.00
376.00	MAINS	316,221,089	R 3.0	60.0	1.67	5,280,892	-15	1.15	1.92	6,071,445	63,268,225	72,758,459	60,928,702	11,829,757	0.25
377.00	COMPRESSOR STATION EQUIPMENT	2,246,186	R 1.0	35.0	2.86	64,241	0	1.00	2.86	64,241	164,456	164,456	192,723	-28,267	0.00
378.00	MEAS. AND REG. STATION EQUIPMENT-GENERAL	7,435,290	S 2.0	35.0	2.86	212,649	0	1.00	2.86	212,649	3,479,948	3,479,948	4,324,404	-844,456	0.00
379.00	MEAS. AND REG. STATION EQUIPMENT-CITY GATE	5,294,746	S 3.0	35.0	2.86	151,430	0	1.00	2.86	151,430	1,214,751	1,214,751	1,320,344	-105,593	0.00
380.00	SERVICES	187,120,798	R 4.0	45.0	2.22	4,154,082	-60	1.60	3.55	6,642,788	52,671,783	84,274,853	83,285,975	988,878	1.33
381.00	METERS	14,097,967	R 3.0	32.0	3.13	441,266	0	1.00	3.13	441,266	4,815,475	4,815,475	4,530,427	285,048	0.00
381.10	METERS-INSTRUMENT	276,522	R 3.0	32.0	3.13	8,655	0	1.00	3.13	8,655	94,411	94,411	113,499	-19,088	0.00
381.20	METERS-ERTS	6,045,353	SQ	15.0	6.67	403,225	0	1.00	6.67	403,225	4,435,265	4,435,265	2,730,186	1,705,079	0.00
382.00	METER INSTALLATIONS	18,597,177	R 3.0	32.0	3.13	582,092	0	1.00	3.13	582,092	4,539,321	4,539,321	4,116,883	422,438	0.00
385.00	INDUSTRIAL MEASURING & REGULATING EQUIPMENT	53,375	S 6.0	19.0	5.26	2,808	0	1.00	5.26	2,808	9,832	9,832	5,332	4,500	0.00
387.00	OTHER EQUIPMENT	2,682,115	S 6.0	19.0	5.26	141,079	0	1.00	5.26	141,079	1,081,159	1,081,159	1,078,797	2,362	0.00
	TOTAL DEPREC. DISTRIBUTION PLANT	561,759,914		48.9	2.05	11,490,733			2.63	14,769,992	135,921,785	177,015,089	162,838,574	14,176,515	
	GENERAL PLANT														
390.00	STRUCTURES AND IMPROVEMENTS	22,648,772	R 1.0	35.0	2.86	647,755	0	1.00	2.86	647,755	3,631,027	3,631,027	5,622,010	-1,990,983	0.00
391.00	OFFICE FURNITURE AND EQUIP.	636,368	S 4.0	18.0	5.56	35,382	5	0.95	5.28	33,600	160,564	152,536	119,886	32,650	0.00
391.10	OFFICE FURNITURE AND EQUIP.-COMPUTERS	867,103	S 4.0	10.0	10.00	86,710	0	1.00	10.00	86,710	451,043	451,043	-403,214	854,257	0.00
391.20	OFFICE FURNITURE AND EQUIP.-LAPTOP COMP.	899,621	S 4.0	5.0	20.00	179,924	0	1.00	20.00	179,924	637,036	637,036	440,849	196,187	0.00
393.00	STORES EQUIPMENT	138,142	SQ	30.0	3.33	4,600	0	1.00	3.33	4,600	30,157	30,157	35,198	-5,041	0.00
394.00	TOOLS, SHOP & GARAGE EQUIPMENT	3,339,457	S 6.0	19.0	5.26	175,655	0	1.00	5.26	175,655	750,378	750,378	754,055	-3,677	0.00
397.00	COMMUNICATION EQUIPMENT	892,402	SQ	10.0	10.00	89,240	0	1.00	10.00	89,240	449,676	449,676	433,204	16,472	0.00
398.00	MISCELLANEOUS GENERAL EQUIPMENT	802,973	S 5.0	15.0	6.67	53,558	0	1.00	6.67	53,558	224,824	224,824	251,165	-26,341	0.00
	TOTAL DEPREC. GENERAL PLANT	30,224,838		23.8	4.21	1,272,826			4.21	1,271,044	6,334,705	6,326,677	7,253,153	-926,476	
	TOTAL DEPREC. GAS PLANT	631,074,215		38.2	2.62	16,530,012			3.14	19,836,841	163,511,780	205,106,324	188,750,655	16,355,670	
														7.97%	
	AMORTIZED PLANT														
392	TRANSPORTATION EQUIPMENT	8,367,661		5.0	20.00	1,673,532	0	1.00	20.00	1,673,532			3,649,940		0.00
396	POWER OPERATED EQUIPMENT	1,378,752		5.0	20.00	275,750	0	1.00	20.00	275,750			683,509		0.00
	TOTAL AMORTIZED PLANT	9,746,413		5.0	20.00	1,949,283			20.00	1,949,283			4,333,449		
	TOTAL DEPREC. & AMORTIZED GAS PLANT	640,820,628		34.7	2.88	18,479,295			3.40	21,786,124			193,084,104		
1050	PLANT HELD FOR FUTURE USE	852,305													
1210	OPI-LAND-RETAINED	13,665													
1211	OPI-STRUCTURES-RETAINED	133,284											133,284		
3020	FRANCHISES AND CONSENTS	250,950													
3040	LAND RIGHTS OWNED	97,504													
3641	LNG PROCSS LAND AND LAND RIGHTS	57,315													
3740	DISTR LAND & LAND RIGHTS	357,903													
3890	GNL LAND RIGHTS	121,489													
	TOTAL GAS PLANT IN SERVICE	642,705,043											193,217,388		

II-239

<u>Liberty Utilities, NH</u>
ENNG – Impacts of Decoupling on Energy Efficiency
As of 6/1/2020

Summary
Attached is a detailed inventory of specific marketing and promotion activities performed in 2018, 2019, and year-to-date in 2020 for the Company's natural gas energy efficiency programs. Activities are differentiated between advertisements, events, and training sessions performed, and further classified as relating to, (a) the promotion of stricter building energy codes in the state, (b) the education activities to builders, and/or (c) the engagement with state and local officials and associations to promote energy efficiency.

In summary, the Company more than doubled its volume of marketing and promotion activities between 2018 and 2019, performing 240 documented tactics in 2019 as compared to 99 in 2018. The Company increased its engagement with state and local officials and associations by 150%, and increased its education activities to builders by 88%. Specific tactics the Company deployed to promote stricter building energy codes in the state increased 64%, including where the Company expressed public support and lobbied for the full adoption of the 2015 IECC standards. In 2020, the Company is on pace to exceed its 2018 activity levels again and come close to matching if not exceeding certain 2019 activity levels, despite the market implementation challenges posed by COVID-19.

In terms of general promotion of the Company's energy efficiency programs, of noteworthy recognition is the Company's implementation of a broad-based, multi-channel mass-media campaign launched in April 2019. The campaign is a natural gas-focused energy efficiency advertising effort utilizing monthly Cable TV commercials and traditional and online radio spots, bus-wrappings, billboard advertisements, and social media marketing. This was a first-of-its kind energy efficiency marketing campaign from any of the NH utilities, which the Company is continuing to deploy on a monthly basis in 2020.

In terms of any measurable impacts decoupling has had on the results of the Company's sponsored energy efficiency programs, the Company increased its lifetime MMBtu savings achievements by 26% in 2019 compared to its 2018 savings achievements, while only increasing its program expenditure levels by 8% between 2019 and 2018.

Lastly, the Company completed a survey of its residential customers in April 2020 to measure the level of energy efficiency program awareness. As part of the survey findings, the Company found that nearly three in four customers (73%) are aware that the Company offers energy efficiency programs to help customers reduce their energy costs, which is significantly higher than the awareness level recently measured as part of the Company's annual customer satisfaction survey completed in the fall of 2019, where energy efficiency program awareness was found to be 64%. The Company had last measured customer awareness of its energy efficiency programs in its 2016 annual customer satisfaction survey, where program awareness was measured to be 57%.

JULY 31, 2020

EVALUATION OF THE EFFECTS OF REVENUE DECOUPLING ON ENERGY EFFICIENCY PROGRAM ACHIEVEMENT

EXPERTS WITH IMPACT™

1. Introduction and Summary

The Power & Utilities practice at FTI Consulting Inc. ("FTI") has been retained by Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty ("Liberty" or the "Company") to evaluate linkages between rate decoupling and outcomes for utility-sponsored Energy Efficiency ("EE") programs. Specifically, FTI was asked to analyze changes in the behaviors of gas utilities that are generally similar to Liberty in terms of size and geography attributable to the implementation of rate decoupling and, to the extent that such changes were identified, attempt to measure the effects.

The context for our inquiry is the rate case with which this report is filed. In Liberty's most recent completed rate proceeding, the New Hampshire Public Utilities Commission (the "Commission") authorized it to implement New Hampshire's first revenue decoupling program, which includes a mechanism to adjust rates for differences between the revenue target contemplated in the Company's most recent base-rate case and actual sales revenues. By accounting for this difference, the revenue decoupling mechanism is designed to eliminate revenue risks that arise from increasing EE penetration, in addition to changes in weather and other variables.[1] When the Commission approved the implementation of this mechanism through the rate settlement in the Company's most recent base-rate proceeding, the Commission directed Liberty to report on the effectiveness of the mechanism in achieving the desired outcome, when the Company next requested a change in distribution rates.[2] This report supports fulfillment of that requirement and provides additional information to the Commission

[1] Order No. 26, 122 at p. 1. Docket No. DG-19-161.
[2] Ibid., p. 46.

and intervenors regarding the effectiveness of the Company's decoupling program in advancing EE achievement.

Our evaluation included two main avenues of inquiry. *First*, we sought to determine whether the Company's behavior regarding its EE programs changed after November 1, 2018. One stated objective of decoupling the Company's rates was the elimination of disincentives to participate in EE programs. If that objective was achieved, we expected to find evidence of greater advocacy for those programs. To determine whether this was the case, we reviewed data regarding the Company's outreach and marketing efforts before and after decoupling took effect and also data showing savings from EE programs in those two periods.

Second, we sought to isolate evidence indicating a relationship between decoupling and EE achievement through a comparative analysis of similar utilities. Here, our thesis was that, if revenue decoupling is positively correlated to EE achievement, we would find evidence of that relationship for utility companies that operate in different jurisdictions, under different management, and which decoupled their rates at different times. To undertake this part of our analysis we reviewed EE data for a number of gas utilities, and one electric utility, throughout New England.

Through this investigation, we found that there is significant evidence that revenue decoupling and EE achievement are linked. Data for Liberty shows that its behavior changed once the Commission approved its request to decouple its rates from its revenues and that significant savings from its EE programs was a direct result. We also found similar outcomes for utilities all over New England, for whom gains in EE program savings coincided with the decoupling of rates.

In the final analysis, we conclude that the Commission's approval of Liberty's request to decouple its rates from its revenues in 2018 has provided measurable support for the Company's subsequent gains in energy efficiency and that decoupling is likely to do so moving forward.

The remainder of this report is organized as follows. Section 2 provides a brief overview of utility decoupling, the Commission's approval of revenue decoupling for Liberty, and the Company's EE program. Section 3 describes the increases in the Company's activity levels we observed after November 2018 and the increases in savings from EE programs that Liberty subsequently achieved. In Section 4, we describe the comparative analyses we conducted of other utilities in New England who have implemented decoupling in roughly the last ten years and our conclusion that there has been a demonstrable increase in spending on EE programs, EE savings, or both, for most of those utilities that coincides with the implementation of decoupling. Lastly, in Section 5, we summarize our findings.

2. Revenue Decoupling

Revenue decoupling is a regulatory mechanism that first appeared in 1978 in the state of California to provide relief to natural gas utilities from reduced revenues due to natural gas supply constraints.[3] Since that time, many states have adopted decoupling measures for its electric and/or natural gas utilities through individual rate cases.

In recent years, decoupling has become more common as a growing number of state regulators and policymakers focus attention on reducing energy usage and greenhouse gas emissions. Traditional

[3] Department of Energy (2010, July). *Natural Gas Revenue Decoupling Regulation: Impacts on Industry.* U.S. Department of Energy. Retrieved from: https://www1.eere.energy.gov/manufacturing/states/pdfs/nat-gas-revenue-decoupling-final.pdf

FTI CONSULTING

ratemaking may incent utilities to seek to increase profits by increasing sales. Simultaneously, utilities may have a financial disincentive to pursue investments and programs, like EE, that tend to reduce sales and revenues.[4] As a result, tensions can arise between policy objectives and utilities' financial outcomes. By "decoupling" revenues from sales, which is often accomplished through some adjustment mechanism that allows the utility to achieve a fixed amount of revenue, expressed on either an overall or on a per-customer basis, that tension can be resolved. With revenues decoupled from sales, utilities can support EE and related programs without putting its revenues at risk.

In April 2018, the Commission authorized Liberty to implement what is known as "full" decoupling in November 2018.[5] Specifically, Liberty is allowed to recover a fixed amount of revenue per customer, regardless of how its throughput changes for any reason.[6] Alternatives to full decoupling include partial decoupling, which allows a utility to recover some but not all of the difference between authorized and actual revenues, and limited decoupling, which provides for recoveries of "lost" revenues attributable to throughput reductions that arise from specific measures; for example, a limited decoupling mechanism may allow a utility to recover the difference between authorized and actual revenues that result from changes to weather but not that arise from changes to economic conditions.[7]

Liberty, along with the other gas and electric utilities in New Hampshire, collaborates to provide its customers EE solutions under the "NH Saves" brand, through which they provide customers with

---

4 Ibid.

5 Regulatory Assistance Project ("RAP") (2016, November). *Revenue Regulation and Decoupling: A Guide to Theory and Application*. Regulatory Assistance Project. Retrieved from: https://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decoupling-guide-second-printing-2016-november.pdf

6 Order No. 26, 122 at p. 43-45. Docket No. DG 17-048.

7 National Renewable Energy Laboratory (2009, December). *Decoupling Policies: Options to Encourage Energy Efficiency Policies for Utilities*. Retrieved from: https://www.nrel.gov/docs/fy10osti/46606.pdf

incentives, information, and support designed to save energy, reduce costs, and promote environmental objectives.[8] Additionally, each of the New Hampshire utilities are individually required to implement the Energy Efficiency Resource Standard ("EERS"), which was established by the Commission in 2016 and creates savings goals expressed as a function of each utility's sales.[9] The EERS additionally requires the annual filing of updates to utility-specific EE plans (the "Statewide EE Plans") through which increasingly stringent EE targets will be achieved. The 2020 Plan Update, filed in September 2019, is the most recent.

Liberty's EE offerings include separate programs for Residential and Commercial & Industrial ("C&I") customers. Residential programs include performance audits, ENERGY STAR appliance rebates, programs targeted at low-income customers, and others.[10] Building and appliance programs are also offered to C&I customers. Additionally, Liberty engages in education and policy advocacy efforts, such as, for example, advocacy before regulatory agencies for more stringent building codes. Most of Liberty's programs also include customer outreach elements, which is to say that it conducts marketing and purchases advertising to make customers aware of its EE programs and the options to create savings they have available.

3. Company Results

FTI reviewed public data regarding Liberty's EE program and data that the Company compiled internally. Both indicate that after decoupling was authorized by the Commission, Liberty spent more on EE,

8 New Hampshire Statewide Energy Efficiency Plan, 2020 Update (the "2020 Plan Update"). Filed September 13, 2019 in DE 17-136 at p. 8.

9 Order No. 25, 932. Docket No. DE 15-137.

10 *Energy Efficiency Programs* (2020). Liberty. Retrieved from: https://new-hampshire.libertyutilities.com/derry/residential/smart-energy-use/natural-gas/index.html

conducted more outreach and achieved greater savings compared to the period prior to decoupling implementation.

Enhanced Marketing Outreach

Liberty more than doubled the volume of its marketing and promotion activities in 2019, compared to 2018. On an ongoing basis, the Company places advertisements for its EE programs; conducts trainings for professionals in the construction and/or EE industries, including, for example, the Company's participation in the Building Operator Certification program or "button-up" workshops whose purpose is to educate homeowners regarding EE opportunities; and participates in events, which include meetings with government agencies, participation in industry conferences, and running open houses and roundtable discussions.[11] Each activity is tracked individually. In 2018, there were 99 separate instances of outreach by the Company designed to promote its EE programs. In 2019, there were 240, an increase of 142%. Outreach instances are shown below by category:

Table 1. Liberty EE Outreach by Category

	Advertisement	Event	Training	Total
2018	45	25	29	99
2019	72	62	106	240
YoY Change	60%	148%	266%	142%

Liberty also tracks the primary objective of each outreach activity. Primary objectives include the Company's promotion of enhanced building standards, which it seeks to achieve through advertisement and participation in industry events; engagement with state and local officials regarding EE and the

[11] Building Operator Certification (2016, January). *BOC Offered in New Hampshire!* Retrieved from: https://www.theboc.info/boc-offered-in-new-hampshire/

Company's EE program, and others.[12] Table 2 shows the change in the frequency of outreach for each type of objective between 2018 and 2019. Note that the totals exceed those reported in Table 1 since some instances of outreach had multiple objectives.

Table 2. Liberty EE Outreach by Objective

	2018	2019	Increase
Promotion of enhanced building codes	11	18	64%
Education activities with builders	16	30	88%
Engagement with state and local officials	22	55	150%
Other activities	66	161	144%

One of the most impactful approaches to outreach regarding its EE programs that the Company has taken has been a broad-based, multi-channel mass-media campaign launched in April 2019. The campaign includes television and radio commercials, online content, "bus-wrappings", billboard advertising, and social media marketing. The program, which is still ongoing, is the first of its kind in New Hampshire. Customer awareness is one of the key metrics that the Company uses to evaluate the effectiveness of its marketing efforts. Those data indicate that the measures described above have yielded benefits. In April 2020, the Company conducted a survey and determined that 73% of its customers were aware of its EE programs and their potential to help reduce energy costs. In mid-2019, awareness had been considerably lower, 64%, and in 2016, the most recent previous survey, awareness was only 57%.

[12] Much of the Company's 2019 efforts were devoted to advocating for full adoption of the 2015 International Energy Conservation Code ("2015 IECC"), which was adopted, with amendments, by the New Hampshire State Building Code Review Board in September 2019. See https://www.puc.nh.gov/EnergyCodes/energypg.htm

Savings in Recent Years

Available data indicate that the Company's EE savings following decoupling have been significant. Overall, the Company increased the savings achieved by the EE program, measured in lifetime MMBtu savings, by 26% in 2019 compared to its 2018 savings achievements, while only increasing its program costs by 8% over the same period. Savings were achieved in most of Liberty's rate classes (and in all of its largest classes).

Using weather-normalized sales data that Liberty provided, FTI calculated normal use per bill for each rate class for the twelve-month period beginning each November (referred to below as a "decoupling year"). To account for long-run trends, normal use per bill for the annual periods of November 1st through the subsequent October 31st were calculated for each of the five decoupling years that end with October 2019. Results are summarized below.

Table 3. Liberty Usage by Customer Group (average dth/bill)

Normal Usage Per Bill by Class	Nov14-Oct15	Nov15-Oct16	Nov16-Oct17	Nov17-Oct18	Nov18-Oct19
R-1	212	216	218	213	196
R-3 & R-4	752	726	738	748	747
G-41, G-42 & G-43	45,209	44,417	46,009	43,002	40,831
G-51 & G-52	16,745	16,210	17,664	17,715	17,453

To compile these data, we grouped customers by rate class with other, similar classes and calculated average consumption per bill (dth) for each aggregation. In some instances, rate classes with a very small number of customers were excluded.[13] The results indicate a decreasing consumption across classes. Large reductions were observed for the C&I high-winter-use group (rate classes G-41, G-42 &

[13] This includes, for example, the G-53 and G-54 industrial customer rate classes.

G-43) and residential non-heating group (R-1). The results for the residential heating group (R-3 & R-4) indicate smaller declines, expressed on a percentage basis, but represent a sizeable portion of the Company's customers.[14] In each instance, the red line indicates the implementation of decoupling.

Figure 1. Change in Annual Consumption, Residential Non-Heating Group

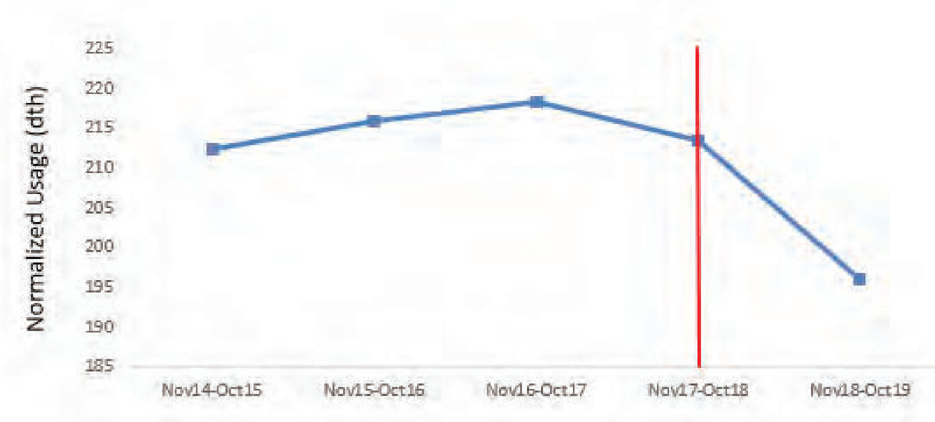
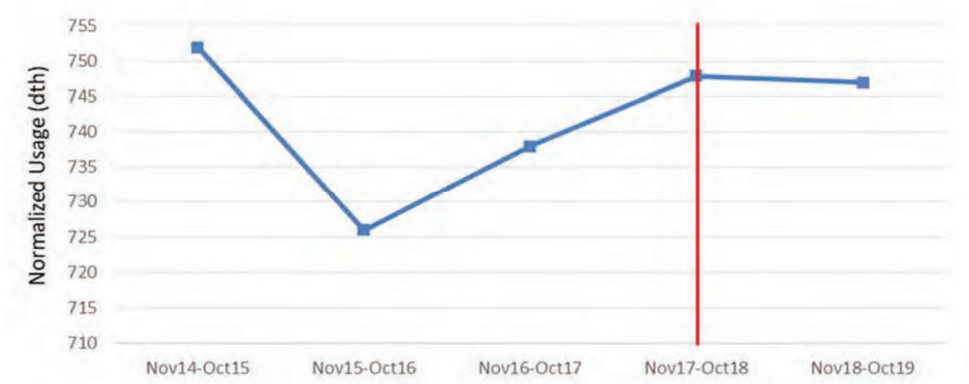


Figure 2. Change in Annual Consumption, Residential Heating Group



The low-winter-usage C&I group (G-51 & G-52) had a significant reduction in usage per bill as well. Although caution should be taken in inferring too much from such a limited sample size, the consistency

[14] As of October 2019, the R-3 rate class (75,307 customers) and the R-4 rate class (5,667 customers) combined for a total of 80,974 customers, or 83% of Liberty's 97,348 total customers.

of these data suggest a change in customer behavior that may have coincided with the implementation of decoupling and the changes in Liberty's outreach efforts described above which, as we describe below, is consistent with our other findings. Year over year changes for each aggregation are shown below.

Figure 3. Change in Annual Consumption, C&I High-Winter-Use Group

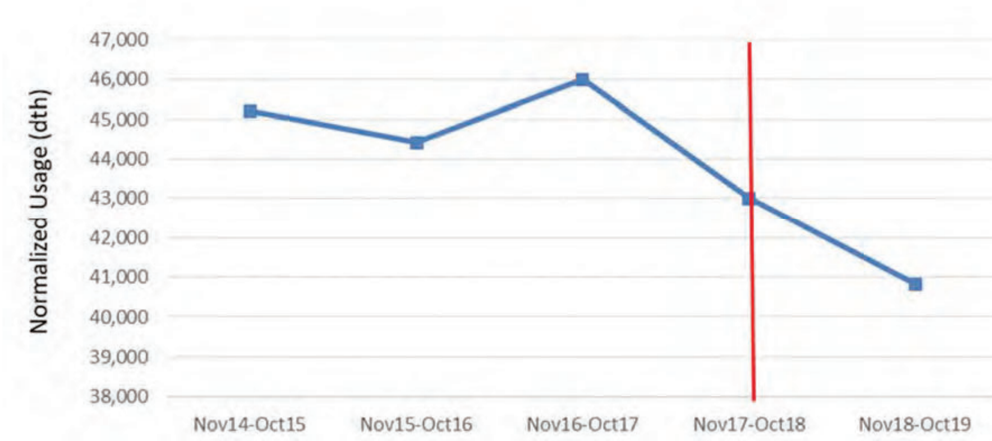
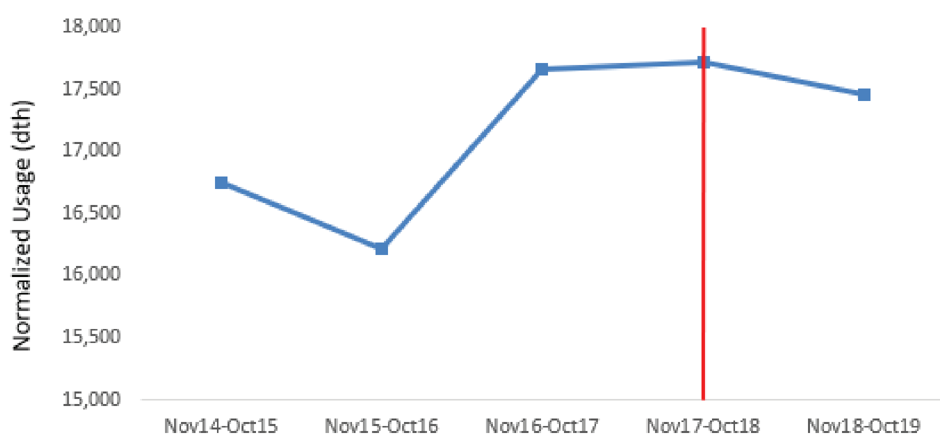
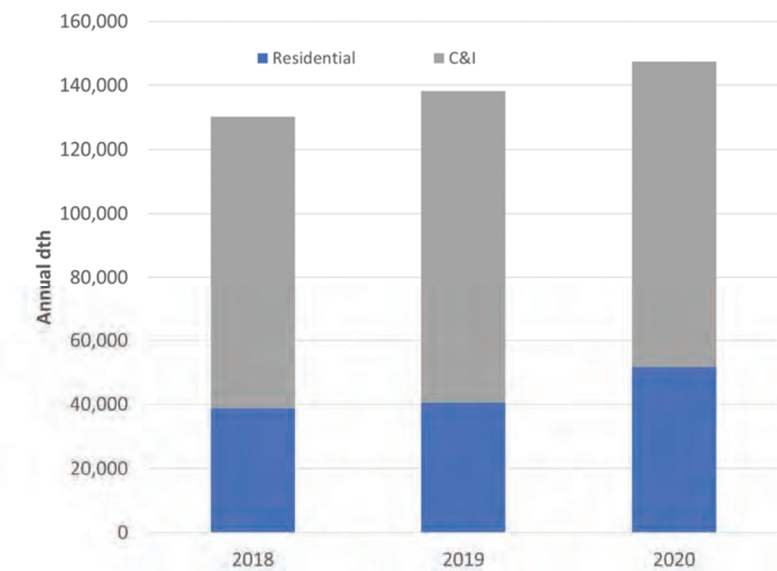


Figure 4. Change in Annual Consumption, C&I Low-Winter-Use Group



Moving forward, Liberty's EE achievement is expected to remain strong, particularly in the residential segment. FTI has reviewed data from the last Statewide EE Plans filed with the Commission in DE 17-136. Those data indicate expectations of continued strong growth in savings. Below, Liberty's EE targets for annual and lifetime savings approved each year by the Commission are reported for the three years ending in 2020.[15,16]

Figure 5. Liberty Energy Efficiency Plan, Annual Savings by Customer Class, 2018-2020



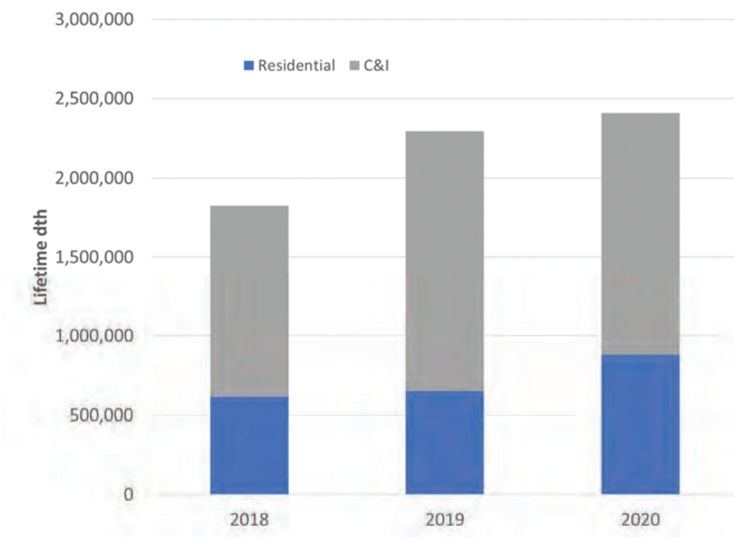
Notably, although C&I gains drove growth in savings from 2018 to 2019, benefits from the residential sector are expected to provide the basis for most of the expansion of the EE program in 2020. Planned residential savings for 2020, expressed on an annual and lifetime basis, are expected to increase by roughly 28% and 35%, respectively, compared to 2019.

---

15 Order No. 26, 323. Docket No. DE 17-136.

16 No attempt has been made to adjust or evaluate the reasonableness of the approved objectives for 2020 given the COVID-19 pandemic, ensuing economic recession, or any other factor.

Figure 6. Liberty Energy Efficiency Plan, Lifetime Savings by Customer Class, 2018-2020



One driver of those gains is expansion of the Company's ENERGY STAR Homes program, a package of incentives it offers to customers seeking to achieve the ENERGY STAR qualification, which requires independent verification that the home is 15% more efficient than currently effective state requirements.[17,18] From 2019 to 2020, acceleration of the ENERGY STAR Homes program is expected to result in an increase in annual savings of roughly 10,000 dth, meaning that the measure accounts for much of the growth shown above.[19]

---

[17] Liberty Utilities (2020). *Building a Home: ENERGY STAR Homes.* Retrieved from: https://libertyutilities.com/residential/smart-energy-use/natural-gas/building-a-home.html

[18] The combination of the Company's participation in the ENERGY STAR program and its advocacy for increasingly stringent building codes has the potential for compounding benefits. For example, passage of the 2015 IECC means that greater savings will be required to achieve the ENERGY STAR qualification, all else equal.

[19] See Attachment I4 of the 2020 Energy Efficiency Plan.

4. Comparative Analysis

In an effort to isolate the impacts of decoupling in these results, FTI compared the effect of decoupling on EE achievement on utilities in other jurisdictions. To do so, we compiled a group of utilities that were generally similar in certain ways to Liberty (and dissimilar in other significant ways) and reviewed data they reported to their regulators to determine how the introduction of decoupling affected their ability to generate energy savings through their EE programs. Our starting point was the universe of gas utilities in New England, of which there are twenty-four, according to the Northeast Gas Association.[20]

Of these, we eliminated the municipal utilities, including Holyoke Gas & Electric, Norwich Public Utilities, and others, as well as the companies that are either considerably larger than Liberty, such as National Grid Massachusetts, or much smaller, including Fitchburg Gas and Electric Light Co. and all of the Maine Local Distribution Companies ("LDCs"). Utilities that do not have revenue decoupling, such as Vermont Gas Services, were not considered, nor were companies such as Columbia Gas of Massachusetts ("CMA") or Liberty's Massachusetts affiliate, which decoupled its rates long enough ago that data regarding EE achievement was not sufficiently available to conduct the before and after comparisons we describe below.[21] Because Maine shares a number of important similarities with New Hampshire, and due to the lack of suitable LDCs from that state to include in our proxy group, we chose to include one electric company from Maine, Central Maine Power ("CMP"), in our analysis.

---

[20] Northeast Gas Association. *Northeast Gas Providers – Links to Individual Company Safety Pages.* Retrieved from: https://www.northeastgas.org/nat_gas_providers.php

[21] In all cases here and in the remainder of this section we adopted the convention to refer to each LDC by its current name regardless of what its name was when any event of note took place. For example, CMA was Bay State Gas at the time it first implemented decoupling.

The five utilities that comprise the proxy group are shown in Table 4. For each, the most recently available customer count is reported as well as the date on which its rates were decoupled and the docket in which the state regulator of relevance first approved decoupling.

Table 4. Proxy Group Utilities

	State	Type	Customers	Decoupling Implemented	Decoupling Docket
Connecticut Natural Gas ("CNG")	CT	Gas	177,000	Jan-14	13-06-08
Southern Connecticut Gas ("SCG")	CT	Gas	197,000	Jan-18	17-05-42
Berkshire Gas ("Berkshire")	MA	Gas	40,000	Feb-19	18-40
National Grid Rhode Island ("NGrid RI")	RI	Gas	272,000	Apr-11	4206
CMP	ME	Electric	600,000	Sep-14	2013-00168

As described in the remainder of this section, for each company we found a positive correlation between decoupling and EE achievement based on the observation that each achieved more savings from their EE programs after implementing decoupling than they did before. Moreover, we find that the change in regime is fairly evident in all cases. The clear difference in achievement pre- and post-decoupling, combined with the fact that the same change in trend was apparent regardless of where or when decoupling was implemented, creates compelling evidence of a causal relationship.

Connecticut

Public Act No. 07-242 (2007) required the Public Utilities Regulatory Authority ("PURA") of Connecticut to implement decoupling for each of the state's gas and electric utilities in the next rate case following the measure's passage. PURA first approved CNG's decoupling program in 2014 while SCG's mechanism was put into place in 2018. The CNG and SCG mechanisms are generally similar. Both are full decoupling mechanisms that reconcile rates on a dollars-per-customer basis and include weather normalization. Charges or refunds are allocated on a class-by-class basis and differentials between budgets and earned revenues are reconciled through the decoupling mechanism only if the difference is greater than $1 million. Minor differences exist regarding the treatment of customers added to the system between rate cases, but otherwise most of the same provisions are used for the two companies.

EE achievement in Connecticut is generally high. In addition to revenue decoupling, statutes also provide an opportunity for both gas and electric companies to earn incentive payments if EE targets are met or exceeded.[22]

CNG and SCG, along with the electric utilities in Connecticut, serve as administrators for the statewide EE plan, one responsibility of which is to develop three-year Conservation & Load Management Plans ("C&LM Plans"), which are approved by PURA and the Department of Energy and Environmental Protection ("DEEP").[23] Once approved, plans are updated on an ongoing basis. The current C&LM Plan covers the period 2019-2021. The latest revision to that plan was filed with PURA and DEEP on March 1, 2020.[24] FTI relied on data from the 2019-21 C&LM Plan in order to evaluate decoupling impacts for CNG and SNG. Figure 7 shows annual savings realized by the CNG EE program beginning in 2012, two years before decoupling was implemented (and the earliest date for which data was readily available) through 2016. The red line in each figure delineates the time series to periods before and after decoupling.

---

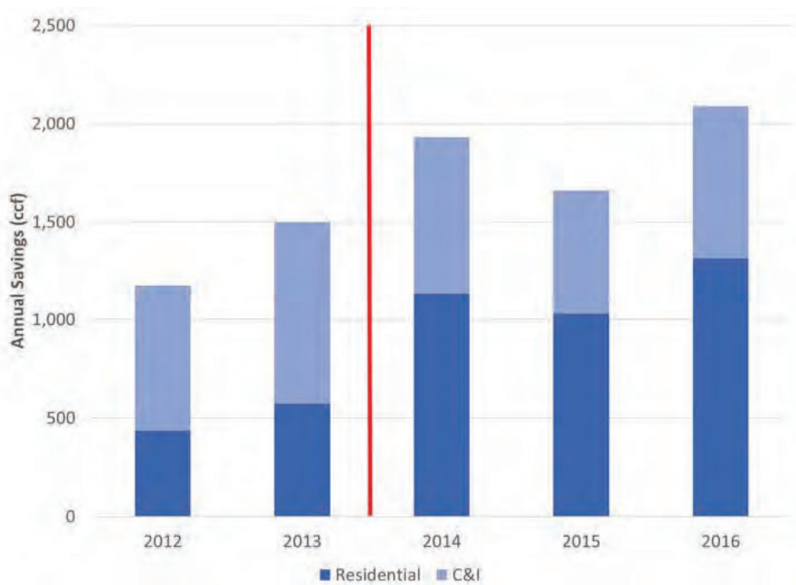
22 C2ES (2019, March). *Decoupling Policies*. Center for Climate and Energy Solutions. Retrieved from: https://www.c2es.org/document/decoupling-policies/

23 Energize Connecticut (2020). *Current and Approved C&LM Plans.* Retrieved from: https://www.energizect.com/connecticut-energy-efficiency-board/current-and-approved-clm-plans

24 Eversource Energy, United Illuminating, Connecticut Natural Gas Corporation, and Southern Connecticut Gas (2019, November). *2020 Plan Update to the 2019-2021 Conservation & Load Management*. Retrieved from: https://portal.ct.gov/-/media/DEEP/energy/ConserLoadMgmt/Final-2020-Plan-Update-Text-11-1-19.pdf?la=en

Based on annual savings, EE achievement increased substantially once decoupling was introduced. Average energy savings from EE programs for the first two years of this dataset (the pre-decoupling period) was 1,340 Ccf,[25] expressed on an annual basis. In the three years afterwards, the average annual savings increases 41% to 1,895 Ccf.

Figure 7. CNG Annual EE Savings, 2012-2016[26]

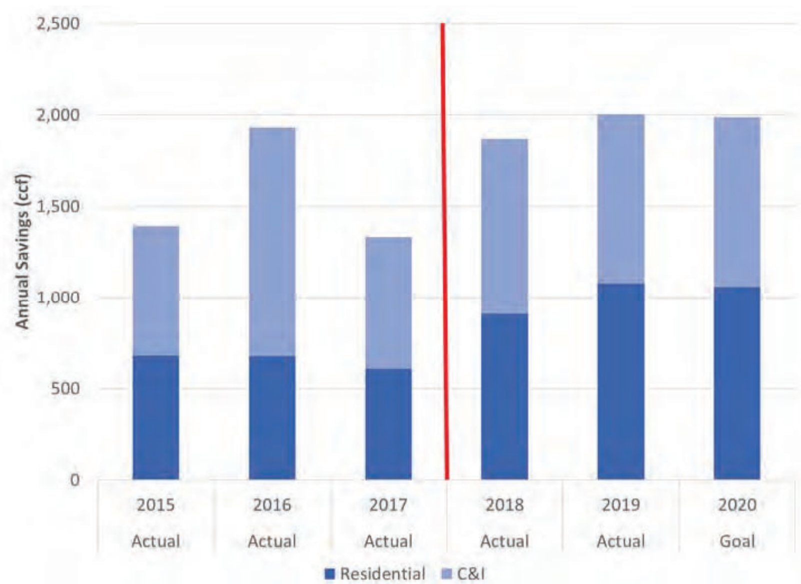


Conducting the same evaluation for SCG reveals the same pattern around the date when that utility's decoupling mechanism was approved. As shown below, for the three-year period ending in 2017, SCG's average annual EE savings was 1,551 Ccf. For the three years beginning in 2018, the year after which decoupling was implemented, annual savings increase 26% to 1,953 Ccf. Note that the 2020 goal was established in the latest C&LM Plan while data for other years report actual achievement.

25 Ccf is the volumetric abbreviation for 100 cubic feet of natural gas and is the equivalent of 1.037 therms.
26 2019-21 C&LM Plan at p. 203.

That CNG and SCG show the same result achieved at different times is impactful. Changes to variables such as weather, economic conditions, or other factors could influence consumption levels, creating a potential "false positive" attribution of the change to the implementing of decoupling. The fact that these two companies experienced the same change in trend, in the same geography but at different times suggests a meaningful correlation rather than coincidence.

Figure 8. SCG Annual EE Savings, 2015-2020[27]



Massachusetts

Berkshire's mechanism, which was first approved by the Massachusetts Department of Public Utilities ("MADPU"), provides for full decoupling on a per-customer basis. Semi-annually, by season, Berkshire reconciles its revenues per customer to a benchmark revenue amount previously established by the

[27] 2019-21 C&LM Plan at p. 224.

MADPU and applies a Revenue Decoupling Adjustment Clause ("RDAC") to either recover or refund any variances. The RDAC is calculated and applied for each rate class.[28]

LDCs in Massachusetts are required to file EE data regarding their EE plans and program achievement regularly. Typically, they file three-year plans and separately file reports of achievement, variances between actuals and plans, and other results. Since the MADPU authorized Berkshire to implement decoupling in early 2019, FTI analyzed actual annual savings for the period 2016-2018 compared to the savings projections included in the most recent EE plan approved by the MADPU.[29]

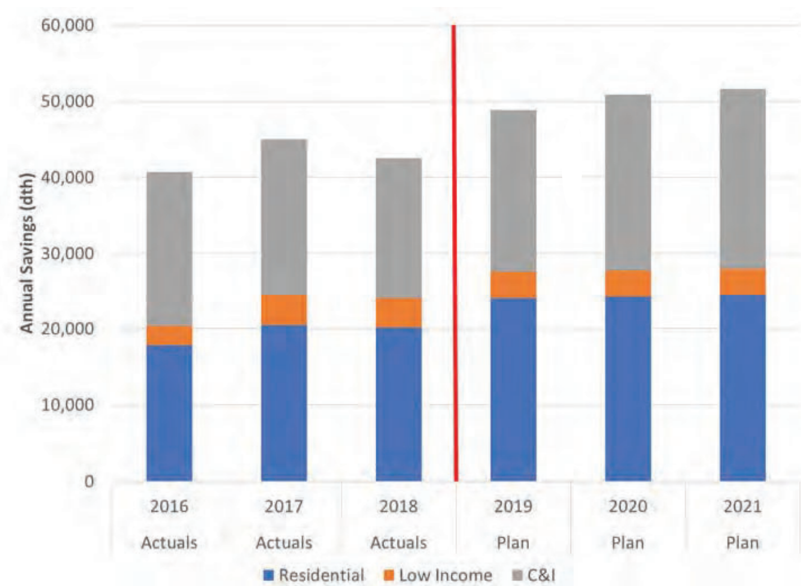
Berkshire's EE savings show the same pattern as do those of the Connecticut utilities: a significant increase in the benefit from EE programs that coincides with the decoupling of rates and revenues. Annual savings for the three years prior to decoupling averaged 42,738 dth, as shown in Figure 10 below. The plan approved by the MADPU indicates expectation that savings will increase by about 18% to an average of 50,464 dth each year.

---

[28] The Berkshire Gas Company (2020, March). Tariff M.D.P.U, No. 548: *Revenue Decoupling Adjustment Clause*.

[29] Actuals for 2016-2018 were reported in Berkshire's August 1, 2016 filling in Docket No. DPU 16-121 and its current plan for 2019-2021 was filed with the DPU in Docket No. DPU 19-91 on August 1, 2019.

Figure 9. Berkshire Annual EE Savings, 2016-2021



The timing associated with these findings is important since Berkshire decoupled its rates at a different time than either of the Connecticut utilities. The fact that it experienced the same results as did those companies implies some causal correlation with the timing of the change in the rate structure.

Rhode Island

Like Connecticut, Rhode Island decoupling was enacted by statute when, in 2010, the Rhode Island legislature passed House Bill 8082, requiring the Rhode Island Public Utilities Commission ("RIPUC") to establish rates that included decoupling mechanisms in each utility's next rate case.[30] NGrid RI's mechanism was subsequently approved in Docket No. 4206 and implemented in April 2011.[31]

---

30 Rhode Island State Legislature (2010, May). *Rhode Island House Bill 8082.* LegiScan. Retrieved from: https://legiscan.com/RI/text/H8082/id/468020

31 RIPUC (2012, May). *Report and Order Re: Narragansett Electric Company d/b/a National Grid's Proposed Revenue Decoupling Mechanism.* Retrieved from: http://www.ripuc.ri.gov/eventsactions/docket/4206-NGrid-RDM-Ord20745(5-25-12).pdf

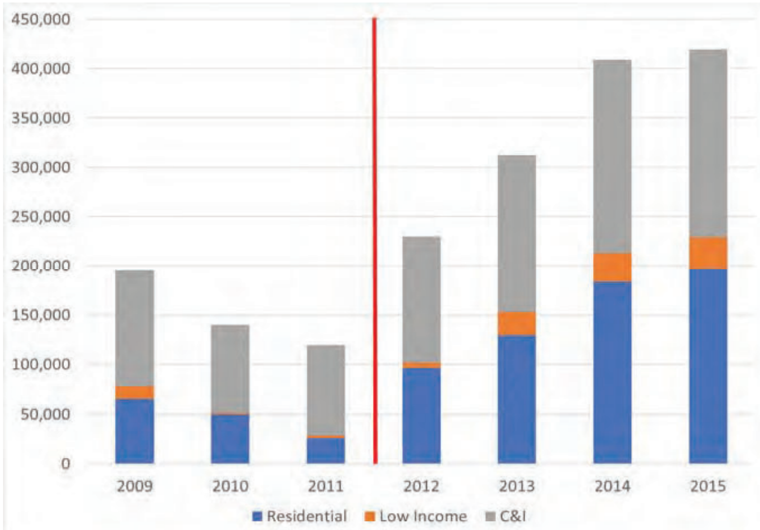
NGrid RI's mechanism provides for full decoupling based on an annual reconciliation of revenues per customer for all classes except large and extra-large C&I customers.[32] Regularly, the utility files a benchmark estimate of per-customer revenues with the RIPUC. Thereafter (assuming that the estimate is approved), variances to the benchmark are calculated and either refunded or recovered through the Revenue Decoupling Mechanism ("RDM"). Changes to the RDM have subsequently been made on an annual basis for 12-month periods from April through the following March each year.

Annually, NGrid RI files with the RIPUC a report indicating its EE achievement for the previous year. FTI reviewed the reports for each year from 2009 to 2015.[33] Among other things, those reports indicate NGrid RI's annual savings from EE programs by customer type. Annual EE savings for the period 2009-2015 are shown in Figure 10.

32 When it proposed its decoupling mechanism, NGrid RI explained that it had excluded the large and extra-large C&I classes because there were a small number of such customers and, as a result, the migration of any one customer from the class to competitive service, which is an option for certain C&I consumers in Rhode Island, could create problematic price distortions and subsidization issues. See the RIPUC's May 25, 2012 Order in Docket No. 4206, at p. 5, for additional details.

33 The reports were filed in dockets 4000 (2009), 4116 (2010), 4209 (2011), 4295 (2012), 4366 (2013), 4451 (2014), and 4527 (2015).

Figure 10. NGrid RI Annual EE Savings, 2009-2015



The data indicates that changes to EE achievement associated with decoupling is similar for NGrid RI as it is for other utilities, namely that it increases markedly at the same time that rates are decoupled from revenues. Total annual EE savings for the three years before decoupling was implemented was 151,637 MMBtu. For the three years following decoupling, the same measure increased by 109% to 317,091 MMBtu.

Maine

Decoupling was adopted in Maine in the late 1980s and early 1990s and subsequently abandoned for multiple reasons, one of the most important of which was a significant recession in the state which reduced energy consumption, causing recurring price increases.[34] Notwithstanding, the Maine Public Utilities Commission ("MEPUC") is authorized under Title 35-A to implement a decoupling mechanism,

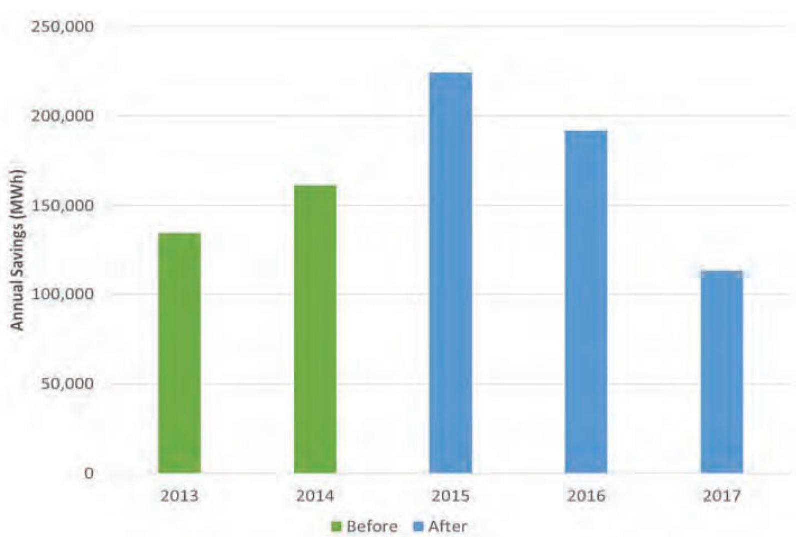
---

[34] RAP, p. 47.

which it did in 2014, granting CMP a decoupling mechanism in Docket No. 2013-00168 which became effective in September 2014.[35]

EE programs in Maine are administered by the Efficiency Maine Trust ("Efficiency Maine"), an independent administrator that is overseen by the MEPUC. Each year, Efficiency Maine publishes reports that explain EE achievement, among other things. Most results are reported on a statewide basis. Because CMP accounts for roughly 80% of the electric load in Maine, FTI chose to compare statewide EE savings before and after CMP's decoupling mechanism took effect.[36] Those results are shown for the two years before decoupling became effective and the three years after, on an annual basis for each year, below in Figure 11. Efficiency Maine's reporting of data does not differentiate results by class.

Figure 11. Maine Annual EE Savings, 2013-2017



[35] Maine Legislature (2019, December) *Title 35-A: Public Utilities*. Retrieved from: http://legislature.maine.gov/statutes/35-A/title35-Ach0sec0.htmll

[36] MEPUC (2020, February). *2019 Annual Report at p. 19.*

Despite the inherent challenges of measuring the impact of decoupling at a single utility using statewide reporting, the same clear pattern emerges from this data as in other sets, namely that the implementation of decoupling coincides with significant increases in EE achievement. In this case, annual savings increased roughly 19% from the two years before decoupling to the three years after, from an average of 148.1 GWh saved to 176.5 GWh.

5. Conclusions

Our analysis of EE savings achieved by Liberty and by other New England utilities who have decoupled their revenues from sales supports at least five conclusions:

- *First*, the decoupling of rates in November 2018 changed the way Liberty does business with regard to its EE programs. The change in its effort to reach out to engage stakeholders and improve market penetration are significant and measurable.
- *Second*, Liberty's savings from EE programs increased significantly once decoupling was implemented.
- *Third,* the strong performance of Liberty's EE programs was expected to continue into 2020 as of the start of this year. If 2020 achievement is lower than expected, that result is most likely attributable to impacts from the COVID pandemic.
- *Fourth*, our analysis of EE achievement by other utilities around New England that have implemented decoupling provides further evidence of a causal relationship. Despite the fact that the companies FTI reviewed have different management and regulators, operate in different weather conditions, and implemented decoupling in different years, in each instance we found that a measurable increase in savings from EE programs coincided with the decoupling of rates.

Based on these findings, we conclude that there is compelling evidence of a causal link between revenue decoupling and the advancement of EE programs. Simply put, EE savings are greater when utility revenues are decoupled from sales. In Liberty's case, it is clear that the increased revenue certainty that came with decoupling either incented it to more zealously expand its EE program, or eliminated disincentives to do so, and that savings from its EE programs increased as a result. It is also reasonable to conclude that the Commission's re-authorization of the Company's decoupling mechanism will promote increased savings in the future.

Liberty Utilities, NH

EE Marketing Activities - ENNG: 2018, 2019 & YTD 2020

As of 6/1/2020

Overall Marketing/Promotion Activities

Count of Year	Column Labels			
Row Labels	**Advertisement**	**Event**	**Training**	**Grand Total**
2018	45	25	29	99
2019	72	62	106	240
2020	21	38	4	63
Grand Total	**138**	**125**	**139**	**402**

Promotion of Stricter Building Codes

Count of Year	Column Labels			
Row Labels	**No**	**Yes**	**Grand Total**	**% Increase**
2018	88	11	99	
2019	222	18	240	64%
2020	51	12	63	
Grand Total	**361**	**41**	**402**	

Education Activities to Builders

Count of Year	Column Labels			
Row Labels	**No**	**Yes**	**Grand Total**	**% Increase**
2018	83	16	99	
2019	210	30	240	88%
2020	47	16	63	
Grand Total	**340**	**62**	**402**	

Engagement with State/Local Officials & Associations

Count of Year	Column Labels			
Row Labels	**No**	**Yes**	**Grand Total**	**% Increase**
2018	77	22	99	
2019	185	55	240	150%
2020	44	19	63	
Grand Total	**306**	**96**	**402**	

Liberty Utilities, NH
EE Marketing Activities - ENNG: 2018, 2019 & YTD 202(
As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
1/18/2018	2018	Advertisement	Email Newsletter	Building Automation Systems: 7 Common Mistakes	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
1/18/2018	2018	Advertisement	Email Newsletter	Saving Energy From the Comfort of Your Couch	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/1/2018	2018	Advertisement	Email	Energy Audit e-blast	Home Performance with ENRGY STAR benefits/opportunities e-blast to 53,885 subscribers	Residential gas customers	Whole house weatherization and efficiency improvements	Residential	No	No	No
2/1/2018	2018	Advertisement	Bill insert sent to 71,500 natural gas customers	Home Performance with ENERGY STAR & Visual Audit Bill Insert	HPwES/Visual Audit bill insert educating customers on program benefits and enrollment	LU residential natural gas customers	Air sealing, insulation, Instant Savings Measures, visual audit, and 2% & 0% financing options	Residential	No	No	No
2/9/2018	2018	Event	Concord	Business & Industry Association Small Business Day	Business to Business energy discussions with NHSaves staff at Exhibitor table	Small business owners and managers, chambers of commerce, business associations	LU's electric and gas measures	C&I	No	No	No
2/14/2018	2018	Advertisement	Direct Mail	Energy Audit Mailer	Home Performance with ENRGY STAR benefits/opportunities mailer to 46,568 residential gas customers	Residential gas customers	Whole house weatherization and efficiency improvements, 2% financing	Residential	No	No	No
2/15/2018	2018	Advertisement	Email Newsletter	3 Options for Multiple Boiler Control	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
2/15/2018	2018	Advertisement	Email Newsletter	Quiz: How Energy Efficient Are You?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/16/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/28/2018	2018	Event	Durham	NH Association of School Business Officials-Facilities Masters Conference	School Facilities Managers' topics of interest	Northern New England school facilities managers	All EE measures	C&I	No	No	Yes
3/2/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Lakes Region Community College, facility managers	All EE measures	C&I	No	No	No
3/12/2018	2018	Event	Keene	NH Energy Week	Business to Business energy discussions with NHSaves staff at Exhibitor table	Keene government officials, community leaders, energy/business professionals	All EE measures	C&I	No	No	No
3/12/2018	2018	Event	Concord	NH Energy Week	Business to Business energy discussions at Exhibitor table	Non-profits, energy and business professionals	All EE measures	C&I	No	No	No
3/16/2018	2018	Training	Laconia	Building Operator Certification	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/20/2018	2018	Advertisement	Email Newsletter	5 Ways to Make Your Meetings Short (and Save Energy)	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
3/20/2018	2018	Advertisement	Email Newsletter	5 Ways to Save While Spring Cleaning	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/3/2018	2018	Event	Plymouth	Grafton Regional Development Corp.	small business EE workshop	Grafton small businesses	All EE measures	C&I	No	No	No
4/3/2018	2018	Training	Plymouth	Grafton Regional Development Corp.	small business EE workshop	Grafton small businesses	All EE measures	C&I	No	No	No
4/4/2018	2018	Event	Concord	Mill Brooke School Tour	NEEP Healthy Schools presentation	School administrators	All EE measures	C&I	No	No	Yes
4/10/2018	2018	Advertisement	Email	Visual Audit e-blast	Highlights and benefits of Visual Audit program sent to 53,007 subscribers	Residential gas customers	Wi-Fi T-Stats, low flow devices, pipe wrap, LEDs	Residential	No	No	No
4/10/2018	2018	Event	Concord	REPA-NH (Residential Energy Professional Associations)	EE program presentation	Energy performance professionals	All EE measures	C&I	No	No	No
4/14/2018	2018	Event	Wilton	EE at Souhegan Sustainability Fair	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates	Residential	No	No	No
4/19/2018	2018	Advertisement	Email Newsletter	Can HVAC Upgrades Improve Worker Performance?	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
4/19/2018	2018	Advertisement	Email Newsletter	Liberty is Offering FREE Energy Saving Products	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/19/2018	2018	Event	Concord	State Employee Manager Presentation	EE program presentation	State employees (managers)	All EE measures	C&I	No	No	Yes
4/25/2018	2018	Event	Pelham	Town of Pelham Open House	EE Table/Booth Setup	Town officials and residents	All EE measures	C&I	No	No	Yes
4/26/2018	2018	Event	Greenland	EE at Lowe's Spring Pro Event	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates	Residential	No	No	No
5/2/2018	2018	Event	Concord	NHBSR Spring Conference	Business to Business energy discussions with NHSaves staff at Exhibitor table	Businesses supporting sustainable/socially responsible operations	All EE measures	C&I	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/3/2018	2018	Training	Manchester	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/3/2018	2018	Training	Manchester	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/11/2018	2018	Event	Pembroke	NH State Employee Conference	EE Table/Booth Setup	State employees	All EE measures	C&I	No	No	Yes
5/12/2018	2018	Event	Nottingham	Nottingham Earth Day Festival	EE Table/Booth Setup	Home owners	Benefits of purchasing ENERGY STAR certified products and appliances and available rebates, refrigerator and freezer recycling program	Residential	No	No	No
5/16/2018	2018	Event	Concord	NHDES Pollution Prevention Training	EE Presentation for Businesses at NHDES	New Hampshire businesses in pollution prevention	All EE measures	C&I	No	No	Yes
5/17/2018	2018	Advertisement	Email Newsletter	Innovations Fuel Process Heating Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
5/17/2018	2018	Advertisement	Email Newsletter	Infographic: Tips for Cool Summer Savings	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
5/17/2018	2018	Training	Atkinson	Energy Codes and Zero Energy Homes Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
5/24/2018	2018	Training	Center Harbor	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
6/1/2018	2018	Event	Loudon	Green Your Fleet	EV event with NHDES-4 utility tables	Businesses interested in electric cars and trucks	All EE measures	C&I	No	No	Yes
6/19/2018	2018	Advertisement	Email Newsletter	Improve Health & Comfort with Gas-Fired Dehumidification	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
6/19/2018	2018	Advertisement	Email Newsletter	5 Ways to Save While Doing Laundry	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Online Key Word Search Ads	Pay Per Click Text Ads	Program Awareness and recognition: 7/2 through 8/20	Residents of NH	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Social Media	Paid Facebook Ad (Boosted Posts)	Program Awareness and recognition: 7/2 through 8/20	Demo: Adults 25+, NH homeowners	All EE measures	Residential	No	No	No
7/2/2018	2018	Advertisement	Social Media	Programmatic Native	Targeting Tactics: Combination of targeting those searching for relevant content related to saving on energy, cutting costs, etc. as well as retargeting those who visit the website: 7/2 through 8/20	Demo: Homeowners 25+ Geo: New Hampshire	Energy efficiency tips	Residential	No	No	No
7/13/2018	2018	Advertisement	Direct Mail	Keene Energy Audit Mailer	Home Performance with ENERGY STAR informational letter sent to 710 residential customers	New Residential Keene customers	Whole house weatherization and efficiency improvements, 2% financing	Residential	No	No	No
7/18/2018	2018	Advertisement	Email	Gas Home Performance Summer Promotion e-blast	Home Performance with ENERGY STAR promo for 75% rebate or 0% financing sent to ~ 57,000 subscribers	Residential gas customers	Whole house weatherization and efficiency improvements	Residential	No	No	No
7/19/2018	2018	Advertisement	Email Newsletter	5 Ways to Save During Non-Business Hours	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
7/19/2018	2018	Advertisement	Email Newsletter	Remodeling? Build In Energy Efficiency	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
8/6/2018	2018	Event	Concord	NEC Roundtable with AIA	NH American Institute of Architects energy discussion	TNC/Warren Street Architects	All EE measures	C&I	No	No	No
8/16/2018	2018	Advertisement	Email Newsletter	Video: Improve Comfort & Reduce Costs with Circulating Fans	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No

II-268

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
8/16/2018	2018	Advertisement	Email Newsletter	Smarter Living with Smart Thermostats	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
8/25/2018	2018	Training	Remote	Code Webinar - LES/NHSaves	Code Webinar - GDS/DES/NHSaves	Business owners and managers	All EE measures	C&I	Yes	Yes	No
8/27/2018	2018	Advertisement	Online Key Word Search Ads	Programmatic Native	EE Tips Promotion from 8/27 through 10/22	Demo: Homeowners 25+ Geo: New Hampshire	Targeting Tactics: Combination of targeting those searching for relevant content related to saving on energy, cutting costs, etc. as well as retargeting those who visit the website	Residential	No	No	No
9/12/2018	2018	Training	Meredith	Residential Code Workshop	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables	Residential	Yes	Yes	No
9/13/2018	2018	Event	Manchester	The Granite Group Heating Trade Show	Heating Systems Supply House and Heating Contractors show	Plumbing, heating, cooling, water & propane supplies specialists	All EE measures	C&I	No	Yes	No
9/13/2018	2018	Training	Manchester	The Granite Group Heating Trade Show	Heating Systems Supply House and Heating Contractors show	Plumbing, heating, cooling, water & propane supplies specialists	All EE measures	C&I	No	Yes	No
9/18/2018	2018	Training	Gorham	Residential Energy Code Training	NHSaves Presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Joe Harnois of Harber Construction.	Residential	Yes	Yes	No
9/18/2018	2018	Training	Gorham	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Joe Harnois of Harber Construction.	Residential	Yes	Yes	Yes
9/20/2018	2018	Event	Portsmouth	North East Electric Distributers Tradeshow	Electric Supply House and Electrical Contractors show	Electrical distributors, electricians	All EE measures	C&I	No	Yes	No
9/20/2018	2018	Training	Portsmouth	North East Electric Distributers Tradeshow	Electric Supply House and Electrical Contractors show	Electrical distributors, electricians	All EE measures	C&I	No	Yes	No
9/25/2018	2018	Advertisement	Email Newsletter	Smart Thermostats: 5 Benefits for Your Business	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
9/25/2018	2018	Advertisement	Email Newsletter	Fall for Energy Savings	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
9/27/2018	2018	Event	Canaan	Mascoma Valley Energy and Sustainability Expo	Energy related event	Upper Valley town energy committees, building professionals, community members	Weatherization, high efficiency heating	C&I	No	Yes	Yes
9/29/2018	2018	Training	Caanan	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/1/2018	2018	Advertisement	Online Key Word Search Ads	Pay Per Click Text Ads	Promote content via ongoing Pay-Per-Click campaign	Residents of NH	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Paid Facebook & YouTube (Boosted Posts)	Program Awareness and recognition	Demo: Adults 25+, NH homeowners	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Facebook- Adults 25+ alternative homeowner behavior targeting	Video, Banners, Quiz	Demo: Adults 25+, alternative homeowner behavior targeting	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	Instagram - Adults 25-40 Estimated Audience Size: 130,000	Video, Banners, Quiz	Demo: Adults 25-40 Estimated Audience Size: 130,000	All EE measures	Residential	No	No	No
10/1/2018	2018	Advertisement	Social Media	YouTube - Adults 18+ Estimated Views: 270,000 - 655,000	(:06) / (:15) Videos	Demo: Adults 18+ Estimated Views: 270,000 - 655,000	All EE measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
10/2/2018	2018	Training	Newmarket	Button Up Workshop	NHSaves Presentation to Newmarket Energy and Environment Advisory Committee, The Newmarket Area Centennial Lions Club and Jonny Boston's International, Plymouth Area Renewable Energy Initiative	1 1/2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/10/2018	2018	Training	Hampton	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Jeffrey Cantara, Solar Design Specialist of ReVision Energy.	Residential	Yes	Yes	No
10/10/2018	2018	Training	Hampton	Residential Energy Code Training	EE program presentation	Residential home builders, municipal officials, architects, people building homes	Reduced energy loads, high efficiency building shells, mechanical systems, domestic hot water, renewables. Guest speaker Jeffrey Cantara, Solar Design Specialist of ReVision Energy.	Residential	Yes	Yes	Yes
10/16/2018	2018	Training	West Lebanon	C&I Codes Training Workshop	EE program presentation	Builders, architects, contractors and sub-contractors	Building codes	C&I	Yes	Yes	Yes
10/18/2018	2018	Advertisement	Email Newsletter	Coming Up For Air: Improving Combustion Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
10/18/2018	2018	Advertisement	Email Newsletter	Slide Show: Simple Steps to Winter Savings & Comfort	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
10/22/2018	2018	Advertisement	Radio	Radio Program Awareness	30 second spot on WHOM, NHPR, WXRV, WFNX, WXRG, WLKC	Residential customers	All EE measures	Residential	No	No	No
10/22/2018	2018	Training	Canterbury	Button Up Workshop	EE Presentation to Canterbury Town Energy Committee, Plymouth Area Renewable Energy Initiative	1 1/2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
10/24/2018	2018	Advertisement	Social Media	Visual Audit promotion via Facebook and Twitter channels	Highlights and benefits of Visual Audit program	Facebook and Twitter followers	Wi-Fi T-Stats, low flow devices, pipe wrap, LEDs	Residential	No	No	No
10/29/2018	2018	Advertisement	Internet Radio	Pandora	(:30) Audio	Demo: Adults 25+ and home owners, apartment/condo renters & owners Estimated Reach: 113,799	All EE measures	Residential	No	No	No
10/30/2018	2018	Training	Manchester	GDS C&I Codes	Building Energy Codes Workshop	Builders, architects, contractors and sub-contractors	Building codes	C&I	Yes	Yes	Yes
10/30/2018	2018	Training	Concord	NHSAA Conference	Overview of EE programs: NH School administrators association of School Business Officials (NHASBO)	School superintendents	Lighting, HVAC and weatherization	C&I	No	No	Yes
11/1/2018	2018	Training	Holderness	Button Up Workshop	EE Presentation to Holderness Energy Committee, Squam Lakes Association, Plymouth Area Renewable Energy Initiative	1 1/2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
11/2/2018	2018	Event	Concord	Advanced Manufacturing Conference	NHMEP Governor's Conference	Politicians, energy professionals, business professionals, manufacturing professionals	All EE measures	C&I	No	No	No
11/5/2018	2018	Event	Nashua	NHRLA Annual Dinner	Upgrade Table and Full Page Ad	Restaurant and Lodging Association	All EE measures	C&I	No	No	No

II-270

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
11/8/2018	2018	Training	Laconia	Button Up Workshop	EE Presentation to Lakes Region Community College, Plymouth Area Renewable Energy Initiative	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	Yes
11/14/2018	2018	Event	Manchester	NHMA Annual Conference	New Hampshire Municipal Association	Municipal officials	All EE measures	C&I	No	No	Yes
11/15/2018	2018	Advertisement	Email	Black Friday Promo for ecobee and Nest Wi-Fi T-Stats	E-blast for Ecobee and Nest manufacturer discounts with Utility rebate special to 64,559 subscribers	Residential gas customers	Wi-Fi T-Stats	Residential	No	No	No
11/15/2018	2018	Event	Manchester	NHMA Annual Conference	New Hampshire Municipal Association	Municipal officials, other non-profits	All EE measures	C&I	No	No	Yes
11/16/2018	2018	Training	Manchester	Compressed Air Training	LU EE and CES Event	Compressed air installers	All EE measures	C&I	No	No	No
11/16/2018	2018	Event	Concord	LES Conference	EE Workshop and 1 pitch to the group	Politicians/lobbyists, non-profits, energy and business professionals	All EE measures	Residential	No	No	Yes
11/20/2018	2018	Advertisement	Email Newsletter	ABC's of Boiler Control	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
11/20/2018	2018	Advertisement	Email Newsletter	Revealed! 6 Hidden Sources of Home Energy Loss	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
11/26/2018	2018	Advertisement	Email	Black Friday Promo for ecobee and Nest Wi-Fi T-Stats	E-blast for Ecobee and Nest manufacturer discounts with Utility rebate special to 64,559 subscribers	Residential gas customers	Wi-Fi T-Stats	Residential	No	No	No
11/27/2018	2018	Training	Rindge/Fitzwilliam	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Lee	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Warren	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/28/2018	2018	Training	Bedford/Hillsborough	Button Up Workshop	EE presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
12/19/2018	2018	Advertisement	Email Newsletter	Boiler Maintenance: 5 Critical Practices for Optimizing Efficiency	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
12/19/2018	2018	Advertisement	Email Newsletter	Is EE on Your Holiday Gift List?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
12/28/2018	2018	Advertisement	Direct Mail	Home Energy Assistance/Visual Audit Mailer	HEA Mailer detailing program benefits sent to 3,443 low income gas customers	LU natural gas customers coded under the low income rate	Air sealing, insulation, heating systems, appliances, Instant Savings Measures, visual audit	Residential	No	No	No
1/1/2019	2019	Advertisement	Bill Insert	House Feeling Drafty? (NH Saves residential offerings for 2019)	LU delivered to all Gas Customers	LU Gas & Electric Customers	All EE measures	Residential	No	No	No
1/8/2019	2019	Event	Concord	Business After Hours - Concord NH Chamber	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	Yes	No
1/13/2019	2019	Advertisement	Social media	Franklin School project case study	Facebook/Twitter	Local Commercial Online Traffic	All EE measures	C&I	No	No	No
1/17/2019	2019	Advertisement	Email Newsletter	What's the Difference? Direct vs. Indirect Gas-Fired Heaters	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
1/17/2019	2019	Advertisement	Email Newsletter	Infographic: Breaking Down Home Energy Use	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
1/17/2019	2019	Training	Webinar	Virtual NHSaves Button Up Workshop	Weatherization webinar with Q&A session to panel and staff	NH Residents	Weatherization	Residential	No	No	No
1/18/2019	2019	Advertisement	Social media	Online Marketplace Promotion - Smart Thermostat	Facebook/Twitter	LU Customers and Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
1/22/2019	2019	Event	City Hall, Concord	Concord 100% Renewable Energy Strategic Plan Stakeholder Committee Meeting	Discussions on all things energy related.	Non-profits, energy and business professionals	All EE measures	C&I	Yes	Yes	Yes
1/23/2019	2019	Advertisement	Social media	HPwES Program promotion	Facebook/Twitter	Local Residential Online Traffic	Weatherization	Residential	No	No	No
1/24/2019	2019	Advertisement	Social media	Smart Thermostat promotion	Facebook/Twitter	Local Residential Online Traffic	NHSaves Gas	Residential	No	No	No
1/30/2019	2019	Training	Nashua	Training w/Wxn Contractor Turn Cycle Solutions	Surveyor/OTTER	Contractor	HPwES	Residential	No	No	No
1/31/2019	2019	Advertisement	Social media	Online Marketplace promotion of Smart Thermostats	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
1/31/2019	2019	Advertisement	Social media	HPwES Program promotion	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
2/1/2019	2019	Training	Keene State College	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/5/2019	2019	Event	State Legislative Office	State Legislative Office - Hearing on HB318	Summary presentation of company's EE programs and efforts ongoing to promote to customers	State Legislature	All EE measures	Both	No	No	Yes
2/7/2019	2019	Advertisement	Social media	Free Energy Savings Measures	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
2/8/2019	2019	Event	Barley House	Concord Chamber of Commerce Local Government Affairs	Business to Business networking	Non-profits, energy and business professionals	All EE measures	C&I	Yes	Yes	Yes
2/13/2019	2019	Training	Roundabout Diner, Portsmouth	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
2/13/2019	2019	Event	Concord	Business After Hours Networking & Promotion event	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	Yes	Yes
2/15/2019	2019	Advertisement	Social media	Smart Thermostat promotion	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
2/15/2019	2019	Training	Concord	14th Annual Small Business Day - NHBIA	Learn about small business solutions	Small business managers	All EE measures	C&I	No	No	No
2/19/2019	2019	Advertisement	Social media	Energy Efficiency Online Tools	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
2/20/2019	2019	Advertisement	Nashua	State of the City Breakfast - Nashua Chamber of Commerce	Update on economic activity with networking following presentation	Business Leaders	All EE measures	C&I	No	Yes	Yes
2/21/2019	2019	Advertisement	Email Newsletter	Video: Maximize Boiler Control with an EMS	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
2/21/2019	2019	Advertisement	Email Newsletter	5 Ways to Start Saving Energy Today	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
2/21/2019	2019	Training	Concord	AIA-NH	Business to Business networking	Architects and General Contractors	All EE measures	C&I	No	No	No
2/22/2019	2019	Advertisement	Social Advertisement	Energy Efficiency Online Tools	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
2/27/2019	2019	Training	Durham	NH Association of School Business Officials-Facilities Masters Conference	School Facilities Managers' topics of interest	Northern New England school facilities managers	All EE measures	C&I	No	No	No
3/1/2019	2019	Advertisement	Bill Insert	Free Energy-Saving Equipment (Visual Audit)	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
3/1/2019	2019	Training	Puritan Back Room	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/8/2019	2019	Training	Doubletree by Hilton, Manchester	New Hampshire State Home Show	Education outreach to contractors and industry associations	NH Residents, Contractors, and Industry Associations	All EE measures	Both	No	No	Yes
3/12/2019	2019	Event	Concord	Business After Hours - Concord NH Chamber	Business to Business networking	Small business owners and General Contractors	All EE measures	C&I	No	No	Yes
3/14/2019	2019	Training	Common Man, Plymouth	1-Day Building Operator Class	Building Operator Training on all energy savings	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
3/22/2019	2019	Advertisement	Email Newsletter	Save Energy With Efficient Water Heating	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
3/22/2019	2019	Advertisement	Email Newsletter	Home Appliances: The Biggest Energy Users	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
3/25/2019	2019	Training	Pease Tradeport in Portsmouth, NH	Energy Week Event: NH Energy Roundtable	How companies are addressing their energy needs, featuring leading experts & company representatives	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/26/2019	2019	Advertisement	Social media	General EE Post - NH SAVES Partnership	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
3/26/2019	2019	Training	OracleDyn in Manchester	Energy Week Event: Emerging Energy Needs Forum	Discussion on the emerging energy needs in NH's largest city & modern approaches to meeting those needs	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/27/2019	2019	Training	NH CIBOR - Bedford NH	NHCIBOR Statewide Meeting	Discussion about current commercial, industrial and municipal opportunities in the state	Commercial lenders, commercial brokers, and other interested parties	All EE measures	C&I	No	No	No
3/27/2019	2019	Training	City Hall	City of Concord	100% Renewable Energy Strategic Plan Stakeholder Committee Meeting	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/27/2019	2019	Training	Salt Hill Pub in Newport	Energy Week Event: NH Energy Roundtable	Discussion on the emerging energy needs in NH's largest city & modern approaches to meeting those needs	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Grappone Conference Center in Concord	Energy Week Event: NH Energy Breakfast	Discussion with a major offshore wind developer & panel of high-level representatives discussing how the regional grid, energy users, utilities, & generators	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Carriage House, Kimball Jenkins Estatein Concord	Energy Week Event: Awards Ceremony & Reception	NH Energy Awards for Business, Municipal, & Legislative Energy Champions	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
3/28/2019	2019	Training	Currier Museum of Art	AIA NH Design Awards	35th Annual Excellence in Design Awards	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/1/2019	2019	Advertisement	WGIR AM Radio	Weatherization Radio Advertisement - Winter & Summer Campaign	iHeart Media: recurring radio spot placement from April through December 2019	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
4/2/2019	2019	Training	White Birch Brewing in Nashua	Energy Week Event: NH Energy Roundtable	Local energy stories from businesses & municipalities	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/11/2019	2019	Training	LAARS Manufacturing	ASHRAE CHP Event	Combined heat and power technology, tour of boiler manufacturing facility	Engineers, Manufacturers, distributors	All EE measures	C&I	No	No	No
4/11/2019	2019	Training	Nashua	Turn Cycle Solutions	Surveyor/OTTER	Residential Electric Customers	HPwES	Residential	No	No	No
4/11/2019	2019	Event	Holiday Inn Concord NH	State of the City - Concord Chamber of Commerce	Update on economic activity with networking prior and following presentation	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/15/2019	2019	Advertisement	Social media	Video about HPwES program	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
4/17/2019	2019	Event	Concord City Wide Community Center	Concord Young Professionals Concord Chamber of Commerce	Business to Business networking	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
4/19/2019	2019	Training	NH Healthcare Association	NHSHFM Monthly Meeting	Building commissioning for healthcare facilities	Healthcare facilities managers, contractors, general contractors	All EE measures	C&I	No	No	No
4/22/2019	2019	Advertisement	Email Newsletter	Boilers: Repair or Replace?	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
4/22/2019	2019	Advertisement	Social media	Earth Day - Thermostat Rebate	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
4/22/2019	2019	Advertisement	E-blast	Smart Thermostats Make Saving Energy Easier	Questline	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
4/22/2019	2019	Advertisement	Email Newsletter	Go Green This Earh Day	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
4/22/2019	2019	Event	Applebee's Nashua	Turn Cycle Solutions	EE program participation and identification of resources	Weatherization contractor	Weatherization	C&I	No	No	No
4/24/2019	2019	Training	FW Webb	Commercial Energy Codes Training	EE program participation and identification of resources	Business Facility Managers and Staff	All EE measures	C&I	Yes	No	No
4/24/2019	2019	Training	NH CIBOR - Bedford NH	NHCIBOR Statewide Meeting	Discussion about current commercial, industrial and municipal opportunities in the state	Commercial lenders, commercial brokers, and other interested parties	All EE measures	C&I	No	No	No
4/30/2019	2019	Training	Londonderry	P&M	Wx 101	Residential Electric Customers	HPwES/HEA	Residential	No	No	No
5/1/2019	2019	Advertisement	Bill Insert	Income Eligible EE Programs & New NH Saves Logo	LU delivered to all Gas Customers	LU Gas Customers	HEA	Residential	No	No	No
5/1/2019	2019	Advertisement	Cable Television	Weatherization Cable TV Advertisement - Winter & Summer Campaign	Comcast: recurring Cable TV spot placement from April through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Digital Billboard	Weatherization Digital Billboard Advertisement - Winter & Summer Campaign	Outfront Media: recurring digital billboard placement from May through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Community Billboard	Weatherization Community Billboard Advertisement - Winter & Summer Campaign	Outfront Media: recurring community billboard placement from May through December 2019	LU Customers and Local Commercial and Residential Community	HPwES	Residential	No	No	No
5/1/2019	2019	Advertisement	Streaming Radio - Pandora	Weatherization Streaming Radio Advertisement - Winter & Summer Campaign	iHeart Media: recurring online streaming radio advertisement from May through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
5/1/2019	2019	Training	Marriott Courtyard Concord NH	NHBSR Spring Conference	EE program participation and identification of resources	Business Facility Managers and Staff	All EE measures	C&I	No	No	No
5/2/2019	2019	Event	Fitzemeyer & Tocci	Trade Ally Meeting with Fitzemeyer & Tocci	EE program participation and identification of resources	Full service mechanical engineering firm	All EE measures	C&I	No	No	No
5/3/2019	2019	Event	A.W.Rose Construction	Trade Ally Meeting with A.W. Rose Construction	EE program participation and identification of resources	General contractor trade ally	All EE measures	C&I	No	Yes	No
5/3/2019	2019	Event	Jay Lee, Berkshire Hathaway	Commercial Lender Trade Ally	EE program participation and identification of resources	Commercial Broker	All EE measures	C&I	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/6/2019	2019	Training	City Hall, Concord	Concord 100% Renewables Listening Session	Discussions on all things energy related.	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
5/9/2019	2019	Training	Mill Brook Primary School	ASHRAE Monthly Meeting	EE program participation and identification of resources	Local engineer trades association	All EE measures	C&I	No	No	No
5/10/2019	2019	Training	Newton	Invictus	EE Program overview	Spray Foam Insulation Contractor and Residential Gas Customers	HPwES	Residential	No	No	No
5/10/2019	2019	Training	Pembroke Readiness Center	2019 State Energy Conference	EE program participation and identification of resources	State facilities staff and administrators	All EE measures	C&I	No	No	Yes
5/14/2019	2019	Event	Manchester	EEI NHSaves program participation and identification of resources	EE program participation and identification of resources	Contractor EEI Representatives	All EE measures	C&I	No	No	No
5/14/2019	2019	Training	Havenwood Heritage Heights	Concord Chamber Business After Hours	EE program participation and identification of resources	Non-profits, energy and business professionals	All EE measures	C&I	No	No	Yes
5/15/2019	2019	Advertisement	Social media	VA Energy Saving Measures and Visual Audit	Facebook/Twitter	Local Residential Online Traffic	Weatherization	Residential	No	No	No
5/16/2019	2019	Training	Franklin	Franklin WWTP Award and Tour	EE program participation	State and municipal staff, and facilities personal	All EE measures	C&I	No	No	Yes
5/17/2019	2019	Event	Lakes Region Chamber of Commerce	EE programs overview presentation	Infrastructure Seminar	State and municipal staff, and facilities personal	All EE measures	Residential	No	No	Yes
5/20/2019	2019	Training	Concord	Turn Cycle Solutions	Blower door training	Contractor	HPwES	Residential	No	No	No
5/21/2019	2019	Advertisement	Email Newsletter	Free Software Calculates Energy Savings of Steam System Insulation	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
5/21/2019	2019	Advertisement	Email Newsletter	5 Ways to Get Your Home Ready for Summer	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
5/22/2019	2019	Advertisement	Email	Promotion of visual audit offeing	Monthly e-newsletter focus	Local Residential Online Traffic	Visual audit	Residential	No	No	No
5/28/2019	2019	Advertisement	Email	Promotion of HPwES program	Monthly e-newsletter focus	Local Residential Online Traffic	HPwES	Residential	No	No	No
5/30/2019	2019	Event	6 Eastpoint Dr., Hooksett	Eckhardt & Johnson	EE Program Participation	HVAC Contractor	All EE measures	C&I	No	No	No
6/1/2019	2019	Advertisement	Bus Wrap	Weatherization Bus Wrap Advertisement - Winter & Summer Campaign	ATA Outdoor Media: recurring bus wrap advertisement from June through December 2019	LU Customers and Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
6/1/2019	2019	Training	Various Locations	Commercial Equipment Heating Equipment Dealer Visits in June	Commercial Equipment Heating Equipment Dealer Visits in June	Deluca Brothers, Kittredge Equipment, NH Restarant Equipment, Perkins/Gordon Food Service, Pitco	Commercial Food Service Equipment (CFSE) rebate program	C&I	No	No	No
6/5/2019	2019	Advertisement	Email	Fathers Day Thermostat Rebate	Special smart thermostat promotion	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/5/2019	2019	Training	Derry	Derry Solar Summit	Promotion of EE programs to attendees	Derry Netzero Task Force/municipal staff, and Derry/Londonderry businesses	All EE measures	Both	No	No	Yes
6/6/2019	2019	Event	Concord Chamber of Commerce	EE programs overview presentation	Promotion of EE programs to attendees	State and municipal staff, and facilities personal	All EE measures	C&I	No	No	No
6/6/2019	2019	Training	Concord Chamber of Commerce	Pinnacle Awards	Promotion of EE programs to attendees	State and municiple staff, and facilities personal	All EE measures	Both	No	No	Yes
6/6/2019	2019	Training	Associated Builders & Contractors	ABC Innovation in Education	Municipal Project Focus	Architects, Municipal Staff and General Contractors	All EE measures	C&I	No	Yes	Yes
6/12/2019	2019	Event	Manchester	Oliver Mechanical	Promotion of EE programs to attendees	HVAC Contractor	All EE measures	C&I	No	No	No
6/13/2019	2019	Training	AIA-NH	AIA COTE Summit	Review of EE program eligibility to attendees	NH architects	All EE measures	C&I	No	Yes	No
6/18/2019	2019	Advertisement	Facebook/Twitter	Fathers Day Thermostat Rebate	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/18/2019	2019	Advertisement	Email Newsletter	Thermostats: What's the Difference?	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
6/18/2019	2019	Event	Londonderry	Walter F. Morris Company	Promotion of EE programs to attendees	Manufacturers Rep	All EE measures	C&I	No	No	No
6/18/2019	2019	Training	Charlestown	Claremont Spray Foam	Mobile home weatherization	Residential Electric Customers	HEA	Residential	No	No	No
6/19/2019	2019	Training	Newton	Invictus	Surveyor/OTTER	Residential Electric Customers	HPwES	Residential	No	No	No
6/20/2019	2019	Training	Net Zero Task Force	Derry Muni Meeting	Review of EE program eligibility to attendees	Municipal Staff	All EE measures	Both	No	No	Yes
6/21/2019	2019	Training	Municipal Energy Staff,	Sierra Club Municipal Conference	Review of EE program eligibility to attendees	Muni Staff	All EE measures	Both	No	No	Yes
6/26/2019	2019	Advertisement	Facebook/Twitter	HPwES Video - A/C Unit	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
6/26/2019	2019	Event	Business and Economic	NH BEA Meeting	Promotion of EE programs to attendees	State Staff	All EE measures	C&I	No	No	No
6/26/2019	2019	Training	Business and Economic	NH BEA Meeting	Promotion of EE programs to attendees	State Staff	All EE measures	Both	No	No	Yes
6/27/2019	2019	Advertisement	Email	Independence Day Thermostat Rebate Special	Special smart thermostat promotion	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
6/27/2019	2019	Event	6 Eastpoint Dr.,	Eckhardt & Johnson	Promotion of EE programs to attendees	HVAC Contractor	All EE measures	C&I	No	No	No
6/28/2019	2019	Advertisement	Social media	Facebook/Twitter: HPwES Video - A/C Unit	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
6/28/2019	2019	Advertisement	Social media	Facebook/Twitter: 4th of July promo - Google	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
7/2/2019	2019	Advertisement	Social media	4th of July promo - Google Home mini and NEST	Facebook/Twitter	Local Residential Online Traffic	Smart Thermostats	Residential	No	No	No
7/2/2019	2019	Event	CENH Home Office	Clean Energy NH Open House	Networking event	Contractors, manufacturer, distributor, city officials, Architects, engineers	All EE measures	C&I	No	No	Yes
7/2/2019	2019	Training	CENH Home Office	Clean Energy NH Open House	Networking event	Contractors, manufacturer, distributor, city officials, Architects, engineers	All EE measures	C&I	No	Yes	Yes
7/11/2019	2019	Advertisement	Social media	Special Rebates for Gas Customers	Facebook/Twitter	Local Residential Online Traffic	All EE measures	Residential	No	No	No
7/11/2019	2019	Event	Walter F. Morris Company	Joint NHSaves - Walter Morris Flyer	Marketing Meeting	Marketing Staff	All EE measures	C&I	No	No	No

II-274

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
7/11/2019	2019	Event	Londonderry	Promotion of EE programs to attendees	Promotion of EE programs to attendees	Marketing Staff	All EE measures	C&I	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	A Whole Building Approach to EE	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&i	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	HVAC Systems: 4 Hidden Energy Costs	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	No	No
7/16/2019	2019	Advertisement	Facebook/Twitter	HPwES Summer Promotion	Facebook/Twitter	Local Commercial and Residential Online Traffic	HPwES	Residential	No	No	No
7/16/2019	2019	Advertisement	Email Newsletter	Video: 5 Ways to Save with Smart Home Technology	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
7/18/2019	2019	Training	Johnson's (Northwood)	Lunch meeting w/ Yankee Thermal Imaging	Review of EE program eligibility to attendees	Jamie Polchies- estimator/auditor	All EE measures	C&I	No	No	No
7/19/2019	2019	Event	RBG office	Promotion of EE programs to attendees	Promotion of EE programs to attendees	Don Perrin	All EE measures	C&I	No	No	Yes
7/19/2019	2019	Training	RBG office	Meeting with State of NH	Review of EE program eligibility to attendees	Don Perrin	All EE measures	C&I	No	No	Yes
7/23/2019	2019	Event	Londonderry	USGBC Summer Meet-up	Networking event with LEED professionals	Builders, architects, and designers	All EE measures	C&I	No	Yes	Yes
7/23/2019	2019	Training	Concord	Rotary Presentation	Power point presentation for the Concord Rotary Club	Business owners and municiple leaders	Focus on commercial w/residential included	Both	No	No	Yes
7/23/2019	2019	Training	Concord	Rotary Presentation	Power point presentation for the Concord Rotary	Business owners and municipal leaders	Focus on commercial	Both	No	No	Yes
7/24/2019	2019	Event	Bedford NH	NH CIBOR Statewide Meeting	Promotion of EE programs to attendees	Commercial brokers, bankers,	All EE measures	C&I	No	No	No
7/24/2019	2019	Event	New Canaan	Dave Gooding Company	Educating manufactures rep. on the NHSaves	Trade Ally Contact	All EE measures	C&I	No	No	No
7/24/2019	2019	Training	Bedford NH	NH CIBOR Statewide Meeting	Promotion of EE programs to attendees	Commerical brokers, bankers,	All EE measures	C&I	No	No	No
7/25/2019	2019	Event	F.W. Webb -	Vendor Counter Day	Tabling the F.W. Webb counter and speaking with	Potential Trade Allies	Heating Systems	C&I	No	No	No
7/26/2019	2019	Event	Gilford	NHSHFM Summer Outing	Networking event with Hospital staff and general	Hospital Facilities Directors, and	All EE measures	C&I	No	No	No
7/26/2019	2019	Event	Sunapee	CENH Summer Outing	Networking event with Clean energy membership	Trade Ally Contacts and customers	All EE measures	C&I	No	No	Yes
7/31/2019	2019	Training	Concord	LU Gas audit	Audit of Heritage Harley Davidson	LU Gas Customer	Gas Audit	C&I	No	No	No
8/1/2019	2019	Event	Bedford	Fulcrum Trade Ally Meeting	Meeting With Fulcrum	General contractor trade ally	All EE measures	C&I	No	No	No
8/2/2019	2019	Advertisement	Email	Promotion of visual audit offeing	Promotion of visual audit offering	LU Customers and Local Residential Online Traffic	Visual audit	Residential	No	No	No
8/2/2019	2019	Event	Manchester	Second Wind Water Systems	Meeting with Secondwind Water Systems	Specialty services trade ally	All EE measures	C&I	No	No	No
8/3/2019	2019	Training	New Canaan	Dave Gooding Company	Educating manufactures rep. on the NHSaves program	Trade Ally Contact	All EE measures	C&I	No	No	No
8/5/2019	2019	Training	Windham	Meeting with The Dubay Group	Meeting to review 42 Nashua Road project	Engineer	All EE measures	C&I	No	No	No
8/8/2019	2019	Advertisement	Social media	Explanation of the Energy Audit Process	Facebook/Twitter	Local Residential Online Traffic	HPwES	Residential	No	No	No
8/8/2019	2019	Training	Derry	NHCIBOR Summer Mixer	Meeting with the commercial realtors and lenders group in central NH	see previous.	All EE measures	C&I	No	No	No
8/8/2019	2019	Training	Manchester	HPwES Energy Audit	On-Boarding Discussion	Invictus	HPwES	Residential	No	No	No
8/13/2019	2019	Training	Concord	REPA - Update on building Codes	Update on newly adopted 2015 building codes with amendments	Energy efficiency companies, and facilities managers	All EE measures	C&I	Yes	No	No
8/14/2019	2019	Event	Concord	Key Account Building Walk-through	Meet with Jason Teaster, facilities director for NH Hospital.	Key Account	All EE measures	C&I	No	No	No
8/14/2019	2019	Event	Concord	Meeting with Peter Mikolaczuk of Air Purchases/ Engel HVAC	NHSaves Program	Territory Manager-HVAC	All EE measures	C&I	No	No	No
8/14/2019	2019	Training	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
8/15/2019	2019	Event	Manchester	Meeting with Freudenberg-NOK	EE program presentation	Kevin Smith, Facilities Manager	All EE measures	C&I	No	No	No
8/16/2019	2019	Training	Lebanon	New Hampshire Society for Healthcare Facilities Managers Seminar	Seminar focused on large energy projects with NH hospitals	Hospital facilities staff	All EE measures	C&I	No	No	No
8/20/2019	2019	Training	Concord	NHSaves Presentation at North Branch	EE program presentation	Program managers, president	All EE measures	C&I	No	No	No
8/21/2019	2019	Training	Concord	ABC Party in the Park	Associated Builders and Contractors summer event	Builders, trade contractors, property management companies	All EE measures	C&I	No	Yes	No
8/22/2019	2019	Training	Manchester	Business After Hours- Manchester COC	TF Moran BAH	Manchester COC, TF Moran, Builders	All EE measures	C&I	No	Yes	Yes
8/27/2019	2019	Training	Concord	Lunch meeting with Anne Copp- Commercial Realtor	EE program training	Anne Copp, Commercial realtor	All EE measures	C&I	No	No	No
8/28/2019	2019	Training	Derry	Meeting with Derry Econ Dev	EE program training	Bev Donovan, Econ Dev Manager	All EE measures	Both	No	No	No
8/28/2019	2019	Training	Concord	Breakfast Club meeting	EE program presentation	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
8/29/2019	2019	Advertisement	Email Newsletter	Simple Steps to Lower Natural Gas Bills	Monthly e-newsletter distribution - 08/29/19	LU Customers and Local Commercial Online Traffic	All EE measures	C&I	No	No	No
8/29/2019	2019	Advertisement	Email Newsletter	Smart Thermostats Make Saving Energy Easier	Monthly e-newsletter distribution - 04/12/19	LU Customers and Local Residential Online Traffic	All EE measures	Residential	No	No	No
9/1/2019	2019	Advertisement	Bill Insert	Promotion of low-coset Energy Savings Measures	LU delivered to all Gas Customers	LU Gas Customers	Visual audit	Residential	No	No	No
9/1/2019	2019	Advertisement	Email	Promotion of low-coset Energy Savings Measures	LU delivered to all Gas Customers with email addresses	LU Gas Customers	Visual audit	Residential	No	No	No
9/10/2019	2019	Event	Nashua	Meeting with Horizon and Invictus	HPwES/Energy Audit	Horizon and Affiliates	HPwES/HEA	Residential	No	No	No
9/10/2019	2019	Training	Nashua	Invictus HPwES Energy Audit	EE Program training	Invictus	HPwES/HEA	Residential	No	No	No
9/11/2019	2019	Training	Concord	Concord Professionals Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
9/11/2019	2019	Training	Concord	Plan NH Business After Hours	Networking	Contractors, etc.	All EE measures	C&I	No	No	No
9/11/2019	2019	Event	Concord	Concord Professionals Breakfast Club Meeting	Networking	Commercial lenders, HVAC distributors, and other members	All EE measures	C&I	No	No	Yes
9/11/2019	2019	Event	Concord	Plan NH Business After Hours	Networking	Commercial lenders, HVAC distributors, and other members	All EE measures	C&I	No	No	Yes

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
9/12/2019	2019	Event	Manchester	Granite Group Trade Show	Conference and Networking	HVAC techs, contractors, etc.	All EE measures	C&I	Yes	No	No
9/12/2019	2019	Event	Randolph, MA	GasNetworks Annual Conference	Conference and Networking	HVAC techs, contractors, etc.	All EE measures	C&I	Yes	No	Yes
9/16/2019	2019	Event	Various Locations	2019 Energy Code Workshop Series	Eventbrite Registration - Commercial and Residential Code Series Discussions in September and October	Residential and Commercial Contractors	All EE measures	C&I	Yes	Yes	No
9/16/2019	2019	Event	Manchester	New Contract Response	Total Climate Control	Horizon and Affiliates	HPwES	Residential	No	No	No
9/17/2019	2019	Advertisement	Email Newsletter	Take Building Performance to the Next Level	Article: Take Building Performance to the Next Level	LU Customers and Local Commercial Online Traffic	All EE measures	C&I	No	Yes	No
9/17/2019	2019	Advertisement	Email Newsletter	INFOGRAPHIC: Preparing for a Home Energy Audit	INFOGRAPHIC: Preparing for a Home Energy Audit	LU Customers and Local Residential Online Traffic	All EE measures	Residential	No	No	No
9/17/2019	2019	Event	Concord	NH School Administrators Conference	Energy Summit	Directors of Buildings and Grounds	All EE measures	C&I	No	No	Yes
9/18/2019	2019	Advertisement	Social media	Special Rebates for Gas Customers	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
9/18/2019	2019	Training	Concord	NH School Administrators Conference	Conference & Networking Day 2	Director of Buildings & Grounds	All EE measures	C&I	No	No	No
9/23/2019	2019	Event	Concord	NH Energy Summit	Energy Summit	Energy Industry Professionals	All EE measures	C&I	No	No	Yes
9/24/2019	2019	Training	FW Webb Company Distribution Center, 10 Webb Dr., Londonderry	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
9/25/2019	2019	Advertisement	Social media	Helping Schools and Towns Save through Rebates & Incentives	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	C&I	No	No	No
9/25/2019	2019	Training	Concord	Meeting with Matt Moore- CCSNH	EE Programs training	Dir of Capitol Improvement Projects	All EE measures	C&I	No	No	No
9/25/2019	2019	Event	Derry	Chamber Business Before Hours	Presentation of EE programs	Chamber members and President of Chamber	All EE measures	C&I	No	No	Yes
9/26/2019	2019	Event	Concord	Associated Builders and Contractors	Business after Hours - Young Professional Group - ABC	Contractors, HVAC techs, engineers, etc.	All EE measures	C&I	No	Yes	No
9/26/2019	2019	Training	Manchester	Tri-City Expo	Expo- walked around to vendors	Contractors, property management companies, etc.	All EE measures	C&I	No	No	No
9/26/2019	2019	Training	Concord	ABC YPG BAH	Business After Hours- Young Professional Group-ABC	Contractors, HVAC techs, engineers,etc.	All EE measures	C&I	No	No	No
9/27/2019	2019	Training	Hooksett	NHSaves Lunch & Learn	PROCON Lunch & Learn	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
9/30/2019	2019	Event	Manchester	Jones Boy New Contract Response	New Contract	Horizon and Affiliates	HPwES/HEA	Residential	No	No	No
10/1/2019	2019	Advertisement	Bill Insert	How EE can help your energy bill	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
10/1/2019	2019	Training	Concord	State of NH Employee Training	Energy Efficiency	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
10/1/2019	2019	Training	The Exeter Inn, 90 Front St., Exeter	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
10/2/2019	2019	Training	Concord	NHSaves Lunch & Learn	HL Turner	Project managers, estimators, etc.	All EE measures	C&I	No	No	No
10/5/2019	2019	Event	669 Union St., Manchester	NHSaves Button Up	UU Fellowship Hall	Homeowners, general public	All EE measures	Residential	No	No	No
10/8/2019	2019	Training	FW Webb Company Distribution Center, 10 Webb Dr., Londonderry	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Commercial Construction Industry	All EE measures	C&I	Yes	Yes	No
10/9/2019	2019	Event	Goffstown	Key Account Meeting	Key Account Meeting with Mike Lencki, Hillsborough County Nursing Home	Purchasing Manager	All EE measures	C&I	No	No	No
10/9/2019	2019	Training	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
10/10/2019	2019	Advertisement	Social media	What does weakening EPA regulations mean?	Facebook/Twitter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Both	Yes	No	No
10/10/2019	2019	Event	Dracut	Key Account Meeting	Key Account Meeting with Bob Norkiewicz, Brox Industries	Plant Manager	All EE measures	C&I	No	No	No
10/10/2019	2019	Training	Church Landing at Mill Falls/Laker Room, 312 Daniel Webster Hwy, Meredith	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Residential Buidling Construction Industry	All EE measures	Residential	Yes	Yes	No
10/10/2019	2019	Training	Concord	Concord Chamber: Building Forum	Discussion about developments in the capital city area	COC members, city officials, architects	All EE measures	C&I	No	Yes	Yes
10/11/2019	2019	Training	Lebanon	Meeting with Atlantic Electrical Distributors	NH Saves Program	Distribution Representatives	All EE measures	C&I	No	No	No
10/15/2019	2019	Advertisement	Email Newsletter	INFOGRAPHIC: Getting Your Facility Ready for Winter	Monthly E-Newsletter	Gas Key Accounts	All EE measures	C&I	No	No	No
10/15/2019	2019	Advertisement	Email Newsletter	Photo Essay: Energy Saving Tips for Fall	Monthly E-Newsletter	LU Customers and Local Commercial and Residential Online Traffic	All EE measures	Residential	No	No	No
10/15/2019	2019	Training	Woodstock Inn Brewery, 135 Main Street, North Woodstock, NH	2019 Energy Code Workshop Series	Exploring changes to energy code in NH	Commercial Construction Industry	All EE measures	C&I	Yes	Yes	No
10/16/2019	2019	Training	Concord	CYPN- Concord Young Professionals	CYPN Networking Night	Young Professionals in various industries, met Steve Duprey, local developer	All EE measures	C&I	No	No	No
10/16/2019	2019	Training	Nashua	Turn Cycle Solutions	Surveyor/OTTER	Contractor and New Staff	All EE measures	Residential	No	No	No
10/17/2019	2019	Training	Hartford, VT	Landlords Energy Efficiency Conference	Meeting of commercial and residential landlords	commercial and residential landlords	All EE measures	Both	No	No	No

II-276

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
10/18/2019	2019	Training	Nashua	NH Society of Healthcare Facility Managers (NHSHFM)	Gave overview of technically assistance funding to NH hospital facility mangers.	Hospital facility managers	All EE measures	C&I	No	No	No
10/23/2019	2019	Training	Portsmouth	NHSaves Lunch & Learn	TMS Architects - AIA lunch and learn series	Architects	All EE measures	C&I	No	Yes	No
10/24/2019	2019	Event	95 Canal Street, Nashua, NH	BAE Systems Energy Expo	Table at Expo to present NHSaves	BAE Employees	All EE measures	Residential	No	No	no
10/25/2019	2019	Training	Lebanon	Tracy St Multi-Family Ribbon Cutting	Official opening of first net zero affordable housing development in NH	Developer, Contractor, funders, Government Reps	All EE measures	C&I	No	No	Yes
10/31/2019	2019	Training	Concord	Advanced Manufacturing Conference	NHMEP Governor's Conference	Politicians, energy professionals, business professionals, manufacturing professionals	All EE measures	C&I	No	No	Yes
11/1/2019	2019	Advertisement	Bill Insert	Home Feeling Drafty? We Can Help!	LU delivered to all Gas Customers	LU Gas Customers	All EE measures	Residential	No	No	No
11/5/2019	2019	Training	Weatherize Guyz, Derry, NH	Contractor meeting with Horizon	Surveyor/OTTER	Contractor and LU Vendor	HPwES	Residential	No	No	No
11/5/2019	2019	Event	Manchester	CCSNH Meeting at MCC	Review MCC project	Colby Co. Engineering and Matt Moore	All EE measures	C&I	Yes	No	Yes
11/5/2019	2019	Event	Concord	Department of Admin Services Meeting	Status update on projects and future planned projects	Don Perrin	All EE measures	C&I	No	No	Yes
11/8/2019	2019	Training	Invictus Spray, Newton, NH	Contractor meeting with Horizon	Support for HPwES Program Development	Contractor and LU Vendor	HPwES	Residential	No	No	No
11/12/2019	2019	Training	Concord	REPA Meeting- Sense	Training on Sense home monitoring device	Energy efficiency companies, and facilities managers	All EE measures	C&I	No	No	No
11/13/2019	2019	Training	Airport Holiday Inn, Manchester	Efficient Heating and Cooling for Commercial Building Managers	Learn how to control energy costs and maximize EE Incentives	Lakes Region Community College Trainging for Facility Managers, COOs, building operators and sustainability officers	All EE measures	C&I	No	No	No
11/14/2019	2019	Event	Manchester	Municipal Association's 78th Annual Conference	Municipal Association's 78th Annual Conference	Municipal employees	All EE measures	C&I	No	no	Yes
11/15/2019	2019	Advertisement	Email Newsletter	Energy Smart Boiler Maintenance	Monthly E-Newsletter	LU Customers and C&I Gas Online Traffic	All EE measures	C&I	No	Yes	No
11/15/2019	2019	Advertisement	Email Newsletter	Busted! 3 Common Myths About Home Heating	Monthly E-Newsletter	LU Customers and Residential Gas Online Traffic	All EE measures	Residential	No	No	No
11/15/2019	2019	Training	Concord Grappone Conference Ctr	Clean Energy NH- Local Energy Solutions Conference	Grappone Conference Center	Energy professionals, contractors, business professionals, politicians	All EE measures	C&I	No	Yes	Yes
11/18/2019	2019	Training	Turn Cycle Solutions, Concord, NH	Field Training with Horizon	Energy Audit and work order review; identifying health and safety hazards, thermal imaging and worst case spillage testing.	Contractors and LU Vendor	All EE measures	Residential	No	Yes	No
11/18/2019	2019	Event	Concord	Concord School SAU #8 Meeting	SAU 8 project review	School Officials	All EE measures	C&I	Yes	no	Yes
11/19/2019	2019	Advertisement	LU Website	Black Friday - Thermostats	Social Media	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
11/19/2019	2019	Training	Common Man, Concord	Energy Efficiency for Restaurants and Hopitality	Learn how to control energy costs and maximize NHSaves Incentives	Lakes Region Community College Trainging for Facility Managers, COOs, building operators and sustainability officers	All EE measures	C&I	No	No	No
11/20/2019	2019	Event	Peterborough, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/20/2019	2019	Event	Orange, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
11/20/2019	2019	Training	Pembroke	State of NH EE Training	EE Training	State employees, facilities managers, building operators, NHSaves employees	All EE measures	C&I	No	Yes	No
11/20/2019	2019	Training	Concord	Energy Efficiency Training- Heating and Cooling- State of NH Employees	HVAC training	State employees, facilities managers, building operators, NHSaves employees	All EE measures	C&I	Yes	no	Yes
11/21/2019	2019	Training	Concord	Community Development Finance Authority (CDFA) Grant Meeting	Grant Applicants training	Grant Applicants	All EE measures	C&I	Yes	Yes	No
11/21/2019	2019	Training	Concord	ASHRAE @ Red Blazer	President of ASHRAE presentation on Integrated Building Design	Local engineer trades association	All EE measures	C&I	No	Yes	Yes

II-277

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
11/27/2019	2019	Event	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	Yes	No	No
11/27/2019	2019	Training	Conference Call	Non-Lighting Upstream C&I Subcommittee Meeting	4th Wednesday of every month	Joint Utilities	EE Gas Measures	C&I	No	No	No
11/27/2019	2019	Training	Bedford NH	NH CIBOR Statewide Meeting	NHSaves Program	Commerical brokers, bankers, engineers, affiliates	All EE measures	C&I	no	No	No
11/28/2019	2019	Advertisement	LU Website	Black Friday - Thermostats	Social Media	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
12/1/2019	2019	Advertisement	Liberty Utilities - Internal Marketing	Looking to Increase Comfort at Home?	Bill Insert	LU Gas & Electric Customers	EE Gas Measures	Residential	No	No	No
12/4/2019	2019	Event	Gilmanton, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
12/4/2019	2019	Event	Concord	USGBC - NH 10th Anniversary	10th anniversary celebration for NH chapter of the USGBC	Energy efficiency companies, and facilities managers	All EE measures	C&I	no	No	Yes
12/5/2019	2019	Training	Manchester	BIA Energy Symposium	BIA (statewide Chamber of Commerce) Energy symposium. Brought together energy professionals for a day long seminar.	Energy Performance professionals	All EE measures	C&I	No	No	Yes
12/10/2019	2019	Training	Concord	REPA Monthly Meeting	Peter Yost presented on roof venting, etc.	Energy efficiency companies, and facilities managers	All EE measures	C&I	No	Yes	No
12/11/2019	2019	Event	Manchester	CENH Member Holiday Dinner	Annual holiday dinner	Energy Performance professionals	All EE measures	C&I	no	No	No
12/15/2019	2019	Advertisement	Questline	Busted! 3 Common Myths About Home Heating	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
12/15/2019	2019	Advertisement	Questline	Energy Smart Boiler Maintenance	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
12/18/2019	2019	Event	Concord	Breakfast Club meeting	Networking	Commercial lender, HVAC distributor, other members	All EE measures	C&I	No	No	No
12/19/2019	2019	Training	Bedford NH	Franklin Energy Meeting	NH Saves Program	C&I Vendor Reps	All EE measures	C&I	No	No	No
12/20/2019	2019	Training	Manchester	Monthly HEA/HPwES Utility Meeting with Joint Utilities	Discuss Measures for 2020	Joint Utilities	All EE measures	C&I and Residential	No	No	No
12/24/2019	2019	Training	Manchester	Utility Monthly Products Meeting	Discuss Measures for 2020 - 4th Tuesday of Every Month	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/1/2020	2020	Advertisement	Questline	Wasting Energy is a Hard Habit to Break; 3 Reasons Why Your Furnace Turns on and Off Constantly; Video: You Can Prevent Freezing Pipes; Visual Audit Link	Eblast	Local Residential Online Traffic	EE Gas Measures	Residential	No	No	No
1/1/2020	2020	Advertisement	Questline	Considering a Smart Thermostat? Now's the Time!; Facilities Win with Natural Gas; Infographic: Gas Train Control; Reciprocating Gas Engines Power Hybrid Microgrids; Infographic: Menu fors an Energy-Efficient Kitchen	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	No	No
1/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	NHSAVES: Your Source for Energy Efficiency	Bill Insert	LU Gas Customer	EE Gas Measures	Residential	No	No	No
1/8/2020	2020	Event	F.W. Webb- Concord	Breakfast Club Networking	Networking	Networking	EE Gas Measures	C&I and Residential	Yes	Yes	Yes
1/8/2020	2020	Event	F.W. Webb- Concord	Breakfast Club Networking	Networking	Commercial lender, HVAC distributor, other members	EE Gas measures	C&I and Residential	Yes	Yes	Yes
1/10/2020	2020	Training	Eversource	Energy Park	Preparation for Meetings with VEIC and EESE Board	Joint Utilities	All EE measures	C&I	No	No	No
1/14/2020	2020	Event	Concord	REPA Monthly Training	Air-source heat pumps	Air-source heat pumps	EE Gas Measures	C&I and Residential	No	No	No
1/14/2020	2020	Event	Concord	REPA Monthly Training	Air-source heat pumps	Contractors	EE Gas Measures	C&I and Residential	No	No	No
1/14/2020	2020	Training	Eversource	Small Business Working Session	NH Saves Program Design	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/15/2020	2020	Event	Bedford	NHCIBOR Meeting	Statewide Marketing Meeting	Statewide Marketing Meeting	EE Gas Measures	C&I and Residential	No	No	No
1/15/2020	2020	Event	Bedford	NHCIBOR Meeting	Statewide Marketing Meeting	Joint Utilities	EE Gas Measures	C&I and Residential	No	No	No
1/15/2020	2020	Training	Eversource	2020 Energy Star Homes Kick Off Meeting	2019 Review and 2020 Goals	Joint Utilities	All EE measures	C&I and Residential	No	No	No
1/16/2020	2020	Training	Merrimack, NH	Wx Crew Training	Blower Door Guided Air Sealing	Contractors	All EE measures	Residential	No	Yes	No
1/17/2020	2020	Event	New London Hospital	NH Society of Health Facility Managers (NHSHFM)	Above-Ceiling Program	Contractors and Facility Representatives	EE Gas Measures	C&I	Yes	Yes	No
1/17/2020	2020	Event	New London Hospital	NH Society of Health Facility Managers (NHSHFM)	Above-Ceiling Program	Above-Ceiling Program	EE Gas Measures	C&I	Yes	Yes	No
1/21/2020	2020	Advertisement	Newsletter	Considering a Smart Thermostat	Questline	Questline	EE Gas Measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
1/24/2020	2020	Event	Concord	Breakfast with Joe Campbell (North Branch)	Review of NHSaves programs, 2020 program, etc.	Commercial lender, HVAC distributor, other members	EE Gas Measures	C&I	Yes	Yes	No
1/24/2020	2020	Event	Manchester	NH Foodbank Walk-Through and Presentation	Walk-through and presentation to Chefs and COO	Joint Utilities	EE Gas Measures	C&I	Yes	No	No
1/24/2020	2020	Event	Concord	Breakfast with Joe Campbell (North Branch)	Review of NHSaves programs, 2020 program, etc.	Review of NHSaves programs, 2020 program, etc.	EE Gas Measures	C&I	Yes	Yes	No
1/24/2020	2020	Event	Manchester	NH Foodbank Walk-Through and Presentation	Walk-through and presentation to Chefs and COO	Walk-through and presentation to Chefs and COO	EE Gas Measures	C&I	Yes	No	No
1/24/2020	2020	Event	Bedford	Breakfast with Marie (AFE Chair)	Networking, review of AFE trade group	AFE Trade Group	EE Gas Measures	C&I	No	No	Yes
1/24/2020	2020	Event	Bedford	Breakfast with Marie (AFE Chair)	Networking, review of AFE trade group	Networking, review of AFE trade group	EE Gas Measures	C&I	No	No	Yes
1/25/2020	2020	Advertisement	Facebook/Twitter	Button Up Workshop - Wilmot	Social Media	Social Media	EE Gas & Electric Measures	Residential	No	No	No
1/25/2020	2020	Event	Wilmot, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
1/29/2020	2020	Event	Derry	Association for Facilities Engineering	Monthly Meeting	Joint Utilities and Contractors	EE Gas Measures	C&I	No	No	Yes
1/29/2020	2020	Event	Derry	Business After Hours	Monthly Networking	Small business owners and General Contractors	All EE measures	C&I	No	No	Yes
1/29/2020	2020	Event	Derry	Association for Facilities Engineering	Monthly Meeting	Monthly Meeting	EE Gas Measures	C&I and Residential	No	No	Yes
1/29/2020	2020	Event	Derry	Business After Hours	Monthly Networking	Monthly Networking	EE Gas Measures	C&I and Residential	No	No	Yes
2/1/2020	2020	Advertisement	Questline	5 Ways to Lower Your Heating Costs; 4 Reasons Why Your Filter Isn't Filtering Air; Power Play: Energy Crossword Puzzle; Visual Audit Link	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
2/1/2020	2020	Advertisement	Questline	The Rising Stars of Natural Gas; Switching to Natural Gas Vehicles: Advice from the Experts; Process Heating: Identifying and Reducing Energy Waste; Who Wants To Be An Energy Expert? Natural Gas;	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
2/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	House Feeling Drafty? We Can Fix That	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
2/1/2020	2020	Advertisement	Bill Insert residential gas customers	Home Performance with ENERGY STAR	Promoting the HPwES program	Residential gas customers	air sealing, imsulation, ISMs	Residential	No	No	No
2/1/2020	2020	Event	Newbury, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/4/2020	2020	Event	Concord	InTown Concord Town Hall Meeting	Town Hall Meeting- Façade Grant Program	Town Hall Meeting- Façade Grant Program	EE Gas Measures	C&I and Residential	No	No	Yes
2/5/2020	2020	Event	Laconia	Lakes Region Community Developers- Compass House Ribbon Cutting	Ribbon Cutting- Compass House	Ribbon Cutting- Compass House	EE Gas Measures	C&I and Residential	No	No	Yes
2/8/2020	2020	Event	Grantham, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/11/2020	2020	Event	Concord	REPA Monthly Training	Energy Efficiency Policy (EERS)	Energy Efficiency Policy (EERS)	EE Gas Measures	C&I and Residential	No	No	No
2/14/2020	2020	Event	Concord	NH Small Business Day	BIA Small Business Day	BIA Small Business Day	EE Gas Measures	C&I	No	No	Yes

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
2/15/2020	2020	Event	New London, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/15/2020	2020	Event	Concord	Concord City Energy & Environment Advisory Committee meeting	Energy & Environment Advisory Committee Meeting	Energy & Environment Advisory Committee Meeting	EE Gas Measures	C&I	Yes	No	Yes
2/19/2020	2020	Event	North Andover, MA	AFE Monthly Meeting	Boston Med Flight Tour	Boston Med Flight Tour	EE Gas Measures	C&I	No	No	Yes
2/20/2020	2020	Event	Hooksett	BNI Meeting	NE Tap House Grille	NE Tap House Grille	EE Gas Measures	C&I	No	No	Yes
2/21/2020	2020	Event	Newington	NHCIBOR- Seacoast Marketing Meeting	NHCIBOR Meeting	NHCIBOR Meeting	EE Gas Measures	C&I	No	No	Yes
2/22/2020	2020	Event	New London, NH	Button Up Workshop	EE program presentation	1 1⁄2 hour presentation about improving the energy efficiency of your home. It covers energy saving tips and NHSaves energy efficiency programs	Improve the energy efficiency of your home, basic building science principles, examples of whole house weatherization measures, energy audits and weatherization, rebates	Residential	No	No	No
2/24/2020	2020	Advertisement	Sidebar in Questline e-newsletter	Visual audit	Promoting the visual audit	Residential gas customers	Wi-Fi T-Stat, LEDs, water saving measures, piep wrap	Residential	No	No	No
2/26/2020	2020	Event	Milford	HBP New Hampshire Trade Show	Harvey Building Products, Trade Show	Harvey Building Products, Trade Show	EE Gas Measures	C&I	Yes	Yes	No
2/26/2020	2020	Event	Bedford	NHCIBOR	NHCIBOR Meeting	NHCIBOR Meeting	EE Gas Measures	C&I	No	No	Yes
2/26/2020	2020	Event	Salem	NNEFMC (Northern New England Facility Masters Conference)	Conference for school facility managers	Conference for school facility managers	EE Gas Measures	C&I	Yes	No	Yes
3/1/2020	2020	Advertisement	Questline	Energy Monitoring Systems Provide Real-Time Savings; Office Buildings: Energy and Cost Saving Strategies; Cybersecurity: Are Your Systems Up to Standard; 4 Women Who Changed the Tech Industry	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
3/1/2020	2020	Advertisement	Questline	Energy Monitoring Systems Provide Real-Time Savings; 5 Key Safety Measures for CNG Vehicle Maintenance Facilities; The Benefits of Boiler Condensate Recovery; 4 Women Who Changed the Tech Industry	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
3/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	Free Energy Saving Equipment	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
3/4/2020	2020	Event	Manchester	NH Business for Social Responsibility (NHBSR) Awards Night	Sustainability Awards Event	Sustainability Awards Event	EE Gas Measures	C&I	No	No	Yes
3/5/2020	2020	Event	Concord	NHSaves Business Partner Rollout	NHSaves event	NHSaves event	EE Gas & Electric Measures	C&I	Yes	Yes	No
3/10/2020	2020	Event	Concord	REPA Monthly Training	Installation of fenestration products & 475 High Performance Building Supply	Installation of fenestration products & 475 High Performance Building Supply	EE Gas Measures	C&I and Residential	No	Yes	No
3/11/2020	2020	Event	Concord	Breakfast Club Networking	Networking	Networking	EE Gas Measures	C&I and Residential	No	Yes	Yes
4/1/2020	2020	Advertisement	Questline	NH EE Covid-19 Contingency Plan; 6 Ways to Save this Spring; Money Savers Low Flow Showerhead;Keep This Planet Green for Me and You	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
4/1/2020	2020	Advertisement	Questline	Covid-19 Information; Steam Systems: Keep the Pressure On and Save; CNG: Powering the Fleets of Tomorrow; 3 Options for Natural Gas Cooling; 811: Call Before You Dig	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
4/23/2020	2020	Advertisement	Questline	We Are Here With You - Ecobee Earth Day - Rebate Incentive Program	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
5/1/2020	2020	Advertisement	Questline	Covid-19 Information; Get Your House in Shape for Summer; Do You Need a Thermostat Adjustment?; Do's and Don'ts: Using the Dishwasher; Ready to Dig? Call 811	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No

As of 6/1/2020

Launch Date	Year	Advertising, Event or Training?	Type/Location of Tactic	Title of Tactic	Details	Key Audiences/Participants	EE Measures Promoted	Market Segment	Promotion of Stricter Building Codes?	Education to Builders?	State/Local Officials & Associations?
5/1/2020	2020	Advertisement	Questline	Covid-19 Information; Stay Cool with Natural Gas; Combined Heat and Power Without the Investment; Double-Effect Absorption Chillers: A Breakdown; Excess Air in Gas Burners: How Much is Too Much?	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No
5/1/2020	2020	Advertisement	Liberty Utilities - Internal Marketing	Weatherization on a Budget	Bill Insert	LU Gas Customers	EE Gas Measures	Residential	No	No	No
6/1/2020	2020	Advertisement	Questline	Summer Living: Staying Cool Upstairs is a Breeze; Do Dishwashers Use More Energy Than Hand Washing? Weather Wisdom: Temperature and Sleep; Fact or Fable? Summer Solstice	Eblast	Local Commercial Online Traffic	EE Gas Measures	Residential	No	No	No
6/1/2020	2020	Advertisement	Questline	Microgrids Power Up with Natural Gas; Cooling Problems? Natural Gas Can Solve Them; Capture Savings with Drain Water Heat Recovery; Safety First: Using Natural Gas in the Workplace	Eblast	Local Commercial Online Traffic	EE Gas Measures	C&I	No	Yes	No

II-281

WNA Tracking 2018-2019

Date	Call Type	Inquiry Details	Follow Up	Representative	Additional Comments	F.A.Q.'s Reference	Resolved
14-Feb	Inquiry	Why this program?	N/A	R.Scott	Asked if they would see the charge every month.	Are there any added benefits to decoupling?	Complete
18-Feb	Inquiry	Why this program?	N/A	T.Grant	Customer did understand why we were charging him	What is Revenue decoupling?	Complete
20-Feb	Inquiry	Hard to Understand	N/A	J.Colon	Didn't understand why we were crediting him	What is Revenue decoupling?	Complete
2-Mar	Inquiry	Why this program?	N/A	A.Reilly	Went over charges	How will this affect my bill?	Complete
3-Mar	Complaint	Escalation in Disagreement	N/A	A.Yusuf	Upset about how much the WNA "cost" for her	What is the main purpose of decoupling?	Complete
5-Mar	Inquiry	When will it start?	N/A	R.Scott	Never noticed it on the bill, questions about program.	What is Revenue decoupling?	Complete
6-Apr	Inquiry	What is this program?	N/A	R.Scott	Wanted to know if the program was optional or not	How does decoupling work?	Complete
22-Apr	Inquiry	What is this program?	N/A	K.Burroughs	Customer wanted to know what the charges were for?	What is the main purpose of decoupling?	Complete

WNA Tracking 2018-2019

Date	Call Type	Inquiry Details	Follow Up	Representative	Additional Comments	F.A.Q.'s Reference	Resolved
13-Nov	Inquiry	Hard to Understand	N/A	M.Grant	Thinks we should just increase the customer charge year round and that might make more sence to the customers	What is the main purpose of decoupling?	Complete
13-Nov	Inquiry	What is this program?	N/A	J.Roberts	Wanted to know more about the program, understands and found interesting	What is Revenue decoupling?	Complete
21-Nov	Inquiry	Why this program?	N/A	J.Brouillet	Why this program? Why not increase the customer charge year round? No follow up need- preferred the customer charge increase	Are there any added benefits to decoupling?	Complete
30-Nov	Inquiry	What is this program?	N/A	J.Brouillet	Questions on how the program works	How does decoupling work?	Complete
5-Dec	Inquiry	What is this program?	N/A	K.Burroughs	When reviewing usage for November, during high bill complaint, questioned the credit on account	How will this affect my bill?	Complete
6-Dec	Inquiry	Why this program?	N/A	N.Soucy	Concerned that the credits/debits are based on usage and not a flat rate for budgeting purposes	Is my bill still based on how much gas I use?	Complete
6-Dec	Inquiry	What is this program?	N/A	A.Cook-Dodge	Customer wanted more information on what the program was about	What is Revenue decoupling?	Complete
6-Dec	Complaint	When will it start?	Supervisor Call Back	A.Cook-Dodge	Wanted to know why it was on one bill and not another. See breakdown on tab A10 by Joanne Iovino		Complete
7-Dec	Inquiry	What is this program?	N/A	D.Duchaine	Wanted to know when this started and if other companies are participating too	Is decoupling a new concept?	Complete
11-Dec	Inquiry	What is this program?	N/A	D.Pisco	Why do I have this charge on the bill? Will I always get it?	How will this affect my bill?	Complete
12-Dec	Inquiry	What is this program?	N/A	A.Cook-Dodge	Curious as to why he had a credit on his account	What is Revenue decoupling?	Complete
12-Dec	Inquiry	Why this program?	N/A	A.Cook-Dodge	How long will the program last?	How will this affect my bill?	Complete
10-Dec	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know more about the program, happy with credit	What is Revenue decoupling?	Complete
18-Dec	Inquiry	What is this program?	N/A	K.Ripaldi	Asked why he had a credit on his bill	How will this affect my bill?	Complete
3-Jan	Inquiry	Hard to Understand	N/A	A.Maggio	Didn't see the charge on the bill, walked customer through the fact that it was the credit. Refered to website for additional details as well.	What is Revenue decoupling?	Complete
16-Jan	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know why there was a credit on his bill that he has never seen before	How will this affect my bill?	Complete
16-Jan	Inquiry	What is this program?	N/A	A.Maggio	Wanted to know more about the program and why he had a credit on his account	What is Revenue decoupling?	Complete
12-Feb	Inquiry	Why this program?	N/A	A.Cook-Dodge	Wanted to know what the charges on the bill were	What is Revenue decoupling?	Complete
1-Mar	Inquiry	What is this program?	N/A	J.Roberts	Wanted to know why he got a credit on his bill	What is Revenue decoupling?	Complete

II-283

A E F NE AMP IRE
BEF RE E
PUBLIC U ILI IE C MMI I N

Docket No. DG 21-130

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

UPDA ED DIREC E IM N

F

DA ID B. IME

AND

CA ERINE A. MCNAMARA

October 19, 2021

Liberty™

THIS PAGE INTENTIONALLY LEFT BLANK

I. IN R DUC I N

. 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.

. Please state by hom you are employed.

A. e 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).

. Please describe your educational background and your business and professional e perience.

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

. Mr. imek and Ms. McNamara have you previously testified in regulatory proceedings before the Ne ampshire Public Utilities Commission (the Commission)

A. es, 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 pro ected 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 ad ustments from deferred gas cost accounts to the pro ected demand and commodity costs for the winter period supply portfolio. These allowable ad ustments, shown on Proposed Second Revised Page 96 (Bates 057), total 161,141. These ad ustments are added to the Unad usted 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).

. **hat are the components of the Unadjusted Anticipated Cost of Gas**

A. The Unad usted 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

. **hat are the components of the allo able adjustments to the Cost of Gas**

A. The allowable ad ustments 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 Ad ustments	_,161,141

These allowable ad ustments are standard ad ustments made to the deferred gas cost balance through the operation of the Company s cost of gas ad ustment clause. e discuss the factors contributing to the prior period under collection later in this testimony.

. o 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 2 - for the 2 2 /2 2 inter 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 Unad usted Direct Cost of Gas.

. o does the proposed firm transportation inter cost of gas rate compare to the rate approved by the Commission for the 2 2 /2 2 inter 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.

. In the calculation of its firm transportation inter 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.

. Did the Company include a fuel inventory revenue re uirement calculation in this filing

A. es. 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.

. o as the statutory ta rate of 2 . on chedule 2 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).

. o as the common e uity pre-ta rate of . on chedule 2 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 .

. as the bad debt percentage in this filing of . changed from the bad debt percentage calculated in the inter 2 2 /2 2 Cost of Gas Reconciliation

A. es. 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 inter 2020/2021 Cost of Gas Reconciliations for the period of May 2019–April 2020 was 1.1 .

. hat as the actual eighted average firm sales cost of gas rate for the 2 2 /2 2 inter 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.

. hat is the current percentage used to calculate the ma imum 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 inter and Summer period Cost of Gas rates.

. Is the Company re uesting an increase to the percentage used to calculate the ma imum allo ed Cost of Gas Rate

A. es, 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 inter period.

. hy is the Company asking that the percentage used to calculate the ma imum allo ed cost of Gas rate be increased for the summer period of May through ctober

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 ad ustment. Given these circumstances, the Company believes the 25 used to calculate the maximum allowed Cost of Gas rate is insufficient. hile the 25 maximum increase was appropriate in prior years when there was a separate filing for the Summer Cost of Gas rate, once the inter 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 ad ustment 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 si e of the under collections during the recent summer periods, the 25 limit has been insufficient to serve that purpose.

. hat percentage used to calculate the ma imum allo ed ummer 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 .

. o did the Company determine that an increase of the ma imum allo ed ummer Cost of Gas from 2 to as appropriate

A. The Company did an analysis of the past four years. e started with the original summer cost of gas monthly ad ustment filings, removed out of period ad ustments 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 . e then rounded down to 40 .

. hy should the Commission increase the percentage used to calculate the ma imum allo ed Cost of Gas rate for the ummer period

A. hen the Company reaches the maximum allowed rate, the under collected balance continues to grow. In the summer of 2021, the pro ected 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 ust 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

. hy doesn t the Company make an interim filing hen the ma imum allo ed 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.

. Is the 2 used to calculate the ma imum allo ed Cost of Gas sufficient for the inter period

A. es, 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 inter Cost of Gas are calculated using more near-term market information than those for the future Summer period.

III. PRI R IN ER PERI D UNDER-C LLEC I N

. Please e plain the prior period under collection of .

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 ad ustments as compared to changes in the underlying costs.

I . FIXED PRICE P I N

. as the Company established a inter period fi ed price pursuant to its Fi ed Price ption Program

A. es. 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 ad ustments to the COG rate during the course of the winter. Schedule 23 (Bates 204) contains the historical results of the FPO program.

. L CAL DELI ER AD U MEN CLAU E (LDAC)

. hat are the surcharges that ill 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 Ad ustment 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.

. hich customers are billed an LDAC

A. All EnergyNorth customers including those in eene are billed an LDAC charge. hen calculating the LDAC charge, the November 1, 2021, through October 31, 2022, forecasted eene 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.

. Please e plain the Energy Efficiency Charge.

A. The Energy Efficiency Charge is designed to recover the pro ected 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 pro ected 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.

. Please e plain 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.

. Did the Company s original filing on eptember 2 2 filing include a schedule sho ing the calculation of the reconciliation of allo ed and actual revenues related to hat as formerly kno n as the Residential Lo Income Assistance Program (RLIAP)

A. es. 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 ob ect to a later effective date to allow for further review and investigation.

. **Does the mismatch described above impact the current reconciliation period related to revenues associated ith 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 categori ed as GAP and, thus, the allowed and actual revenues for the R-4 customer class are in alignment.

. **hat 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 ad ustment 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 ad ustment.

. In rder No. 2 2 (Feb. 2 2) in Docket No. DG - 22 relating to short-term debt issues the Company agreed to adjust its short-term debt limits each year as part of the Company s inter Period Cost of Gas filing. Did the Company calculate the short-term debt limit for fuel and non-fuel purposes in accordance ith this settlement

A. es, 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.

. as the Company updated the Environmental urcharge (ariff Page)

A. es, 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.

. Please describe ho the Company calculated the Environmental urcharge 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 amorti ed remediation costs. The amorti ed actual to forecast true-up recovery costs through June 2019 of 341,389 (total amount is 1,024,167 which is amorti ed 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.

. Did the Company include a Rate Case E pense (RCE) surcharge in this filing

A. es. 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.

. as the Company also updated its Company Allo ance percentage for the period November 2 2 through ctober 2 22 in accordance ith ection of the Company s Delivery erms and Condition

A. es, 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.

I. CU MER BILL IMPAC

. hat are the estimated impacts of the proposed firm sales cost of gas rate and proposed LDAC surcharges on an average heating customer s inter bill as compared to the inter 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 ad ustments on heating customers.

II. ER ARIFF C ANGE

. Is the Company updating its Delivery erms and Conditions in the filing

A. es. 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.

. Please describe the changes to tariff Page .

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

. Please describe the changes to tariff Page .

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.

III. UMMER 2 2 C F GA FAC R

. hat are the proposed 2 22 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).

. Please e plain tariff pages Proposed hird Revised Page and Proposed hird Revised Page 2.

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 summari e 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 pro ected 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 inter Use Cost of Gas Rate of 0.5593 per therm and the Commercial/Industrial Low inter 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 Unad usted Anticipated Cost of Gas of 10,330,821 and adds the Net Ad ustment totaling 4,695,023.

. hat are the components of the Unadjusted Anticipated Cost of Gas

A. The Unad usted 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 Unad usted Anticipated Cost of Gas	15,025,844

. hat are the components of the adjustments to the cost of gas

A. The ad ustments 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 Ad ustments	4,695,023

. o does the proposed average Residential ummer cost of gas rate in this filing compare to the initial cost of gas rate approved by the Commission for the 2 2 ummer 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 pro ected increase in supply costs and an under collection from the prior summer of 4,472,186.

. Does this conclude your testimony

A. es, it does.

THIS PAGE INTENTIONALLY LEFT BLANK

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

DEBORAH M. GILBERTSON

September 1, 2021

Liberty

THIS PAGE INTENTIONALLY LEFT BLANK

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.

THIS PAGE INTENTIONALLY LEFT BLANK

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

Docket No. DG 21-008 Request No. CLF 1-20

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™

THIS PAGE INTENTIONALLY LEFT BLANK

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. STATUS OF INSURANCE COVERAGE LITIGATION

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.

THIS PAGE INTENTIONALLY LEFT BLANK

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~~

Issued: ~~October xx, 2020~~ October xx, 2021 Issued by: ______________________
Neil Proudman

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

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

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-	~~$ 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-4	~~$ 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-5	~~$ 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~~

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

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

Issued by: ____________________
Neil Proudman
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 94
Superseding Proposed First Revised Page 94

II. RATE SCHEDULES
CALCULATION OF FI ED INTER PERIOD COST OF GAS RATE
PERIOD CO ERED INTER PERIOD NO EMBER 1 2021 THROUGH APRIL 30 2022
~~PRIOR PERIOD CO ERED INTER PERIOD NO EMBER 1 2020 THROUGH APRIL 30 2021~~
Refer to Te t in Section 17 A Fi ed 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		
Pro ected 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	
Ad ustment 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		
Pro ected 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 A ERAGE COST OF GAS EFFECTI E ~~11/01/20~~ 11/01/21		~~0.5597~~		0.905	
<u>Calculation of FPO</u>					
TOTAL PERIOD A ERAGE COST OF GAS EFFECTI E ~~11/01/20~~ 11/01/21		~~0.5597~~		0.905	
PO Risk Premium		~~$ 0.0200~~		$ 0.0200	
TOTAL PERIOD FI ED PRICE OPTION COST OF GAS RATE EFFECTI E ~~11/01/20~~ 11/01/21		~~0.5797~~		0.925	
RESIDENTIAL COST OF GAS RATE - E CLUDING GAP - ~~11/01/2020~~ 11/1/2021	/therm	~~0.5797~~	/therm	0.925	

Col 1	Col 2	Col 3	Col 2	Col 3	
Total Anticipated Direct Cost of Gas	~~$ 47,150,454~~		$ 74,822,730		
Pro ected 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	
Ad ustment 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		
Pro ected 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 A ERAGE COST OF GAS EFFECTI E ~~11/01/20~~ 11/01/21		~~0.5597~~		0.905	
<u>Calculation of FPO</u>					
TOTAL PERIOD A ERAGE COST OF GAS EFFECTI E ~~11/01/20~~ 11/01/21		~~0.3078~~		0.4981	
PO Risk Premium		$ 0.0110		$ 0.0110	
TOTAL PERIOD FI ED PRICE OPTION COST OF GAS RATE EFFECTI E ~~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	

Issued: ~~October xx, 2020~~ October xx, 2021 — Issued by: Neil Proudman

Effective: ~~November 1, 2020~~ November 1, 2021 — Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 95
Superseding Proposed First Revised Page 95

CALCULATION OF FIRM SALES COST OF GAS RATE

PERIOD CO ERED INTER PERIOD NO EMBER 1 2021 THROUGH APRIL 30 2022
~~PRIOR PERIOD CO ERED INTER PERIOD NO EMBER 1 2020 THROUGH APRIL 30 2021~~
Refer to Te t 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		
Pro ected 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	
Ad ustment 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		
Pro ected 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 A ERAGE COST OF GAS EFFECTI E 11/01/21				$ 1.1339	per Therm
~~TOTAL PERIOD A ERAGE COST OF GAS EFFECTI E 11/01/19~~		~~$ 0.5597~~			

RESIDENTIAL COST OF GAS RATE - 11/01/21	COG r	1.1339	/therm
~~RESIDENTIAL COST OF GAS RATE - 11/01/20~~	~~COG r~~	~~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. 23	/therm
~~GAS ASSISTANCE PLAN RESIDENTIAL COST OF GAS RATE R-4 R-7 - 11/01/20~~		~~0.3078~~	~~/therm~~
Maximum	COG 25	~~$ 0.3848~~	$ 0.7796
C I LO INTER USE COST OF GAS RATE - 11/01/21	COG l	1.1324	/therm
~~C I LO INTER USE COST OF GAS RATE - 11/01/20~~	~~COG l~~	~~0.5 8~~	~~/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: ow Winter Use Ratio Winter	~~1.0620~~	0.9910			
Times: Correction actor	~~0.9984~~	1.0001			
Ad usted Demand Cost of Gas Rate	~~$ 0.1560~~	$ 0.1572			
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238			
Ad ustment Cost of Gas Rate	~~0.0115~~	0.0018			
Indirect Cost of Gas Rate	~~0.0252~~	0.0496			
Ad usted C I ow Winter Use Cost of Gas Rate	~~$ 0.5686~~	$ 1.1324			

C I HIGH INTER USE COST OF GAS RATE - 11/01/21	COG h	1.1341	/therm
~~C I HIGH INTER USE COST OF GAS RATE - 11/01/20~~	~~COG h~~	~~0. 190~~	~~/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 actor	~~0.9984~~	1.0001			
Ad usted Demand Cost of Gas Rate	~~$ 0.1452~~	$ 0.1589			
Commodity Cost of Gas Rate	~~$ 0.3759~~	$ 0.9238	Minimum		
Ad ustment Cost of Gas Rate	~~0.0115~~	0.0018	Maximum		
Indirect Cost of Gas Rate	~~0.0252~~	0.0496			
Ad usted C I High Winter Use Cost of Gas Rate	~~$ 0.5578~~	$ 1.1341			

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

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

Issued by: ____________________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 9
Superseding Proposed First Revised Page 9

Anticipated Cost of Gas
PERIOD CO ERED INTER PERIOD NO EMBER 1 2021 THROUGH APRIL 30 2022
~~PRIOR PERIOD CO ERED INTER PERIOD NO EMBER 1 2020 THROUGH APRIL 30 2021~~
REFER TO TE T 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	~~-~~		-	
Unad usted Anticipated Cost of Gas		~~$ 46,136,054~~		$ 94,649,751
Ad ustments				
Prior Period Over Under Recovery as of 05 01 21	~~$ 2,227,421~~		$ 1,431,639	
Interest	~~74,791~~		44,085	
uel Inventory Revenue Re uirement	~~441,037~~		335,667	
roker Revenues	~~32,725~~		3,600	
Refunds from Suppliers	~~-~~		-	
uel inancing	~~-~~		-	
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	~~-~~		-	
ixed Price Option Administrative Costs	~~45,000~~		36,800	
Total Ad ustments		~~1,014,399~~		161,141
Total Anticipated Direct Cost of Gas		~~$ 47,150,454~~		$ 94,810,891
Anticipated Indirect Cost of Gas				
or ing Capital				
Total Unad usted Anticipated Cost of Gas 11 01 21 - 04 30 22	~~$ 46,136,054~~		$ 94,649,751	
Working Capital Rate: ead ag 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 De t				
Total Unad usted Anticipated Cost of Gas 11 01 21 - 04 30 22	~~$ 46,136,054~~		$ 94,649,751	
ess: 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	
ad Debt Percentage	~~1.11~~		0.70	
ad Debt Allowance	~~$ 536,744~~		$ 673,983	
Plus: ad Debt Reconciliation Acct 175.52	~~296,628~~		223,340	
Total ad 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

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

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

Issued by: Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 98
Superseding Proposed First Revised Page 98

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD CO ERED INTER PERIOD NO EMBER 1 2021 THROUGH APRIL 30 2022
~~PRIOR PERIOD CO ERED INTER PERIOD NO EMBER 1 2020 THROUGH APRIL 30 2021~~
Refer to te t in Section1 Firm Transportation Cost of Gas Clause

Col 1	~~Col 2~~	~~Col 3~~	~~Col 4~~	Col 2	Col 3	Col 4
ANTICIPATED COST O SUPP EMENTA GAS SUPP IES:						
PROPANE	~~$ 568,511~~			$ 920,459		
NG	~~$ 1,023,026~~			1,378,925		
TOTA ANTICIPATED COST O SUPP EMENTA GAS SUPP IES	~~1,591,538~~			2,299,384		
ESTIMATED PERCENTAGE USED OR PRESSURE SUPPORT PURPOSES	~~8.7~~			8.7		
ESTIMATED COST O I UIDS USED OR PRESSURE SUPPORT PURPOSES	~~$ 138,464~~			$ 200,046		
PRO ECTED IRM THROUGHPUT THERMS :						
IRM SA ES	~~89,364,968~~	~~67.8~~		91,676,680	68.3	
IRM TRANSPORTATION SU ECT TO TCG	~~42,456,275~~	~~32.2~~		42,583,790	31.7	
TOTA IRM THROUGHPUT SU ECT TO COST O GAS CHARGE	~~131,821,243~~	~~100.0~~		134,260,470	100.0	
TRANSPORTATION SHARE O SUPP EMENTA GAS SUPP IES	~~32.2~~ x	~~138,464~~	~~$ 44,596~~	31.7 x	$ 200,046	$ 63,449
PRIOR O ER OR UNDER CO ECTION			40,053			56,511
NET AMOUNT TO CO ECT ROM RETURNED TO TRANSPORTATION CUSTOMERS			~~$ 4,543~~			$ 6,938
PRO ECTED IRM TRANSPORTATION THROUGHPUT			~~42,456,275~~			42,583,790
IRM TRANSPORTATION COST O GAS			~~$ 0.0001~~			$ 0.0002

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

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

Issued by: ____________________
Neil Proudman
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 99
Superseding Proposed First Revised Page 99

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants

Re uired Annual Environmental Increase	~~$ 2,864,179~~	$ 2,351,805	
Second one-third of prior period under recoveries through une 2019	~~$ 341,389~~	$ 341,389	
uly 2020 - une 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	

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

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

Issued by: ____________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed First Revised Page 100
Superseding Original Page 100

iberty Utilities Energy North Natural Gas Corp. d b a iberty
ocal Distribution Ad ustment Charge DAC decrease due to Rate Case Expense and Recoupment
or DAC effective November 1, 2021 - October 31, 2022
~~or DAC 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 une 30, 2021	$785,177
4	alance at une 30, 2021	$773,228
5	ess: Accrual alance	$26,000
6	Ad usted 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	uly 1, 2021 alance	$2,078,448
14		
15	Estimated Remaining Expenses	$97,375
16		
17	Plus Estimated Interest from uly 2021 through October 2021	$19,820
18		
19	Minus Estimated Recoveries from uly 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

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

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

Issued by: Neil Proudman
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 101
Superseding Proposed First Revised Page 101

Local Delivery Ad ustment 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 Ad ustment actor RDA		~~$ 0.0562~~		$ 0.0152				
Energy Efficiency Resource Standard ost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense actor RCE		~~$ 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- 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 Ad ustment actor RDA		~~$ 0.0562~~		$ 0.0152				
Energy Efficiency Resource Standard ost Revenue Mechanism		~~$ -~~		$ -				
Rate Case Expense actor RCE		~~$ 0.0002~~		$ 0.0121				
Gas Assistance Program GAP		~~$ 0.0121~~		$ 0.0156				
LDAC		~~0.0589~~		0.1444				per therm
Commercial/Industrial Lo 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 Ad ustment actor RDA		~~$ 0.0206~~		$ 0.0039	~~$ 0.0241~~	$ 0.0039	~~$ 0.0213~~	
Energy Efficiency Resource Standard ost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense actor RCE		~~$ 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-5								
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 Ad ustment actor RDA		~~$ 0.0206~~		$ 0.0039	~~$ 0.0241~~	$ 0.0039	~~$ 0.0213~~	
Energy Efficiency Resource Standard ost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense actor RCE		~~$ 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-4 G-5 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 Ad ustment actor RDA		~~$ 0.0206~~		$ 0.0039	~~$ 0.0241~~	$ 0.0039	~~$ 0.0213~~	
Energy Efficiency Resource Standard ost Revenue Mechanism		~~$ -~~		$ -	~~$ 0.0001~~	$ -		
Rate Case Expense actor RCE		~~$ 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

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

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

Issued by: ____________________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

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	
I .	Company Allowance Calculation (per Schedule 25)			
		~~169,030,868~~	165,859,380	Total Sendout - Therms ul -2020 - un-2021 ~~Total Sendout - Therms ul-2019 - un-2020~~
		~~166,311,578~~	163,831,092	Total Throughput - Therms ul-2020 - un-2021 ~~Total Throughput - Therms ul-2019 - un-2020~~
		~~2,719,290~~	2,028,288	ariance Sendout - Throughput
Company Allowance Percentage	2021-22 ~~2020-21~~	~~1.6~~	1.2	ariance Total Sendout

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

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

Issued by: ______________________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

III DELI ERY TERMS AND CONDITIONS

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Second Revised Page 154
Superseding Proposed First Revised Page 154

ATTACHMENT C

CAPACITY ALLOCATORS

Rate Class		Pipeline	Storage	Pea ing	Total
G-41	ow Annual High Winter Use	~~4 .1~~ 69.1	~~17.1~~ 16.8	~~3 .8~~ 14.1	100.0
G-51	ow Annual ow Winter Use	~~59.3~~ 76.2	~~12.9~~ 12.9	~~27.9~~ 10.9	100.0
G-42	Medium Annual High Winter	~~4 .1~~ 69.1	~~17.1~~ 16.8	~~3 .8~~ 14.1	100.0
G-52	High Annual ow Winter Use	~~59.3~~ 76.2	~~12.9~~ 12.9	~~27.9~~ 10.9	100.0
G-43	High Annual High Winter	~~4 .1~~ 69.1	~~17.1~~ 16.8	~~3 .8~~ 14.1	100.0
G-53	High Annual oad actor 90	~~59.3~~ 76.2	~~12.9~~ 12.9	~~27.9~~ 10.9	100.0
G-54	High Annual oad actor 90	~~59.3~~ 76.2	~~12.9~~ 12.9	~~27.9~~ 10.9	100.0

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

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

Issued by: _______________________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

Li erty Utilities EnergyNorth Natural Gas Corp.
d/ /a Li erty
Pea 2021 - 2022 inter Cost of Gas Filing

Ta le of Contents

Ta	Title	Description
Summary	Summary	Summary
1	Schedule 1	Summary of Supply and Demand orecast
2	Schedule 2	Contracts Ranked on a per Unit Cost asis
3	Schedule 3	COG Over Under Cumulative Recovery alances and Interest Calculation
4	Schedule 4	Ad ustments to Gas Costs
5	Schedule 5A	Demand Costs
	Schedule 5	Demand olumes
	Schedule 5C	Demand Rates
	Schedule 5D	Pipeline Tariff Sheets
6	Schedule 6	Supply and Commodity Costs, olumes and Rates
7	Schedule 7	N ME utures Henry Hub
8	Schedule 8, Page 1	Annual ill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Residential Heating Rate R-3
	Schedule 8, Page 2	Annual ill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-41
	Schedule 8, Page 3	Annual ill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-42
	Schedule 8, Page 4	Annual ill Comparisons, Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-52
	Schedule 8, Page 5	Residential Heating
9	Schedule 9	ariance Analysis of the Components of the Winter 2020-2021 Actual Results vs Proposed Winter 2021-2022 Cost of Gas Rate
10	Schedule 10A Pages 1-2	Capacity Assignment Calculations 2020-2021 Derivation of Class Assignments and Weightings
	Schedule 10A Page 3	Correction actor Calculation
	Schedule 10	irm and Transportation Sales
11	Schedule 11A	Normal and Design ear olumes Normal ear
	Schedule 11	Normal and Design ear olumes Design ear
	Schedule 11C	Capacity Utilization
	Schedule 11D	orecast of Upcoming Winter Period Design Day Report
12	Schedule 12, Page 1	Transportation Available for Pipeline Supply and Storage
	Schedule 12, Page 2	Agreements for Gas Supply and Transportation
13	Schedule 13	oad Migration rom Sales to Transportation in the C I High and ow Winter Use Classes
14	Schedule 14	Delivered Costs of Winter Supplies to Pipeline Delivered Supplies from the Prior ear
15	Schedule 15	uly and August Consumption of C I High and ow Winter Classes as a Percentage of Their Annual Consumption
16	Schedule 16	Storage Inventory, Undergound, PG and NG including Calculation of Money Pool Interest Costs Associated with Natural Gas
17	Schedule 17	orecast of irm Transportation olumes and Cost of Gas Revenues
18	Schedule 18	Winter 2018-2019 Cost of Gas Reconciliation is no longer included in this filing
19	Schedule 19	ocal Distribution Ad ustment Charge Calculation
20	Schedule 20	Environmental Surcharge
21	Schedule 21	Supplier alancing Charge and Peaking Demand Charge Calculations
22	Schedule 22	Capacity Allocators Calculation
23	Schedule 23	ixed Price Option PO Historical Summary
24	Schedule 24	Short-Term Debt imitations
25	Schedule 25	Company Allowance and ost and Unaccounted or Gas AU Calculation
26	Schedule 26	uel Inventory Revenue Re uirement

1	Li erty Utilities EnergyNorth Natural Gas Corp.			
2	d/ /a Li erty			
3	Pea 2021 - 2022 inter Cost of Gas Filing			
4	Summary			
5				P 21-22
6		Reference		Nov - Apr
7	a	b		c
8				
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
13				
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
17				
18	Produced Gas:	Sch. 6, col i , ln 56	$	2,299,384
19				
20	Hedge Contract Savings oss	Sch. 7, col i , ln 34	$	-
21	Hedge Underground Storage Contract Savings oss	Sch. 16, col e , ln 172	$	-
22				
23	Total Unad usted Cost of Gas		$	94,649,751
24				
25	Ad ustments			
26				
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 ln 189		44,085
29	uel Inventory Revenue Re	Sch. 26, col b ln 8		335,667
30	Refunds from Suppliers	Sch. 4, ln 26 col c		-
31	roker Revenues	Sch. 4, ln 26 col d		3,600
32	uel inancing	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		-
37	ixed Price Option Administrative Costs	Sch. 4, ln 26 col k		36,800
38				
39	Total Ad ustments		$	161,141
40				
41	Total Anticipated Direct Costs	lns 23 39	$	94,810,891
42				
43	Anticipated Indirect Cost of Gas			
44	or ing Capital			
45	Total Unad usted Anticipated Cost of Gas	n 23	$	94,649,751
46	ead ag 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
51				
52	Total or ing Capital Allo ance	lns 49 50	$	201,902
53				
54	Bad De t			
55	Total Unad usted Anticipated Cost of Gas	ln 23	$	94,649,751
56	ess 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	ad Debt Percentage	per GTC 18 f		0.70
61				
62	ad Debt Allowance	ln 59 ln 60	$	673,983
63	Prior Period ad Debt Allowance	Sch. 3, col c , ln 169		223,340
64				
65	Total Bad De t Allo ance	lns 62 63	$	450,643
66				
67	Production and Storage Capacity	per GTC18 f	$	3,685,458
68				
69				
70	Miscellaneous Overhead	lns 69 72	$	-
71				
72	Total Anticipated Indirect Cost of Gas	lns 52 65 67 70	$	4,338,002
73				
74	Total Cost of Gas	lns 41 72	$	99,148,894
75				
76	Pro ected Forecast Sales Therms	Sch. 3, col , ln 52		87,443,741

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter 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												
7	or Month of:			May 21 - Oct 21	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	May-22	Nov - Apr
8		a	b	c	d	e	f	g	h	i		k
9	I. Gas olumes Therms											
10											1,139,930	1.2
11	A.	Firm Demand olumes										
12		irm Gas Sales	Sch. 10 , 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		ost 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 olumes		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 olumes 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 - aseload	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 COM O	Sch. 6, ln 72	-	89,306	231,576	1,424,042	1,188,519	1,411,967	-		4,345,410
28		NG 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 4	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 olumes		-	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		NG apor	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	ess - Gas Refill:											
44		NG 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 irm Sendout olumes		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												

REDACTED
Updated Schedule 1
Page 2 of 4

1	Li erty Utilities EnergyNorth Natural Gas Corp.											
2	d/ /a Li erty											
3	Pea 2021 - 2022 inter Cost of Gas Filing											
4	Summary of Supply and Demand Forecast											
51	II. Gas Costs											
52	A.	Demand Costs										
53												
54												
55				Peak Costs								Peak Period
56	or Month of:			May 21 - Oct 21	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	May-22	Nov - Apr
57		a	b	c	d	e	f	g	h	i		k
58	Supply											
59		Niagara Supply	Sch.5A, ln 12	[redacted]								
60		Subtotal Supply Demand										
61		ess Capacity Credit										
62		Net Pipeline Demand Costs										
63												
64	Pipeline:											
65		Iro uois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]								
66		Tenn Gas Pipeline 95346 5- 6	Sch.5A, ln 17									
67		Tenn Gas Pipeline 2302 5- 6	Sch.5A, ln 18									
68		Tenn Gas Pipeline 8587 0- 6	Sch.5A, ln 19									
69		Tenn Gas Pipeline 8587 1- 6	Sch.5A, ln 20									
70		Tenn Gas Pipeline 8587 4- 6	Sch.5A, ln 21									
71		Tenn Gas Pipeline Dracut 42076 6- 6	Sch.5A, ln 22									
72		Tenn Gas Pipeline Dracut 358905 6- 7	Sch.5A, ln 23									
73		Tenn Gas Pipeline Concord ateral 6- 6	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 Iro uois	Sch.5A, ln 27									
77		TransCanada via Union to Portland	Sch.5A, ln 28									
78		Tenn Gas Pipeline 4- 6 stg 632	Sch.5A, ln 29									
79		Tenn Gas Pipeline 4- 6 stg 11234	Sch.5A, ln 30									
80		Tenn Gas Pipeline 5- 6 stg 11234	Sch.5A, ln 31									
81		National uel ST 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		ess 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 ateral 6- 6	Sch.5A, ln 37	[redacted]								
88		Demand S	Sch.5A, ln 38									
89		Constellation Demand	Sch.5A, ln 39									
90		Subtotal Peaking Demand										
91		ess 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 uel - Demand	Sch.5A, ln 52									
99		National uel - 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		ess 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 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 Summary of Supply and Demand Forecast

REDACTED
Updated Schedule 1
Page 3 of 4

Line	a	b	Peak Costs May 21 - Oct 21 c	Nov-21 d	Dec-21 e	an-22 f	eb-22 g	Mar-22 h	Apr-22 i	May-22	Peak Period Nov - Apr k
111	B. Commodity Costs										
112											
113											
114											
115											
116											
117											
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 - aseload	Sch. 6, ln 15									
123	Dracut Supply 2 - Swing	Sch. 6, ln 16									
	Dracut Supply 3 - Swing	Sch. 6, ln 17									
124	Constellation COM O	Sch. 6, ln 18									
125	NG 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 4	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	NG apor	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	ess Storage Refills:										
141	NG 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 olumetric 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 - aseload	Sch. 6, ln 31									
154	Dracut Supply 2 - Swing	Sch. 6, ln 32									
	Dracut Supply 3 - Swing	Sch. 6, ln 33									
155	Subtotal Pipeline olumetric 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 olumetric 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											

THIS PAGE HAS BEEN REDACTED

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 Summary of Supply and Demand Forecast
164 D. Supply and Demand Costs y Source

REDACTED
Updated Schedule 1
Page 4 of 4

165											
166											
167											
168			Peak Costs								Peak Period
169				Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	May-22	Nov - Apr
170	a	b	c	d	e	f	g	h	i		k
171	Purchased Gas Demand Costs										
172	Pipeline Gas Demand Costs	Ins 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	In 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	ess Capacity Credit	Ins 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	In 102	$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105		$ 1,393,257
180	ess Capacity Credit	In 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	Ins 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	In 130	[redacted]								
187	ess Storage In . TGP Storage	In 143									
188	ess Storage Transportation	In 144									
189	ess NG Truck	In 141									
190	ess Propane Truck	In 142									
191	Plus Transportation Costs	In 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	In 133	$ -	$ 838,477	$ 258,921	$ 1,676,210	$ 1,489,505	$ 1,449,899	$ 417,423		$ 6,130,435
196	Transportation Costs	In 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	In 138	$ -	$ 14,924	$ 296,153	$ 644,056	$ 1,138,771	$ 190,796	$ 14,685		$ 2,299,384
200											
201	Su total Commodity Costs	Ins 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 oss		$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
204											
205	Total Commodity Costs	Ins 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	In 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	In 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	Ins 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											

THIS PAGE HAS BEEN REDACTED

1	Li erty Utilities EnergyNorth Natural Gas Corp.					REDACTED
2						Updated Schedule 2
3						Page 1 of 1
4	Pea 2021 - 2022 inter Cost of Gas Filing					
5	Contracts Ran ed on a per Unit Cost Basis					Pea Period
6				Contract	Unit Dth	Cost per
7	Supplier	Contract	Contract Type	Unit	MD /AC	Unit Dth
8	a	b	c	d	e	f
9						
10	Demand Costs					
11						[redacted]
12	Dominion - Capacity Reservation	GSS 300076	Storage	AC	102,700	
13	Tenn Gas Pipeline - Cap. Reservations	S-MA 523	Storage	AC	1,560,391	
14	National uel - Capacity Reservation	SS-O02357	Storage	AC	670,800	
15	Tenn Gas Pipeline - Demand	S-MA 523	Storage	MD	21,844	
16	Dominion - Demand	GSS 300076	Storage	MD	934	
17	National uel - Demand	SS-O02357	Storage	MD	6,098	
18	National uel	ST N02358	Transportation	MD	6,098	
19	Tenn Gas Pipeline	42076 TA 6- 6	Transportation	MD	20,000	
20	Tenn Gas Pipeline	358905 TA 6- 6	Transportation	MD	40,000	
21	Iro uois Gas Trans Service	RTS 470-01	Transportation	MD	4,047	
22	Honeoye - Demand	SS-N	Storage	MD	1,362	
23	Tenn Gas Pipeline	2302 5- 6	Transportation	MD	3,122	
24	Tenn Gas Pipeline	95346 5- 6	Transportation	MD	4,000	
25	Tenn Gas Pipeline short haul	11234 5- 6 stg	Transportation	MD	1,957	
26	Tenn Gas Pipeline short haul	11234 4- 6 stg	Transportation	MD	7,082	
27	Tenn Gas Pipeline short haul	8587 4- 6	Transportation	MD	3,811	
28	Tenn Gas Pipeline short haul	632 4- 6 stg	Transportation	MD	15,265	
29	Tenn Gas Pipeline Concord ateral 6- 6	irm Transportation	Transportation	MD	30,000	
30	ANE TransCanada via Union to Iro uois	Dawn - Parkway to Iro uois	Transportation	MD	4,047	
31	TransCanada via Union to Portland	Dawn -Parkway to Portland	Transportation	MD	5,077	
32	Tenn Gas Pipeline long haul	8587 1- 6	Transportation	MD	14,561	
33	Tenn Gas Pipeline long haul	8587 0- 6	Transportation	MD	7,035	
34	Portland Natural Gas Trans Service	T-208544	Transportation	MD	1,000	
35	Portland Natural Gas	T 233320	Transportation	MD	5,000	
36	Peaking Demand	NS 041	Peaking	MD	10,000	
37						
38	Supply Costs - Commodity					
39	TGP Supply 4		Pipeline	Dkt	1,475,358	[redacted]
40	Niagara Supply		Pipeline	Dkt	421,275	
41	Constellation COM O		Pipeline	Dkt	434,541	
42	TGP Supply Direct		Pipeline	Dkt	1,728,355	
43	Dawn Supply		Pipeline	Dkt	523,333	
44	Dracut Supply 1 - aseload		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	NG 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	NG apor Storage		Produced	Dkt	197,875	
54						
55	Supply Costs - olumetric Transportation					
56	Dracut Supply 1 - aseload		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	

THIS PAGE HAS BEEN REDACTED

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation

Updated Schedule 3
Page 1 of 3

Ln		Days in Month	Prior Period al Apr-21 Ending al Plus May illings	May-21 31	un-21 30	ul-21 31	Aug-21 31	Sep-21 30	Oct-21 31	Nov-21 30	Dec-21 31	an-22 31	eb-22 28	Mar-22 31	Apr-22 30	May-22 31	Peak Period Total
9	a	b	c	d	e	f	g	h	i		k	l	m	n	o	p	
10	Account 1920-1740 COG Over /Under Balance - Interest Calculation																
11																	
12	Beginning Balance	Account 1920-1740 1	1 431 39	$ 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	cst 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	Pro ected 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	Pro ected 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	Ad ustment			1,233,644	1,008,659					-							2,242,302
19	Add Net Ad ustments	Schedule 4		-	-	-	-	-	-	243,108	283,455	283,617	282,374	279,025	278,672	-	1,650,251
20	Gas Cost illed	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 alance	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 ith 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	cst 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	Pro ected 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	Pro ected 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 Ad ustments	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 illed	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 alance			$ 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	orecast 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	ess orecast illing Therm Sales	Sch. 10 , 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	ess orecast Unaccounted or	Sch 1								131,257	200,043	232,437	192,597	165,642	95,906		1,017,882
54	ess orecast Company Use	Sch 1								15,738	23,986	27,870	23,093	19,861	11,500		122,048
55	Unbilled olumes									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	CO 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 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation

Line	a	b	Prior Period al Apr-21 Ending al May Collections	May-21 31 c	un-21 30 d	ul-21 31 e	Aug-21 31 f	Sep-21 30 g	Oct-21 31 h	Nov-21 30 i	Dec-21 31	an-22 31 k	eb-22 28 l	Mar-22 31 m	Apr-22 30 n	May-22 31 o	Peak Period Total p
67		Days in Month															
70	Account 11 3-1422 or ing Capital Over /Under Balance - Interest Calculation																
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 ag			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	orecast 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	Pro ected 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	Pro ected 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 Ad ustments			1,062	1,595	-	-	-	-	-	-	-	-	-	-	-	2,657
84	Working Capital illed	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 alance	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 or ing Capital ith Interest																
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	orecast 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	Pro ected Rev. with interest	ln 116 ln 122		-	-	-	-	-	-	7,203	40,373	47,243	39,830	33,964	20,524	9,842	198,979
103	Pro ected 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 Ad ustments	ln 82	-	1,062	1,595	-	-	-	-	-	-	-	-	-	-	-	2,657
106	Working Capital illed	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 alance			$ 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	orecast 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 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation

Updated Schedule 3
Page 3 of 3

Line			Prior Period al Apr-21 Ending al May Collections	May-21 31 c	un-21 30 d	ul-21 31 e	Aug-21 31 f	Sep-21 30 g	Oct-21 31 h	Nov-21 30 i	Dec-21 31	an-22 31 k	eb-22 28 l	Mar-22 31 m	Apr-22 30 n	May-22 31 o	DemandPeriod Total p
123																	
124																	
125																	
126																	
127		Days in Month															
128	a	b															
129																	
130	Account 1920-1743 Bad De t Over /Under Balance - Interest Calculation																
131																	
132	orecast 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	orecast 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 alance	ln 42								238,607	238,607	238,607	238,607	238,607	238,607		1,431,639
135	Total orecast 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	orecast ad 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	Pro ected 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	Pro ected 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	ad Debt illed	Account 1920-1743 2	-		-	-	-	-	-		-	-	-	-	-	-	-
146																	
147	Add Net Ad ustments		-	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 alance	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 De t ith 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	orecast ad 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	Pro ected Revenues with int.	ln 178 ln 184		-	-	-	-	-	-	14,652	82,124	96,099	81,019	69,088	41,748	20,021	404,751
165	Pro ected 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	ad Debt illed	ln 145	-		-	-	-	-	-	-	-	-	-	-	-	-	0
168	Add Interest	ln 155		-	-	-	-	-	-	652	510	259	116	79	76	-	1,693
169	Add Net Ad ustments	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 alance			$ 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	orecast 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 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 Ad ustments to Gas Costs
5

REDACTED
Updated Schedule 4
Page 1 of 1

			Prior Period Ad ustments	Refunds from Suppliers	Bro er Revenue	Inventory Finance Charges	Transportation CGA Revenues Schedule 17	Interrupti le Sales Margin	Off System Sales Margin	Capacity Release	Net Option Premiums	Fi ed Price Option Administrative Costs	Total Ad ustments
6	Ad ustments												
7	a		b	c	d	e	f	g	h	i		k	m
8													
9	May-20		$ -	$ -	$ -	$ -	$ -	$ -	[redacted]		$ -	$ -	$ -
10	un-20		-	-	-	-	-	-			-	-	-
11	ul-20	1	-	-	-	-	-	-			-	-	-
12	Aug-20	1	-	-	-	-	-	-			-	-	-
13	Sep-20	1	-	-	-	-	-	-			-	-	-
14	Oct-20	1	-	-	-	-	-	-			-	-	-
15	Nov-20	1	-	-	47	-	1,032	-			-	36,800	243,108
16	Dec-20	1	-	-	624	-	1,276	-			-	-	283,455
17	an-21	1	-	-	751	-	1,436	-			-	-	283,617
18	eb-21	1	-	-	816	-	1,199	-			-	-	282,374
19	Mar-21	1	-	-	757	-	1,145	-			-	-	279,025
20	Apr-21	1	-	-	605	-	851	-			-	-	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 inance Charges for Nov 20 - Apr 21 calculated on Schedule 16

1	Li erty Utilities EnergyNorth Natural Gas Corp.										REDACTED
2	d/ /a Li erty										Updated Schedule 5A
3	Pea 2021 - 2022 inter Cost of Gas Filing										Page 1 of 1
4	Demand Costs										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 20 -Oct 20	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Total
9	a	b	c	d	e	f	g	h	i		k
10											
11	Supply										
12	Niagara Supply		Sch 5 , ln 9 Sch 5C ln 9 x days	[redacted]							
13	Subtotal Supply Demand Reservation Charges										
14											
15	Pipeline										
16	Iro uois Gas Trans Service RTS 470-0		Sch 5 , ln 12 Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 5- 6		Sch 5 , ln 13 Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 5- 6		Sch 5 , ln 14 Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 0- 6		Sch 5 , ln 15 Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 1- 6		Sch 5 , ln 16 Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 4- 6		Sch 5 , ln 17 Sch 5C ln 22 x days								
22	Tenn Gas Pipeline Dracut 42076 6- 6	peak	Sch 5 , ln 18 Sch 5C ln 24 x days								
23	Tenn Gas Pipeline Dracut 358905 6- 7	peak	Sch 5 , ln 19 Sch 5C ln 25 x days								
24	Tenn Gas Pipeline Concord ateral 6- 6	peak	Sch 5 , ln 20 Sch 5C ln 28 x days								
25	Portland Natural Gas Trans Service		Sch 5 , ln 21 Sch 5C ln 30 x days								
26	Portland Natural Gas		Sch 5 , ln 22 Sch 5C ln 31 x days								
27	ANE TransCanada via Union to Iro uois		Sch 5 , ln 23 Sch 5C ln 32 x days								
28	TransCanada via Union to Portland		Sch 5 , ln 24 Sch 5C ln 33 x days								
29	Tenn Gas Pipeline 4- 6 stg 632	peak	Sch 5 , ln 25 Sch 5C ln 34 x days								
30	Tenn Gas Pipeline 4- 6 stg 11234	peak	Sch 5 , ln 26 Sch 5C ln 36 x days								
31	Tenn Gas Pipeline 5- 6 stg 11234	peak	Sch 5 , ln 27 Sch 5C ln 38 x days								
32	National uel ST 2358	peak	Sch 5 , 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	Pea ing Supply										
37	Tenn Gas Pipeline Concord ateral 6- 6	peak	Sch 5 , ln 31 Sch 5C ln 28 x days	[redacted]							
38	Demand S	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	Su total Supply Pipeline Pea ing		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	ess 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 Pea ing 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 5 , 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 5 , 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 5 , 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 uel - Demand	peak	Sch 5 , 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 uel - Capacity	peak	Sch 5 , 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 5 , 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 5 , 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	Su total Storage Demand Costs			$ 696,628	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 1,393,257
58											
59	ess 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				THIS PAGE HAS BEEN REDACTED							

Updated Schedule 5
Page 1 of 1

1	Li erty Utilities EnergyNorth Natural Gas Corp.									
2	d/ /a Li erty									
3	Pea 2021 - 2022 inter Cost of Gas Filing									
4	Demand olumes									
5										
6			Peak	Reference	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22
7		a	b	c	d	e	f	g	h	i
8	Supply									
9		Niagara Supply			-	-	-	-	-	-
10										
11	Pipeline									
12		Iro uois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
13		Tenn Gas Pipeline		95346 5- 6	4,000	4,000	4,000	4,000	4,000	4,000
14		Tenn Gas Pipeline		2302 5- 6	3,122	3,122	3,122	3,122	3,122	3,122
15		Tenn Gas Pipeline long haul		8587 0- 6	7,035	7,035	7,035	7,035	7,035	7,035
16		Tenn Gas Pipeline long haul		8587 1- 6	14,561	14,561	14,561	14,561	14,561	14,561
17		Tenn Gas Pipeline short haul		8587 4- 6	3,811	3,811	3,811	3,811	3,811	3,811
18		Tenn Gas Pipeline	peak	42076 TA 6- 6	20,000	20,000	20,000	20,000	20,000	20,000
19		Tenn Gas Pipeline	peak	358905 TA 6- 6	40,000	40,000	40,000	40,000	40,000	40,000
20		Tenn Gas Pipeline Concord ateral	peak	irm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
21		Portland Natural Gas Trans Service		T-208544	1,000	1,000	1,000	1,000	1,000	1,000
22		Portland Natural Gas		T 233320	5,000	5,000	5,000	5,000	5,000	5,000
23		ANE TransCanada via Union to Iro uois		Dawn - Parkway to Iro uois	4,047	4,047	4,047	4,047	4,047	4,047
24		TransCanada via Union to Portland		Dawn -Parkway to Portland	5,077	5,077	5,077	5,077	5,077	5,077
25		Tenn Gas Pipeline short haul	peak	632 4- 6 stg	15,265	15,265	15,265	15,265	15,265	15,265
26		Tenn Gas Pipeline short haul	peak	11234 4- 6 stg	7,082	7,082	7,082	7,082	7,082	7,082
27		Tenn Gas Pipeline short haul	peak	11234 5- 6 stg	1,957	1,957	1,957	1,957	1,957	1,957
28		National uel	peak	ST N02358	6,098	6,098	6,098	6,098	6,098	6,098
29										
30	Pea ing									
31		Tenn Gas Pipeline Concord ateral	peak		-	-	-	-	-	-
32		Demand S	peak		3,000	3,000	3,000	3,000	3,000	-
33		Peaking Demand	peak	NS 041	7,000	7,000	7,000	7,000	7,000	-
34										
35	Storage									
36		Dominion - Demand	peak	GSS 300076	934	934	934	934	934	934
37		Dominion - Capacity Reservation	peak	GSS 300076	102,700	102,700	102,700	102,700	102,700	102,700
38		Honeoye - Demand	peak	SS-N	1,362	1,362	1,362	1,362	1,362	1,362
39		Honeoye - Capacity	peak	SS-N	245,380	245,380	245,380	245,380	245,380	245,380
40		National uel - Demand	peak	SS-O02357	6,098	6,098	6,098	6,098	6,098	6,098
41		National uel - Capacity Reservation	peak	SS-O02357	670,800	670,800	670,800	670,800	670,800	670,800
42		Tenn Gas Pipeline - Demand	peak	S-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
43		Tenn Gas Pipeline - Cap. Reservations	peak	S-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

REDACTED
Updated Schedule 5C
Page 1 of 2

Line						Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov - Apr
1	Li erty Utilities EnergyNorth Natural Gas Corp.											
2	d/ /a Li erty											
3	Pea 2021 - 2022 inter Cost of Gas Filing											
4	Demand Rates											
5						Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov - Apr
6	Tariff Rates					30	31	31	28	31	30	181
7						Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
8	Supply											
9	Niagara Supply		[redacted]			[redacted]						
10												
11	Pipeline											
12	Iro uois Gas Trans Service	RTS 470-01	$	5.2357	orth Revised Sheet No. 4	$ 0.1745	$ 0.1689	$ 0.1689	$ 0.1870	$ 0.1689	$ 0.1745	$ 0.1738
13												
14	Tenn Gas Pipeline	95346 5- 6	$	6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
15												
16	Tenn Gas Pipeline	2302 5- 6	$	6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
17												
18	Tenn Gas Pipeline	8587 0- 6	$	20.3736	T-A 0 - 6	$ 0.6791	$ 0.6572	$ 0.6572	$ 0.7276	$ 0.6572	$ 0.6791	$ 0.6763
19												
20	Tenn Gas Pipeline	8587 1- 6	$	18.0875	T-A 1 - 6	$ 0.6029	$ 0.5835	$ 0.5835	$ 0.6460	$ 0.5835	$ 0.6029	$ 0.6004
21												
22	Tenn Gas Pipeline	8587 4- 6	$	7.1645	T-A 4 - 6	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
23												
24	TGP Dracut	42076 TA 6- 6	$	4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
25												
26	TGP Dracut	358905 TA 6- 6	$	4.1818	17th Rev Sheet No. 14	$ 0.1394	$ 0.1349	$ 0.1349	$ 0.1494	$ 0.1349	$ 0.1394	$ 0.1388
27												
28	TGP Concord ateral	irm Transportatio	$	12.2113	Per contract	$ 0.4070	$ 0.3939	$ 0.3939	$ 0.4361	$ 0.3939	$ 0.4070	$ 0.4053
29												
30	Portland Natural Gas	T-208544	$	18.2633	Negot Dmd CMD Part 4.1 7	$ 0.6088	$ 0.5891	$ 0.5891	$ 0.6523	$ 0.5891	$ 0.6088	$ 0.6062
31												
32	Portland Natural Gas	T 233320	$	22.8125	Negot Dmd CMD Part 4.1 7	$ 0.7604	$ 0.7359	$ 0.7359	$ 0.8147	$ 0.7359	$ 0.7604	$ 0.7572
33												
34	Tenn Gas Pipeline	632 4- 6 stg	$	7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
35												
36	Tenn Gas Pipeline	11234 4- 6 stg	$	7.1645	17th Rev Sheet No. 14	$ 0.2388	$ 0.2311	$ 0.2311	$ 0.2559	$ 0.2311	$ 0.2388	$ 0.2378
37												
38	Tenn Gas Pipeline	11234 5- 6 stg	$	6.2957	17th Rev Sheet No. 14	$ 0.2099	$ 0.2031	$ 0.2031	$ 0.2248	$ 0.2031	$ 0.2099	$ 0.2090
39												
40	National uel	ST N02358	$	4.5274	4.010 ersion 31.0.1 Pg 1	$ 0.1509	$ 0.1460	$ 0.1460	$ 0.1617	$ 0.1460	$ 0.1509	$ 0.1503
41												
42					THIS PAGE HAS BEEN REDACTED							

1 Li erty Utilities EnergyNorth Natural Gas Corp. — REDACTED
2 d/ /a Li erty — Updated Schedule 5C
3 Pea 2021 - 2022 inter Cost of Gas Filing — Page 2 of 2

43	ANE Union Gas		$ 3.6665								
44	TransCanada Pipelines imited		$ 11.9842	Dawn - Parkway to Iro uois							
45	Delivery Pressure Demand Charge		$ 0.6083	Dawn - Parkway to Iro uois							
46	Sub Total Demand Charges		$ 16.2590								
47	Conversion rate G to MM TU		$ 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 imited		$ 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 G to MM TU		$ 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	Pea ing										
60	Demand S		[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-N	$ 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 uel - Demand	SS-O02357	$ 2.6325	4.020 ersion 26.0.0 Pg 1	$ 0.0878	$ 0.0849	$ 0.0849	$ 0.0940	$ 0.0849	$ 0.0878	$ 0.0873
71	National uel - Capacity	SS-O02357	$ 0.0476	4.020 ersion 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	S-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	S-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.

Eastern Gas Transmission and Storage, Inc.
FERC Gas Tariff
Sixth Revised Volume No. 1

GSS, GSS-E & ISS Rates - Settled Parties
Tariff Record No. 10.30.
Version 1.0.0
Superseding Version 0.0.0

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 Schedule (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 I

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 **Energy North Natural Gas Inc.**	Contract Category **Storage**	Contract Number **EN-11234**	Service Type FT	Status Active	Currency USD
Deal Maker Richard Nardon	Deal Date 01/17/1986	Deal Time (hh:mm) 09:00	Master Agreement - None -	Units Dth	
Contact Name Sarah Finegan	Contact Number 1 603-2163569	Contact Number 2	Contact Email sarah.finegan@libertyutilities.com		

Contract Dates

Effective Date (First Gas Day)
08/01/2010

Termination Date (Last Gas Day)
01/31/2050

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.S.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
05/01/13	01/01/50	9,350.5800

FERC Information

Capacity Release Contract: Yes No

Shipper Affiliation: NONE

Maximum Tariff Rate: OR Market Based Rates

Award:

Negotiated Rate Indicator: Yes No

Rate Schedule: FT

Contract Quantity Limits

Monthly MSQ Table

From	To	Max Qty	Min Qty
08/01/10	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) 3/ ----------

	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 4/1/2022
RTS DEMAND (Monthly):						
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5897	$5.4177	$5.2357
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998	$4.6438	$4.4878
Inter-Zone	$0.0000	$10.4759	$ 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.

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.

Effective On: April 1, 2021

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		$7.3446	$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.

Issued: September 30, 2020
Effective: November 1, 2020

Docket No. RP20-1253-000
Accepted: October 29, 2020

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.

Issued: September 30, 2020
Effective: November 1, 2020

Docket No. RP20-1253-000
Accepted: October 29, 2020

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		$0.0067	$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	$0.0045	$0.0046	$0.0066
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0085	$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
Effective: April 1, 2021

Docket No. RP21-552-000
Accepted: March 31, 2021

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

Seventeenth Revised Sheet No. 32
Superseding
Sixteenth Revised Sheet No. 32

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%	0.60%	1.22%
5	4.08%		3.55%	1.42%	1.67%	0.66%	0.65%	0.96%
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	\$0.0019	\$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%.

Issued: March 1, 2021
Effective: April 1, 2021

Docket No. RP21-552-000
Accepted: March 31, 2021

Effective
2021-07-01
Rate M12
Page 1 of 4

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 then the identified rates.

	Monthly Demand Charges (applied to daily contract demand)	Fuel and Commodity Charges			
		Union Supplied Fuel	Shipper Supplied Fuel		
	Rate/GJ	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 $5.09167/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	0.92374	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	-	0.0236
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	-	0.5281	-	0.0271
10	Union NDA	East Hereford	-	0.7581	-	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	-	0.0062
18	Union NDA	Philipsburg	-	0.6346	-	0.0347
19	Union NDA	Spruce	-	0.5960	-	0.0660
20	Union NDA	St. Clair	-	0.6177	-	0.0336
21	Union NDA	Welwyn	-	0.7376	-	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	Central 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	22.51746	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	16.12986	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	3.47359	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	12.02087	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	-	0.0679
63	Union SSMDA	TransGas SSDA	-	0.7252	-	0.0619
64	Union SSMDA	Centram SSDA	-	0.6344	-	0.0705
65	Union SSMDA	Centram MDA	-	0.5446	-	0.0582
66	Union SSMDA	Central MDA	-	0.5365	-	0.0584
67	Union SSMDA	Union WDA	-	0.7185	-	0.0606
68	Union SSMDA	Nipigon WDA	-	1.0474	-	0.0677
69	Union SSMDA	Union NDA	-	0.8256	-	0.0597

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 Supply and Commodity Costs olumes and Rates

REDACTED
Updated Schedule 6
Page 1 of 5

Line		Reference		Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Peak Nov- Apr
6	or Month of:	Reference		Nov-21	Dec-21	an-22	eb-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 - aseload	ln 69	ln 117							
16	Dracut Supply 2 - Swing	ln 70	ln 122							
17	Dracut Supply 3 - Swing	ln 71	ln 123							
18	Constellation COM O	ln 72	ln 138							
19	NG 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 4	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	olumetric 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 - aseload	ln 69	ln 263							
32	Dracut Supply 2 - Swing	ln 70	ln 263							
33	Dracut Supply 3 - Swing	ln 71	ln 264							
34	Constellation COM O	ln 72	ln 263							
35	TGP Storage - Withdrawals	ln 82	ln 179							
36										
37	Total olumetric Transportation Costs			$ 288,190	$ 216,647	$ 275,048	$ 239,882	$ 238,945	$ 59,504	$ 1,318,217
38										
39	Less - Gas Refill									
40	NG 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	NG apor	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

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 Supply and Commodity Costs olumes and Rates

Updated Schedule 6
Page 2 of 5

5									Peak
6	or Month of:	Reference	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Nov- Apr
7	a	b	c	d	e	f	g	h	i
62									
63	olumes 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 - aseload		-	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 COM O		89,306	231,576	1,424,042	1,188,519	1,411,967	-	4,345,410
73	NG 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 4		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 olumes		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	NG apor		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	NG 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 olumes		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									
1	Li erty Utilities EnergyNorth Natural Gas Corp.								REDACTED
2	d/ /a Li erty								Updated Schedule 6
3	Pea 2021 - 2022 inter Cost of Gas Filing								Page 3 of 5
4	Supply and Commodity Costs olumes and Rates								
5									Peak
6	or Month of:	Reference	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Nov- Apr
7	a	b	c	d	e	f	g	h	i
101	Gas Costs and olumetric Transportation Rates								
102									
103	Pipeline Gas								
104	Da n Supply								Average Rate
105	N ME Price	Sch 7, ln 10 10	[redacted]						
106	asis Differential								
107	Net Commodity Costs								
108									
109	Niagara Supply								
110	N ME Price	Sch 7, ln 10 10	[redacted]						
111	asis Differential								
112	Net Commodity Costs								
113									
114	Dracut Supply 1 - Baseload								
115	Commodity Costs - N ME Price	Sch 7, ln 10 10	[redacted]						
116	asis Differential								
117	Net Commodity Costs								
118									
119	Dracut Supply 2 - S ing								
120	Commodity Costs - N ME Price	Sch 7, ln 10 10	[redacted]						
121	asis Differential								
122	Net Commodity Costs								
123									
124	Dracut Supply 3 - S ing								
125	Commodity Costs - N ME Price	Sch 7, ln 10 10	[redacted]						
126	asis Differential								
127	Net Commodity Costs								
128									
129	TGP Supply Direct								
130	N ME Price	Sch 7, ln 10 10	[redacted]						
131	asis Differential								
132	Net Commodity Costs								
133									
134									
135	Constellation COMBO								
136	N ME Price	Sch 7, ln 10 10	[redacted]						
137	asis Differential								
138	Net Commodity Costs								
139									
140	LNG Truc	Sch 7, ln 10 10	[redacted]						
141									
142	Propane Truc	Propane WACOG	[redacted]						
143									
144	PNGTS								
145	N ME Price	Sch 7, ln 10 10	[redacted]						
146	asis Differential								
147	Net Commodity Cost								
148									
149	PNGTS E P								
150	N ME Price	Sch 7, ln 10 10	[redacted]						
151	asis Differential								
152	Net Commodity Cost								
153									
154	TGP Supply 4								
155	N ME Price	Sch 7, ln 10 10	[redacted]						
156	asis Differential								
157	Net Commodity Cost								
158									
159	LNG apor Storage	Sch 16, ln 95 10	[redacted]						
160									
161	Propane	Sch 16, ln 66 10	[redacted]						
162									
163	Storage Refill								
164	LNG Truc	ln 140	[redacted]						
165	Propane	ln 142							
166									
167									

THIS PAGE HAS BEEN REDACTED

1	Li erty Utilities EnergyNorth Natural Gas Corp.								REDACTED
2	d/ /a Li erty								Updated Schedule 6
3	Pea 2021 - 2022 inter Cost of Gas Filing								Page 4 of 5
4	Supply and Commodity Costs olumes and Rates								
5									Peak
6	or Month of:	Reference	Nov-21	Dec-21	an-22	eb-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 ithdra al	Sch 16, ln 34 10	$0.3046	$0.3046	$0.3046	$0.3046	$0.3046	$0.3361	$0.3098
172									
173	TGP - Max Commodity - 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 - 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 - 4-6		$0.00940	$0.00940	$0.00940	$0.00940	$0.00940	$0.00940	$0.00940
176	TGP - uel Charge - 4-6	17th Rev Sheet No. 32	1.22	1.22	1.22	1.22	1.22	1.22	1.22
177	TGP - uel Charge - 4-6 - N ME 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 olumetric Transportation Rate - TGP Storage		$0.01399	$0.01399	$0.01399	$0.01399	$0.01399	$0.01437	$0.01405
180									
181	Total TGP - Comm. ol. Trans. Rate	ln 171 ln 179	0.3185	0.3185	0.3185	0.3185	0.3185	0.35044	0.32387
182									
183									
184	Per Unit olumetric Transportation Rates								
185	Da n Supply olumetric 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 G	Dawn - Parkway to Iro uois	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
189	Conversion Rate G to MM TU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
190	Conversion Rate to US$	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 uel	Dawn - Parkway to Iro uois	0.97	0.95	1.20	1.09	0.97	0.78	0.99
193	TransCanada uel Percentage	ln 186 x ln 192	$0.00524	$0.00545	$0.00702	$0.00639	$0.00540	$0.00311	$0.00544
194	Subtotal TransCanada		0.005 4	0.00585	0.00742	0.00 79	0.00580	0.00351	0.00583
195	IGTS - 1 RTS Commodity	orth Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
196	IGTS - 1 RTS ACA Rate Commodity	orth Revised Sheet No. 4	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
197	IGTS - 1 RTS Deferred Asset Surcharge	orth Revised Sheet No. 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
198	Subtotal IGTS - Trans Charge - 1 RTS Commodity		0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
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 - uel Use actor - Percentage	orth Revised Sheet No. 4	1.00	1.00	1.00	1.00	1.00	1.00	1.00
201	IGTS - uel Use actor - uel Percentage	ln 186 x ln 200	0.00542	0.00572	0.00584	0.00589	0.00559	0.00398	0.00541
202	TGP TA uel Charge 5-6	17th Rev Sheet No. 32	0.86	0.86	0.86	0.86	0.86	0.86	0.86
203	TGP TA uel Percentage	ln 186 x ln 202	0.004	0.00492	0.00503	0.0050	0.00480	0.00342	0.004 5
204	Total olumetric Transportation Charge - Da n Supply		0.01 30	0.0170	0.01887	0.01832	0.01 77	0.01149	0.01 47
205									
206									
207	Niagara Supply olumetric Transportation Charge								
208	Commodity Costs	n 112	[redacted]						
209									
210	TGP TA - TA 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 TA - TA 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 TA - TA 5-6 Commodity Rate		0.00717	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
213	TGP TA uel Charge 5-6	17th Rev Sheet No. 32	0.86	0.86	0.86	0.86	0.86	0.86	0.86
214	TGP TA uel Percentage	ln 208 x ln 213	[redacted]						
215	Total olumetric Transportation Rate - Niagara Supply								
216									
217									

THIS PAGE HAS BEEN REDACTED

1	Li erty Utilities EnergyNorth Natural Gas Corp.								REDACTED
2	d/ /a Li erty								Updated Schedule 6
3	Pea 2021 - 2022 inter Cost of Gas Filing								Page 5 of 5
4	Supply and Commodity Costs olumes and Rates								
5									Peak
6	or Month of:	Reference	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Nov- Apr
7	a	b	c	d	e	f	g	h	i
218									
219									
220									
221	TGP Direct olumetric Transportation Charge								Average Rate
222	Commodity Costs	n 130	[redacted]						
223									
224	TGP - Max Comm. ase Rate - 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 - 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 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 - 0-6		0.00875	0.00875	0.00875	0.00875	0.00875	0.00875	0.00875
229	TGP - Max Comm. ase Rate - 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 - 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 - 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 - 1-6		0.01579	0.01579	0.01579	0.01579	0.01579	0.01579	0.01579
234	TGP - uel Charge - 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 uel Charge - 0-6		1.52	1.52	1.52	1.52	1.52	1.52	1.52
237	TGP - uel Charge - 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 uel Charge - uel Charge - 1-6		2.74	2.74	2.74	2.74	2.74	2.74	2.74
240	TGP - uel Charge - 0-6	ln 222 x ln 236	0.00849	0.00874	0.00889	0.00874	0.00825	0.00 23	0.00822
241	TGP - uel Charge - 1-6	ln 222 x ln 239	0.01530	0.01574	0.01 02	0.01573	0.0148	0.01121	0.01481
242	Total olumetric Transportation Rate - TGP Direct		0.04833	0.04902	0.04945	0.04901	0.047 5	0.04198	0.04757
243									
244	TGP one Purchase olumetric Transportation Charge								
245	Commodity Costs	n 130	[redacted]						
246									
247	TGP - Max Comm. ase Rate - 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 - 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 - 6-6		0.00312	0.00312	0.00312	0.00312	0.00312	0.00312	0.00312
250	TGP - uel Charge - 6-6	17th Rev Sheet No. 32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
251	TGP - uel Charge	ln 245 x ln 250	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
252	Total ol. Trans. Rate - TGP one		0.00312	0.00312	0.00312	0.00312	0.00312	0.00312	0.00312
253									
254									
255	TGP Dracut								
256	Commodity Costs - NYME Price	n 117	[redacted]						
257									
258	TGP - Trans Charge - Comm. - 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 - 6-6	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 - 6-6		0.00312	0.00312	0.00312	0.00312	0.00312	0.00312	0.00312
261	TGP - uel Charge - 6-6	17th Rev Sheet No. 32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
262	TGP - uel Charge	ln 256 x ln 261	[redacted]						
263	Total olumetric Transportation Rate - TGP Dracut								
264									
265									

THIS PAGE HAS BEEN REDACTED

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 NYME Futures Henry Hu
5

Updated Schedule 7
Page 1 of 1

										Peak
6	or Month of:	Reference		Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Strip Average
7	a	b		c	d	e	f	g	h	i
8	I. NYME Opening Prices as of									
9	Opening Prices			$5.5900	$5.7530	$5.8540	$5.7500	$5.4290	$4.0980	$5.4123
10	N ME		Filed COG	$5.5900	$5.7530	$5.8540	$5.7500	$5.4290	$4.0980	$5.4123

Li erty Utilities EnergyNorth Natural Gas Corp.
1 d/ /a Li erty
2 Pea 2021 - 2022 inter 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 Novem er 1 2021 - April 30 2022
7 Residential Heating R3

Line										
8	PROPOSED									inter
9				Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov-Apr
10	average Usage Therms			62	110	123	148	132	92	667
11			8 1 2021 - Current							
12	inter									
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	H Threshold		-							
17										
24	Total ase 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	DAC			$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
30	DAC amount			$ 8.95	$ 15.89	$ 17.76	$ 21.37	$ 19.06	$ 13.29	$ 96.33
31										
32	Total Bill			129.5	217.9	241.90	287.94	258.47	184.81	1 320. 3

33
34 Novem er 1 2020 - April 30 2021
35 Residential Heating R3

Line										
36	CURRENT									inter
37				Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	Nov-Apr
38	average Usage Therms			62	110	123	148	132	92	667
39										
40	inter	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	H Threshold	-	-							
45										
52	Total ase 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	DAC			$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
58	DAC 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	1 .28	128.82	851.20

61
62 DIFFERENCE

Line										
63	Total Bill			40. 7	72.24	91.95	11 .40	92.19	55.99	4 9.43
64	Change			45.75	49.57	1.32	7.8	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			41.0	72.8	92. 2	117.19	92.90	5 .53	473.1
70	Change			118.89	118.89	1 1.45	185.18	13 .51	101.5	139.09

Li erty Utilities EnergyNorth Natural Gas Corp.

Updated Schedule 8
Page 2 of 5

#										
1	d/ /a Li erty									
2	Pea 2021 - 2022 inter Cost of Gas Filing									
3	Annual Bill Comparisons Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-41									
4										
5										
6	Novem er 1 2021 - April 30 2022									
7	Commercial Rate G-41									
8	PROPOSED									inter
9				Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov-Apr
10	average Usage Therms			89	277	504	457	331	297	1,955
11										
12	inter		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	H Threshold		100							
17										
24	Total ase 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	DAC			$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
30	DAC 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	3 437.4
33										
34	Novem er 1 2020 - April 30 2021									
35	Commercial Rate G-41									
36	CURRENT									inter
37				Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	Nov-Apr
38	average Usage Therms			89	277	504	457	331	297	1,955
39										
40	inter	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	H Threshold	100	100							
45										
52	Total ase 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	DAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
58	DAC 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	3 .09	3 2.52	2 144.09
61										
62	DIFFERENCE									
63	Total Bill			53.79	1 8.39	352.48	337.30	215.05	1 .3	1 293.37
64	Change			34.99	51.07	71.28	77.10	58.74	45.89	0.32
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

Li erty Utilities EnergyNorth Natural Gas Corp.

Updated Schedule 8
Page 3 of 5

Row	Description									
1	d/ /a Li erty									
2	Pea 2021 - 2022 inter Cost of Gas Filing									
71	Annual Bill Comparisons Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-42									
72										
73										
74	Novem er 1 2021 - April 30 2022									
75	C I High inter Use Medium G-42									
76	PROPOSED									inter
77				Nov-21	Dec-21	an-22	Fe -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	inter									
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	H Threshold		1,000							
85										
92	Total ase 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	DAC			$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
98	DAC amount			$ 72.88	$ 192.21	$ 325.59	$ 299.07	$ 228.56	$ 210.30	$ 1,328.61
99										
100	Total Bill			1 539.04	3 09. 0	5 89 .92	5 442.17	4 233.01	3 919.80	24 40.53
101										
102	Novem er 1 2020 - April 30 2021									
103	C I High inter Use Medium G-42									
104	CURRENT									inter
105				Nov-20	Dec-20	an-21	Fe -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	inter	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	H Threshold	1,000	1,000							
113										
120	Total ase 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	DAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	0.0555
126	DAC 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 92 . 7	2 540.07	2 57 .41	14 57.15
129										
130	DIFFERENCE									
131	Total Bill			504.19	1 332.53	2 594.84	2 515.50	1 92.93	1 343.39	9 983.38
132	Change			48.72	58.52	78.58	85.95	. 5	52.14	8.11
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

Li erty Utilities EnergyNorth Natural Gas Corp.
1 d/ /a Li erty
2 Pea 2021 - 2022 inter Cost of Gas Filing
139 Annual Bill Comparisons Nov 19 - Apr 20 vs Nov 20 - Apr 21 - Commercial Rate G-52

Updated Schedule 8
Page 4 of 5

140
141
142 Novem er 1 2021 - April 30 2022
143 Commercial Rate G-52

Row										inter
144	PROPOSED									inter
145				Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov-Apr
146	average Usage Therms			1,352	1,866	2,284	2,160	1,886	1,760	11,308
147										
148	inter		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	H Threshold		1,000							
153										
160	Total ase 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	DAC			$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878	$ 0.0878
166	DAC amount			$ 118.72	$ 163.85	$ 200.55	$ 189.66	$ 165.60	$ 154.54	$ 992.92
167										
168	Total Bill			2 120. 3	2 830.93	3 408.57	3 237.21	2 858.57	2 84.45	17 140.34

169
170 Novem er 1 2020 - April 30 2021
171 Commercial Rate G-52

Row										inter
172	CURRENT									inter
173				Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	Nov-Apr
174	average Usage Therms			1,352	1,866	2,284	2,160	1,886	1,760	11,308
175										
176	inter	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	H Threshold	1,000	1,000							
181										
188	Total ase 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	DAC			$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555	$ 0.0555
194	DAC amount			$ 75.04	$ 103.56	$ 126.76	$ 119.88	$ 104.67	$ 97.68	$ 627.59
195										
196	Total Bill			1 313.72	1 71 . 5	1 837.1	1 7.39	1 54.0	1 717.8	9 90 .84

197
198 DIFFERENCE

Row										
199	Total Bill			80 .91	1 114.28	1 571.41	1 5 9.82	1 204.51	9 .59	7 233.51
200	Change			1.42	4.91	85.53	94.15	72.82	5 .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

Li erty Utilities EnergyNorth Natural Gas Corp.
1 d/ /a Li erty
2 Pea 2021 - 2022 inter Cost of Gas Filing

Updated Schedule 8
Page 5 of 5

207	Residential Heating			
208			Winter 2020-21	Winter 2021-22
209	Customer Charge		$ 15.50	$ 15.39
210	irst 100 Therms		$ 0.5678	$ 0.5632
211	Excess 100 Therms		$ 0.5678	$ 0.5632
212	DAC		$ 0.0589	$ 0.1444
213	COG		$ 0.5100	$ 1.1339
214	Total Ad ust		$ 0.5689	$ 1.2783

					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						
222	Cooking alone	5	$21.05	$24.60	$3.55	16.85	$0.00	0	$3.12	13	$0.43	2.03
224		10	$26.71	$33.81	$7.09	26.56	$0.00	0	$6.24	18	$0.86	3.20
226		20	$38.03	$52.22	$14.19	37.30	$0.00	0	$12.48	24	$1.71	4.50
228	Water Heating alone	30	$49.35	$70.64	$21.28	43.12	$0.00	0	$18.72	26	$2.57	5.20
230		45	$66.34	$98.26	$31.92	48.12	$0.00	0	$28.07	29	$3.85	5.80
232		50	$72.00	$107.47	$35.47	49.27	$0.00	0	$31.19	29	$4.28	5.94
234	Heating Alone	80	$100.30	$153.50	$53.20	53.04	$0.00	0	$46.79	30	$6.41	6.39
236		125	$165.96	$260.31	$94.35	56.85	$0.00	0	$82.97	32	$11.37	6.85
238		150	$185.21	$291.62	$106.41	57.45	$0.00	0	$93.58	32	$12.83	6.93
240		200	$241.82	$383.69	$141.88	58.67	$0.00	0	$124.77	33	$17.10	7.07

1 Li erty Utilities EnergyNorth Natural Gas Corp. — Updated Schedule 9
2 d/ /a Li erty — Page 1 of 1
3 Pea 2021 - 2022 inter Cost of Gas Filing
4 ariance Analysis of the Components of the inter 2020-2021 Actual Results vs Proposed inter 2021-2022 Cost of Gas Rate

Line		INTER 2020-2021 ACTUAL RESULTS months actual			INTER 2021-2022 months Proposed		
11	Therm Sales COG	124,069,459			87,443,741		
12–14		THERM SENDOUT	COSTS	E ECT ON COST O GAS	THERM SENDOUT	COSTS	E ECT ON COST O 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 oss		-	-		-	-
25	Total olumes and Cost	91,441,600	$ 37,412,947	$ 0.3015	94,216,591	$ 94,649,750	$ 1.0824
27	Direct Costs						
28	Prior Period alance		$ 2,901,813	$ 0.0234		$ 1,431,639	$ 0.0164
29	Interest		29,768	0.0002		44,085	0.0005
30	Prior Period Ad ustment		-	-		335,667	0.0038
31	roker Revenues		1,528,286	0.0123		3,600	0.0000
32	Refunds from Suppliers		-	-		-	-
33	uel inancing		-	-		-	-
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	PO 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	ad Debt Ad ustment		-	-		652,544	0.0075
45	Cashout, roker penalty, Canadian Managed,		-	-		-	-
46	Total Ad usted Cost		$ 39,074,214	0.3149		$ 99,148,893	1.1339

Li erty Utilities EnergyNorth Natural Gas Corp.

d/ /a Li erty

Pea 2021 - 2022 inter Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
Derivation of Class Assignments and eightings

Updated Schedule 10A
Page 1 of 3

asic assumptions:
1 Residential class pays average seasonal gas cost rate using M A method to allocate costs to seasons
2 Residual gas costs are allocated to C I H and classes based on M A method
3 The M A 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 ase 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	Ad usted Design Day Demand, Dt	Percent of Total		Avg Daily ase Use oad, 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				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. 07		3,719	69,396
14	Total				75,211	82,510	48.083		2,626	79,885
15	H 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 reakdown									
19	Total								2,626	79,885
20	H Total								4,232	11,745
21	Total								6,858	91,630
22										
23	C I reakdown Percentage									
24	Total								38.291	87.182
25	H Total								61.709	12.818
26	Total								100.0	100.0
27										
28					Capacity Cost	MD , 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	MD , Dt	$ Dt-Mo.			
38	Pipeline - aseload				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	MD , Dt	$ Dt-Mo.			
46	Pipeline - ase	ine 38	ine 13 Col C	42. 07	615,228	4,506	$11.3770			
47	Pipeline - Remaining	ine 39	ine 13 Col C	42. 07	6,348,623	46,502	$11.3770			
48	Storage	ine 40	ine 13 Col C	42. 07	1,755,962	11,979	$12.2156			
49	Peaking	ine 41	ine 13 Col C	42. 07	1,754,952	10,127	$14.4412			
50	Total			42. 07	10,474,751	73,114	$11.9388			

Li erty Utilities EnergyNorth Natural Gas Corp.

d/ /a Li erty

Pea 2021 - 2022 inter Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
Derivation of Class Assignments and eightings

51								
52								Ratios for COG
53	C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
54	Pipeline - ase	ine 38 - ine 46			828,730	6,070	$11.3770	
55	Pipeline - Remaining	ine 39 - ine 47			8,551,745	62,640	$11.3769	
56	Storage	ine 40 - ine 48			2,365,348	16,136	$12.2157	
57	Peaking	ine 41 - ine 49			2,364,048	13,642	$14.4410	
58	Total			57.393	14,109,870	98,488	$11.9388	1.0000
59								
60								
61	- C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
62	Pipeline - ase	ine 54	ine 24 Col E		317,329	2,324	$11.3787	
63	Pipeline - Remaining	ine 55	ine 24 Col		7,455,589	54,610	$11.3770	
64	Storage	ine 56	ine 24 Col		2,062,160	14,068	$12.2154	
65	Peaking	ine 57	ine 24 Col		2,061,026	11,893	$14.4415	
66	Total			48.3884	11,896,104	82,895	$11.9590	1.0017
67				38.291	84			ine 66 ine 58
68								
69	H - C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
70	Pipeline - ase	ine 54 - ine 62			511,401	3,746	$11.3766	
71	Pipeline - Remaining	ine 55 - ine 63			1,096,156	8,030	$11.3756	
72	Storage	ine 56 - ine 64			303,188	2,068	$12.2174	
73	Peaking	ine 57 - ine 65			303,022	1,749	$14.4379	
74	Total			9.0047	2,213,767	15,593	$11.8310	0.9910
75								ine 74 ine 58
76								

77	Unit Cost	Residential	C I	H 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	oad Makeup	Residential	LLF C I	HLF C I	
86					
87	Pipeline	69.77	8. 8	75.52	
88	Storage	16.38	1 .97	13.2	
89	Peaking	13.85	14.35	11.22	
90	Total	100.00	100.00	100.00	
91					
92					
93	Supply Makeup	Residential	C I	H 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	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 10A
2	d/ /a Li erty								Page 3 of 3
3	2021 - 2022 inter Cost of Gas Filing								
4	Correction Factor Calculation								
5									
6									
7		d	e	f	g	h	i		
8	Data Source: Schedule 10							Total	
9		Nov	Dec	an	eb	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	ow 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	
24									
25									
26	Total Sales				39,276,150				
27	ow Winter Use				6,603,260				
28	Winter Ratio for ow 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 actor	Total Sales	ow Winter Use x Winter Ratio for		ow Winter Use	High Winter Use x Winter Ratio for High Winter Use			
33	Correction actor				100.0099				
34									
35									
36	Allocation Calculation for Miscellaneous Overhead								
37									
38	Pro ected Winter Sales olume				11 1 21- 4 30 22		91,676,680	Sch.10 , ln 23	
39	Pro ected Annual Sales olume				11 1 21 - 10 31 22		115,042,810	Sch.10 , ln 23	
40	Percentage of Winter Sales to Annual Sales						79.69		

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
4
5
6 Dry Therms

	Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Su total P 21-22	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Su total OP 22	Total
7 Firm Sales															
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 olume	11 723 720	17 742 350	20 7 1 510	17 503 20	14 92 0 0	9 019 420	91 7 80	5 274 850	2 751 830	2 28 170	2 318 030	3 434 190	7 301 0 0	23 3 130	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	33 940	7 828 880	8 811 910	7 357 300	7 024 370	5 224 390	42 583 790	4 28 130	3 488 290	3 399 230	3 558 2 0	3 951 180	5 184 130	23 8 7 220	451 010
35															
36 Total All Sales	18 0 0 0	25 571 230	29 573 420	24 8 0 920	21 950 430	14 243 810	134 2 0 470	9 5 0 980	240 120	5 85 400	5 87 290	7 385 370	12 485 190	47 233 350	181 493 820

#		Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Pea Nov - Apr
1	Li erty Utilities EnergyNorth Natural Gas Corp.							
2	d/ /a Li erty							
3	Pea 2021 - 2022 inter Cost of Gas Filing							
5								Updated Schedule 11A
6								Page 1 of 1
7	olumes Therms	Normal Year						
8								
9	For the Months of May 21 - Octo er 21							
10								
11								
12								
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 - aseload	-	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	NG 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 4	1,814,902	1,924,268	1,927,178	1,746,396	1,892,764	5,448,071	14,753,578
26	Subtotal Pipeline olumes	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	NG apor	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	ess - Gas Refills:							
37	NG 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 olumes	12,149,289	18,516,267	21,514,739	17,827,032	15,332,053	8,877,211	94,216,591
43								

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty
3 Pea 2021 - 2022 inter Cost of Gas Filing
44 Normal and Design Year olumes

Updated Schedule 11B
Page 1 of 1

45
46
47 olumes Therms — Design Year
48
49 For the Months of May 21 - Octo er 21
50

		Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Pea 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 - aseload	-	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	NG 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 4	1,820,806	1,924,268	1,927,178	1,746,396	1,892,764	5,620,543	14,931,954
66	Subtotal Pipeline olumes	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	NG apor	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	ess - Gas Refills:							
77	NG 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 olumes	15,015,933	19,196,663	22,814,130	19,850,092	16,495,460	11,158,474	104,530,752

		Peak Period Normal ear Use Therms	MD MM tu day	Seasonal uantity Therms	Utilization Rate	Peak Period Design ear Use Therms	MD MM tu day	Seasonal uantity Therms	Utilization Rate
1	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 11C
2	d/ /a Li erty								Page 1 of 1
3	Pea 2021 - 2022 inter Cost of Gas Filing								
4	Capacity Utili ation								
5	olumes Therms								
11	Pipeline Gas								
12	Dawn Supply	5,233,331	4,000	7,240,000	72	5,257,245	4,000	7,240,000	73
13	Niagara Supply	4,212,753	3,122	5,650,820	75	4,212,753	3,122	5,650,820	75
14	TGP Supply Gulf 4	32,037,125	21,596	39,088,760	82	32,412,730	21,596	39,088,760	83
15	Dracut Supply 1 2 3	20,704,916	90,000	162,900,000	13	30,503,096	90,000	162,900,000	19
16	NG Truck	747,817	-	-	-	753,030	-	-	-
17	Propane Truck	695,072	-	-	-	695,779	-	-	-
18	PNGTS	1,313,941	1,000	1,810,000	73	1,313,941	1,000	1,810,000	73
19	Portland Natural Gas	6,284,969	5,000	9,050,000	69	6,392,220	5,000	9,050,000	71
20	Constellation apor	4,345,410	7,000	6,300,000	69	4,348,701	7,000	6,300,000	69
23	Subtotal Pipeline olumes	75,575,334				85,889,495			
25	Storage Gas								
26	TGP Storage	19,999,699		25,791,710	78	19,999,699		25,791,710	78
28	Produced Gas								
29	NG apor	1,978,752				1,978,752			
30	Propane	818,023.3				818,023			
32	Subtotal Produced Gas	2,796,775				2,796,775			
34	Less - Gas Refills								
35	NG Truck	747,817				747,817			
36	Propane	695,072				695,072			
37	TGP Storage Refill	2,712,328				2,712,328			
39	Subtotal Refills	4,155,217				4,155,217			
41	Total Sendout olumes	94,216,591				104,530,752			

Li erty Utilities EnergyNorth Natural Gas Corp. — Updated Schedule 11D
d/ /a Li erty — Page 1 of 1
Pea 2021 - 2022 inter Cost of Gas Filing

orecast of Upcoming Winter Period
Design Day Report
2020 2021 Heating Season
Therms

iberty Utilities EnergyNorth Natural Gas Corp.
d b a iberty

Re uirements	
irm Sales	1,283,926
Interruptible Sales	0
irm Transportation	432,092
Interruptible Transportation	0
Total Re uirements	1,716,018
Resources	
Purchased Pipeline Gas	1,197,180
Underground Storage Gas	281,150
Propane Air Production	41,688
NG 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: orecasted irm Transportation volumes are for customers using utility capacity only.

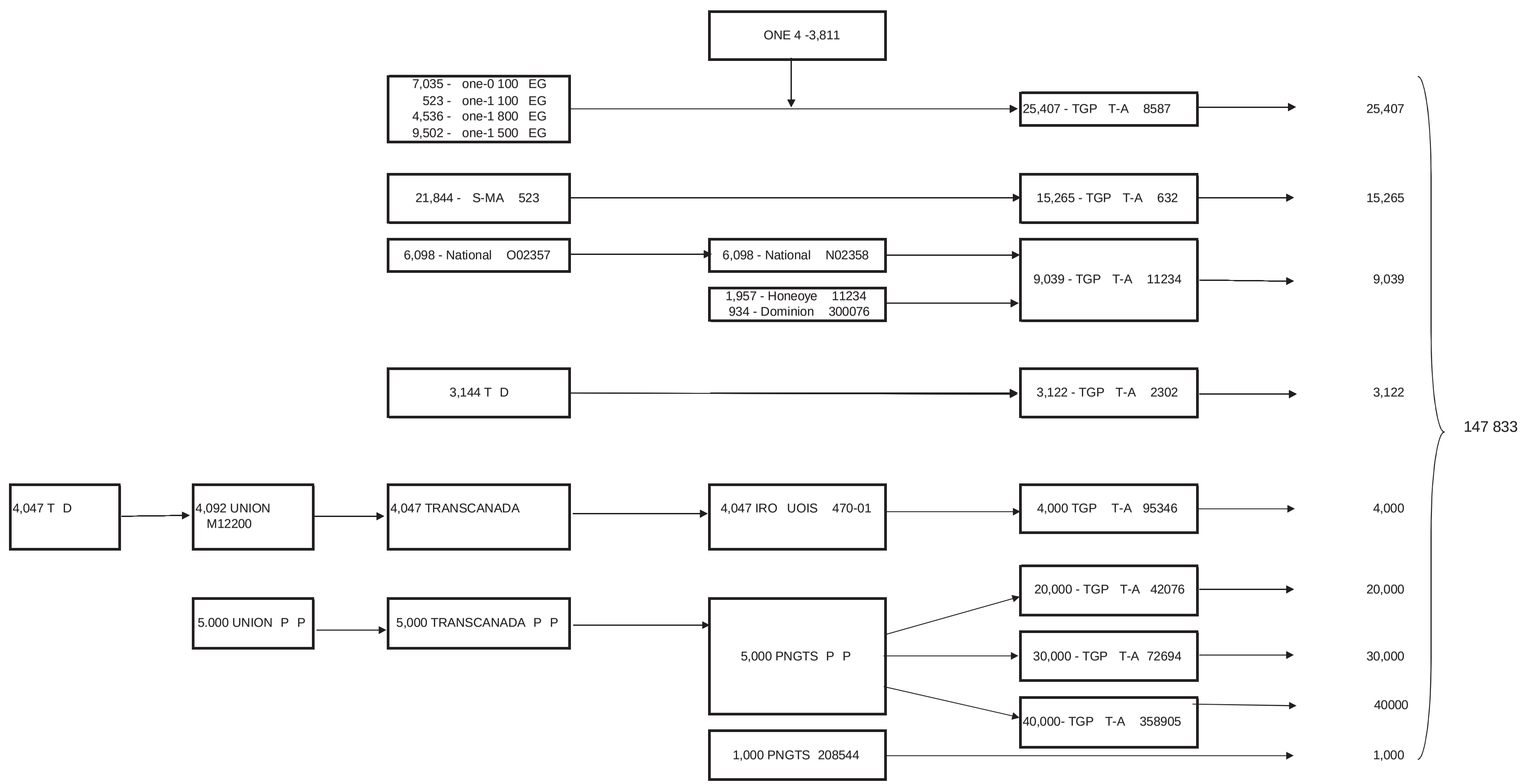
Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
Pea 2021 - 2022 inter Cost of Gas Filing
Transportation Availa le for Pipeline Supply and Storage
MMBtu

Updated Schedule 12
Page 1 of 2



LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
Pea 2021 - 2022 inter Cost of Gas Filing
Transportation Availa le for Pipeline Supply and Storage

Updated Schedule 12
Page 2 of 2

Agreements for Gas Supply and Transportation

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MD MMBTU	MA MMBTU	E PIRATION DATE	NOTIFICATION DATE	RENE AL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N A	Terminates
Constellation	CS		irm Combination i uid and apor Svc	Up to 10 trucks	730,000	3 31 2021 Peak Only	N A	Terminates
Dracut or	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-N	11234	Storage	1,957	245,380	3 31 2022	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	SS	O02358	Storage	6,098	670,800	3 31 2022	3 31 2022	Evergreen Provision
National Fuel Gas Supply Corporation	SST	N02358	Transportation	6,098	670,800	3 31 2022	3 31 2022	Evergreen Provision
Iro uois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11 1 2022	11 1 2021	Evergreen Provision
Portland Natural Gas Transmission System	T	208544	Transportation	1,000	365,000	11 30 2032	11 31 2031	Evergreen Provision
Portland Natural Gas Transmission System	T	P P	Transportation	5,000	1,825,000	10 31 2040	10 31 2039	Precedent Agreement
Tennessee Gas Pipeline Company	S-MA	523	Storage	21,844	1,560,391	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	8587	Transportation	25,407	9,273,555	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	2302	Transportation	3,122	1,139,530	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	632	Transportation	15,265	5,571,725	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	11234	Transportation	9,039	3,299,235	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	72694	Transportation	30,000	10,950,000	10 31 2029	10 31 2028	Evergreen Provision
Tennessee Gas Pipeline Company	TA	95346	Transportation	4,000	1,460,000	11 30 2021	11 30 2021	Evergreen Provision
Tennessee Gas Pipeline Company	TA	42076	Transportation	20,000	7,300,000	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	358905	Transportation	40,000	14,600,000	10 31 2041	10 31 2040	Evergreen Provision
TransCanada Pipeline	T	41232	Transportation	4,047	1,477,155	10 31 2026	10 31 2040	Evergreen Provision
TransCanada Pipeline	T	P P	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	P P	Transportation	5,000	1,825,000	10 31 2040	10 31 2021	Precedent Agreement

MA is calculated on a 365 day calendar year.

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Pea 2021 - 2022 inter Cost of Gas Filing

Load Migration From Sales to Transportation in the C I High and Lo inter Use Classes

uly 2020 - une 2021 Normali ed Sales and Transportation olumes Therms

C I Rate Classes	Annual Sales	of Total y Class	of Sales to Total olume y 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 y Class	of Transportation to Total olume y 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 y 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	

1	Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty				Updated Schedule 14
2	Pea 2021 - 2022 inter Cost of Gas Filing				Page 1 of 1
3					
4	Delivered Costs of inter Supplies to Pipeline Delivered Supplies from the Prior Year				
5					
6					
7		Off-Pea	Pea	Total	
8		May 20 - Oct 20	Nov 20-Apr 21	May 20 - Apr 21	
9		Therms	Therms	Therms	
10	Pipeline Deliveries	18,824,010	84,277,810	103,101,820	
11	All Others	132,500	1,914,540	2,047,040	
12		18,956,510	86,192,350	105,148,860	
13					Ratio
14	Total Winter Supplies				86,192,350
15	Total Pipeline Deliveries				103,101,820
16					
17	Ratio Winter Supplies to Pipeline Supplies				0.836

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty — Updated Schedule 15

Pea 2021 - 2022 inter Cost of Gas Filing — Page 1 of 1

uly and August Consumption of C I High and Lo inter Classes as a Percentage of Their Annual Consumption

C I Sales Normali ed Therms	ul-20	Aug-20	ul - Aug Total	Total Annual	of ul-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

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

Updated Schedule 16
Page 1 of 2

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2 Pea 2021 - 2022 inter Cost of Gas Filing
3
4 Storage Inventory Undergound LPG and LNG including Calculation of Money Pool Interest Costs Associated ith Natural Gas
5
6 Underground Storage Gas

Ln	Description	Reference	May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Total
8			Actual	Actual	Actual	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	Estimate	
9	eginning alance MM tu		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	In ections MM tu	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 Ad ustments		3,346	4,221	4,378	-	-	-	-	-	-	-	-	-	11,945
16															
17	Withdrawals MM tu	Sch 11A ln 29 10	-	-	-	-	-	-	275,298	85,012	550,352	489,051	476,047	124,208	1,999,970
18															
19	Ending alance MM tu		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	eginning alance		$ 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	In ections	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 Ad ustments		$ 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 alance		$ 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 or 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 In ections	Actual or N ME 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	or Informational Purposes								Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	Total
39	Summer Hedge Contracts - ols Dth								-	-	-	-	-	-	-
40	Average Hedge Price								$ -	$ -	$ -	$ -	$ -	$ -	
41	N ME								$ 5.5900	$ 5.7530	$ 5.8540	$ 5.7500	$ 5.4290	$ 4.0980	
42															
43	Hedged olumes at Hedged Price								$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	ess Hedged olumes at N ME								$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Hedge Savings oss								$ -	$ -	$ -	$ -	$ -	$ -	$ -
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 inance 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 inance Charge	ln 47 ln 49				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
52	inancial Expenses					-	-	-	-	-	-	-	-	-	
53	Total Inventory inance Charges					$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
54															
55															
38															

0379

Updated Schedule 16
Page 2 of 2

Ln	Li uid Propane Gas LPG		May-21 Actual	un-21 Actual	ul-21 Actual	Aug-21 Estimate	Sep-21 Estimate	Oct-21 Estimate	Nov-21 Estimate	Dec-21 Estimate	an-22 Estimate	eb-22 Estimate	Mar-22 Estimate	Apr-22 Estimate	Total
44	eginning alance		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	In ections	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	Ad ustment for change in temperature		1,113	192	435	-	-	-	-	-	-	-	-	-	1,356
53	Ad ustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
54	Ending alance		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	eginning alance		$ 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	In ections	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 Ad ust	ln 52 ln 67	11,942	2,060	4,667	-	-	-	-	-	261,807	658,652	-	-	935,008
65	Ending alance		$ 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 or 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 In ections	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 inance 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 inance Charge	ln 72 ln 74				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Ln	Li uid Natural Gas LNG		May-21 Actual	un-21 Actual	ul-21 Actual	Aug-21 Estimate	Sep-21 Estimate	Oct-21 Estimate	Nov-21 Estimate	Dec-21 Estimate	an-22 Estimate	eb-22 Estimate	Mar-22 Estimate	Apr-22 Estimate	Total
81	eginning alance		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	In ections	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 alance		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	eginning alance		$ 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	In ections	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 alance		$ 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 or 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	NG Rate for In ections	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 inance 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 inance Charge	ln 107 ln 109				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
114	Total uel inancing	lns 53 76 111				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty — Updated Schedule 17

Pea 2021 - 2022 inter Cost of Gas Filing — Page 1 of 1

Forecast of Firm Transportation olumes 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
an-22	8,811,910	0.0002	1,436
eb-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		938

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

iberty Utilities EnergyNorth Natural Gas Corp. d b a iberty — Updated Schedule 19

ocal Delivery Ad ustment Charge DAC increase due to Rate Case Expense and Recoupment — RCE

or DAC effective November 1, 2021 - October 31, 2022 — Page 1 of 2

1	Rate Case Exepense	
2	Prior Period Balance	$11,949
3	Expenses thru une 30, 2021	$785,177
4	alance at une 30, 2021	$773,228
5	ess: Accrual alance	$26,000
6	Ad usted 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	eginning alance	$2,078,448
14		
15	Estimated Remaining Expenses	$97,375
16		
17	Plus Estimated Interest from uly 2021 through October 2021	$19,820
18		
19	Minus Estimated Recoveries from uly 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

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	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	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	30	31	31	28	31	31	30	31	31	30	31	30	
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	$ 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	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)	(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	$ 2,090,900	$ 2,175,009	$ 2,179,052	$ 2,181,752	$ 1,967,362	$ 1,660,764	$ 1,304,811	$ 1,005,145	$ 739,995	$ 568,704	$ 453,953	$ 379,192	$ 310,992	$ 240,282	$ 151,201	$ (202)	$ 8,782,201
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	$ 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%	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	$ 2,413	$ 1,810	$ 1,368	$ 1,152	$ 954	$ 738	$ 541	$ 202	26,727
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	$ 742,408	$ 570,514	$ 455,322	$ 380,344	$ 311,946	$ 241,019	$ 151,743	$ (0)	

Li erty Utilities Energy North Natural Gas Corp. d/ /a Li erty Uitilities
Revenue Decoupling Ad ustment Factor RDAF
For LDAC effective Novem er 1 2021 - Octo er 31 2022

Updated Schedule 19
RDAF
Page 1 of 4

	Residential	
1	Residential Pro ected September 1, 2021 Reconciliation alance 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 Ad ustments	$999,001
4	Ad ustments to Residential prior year filings for low income customer treatment	
5	2019 iling total ad ustment is $1,932,224 collected over two years	$966,112
6	2020 iling total ad ustment is $2,092,605 collected over two years	$1,046,302
7	Removal of Ad ustments 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 Pro ected September 1, 2021 Reconciliation alance 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

Li erty Utilities EnergyNorth Natural Gas Corp.
Revenue Decoupling
Ad ustments to Residential prior year filings for lo income customer treatment

2019-2020 Filing

		Filing	Ad usted 1	Difference
	Residential			
1.	Allowed ase Revenue	$ 40,585,321	$ 42,517,544	$ 1,932,224
2.	less: Actual and Estimated ase 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 ase Revenue	$ 31,436,763	$ 31,436,763	$ -
5.	less: Actual and Estimated ase Revenue	34,368,401	34,368,401	-
6.	Revenue Deficiency Excess	2,931,638.28	2,931,638.28	$ -
7.	TOTAL Revenue Deficiency / E cess	7 01 791.21	5 084 5 7.82	1 932 224

2020-2021 Filing

		Filing	Ad usted 1	Difference
	Residential			
8.	Allowed ase Revenue	$ 47,055,148	$ 49,147,752	$ 2,092,605
9.	less: Actual and Estimated ase 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 ase Revenue	$ 36,558,043	$ 36,558,043	$ -
12.	less: Actual and Estimated ase Revenue	38,373,247	38,373,247	-
13.	Revenue Deficiency Excess	1,815,203.44	1,815,203.44	$ -
14.	TOTAL Revenue Deficiency / E cess	4 9 5 94 .79	2 873 342.41	2 092 05

1 The calculations of the ad usted allowed revenue are included in attachment Attachment 2019-2020 RDA Ad ustment and Attachment 2020-2021 RDA Ad ustment

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

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

Updated Schedule 19
Energy Efficiency
Page 1 of 3

Month	Actual or Forecast	Beginning Balance Over /Under	Residential DSM Rate Per Therm	DSM Collections	Forecasted DSM E penditures	Actual DSM E penditures Residential	Actual DSM E penditures Lo -Income	Incentive	Ending Balance Over /Under	Average Balance Over /Under	Interest Monthly Federal Prime Rate	Interest Fed Reserve Ban 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
une 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
uly 21	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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
anuary 22	orecast	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
ebruary 22	orecast	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	orecast	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	orecast	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	orecast	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
une 22	orecast	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
uly 22	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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 Novem er 1 2021 - Octo er 31 2022		
eginning alance	$	733,819
Program udget Nov 2021-Oct 2022		4 932 804
Pro ected Interest		13,794
Pro ected udget with Interest	$	5,652,830
Total Charges		5 52 830
Pro ected Therm Sales		5 49 919
Residential Rate		0.08 1
Total Charges ith Interest		5 52 830
Pro ected Therm Sales		5 49 919
Residential Rate		0.08 1

Residential Non Heating Therm Sales	0	741 340	741 340	0
Residential Heating Therm Sales	35	4 908 579	4 908 579	35
C I Therm Sales	64	117 249 138	117 249 138	64
Total Therms	100	182 899 057	182 899 057	100
		udget	udget	
		2021	2022	
ow-Income Program udget		1 523 570	1 27 400	
Other Refund		-	-	
Total Shared Budget		1 523 570	1 27 400	
Residential Program udget		3 92 32	4 059 085	
Residential Performance Incentive		299 744	312 757	
Total Residential Program Budget		4 22 070	4 371 842	
Commercial Industrial Program udget		3 512 2 0	3 88 433	
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 E penses		1 523 570	1 20 804	
Total Residential including allocation of Shared udget		$ 4,772,941	$ 4,949,386	
Total C I including allocation of Shared udget		4,682,133	5,143,447	
Total Budget		9 455 074	10 092 833	

Total Residential including allocation of Shared udget	$ 4,772,941	$ 4,949,386
Total C I including allocation of Shared udget	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 E penditures	Actual DSM E penditures C I	Actual DSM E penditures Lo -Income	Incentive	Ending Balance Over /Under	Average Balance Over /Under	Interest Fed Reserve Prime Rate	Interest Fed Reserve Ban 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
une 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
uly 21	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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
anuary 22	orecast	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
ebruary 22	orecast	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	orecast	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	orecast	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	orecast	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
une 22	orecast	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
uly 22	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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	orecast	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 Novem er 1 2021 - Octo er 31 2022	
eginning alance	400,298
Program udget Nov 2021-Oct 2022	5 197 419
Pro ected Interest	21,123
Program udget with Interest	4,775,998
Total Charges	4 775 998
Pro ected Therm Sales	117 179 952
C I Rate	$0.0408
Total Charges with Interest	4 780 942
Pro ected 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

Updated Schedule 19
Energy Efficiency
Page 3 of 3

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	C I	Low-Income	Total	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
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

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Gas Assistance Program

1	Distri ution	Customer Charge		Bloc		Total		
2	R-3 ase Rates	$	15.39	$	0.5632			
3	R-4 ase 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		eene		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 n 5 n 14	$	303.68	$	343.21	$	646.89	
17								
18	Winter Distribution Subsidy times Number of Participants n 7 n 9					$	1,023,450	
19	Winter COG Subsidy times Number of Participants n 9 n 16					$	1,617,433	
20	Prior ear Ending alance - 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						0.015	

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

Li erty Utilities EnergyNorth Natural Gas Corp d/ /a Li erty
uarterly Report
Gas Assistance Program GAP
2020-21 Discounted 45

2333

	Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Summary: Actual/ Pro ected Total To Date 1	Summary: Original Pro ection 2	Summary: ariance
Customer Count	Actual	Actual	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected	Pro ected			
Actual Pro ected No. of Customers													Average		
IHEAP	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- IHEAP	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 Pro ected															
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
Ad ustment	$1,735	$190	$0	$0	$0	$0	$0	$0	$0	$0	$0		$1,925	$0	
Total Ad usted 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 Pro ected 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 alance 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
ixed 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
ariable 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 pro ected data for the remaining months in the 12-month program year.
2 GAP Pro ection on ates 127 of the 2020-21 Cost of Gas iling, 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 ear 2019-20 under over ending balance.

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Re uired Annual Environmental Increase	$2,351,805	
Second one-third of prior period under recoveries through une 2019	$341,389	
uly 2020 - une 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.

Concord Pond: 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 *ra r o r ort at t o or t ar o p t*

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

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]		313,043.04
2	Concord MGP	DEF077	2,734.00	84,993.95	0.00	0.00	340,224.44	427,952.39			383,711.57
3	Laconia/Liberty Hill	DEF086	0.00	12,243.50	0.00	0.00	2,657.60	14,901.10			14,901.10
4	Manchester MGP	DEF057	0.00	32,277.20	0.00	0.00	12,198.45	44,475.65			5,080.33
5	Nashua MGP	DEF054	0.00	95,857.14	0.00	0.00	1,006.70	96,863.84			61,016.23
6	General Expenses	DEF064	0.00	0.00	0.00	0.00	5,645.56	5,645.56			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**

THIS PAGE HAS BEEN REDACTED

LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
MANUFACTURED GAS PLANT EN IRONMENTAL COSTS
NASHUA - REMEDIATION
PRO ECT DEF054

REDACTED
Schedule 20.2
Page 2 of 7

LINE NO.	ENDOR	REF NO.	1101 LEGAL E PENSES	1102 CONSULTING E PENSES	1105 REMEDIATION E PENSES	110 SETTLEMENT E PENSES	1107 OTHER E PENSES	SUBTOTAL E PENSES	1108 INSURANCE THIRD PARTY E PENSE	1109 INSURANCE THIRD PARTY RECO ERIES	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]										

THIS PAGE HAS BEEN REDACTED

LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
MANUFACTURED GAS PLANT EN IRONMENTAL COSTS
CONCORD POND - REMEDIATION
PRO ECT DEF05

REDACTED
Schedule 20.2
Page 3 of 7

			1101	1102.00	1105	110	1107		1108	1109	
LINE NO.	ENDOR	REF NO.	LEGAL E PENSES	CONSULTING E PENSES	REMEDIATION E PENSES	SETTLEMENT E PENSES	OTHER E PENSES	SUBTOTAL E PENSES	INSURANCE THIRD PARTY E PENSES	INSURANCE THIRD PARTY RECO ERIES	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]										

THIS PAGE HAS BEEN REDACTED

LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
MANUFACTURED GAS PLANT EN IRONMENTAL COSTS
MANCHESTER - REMEDIATION
PRO ECT DEF057

REDACTED
Schedule 20.2
Page 4 of 7

			1101	1102	1105	110	1107		1108	1109	
LINE NO.	ENDOR	REF NO.	LEGAL E PENSES	CONSULTING E PENSES	REMEDIATION E PENSES	SETTLEMENT E PENSES	OTHER E PENSES	SUBTOTAL E PENSES	INSURANCE THIRD PARTY E PENSE	INSURANCE THIRD PARTY RECO ERIES	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]										

THIS PAGE HAS BEEN REDACTED

LIBERTY UTILITIES ENERGYNORTH NATURAL GAS CORP.
MANUFACTURED GAS PLANT EN IRONMENTAL COSTS
GENERAL E PENSES
PRO ECT DEF0 4

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 EN IRONMENTAL COSTS
CONCORD MGP - REMEDIATION
PRO ECT DEF077

REDACTED
Schedule 20.2
Page 6 of 7

LINE NO.	ENDOR	REF NO.	1101 LEGAL E PENSES	1102 CONSULTING E PENSES	1105 REMEDIATION E PENSES	110 SETTLEMENT E PENSES	1107 OTHER E PENSES	SUBTOTAL E PENSES	1108 INSURANCE THIRD PARTY E PENSE	1109 INSURANCE THIRD PARTY RECO ERIES	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]										

THIS PAGE HAS BEEN REDACTED

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

Schedule 20.2
Page 7 of 7

LINE NO.	ENDOR	REF NO.	1101 LEGAL E PENSES	1102 CONSULTING E PENSES	1105 REMEDIATION E PENSES	110 SETTLEMENT E PENSES	1107 OTHER E PENSES	SUB-TOTAL E PENSES	1108 INSURANCE THIRD PARTY E PENSES	1109 INSURANCE THIRD PARTY RECO ERIES	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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

Schedule 20.3
Page 1 of 9

Li erty 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	DEF05 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	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- 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 une 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 ase Rate Rev	0				- , 23											- , 23
29	Act Nov 2010-Oct 2011 ase Rate Rev	0				-32,310											-32,310
30	Act Nov 2011-Oct 2012 ase Rate Rev	0				-28, 8											-28, 8
31	Act Nov 2012-Oct 2013 ase Rate Rev	0				-2,1 3	-2,1 3										- ,286
32	Act Nov 2013-Oct 201 ase Rate Rev	0															0
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	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	Re uired annual increase in rates:																
53	smal er of D or	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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

REDACTED
Schedule 20.3
Page 2 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

Laconia Li erty Hill

		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	i.o. no. 500005 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	DEF08 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	Subtotal - net recoveries	11,6 3	21,729	0	0	0	0	0									33,372
10																	
11	A- 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 une 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 ase Rate Rev	0				- ,296											- ,296
29	Act Nov 2010-Oct 2011 ase Rate Rev	0				-31,38											-31,38
30	Act Nov 2011-Oct 2012 ase Rate Rev	0				-27,632											-27,632
31	Act Nov 2012-Oct 2013 ase Rate Rev	0				0	-1 ,208										-1 ,208
32	Act Nov 2013-Oct 201 ase Rate Rev	0					-28, 33	-28, 33	28,433								-85,298
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	amortization		0	0	0	0	0	0									1,588,357
51																	
52	Re uired annual increase in rates:																
53	smal er of D or	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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

Schedule 20.3
Page 3 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

		Manchester														DEF057	
		9 00 - 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	7 15 - 6 16	7 16 - 6 17	7 17 - 6 18	7 18 - 6 19	7 19 - 6 20	7 20 - 6 21	
		ool 1 - 7	ool 8	ool 9	ool 10	ool 11	ool 12	ool 13	ool 1	ool 15	ool 16	ool 17	ool 18	ool 19	ool 20	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	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- 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 une 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 ase Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 ase Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 ase Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 ase Rate Rev	0				0	-23,337										-23,337
32	Act Nov 2013-Oct 201 ase Rate Rev	0															0
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	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	Re uired annual increase in rates:																
53	smal er of D or	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.

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

Filed under the follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

Schedule 20.3
Page 4 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

		Nashua														DEF054	
							Corrected per 2 08 Audit										
		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
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	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- 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 une 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 ase Rate Rev	0				0											0
29	Act Nov 2010-Oct 2011 ase Rate Rev	0				0											0
30	Act Nov 2011-Oct 2012 ase Rate Rev	0				0											0
31	Act Nov 2012-Oct 2013 ase Rate Rev	0				0	-20,916										-20,916
32	Act Nov 2013-Oct 201 ase Rate Rev	0															0
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	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	Re uired annual increase in rates:																
53	smal er of D or	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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

Schedule 20.3
Page 5 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

		Dover												
													DEF059	
		9 02 - 9 03 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 1 ool 11	7 1 - 6 15 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	Subtotal - net recoveries	0	0	0	0	0	0	0	0	0	0	0	0	0
10														
11	A- 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 une 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 ase Rate Rev													0
29	Act Nov 2010-Oct 2011 ase Rate Rev													0
30	Act Nov 2011-Oct 2012 ase Rate Rev													0
31	Act Nov 2012-Oct 2013 ase Rate Rev													0
32	Act Nov 2013-Oct 201 ase Rate Rev													0
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	amortization	0	0	0	0	0	0	0	0	0	0	0	0	
51														
52	Re uired annual increase in rates:													
53	smal er of D or	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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31   dated Octo er 11 1999 in Doc et No. DG 99 132

REDACTED
Schedule 20.3
Page 6 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation   MGPs
Tariff page 99

		eene												
													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	Subtotal - net recoveries	0	0	18,831	823	0	0	0	0	0	0			
10														
11	A- 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 une 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 ase Rate Rev													-
29	Act Nov 2010-Oct 2011 ase Rate Rev													-
30	Act Nov 2011-Oct 2012 ase Rate Rev													-
31	Act Nov 2012-Oct 2013 ase Rate Rev													-
32	Act Nov 2013-Oct 201 ase Rate Rev													-
33	Act Nov 201 -Oct 2015 ase 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- C	10,165	16,771	56,622	66,211	66,2	269	0	0	88	1, 00	[redacted]		
3														
	E Allocat on of it 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	amortization	0	0	0	0	0	0	0	0	0	0			
51														
52	Re uired annual increase in rates:													
53	smal er of D or	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]		

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

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

Filed under the follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

REDACTED
Schedule 20.3
Page 7 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

		Concord														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	Corrected per 2 08 Audit 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	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- 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 une 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 ase Rate Rev	0				-1,891											1,891
29	Act Nov 2010-Oct 2011 ase Rate Rev	0				-13,816											13,816
30	Act Nov 2011-Oct 2012 ase Rate Rev	0				-12,16											12,164
31	Act Nov 2012-Oct 2013 ase Rate Rev	0				-6,79	-6,79										13,588
32	Act Nov 2013-Oct 201 ase Rate Rev	0															-
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	amortization	0	0	0	0	0	0	0	0	23,398	13,650						
51																	
52	Re uired annual increase in rates:																
53	smal er of D or	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]					

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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

REDACTED
Schedule 20.3
Page 8 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

		General														DEF0 4		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	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- 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 une 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 ase Rate Rev																0	10,611
29	Act Nov 2010-Oct 2011 ase Rate Rev																0	77,509
30	Act Nov 2011-Oct 2012 ase Rate Rev																0	68,244
31	Act Nov 2012-Oct 2013 ase Rate Rev																0	76,335
32	Act Nov 2013-Oct 201 ase Rate Rev																0	85,298
33	Act Nov 201 -Oct 2015 ase 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- 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 it 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	amortization	0	0	0	0	0	0	0	0	-1,091	1,697	935	1 5 3	981	1,016	807		
51																		
52	Re uired annual increase in rates:																	
53	smal er of D or	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

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 follo ing protective orders
Order No. 22 853 dated Fe ruary 18 1998 in Doc et No. DR 97 130
Order No. 23 31 dated Octo er 11 1999 in Doc et No. DG 99 132

REDACTED
Schedule 20.3
Page 9 of 9

Li erty Utilities EnergyNorth Natural Gas Corp.
Environmental Remediation MGPs
Tariff page 99

E pense 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	[redacted]
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	[redacted]
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	[redacted]
6	Cash recover es i.o. 50000	- 5,985	0	0	0	0	0	0	0	0	0	0	0	0	0	[redacted]
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	[redacted]
8	Transfer Credit from Gas Restructuring	0	-3 331	0	0	0	0	0	0	0	0	0	0	0	0	[redacted]
9	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	[redacted]
10																[redacted]
11	A- 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	[redacted]
12																
13																
1	Surcharge revenue:															
15	Act une 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 ase 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 ase 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 ase 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 ase 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 ase 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 ase 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- 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 it gated Recovery

5
6 Surcharge calculation
7 Unrecovered costs D E
8 remaining life
9 one year
50 amortization
51
52 Re uired annual increase in rates:
53 smal er of D or
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.

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Calculation of Supplier Balancing Charge
2020-2021

Rate 0.1807 /MMBtu

	Rate	olume		Total	
In ection Cost	$ 0.0087	38 014	$	3,358	
uel 1.75	$ 0.0481	38 014	$	18,577	
Withdrawal Cost	$ 0.0087	195 7 8	$	1,703	
Delivery Rate	$ 0.0431	195,768	$	8,432	
TA Demand Charge	$ 0.2357	195,768	$	46,138	
TA Commodity Charge	$ 0.1003	195,768	$	19,636	
uel 1.35	$ 0.0371	195,768	$	7,268	
		Total Cost	$	105,112	
Absolute alue of the Sendout Error				581 782	MM tu
		Rate	$	0.1807	MM TU

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

TGP	SMA In ection Charge	$	0.0087	MM tu
TGP	SMA Withdrawal Charge	$	0.0087	MM tu
TGP	SMA Deliverability Charge	$	1.3094	MM tu per month
		$	0.0431	MM tu per day
TGP	4-6 Demand Charge	$	7.1645	MM tu per month
		$	0.2357	MM tu per day
TGP	4-6 Commodity Charge	$	0.1003	MM tu

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Calculation of Supplier Balancing Charge
2020-2021

Estimated Monthly Im alances

Date	Forecasted DD	Actual DD	Forecaster Error DD	Forecasted Sendout MMBtu	Actual Sendout MMBtu	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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
an	1,122	1,118	4	2,564,525	2,556,052	8,473	84,733	46,603	38,130
eb	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
un	32	21	11	221,781	216,450	5,330	7,269	6,300	969
ul	-	-	-	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	17	14 714 420	14 524 173	190 24	581 782	38 014	195 7 8

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
Calculation of Supplier Balancing Charge
2021-2022

Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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
un 1, 2020	10	10	0	16305.53853	16305.53853	0	0	0	0
un 2, 2020	3	2	1	12913.42533	12428.83773	484.5875993	484.5875993	484.5875993	0
un 3, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 4, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 5, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0

Li erty Utilities EnergyNorth Natural Gas Corp.
Calculation of Supplier Balancing Charge
2019-2020
Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als MMBtu
un 6, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 7, 2020	5	2	3	13882.60053	12428.83773	1453.762798	1453.762798	1453.762798	0
un 8, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 9, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 10, 2020	0	1	-1	11459.66253	11944.25013	-484.587599	484.5875993	0	484.5875993
un 11, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 12, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 13, 2020	3	4	-1	12913.42533	13398.01293	-484.587599	484.5875993	0	484.5875993
un 14, 2020	6	2	4	14367.18813	12428.83773	1938.350397	1938.350397	1938.350397	0
un 15, 2020	3	0	3	12913.42533	11459.66253	1453.762798	1453.762798	1453.762798	0
un 16, 2020	2	0	2	12428.83773	11459.66253	969.1751986	969.1751986	969.1751986	0
un 17, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 18, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 19, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 20, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 21, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 22, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 23, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 24, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 25, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 26, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 27, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 28, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 29, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
un 30, 2020	0	0	0	11459.66253	11459.66253	0	0	0	0
ul 1, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 2, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 3, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 4, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 5, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 6, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 7, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 8, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 9, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 10, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 11, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 12, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 13, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 14, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 15, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 16, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 17, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 18, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 19, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 20, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 21, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 22, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 23, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 24, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 25, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 26, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 27, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 28, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 29, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 30, 2020	0	0	0	9828.682335	9828.682335	0	0	0	0
ul 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

Li erty Utilities EnergyNorth Natural Gas Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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

Li erty Utilities EnergyNorth Natural Gas Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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

Li erty Utilities EnergyNorth Natural Gas Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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
an 1, 2021	30	31	-1	69606.61887	71724.95338	-2118.3345	2118.334502	0	2118.334502
an 2, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
an 3, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
an 4, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
an 5, 2021	33	33	0	75961.62238	75961.62238	0	0	0	0
an 6, 2021	33	34	-1	75961.62238	78079.95688	-2118.3345	2118.334502	0	2118.334502
an 7, 2021	35	35	0	80198.29138	80198.29138	0	0	0	0
an 8, 2021	36	36	0	82316.62588	82316.62588	0	0	0	0
an 9, 2021	37	35	2	84434.96038	80198.29138	4236.669003	4236.669003	4236.669003	0
an 10, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
an 11, 2021	35	36	-1	80198.29138	82316.62588	-2118.3345	2118.334502	0	2118.334502
an 12, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
an 13, 2021	33	31	2	75961.62238	71724.95338	4236.669003	4236.669003	4236.669003	0
an 14, 2021	32	31	1	73843.28788	71724.95338	2118.334502	2118.334502	2118.334502	0
an 15, 2021	28	26	2	65369.94987	61133.28087	4236.669003	4236.669003	4236.669003	0
an 16, 2021	27	24	3	63251.61537	56896.61186	6355.003505	6355.003505	6355.003505	0
an 17, 2021	29	25	4	67488.28437	59014.94637	8473.338006	8473.338006	8473.338006	0
an 18, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
an 19, 2021	33	32	1	75961.62238	73843.28788	2118.334502	2118.334502	2118.334502	0
an 20, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
an 21, 2021	36	38	-2	82316.62588	86553.29489	-4236.669	4236.669003	0	4236.669003
an 22, 2021	34	33	1	78079.95688	75961.62238	2118.334502	2118.334502	2118.334502	0
an 23, 2021	46	46	0	103499.9709	103499.9709	0	0	0	0
an 24, 2021	43	43	0	97144.96739	97144.96739	0	0	0	0
an 25, 2021	38	39	-1	86553.29489	88671.62939	-2118.3345	2118.334502	0	2118.334502
an 26, 2021	34	36	-2	78079.95688	82316.62588	-4236.669	4236.669003	0	4236.669003
an 27, 2021	34	32	2	78079.95688	73843.28788	4236.669003	4236.669003	4236.669003	0
an 28, 2021	47	47	0	105618.3054	105618.3054	0	0	0	0
an 29, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
an 30, 2021	51	53	-2	114091.6434	118328.3124	-4236.669	4236.669003	0	4236.669003
an 31, 2021	46	48	-2	103499.9709	107736.6399	-4236.669	4236.669003	0	4236.669003
eb 1, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
eb 2, 2021	36	33	3	83276.32165	78176.98524	5099.336415	5099.336415	5099.336415	0
eb 3, 2021	35	32	3	81576.54285	76477.20643	5099.336415	5099.336415	5099.336415	0
eb 4, 2021	37	39	-2	84976.10046	88375.65807	-3399.55761	3399.55761	0	3399.55761
eb 5, 2021	32	36	-4	76477.20643	83276.32165	-6799.11522	6799.11522	0	6799.11522
eb 6, 2021	39	37	2	88375.65807	84976.10046	3399.55761	3399.55761	3399.55761	0
eb 7, 2021	37	40	-3	84976.10046	90075.43687	-5099.33642	5099.336415	0	5099.336415
eb 8, 2021	46	45	1	100274.1097	98574.3309	1699.778805	1699.778805	1699.778805	0
eb 9, 2021	45	45	0	98574.3309	98574.3309	0	0	0	0
eb 10, 2021	43	43	0	95174.77329	95174.77329	0	0	0	0
eb 11, 2021	49	47	2	105373.4461	101973.8885	3399.55761	3399.55761	3399.55761	0
eb 12, 2021	49	46	3	105373.4461	100274.1097	5099.336415	5099.336415	5099.336415	0
eb 13, 2021	42	38	4	93474.99448	86675.87926	6799.11522	6799.11522	6799.11522	0
eb 14, 2021	38	36	2	86675.87926	83276.32165	3399.55761	3399.55761	3399.55761	0
eb 15, 2021	35	35	0	81576.54285	81576.54285	0	0	0	0
eb 16, 2021	36	35	1	83276.32165	81576.54285	1699.778805	1699.778805	1699.778805	0
eb 17, 2021	43	41	2	95174.77329	91775.21568	3399.55761	3399.55761	3399.55761	0
eb 18, 2021	38	39	-1	86675.87926	88375.65807	-1699.77881	1699.778805	0	1699.778805
eb 19, 2021	38	38	0	86675.87926	86675.87926	0	0	0	0
eb 20, 2021	40	41	-1	90075.43687	91775.21568	-1699.77881	1699.778805	0	1699.778805
eb 21, 2021	42	42	0	93474.99448	93474.99448	0	0	0	0
eb 22, 2021	33	31	2	78176.98524	74777.42763	3399.55761	3399.55761	3399.55761	0
eb 23, 2021	27	26	1	67978.31241	66278.5336	1699.778805	1699.778805	1699.778805	0
eb 24, 2021	25	20	5	64578.7548	56079.86077	8498.894025	8498.894025	8498.894025	0
eb 25, 2021	37	32	5	84976.10046	76477.20643	8498.894025	8498.894025	8498.894025	0
eb 26, 2021	35	33	2	81576.54285	78176.98524	3399.55761	3399.55761	3399.55761	0
eb 27, 2021	29	30	-1	71377.87002	73077.64882	-1699.77881	1699.778805	0	1699.778805
eb 28, 2021	26	26	0	66278.5336	66278.5336	0	0	0	0

Li erty Utilities EnergyNorth Natural Gas Corp.
Calculation of Supplier Balancing Charge
2019-2020

Estimated Daily Im alances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error MMBtu	A s. alue Sendout Error MMBtu	In ections MMBtu	ithdra als 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
un	32	21	11	359297	353966	5330	7269	6300	969
ul	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
an	1122	1118	4	2564525	2556052	8473	84733	46603	38130
eb	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

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Doc et DE 98-124 Gas Restructuring
Pea ing 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 (5- 6) 2302	3,122		
7		TGP FT-A (0- 6) 8587	7,035		
8		TGP FT-A (1- 6) 8587	14,561		
9		TGP FT-A (6- 6) 42076	20,000		
		TGP FT-A (6- 6) 358905	40,000		
		TGP FT-A (6- 6) 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 (4- 6) 632	15,265	Dekatherm	
14		TGP FT-A (4- 6) 8587	3,811		
15		TGP FT-A (4- 6) 11234	7,082		
16		TGP FT-A (5- 6) 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 Pea ing MD		54.72	/De atherm	Line 29 divided by 6 month

Li erty Utilities EnergyNorth Natural Gas Corp.

Tennessee Allocations

Resource Type	High Load Factor	Lo 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 Novem er 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									
	TCP Union	FT to Parkway & IGTS	M12200 & 41232	4,000		$13.6260		10/31/2026	
	Iro uois	RTS to Wright	470-01	4,047		$5.2357		11/1/2022	
	TGP	NET-NE (5- 6)	95346	4,000		$6.2957		11/30/2022	
	TGP	FT-A (5- 6)	2302	3,122		$6.2957		10/31/2025	
	TGP	FT-A (0- 6)	8587	7,035		$20.3736		10/31/2025	
	TGP	FT-A (1- 6)	8587	14,561		$18.0875		10/31/2025	
	TCP 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 (6- 6)	42076	20,000		$4.1818		10/31/2025	
	TGP	FT-A (6- 6)	358905	40,000		$4.1818		10/31/2041	
	TGP	FT-A (6- 6)	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 (4- 6)	632	15,265		$7.1645		10/31/2025	
	TGP	FT-A (4- 6)	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 (4- 6)	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	
	TGP	FT-A (5- 6)	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 (4- 6)	11234	932		$7.1645		10/31/2025	
Pea ing									
	Energy North	NG Propane		23,769	-	$54.7200	$0.0000		

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 ill e released at ma imum tariff rates. A ove rates are ma imum tariff rates effective 11/01/21. Because rates can change please refer to the applica le pipeline tariff for current rates.

A ove capacity is for all customers in the EnergyNorth Service territory ith the e ception of Berlin NH. Any customers ehind the Berlin citygate ill e allocated 100 PNGTS capacity at a demand rate of 18.2 33 /dth.

ENERGYNORTH NATURAL GAS INC.

Doc et 98-124 Gas Restructuring
Pea ing Demand Rate
Pea ing Costs

	olume	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 - 2

Capacity ssi nment able

			ipeline	o ea ay Re irement tora e	ea in	otal
G	L	o Ann a l - igh inter se	46.1	17.1	36.8	100.0
G	L L	o Ann a l - o inter se	59.3	12.9	27.9	100.0
G		Medi m l - igh inter se	46.1	17.1	36.8	100.0
G	L	Medi m l - o inter se	59.3	12.9	27.9	100.0
G		igh Ann a l - igh inter se	46.1	17.1	36.8	100.0
G	L	igh Ann a l - 90	59.3	12.9	27.9	100.0
G	L G	igh Ann a l - 90	59.3	12.9	27.9	100.0

L	igh oad actor	59.25	12.89	27.85	100
LL	o oad actor	46.09	17.06	36.85	100
	Tota	47.29	16.68	36.03	100

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

Schedule 22
Page 2 of 6

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE - 2

llocation o ea ay

esi n ay ro p t llocate to Rate Classes

esi n		ase loa	eat loa	otal
L	R RN	102	457	558
LL	R R	3 545	69 811	73 356
LL	G L	770	30 823	31 593
L	G	739	1 812	2 551
LL	G L	1 473	37 931	39 404
L	G	1 781	3 820	5 601
LL	G LL	663	8 239	8 901
L	G LLL	1 146	2 222	3 368
L	G LLG	461	2 780	3 241
	L	10 678	157 896	168 574

L	4 227	11 092	15 319
LL	6 450	146 804	153 255
otal	10 678	157 896	168 574

llocate Class esi n ay ro p t to pply o rces

	ase ipeline	Remainin ipeline	b total ipeline	tora e	ea in	otal
R RN	102	200	301	81	175.73	558
R R	3 545	30 525	34 070	12 431	26 856	73 356
G L	770	13 477	14 247	5 488	11 857	31 593
G	739	792	1 531	323	697	2 551
G L	1 473	16 585	18 058	6 754	14 592	39 404
G	1 781	1 670	3 451	680	1 470	5 601
G LL	663	3 602	4 265	1 467	3 169	8 901
G LLL	1 146	972	2 117	396	855	3 368
G LLG	461	1 216	1 676	495	1 070	3 241
L	10 678	69 040	79 718	28 115	60 741	168 574

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

o ea ay Re irement

	ipeline	tora e	ea in	otal
R RN	54.0	14.6	31.5	100.0
R R	46.4	16.9	36.6	100.0
G L	45.1	17.4	37.5	100.0
G	60.0	12.6	27.3	100.0
G L	45.8	17.1	37.0	100.0
G	61.6	12.1	26.2	100.0
G LL	47.9	16.5	35.6	100.0
G LLL	62.9	11.7	25.4	100.0
G LLG	51.7	15.3	33.0	100.0
L	47.3	16.7	36.0	100.0

i Loa actor	59.25	12.89	27.85	100
Lo Loa actor	46.09	17.06	36.85	100
otal	47.29	16.68	36.03	100

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE - 2

A ocate Design Da Sendo t

Calc late esi n ay ro p t

esi n

	aily aseloa	eatin actor	eat loa eatin actor esi n	otal
R RN	102	6.01	430	532
R R	3 545	918.47	65 711	69 256
G L	770	405.52	29 013	29 783
G	739	23.84	1 706	2 445
G L	1 473	499.04	35 703	37 176
G	1 781	50.26	3 596	5 376
G LL	663	108.39	7 755	8 418
G LLL	1 146	29.24	2 092	3 238
G LLG	461	36.58	2 617	3 078
L	10 678	1 939.15	148 622	159 300

L	4 227	146	10 440	14 668
LL	6 450	1 793	138 182	144 632
otal	10 678	1 939	148 622	159 300

esi n ay rom C G			
esi n ay rom Gas Loa Calc lation			159 300
ariance			9 274

aseloa as o otal Class Loa	eat Loa as o otal
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

llocate esi n ay en o t to Rate Classes

ase Loa	eat Loa	otal
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 - 2

Schedule 22
Page 4 of 6

CALCULA I N F N RMAL ALE LUME

Actual olumes

otal Core ales olumes(s) MMB U

		Nov-	Dec-	an-2	Feb-2	Mar-2	Apr-2	May-	un-	ul-	Aug-	ep-	ct-	otal	Monthly Baseload (ul Aug)/2	Daily Baseload
LF	R- RN	7	9	9	8	8	6	5	4	3	3	4	5	70	3.149	0.102
LLF	R- R	731	957	994	889	717	509	274	143	111	110	142	327	5,904	109.892	3.545
LLF	G- L	285	394	409	364	274	188	88	36	24	24	36	106	2,228	23.872	0.770
LF	G-	36	43	43	40	34	30	30	25	23	25	25	29	383	22.908	0.739
LLF	G- 2 ML	394	516	531	474	375	262	142	64	46	48	71	175	3,100	45.648	1.473
LF	G- 2 M	91	103	106	98	79	71	67	56	55	58	60	73	917	55.198	1.781
LLF	G- LL	98	127	130	121	102	70	45	25	21	22	27	49	836	20.550	0.663
LF	G- LLL	50	56	61	59	53	44	46	39	38	40	36	48	571	35.515	1.146
LF	G- LLL	20	26	27	25	20	18	18	14	16	16	15	18	233	14.280	0.461
LF	G- LLG															
	AL	1,713	2,229	2,311	2,080	1,662	1,198	714	406	337	346	416	829	14,242	341.449	11.014
	LF	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 uly and August volumes)

		Nov-	Dec-	an-2	Feb-2 2	Mar-2	Apr-2	May-	un-	ul-	Aug-	ep-	ct-	otal
LF	R- RN	3	3	3	3	3	3	3	3	3	3	3	3	37
LLF	R- R	106	110	110	103	110	106	110	106	111	110	106	110	1,297
LLF	G- L	23	24	24	22	24	23	24	23	24	24	23	24	282
LF	G-	22	23	23	21	23	22	23	22	23	25	22	23	270
LLF	G- 2 ML	44	46	46	43	46	44	46	44	46	48	44	46	539
LF	G- 2 M	53	55	55	52	55	53	55	53	55	58	53	55	652
LLF	G- LL	20	21	21	19	21	20	21	20	21	22	20	21	243
LF	G- LLL	34	36	36	33	36	34	36	34	38	40	34	36	419
LF	G- LLL	14	14	14	13	14	14	14	14	16	16	14	14	169
LF	G- LLG	0	0	0	0	0	0	0	0	0	0	0	0	0
	AL	320	331	331	310	331	320	331	320	337	346	320	331	3,908
	LF	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
Docket No DE - 2

Schedule 22
Page 5 of 6

eating olumes (Actual olumes - Baseload)

		Nov-	Dec-	an-2	Feb-2	Mar-2	Apr-2	May-	un-	ul-	Aug-	ep-	ct-	otal
LF	R- RN	4	5	6	5	5	3	2	1	0	0	0	2	32
LLF	R- R	625	848	884	786	607	403	164	37	0	0	35	217	4,607
LLF	G- L	262	370	386	342	250	165	64	13	0	0	13	82	1,946
LF	G-	14	20	20	19	11	8	7	2	0	0	3	6	112
LLF	G- 2 ML	350	470	485	432	329	218	97	20	0	0	27	129	2,561
LF	G- 2 M	38	48	50	46	24	17	12	3	0	0	7	18	265
LLF	G- LL	78	106	110	102	81	50	24	5	0	0	7	29	593
LF	G- LLL	15	20	26	26	18	10	11	5	0	0	1	13	152
LF	G- LLL	6	11	13	12	6	4	4	0	0	0	2	3	65
LF	G- LLG	0	0	0	0	0	0	0	0	0	0	0	0	0
	AL	1,393	1,898	1,980	1,771	1,331	878	383	86	0	0	95	498	10,333

LF	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	.	.	2 .	.	2 .	.	2 .	.	.	.	.	.	5823.0

eat Factors

		Nov-	Dec-	an-2	Feb-2	Mar-2	Apr-2	May-	un-	ul-	Aug-	ep-	ct-	otal	A G	A G Peak
LF	R- RN	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- R	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- L	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
LF	G-	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- 2 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
LF	G- 2 M	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- 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
LF	G- LLL	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
LF	G- LLL	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
LF	G- LLG	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
	AL	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 - 2

Actual DD	.	.	2 .	.	2 .	.	2 .	.	.	.	.	.	2 .
Norm DD	.2	.	2 .	.2	.	.	22 .	.	.	.2	.	.2	2 .

Normal olumes (eating olumes Normal DD/Actual DD Baseload)

		Nov-	Dec-	an-2	Feb-2	Mar-2	Apr-2	May-	un-	ul-	Aug-	ep-	ct-	otal
LF	R- RN	6	8	10	9	9	6	5	4	3	3	4	5	72
LLF	R- R	635	950	1,159	977	859	524	254	165	111	110	150	369	6,264
LLF	G- L	245	391	482	403	332	194	80	43	24	24	39	121	2,378
LF	G-	34	42	47	43	37	30	29	26	23	25	26	30	392
LLF	G- 2 ML	340	512	622	523	452	270	131	77	46	48	78	200	3,298
LF	G- 2 M	85	103	115	103	85	71	65	58	55	58	62	77	937
LLF	G- LL	86	126	151	133	121	72	42	27	21	22	29	55	883
LF	G- LLL	47	55	66	62	57	45	45	43	38	40	36	51	585
LF	G- LLL	19	25	29	27	22	18	17	15	16	16	16	18	238
LF	G- LLG	-	-	-	-	-	-	-	-	-	-	-	-	-
	AL	1,498	2,213	2,681	2,279	1,974	1,230	669	458	337	346	439	926	15,049

LF	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

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

Updated Schedule 23
Page 1 of 1

Li erty Utilities EnergyNorth Natural Gas Corp.
Pea 2021 - 2022 inter Cost of Gas Filing
Fi ed Price Option

		Participation	Premium	FPO olumes	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	

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
Pea 2021 - 2022 inter Cost of Gas Filing
Short-Term De t Limitations

Updated Schedule 24
Page 1 of 1

		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 Pro ected Net Plant	$	577,357,182
of Debt to Net Plant		20
Short Term Debt	$	115,471,436

Li erty Utilities EnergyNorth Natural Gas Corp.
d/ /a Li erty
2021 - 2022 inter Cost of Gas Filing

Company Allo ance Calculation

	ul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	an-2021	eb-2021	Mar-2021	Apr-2021	May-2021	un-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
ariance	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

	ul-2020	Aug-2020	Sep-2020	Oct-2020	Nov-2020	Dec-2020	an-2021	eb-2021	Mar-2021	Apr-2021	May-2021	un-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
ariance	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
AU													1.08

Li erty Utilities EnergyNorth Natural Gas Corp.
d/ /a Li erty
Fuel Inventory Revenue Re uirement

	a	b	c	d	e	f	g
1		5 uarter Avg	2 2020	3 2020	4 2020	1 2021	2 2021
2	Gas Stored Underground	$ 1,861,932	$ 1,684,887	$ 2,749,506	$ 2,331,076	$ 456,008	$ 2,088,182
3	uel Stock - Propane	$ 1,103,820	$ 1,182,985	$ 1,306,812	$ 1,314,267	$ 879,390	$ 835,646
4	UG Storage - NG	$ 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 Re uirement	$ 335,667					

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Rates effective November 1, 2021 - April 30, 2022 ~~Rates effective November 1, 2021 - April 30, 2021~~ inter 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
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Third Revised Page 89
Superseding Proposed First Revised Page 89

	Rates effective November 1, 2021 - April 30, 2022 ~~Rates effective November 1, 2021 - April 30, 2021~~ inter 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 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-	~~$ 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-4	~~$ 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-5	~~$ 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~~

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

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

Issued by: ______________________
Neil Proudman

Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Third Revised Page 91
Superseding Proposed First Revised Page 91

Anticipated Cost of Gas
PERIOD CO ERED SUMMER PERIOD MAY 1 2022 THROUGH OCTOBER 31 2022
~~PERIOD CO ERED SUMMER PERIOD MAY 1 2021 THROUGH OCTOBER 31 2021~~
REFER TO TE T ON IN SECTION 1 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	~~-~~		-	
			-	
Unad usted Anticipated Cost of Gas		~~$ 5,144,637~~		$ 10,330,821
Ad ustments				
Prior Period Over Under Recovery as o ~~April 30, 2018~~ September 01, 2019 monthly ad ustment filing	~~$ 1,885,446~~		$ 4,472,186	
Interest	~~51,144~~		222,837	
Prior Period Ad ustments	~~-~~		-	
roker Revenues	~~-~~		-	
Refunds from Suppliers	~~-~~		-	
uel inancing	-		-	
Transportation CGA Revenues	~~-~~		-	
Interruptible Sales Margin	~~-~~		-	
Capacity Release and Off System Sales Margin	~~-~~		-	
Hedging Costs	~~-~~		-	
ixed Price Option Administrative Costs	~~-~~		-	
Total Ad ustments		~~1,936,590~~		4,695,023
Total Anticipated Direct Cost of Gas		~~$ 7,081,227~~		$ 15,025,844
Anticipated Indirect Cost of Gas				
or ing 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 De t				
Total anticipated Direct Cost of Gas ~~05 01 2018 - 10 31 2018~~ 05 01 19 - 10 31 19	~~$ 5,144,637~~		$ 10,330,821	
ess: 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	
ad Debt Percentage	~~1.11~~		0.70	
ad Debt Allowance	~~77,896~~		103,658	
Plus: ad Debt Reconciliation ~~Acct 175.52~~ Acct 1163-1754	~~280,167~~		23,159	
Total ad 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

Issued: ~~October xx, 2020~~ October xx, 2021
Effective: ~~November 1, 2020~~ November 1, 2021

Issued by: ____________
Neil Proudman
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

NHPUC NO. 11 - GAS
LIBERTY UTILITIES

Proposed Third Revised Page 92
Superseding Proposed First Revised Page 92

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD CO ERED SUMMER PERIOD MAY 1 2022 THROUGH OCTOBER 31 2022
~~PERIOD CO ERED SUMMER PERIOD MAY 1 2021 THROUGH OCTOBER 31 2021~~
Refer to Te t 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		
Pro ected 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	
Ad ustment 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		
Pro ected 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 A ERAGE COST OF GAS EFFECTI E 05/01/22				$ 0.5587	per Therm
~~TOTAL PERIOD A ERAGE COST OF GAS EFFECTI E 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 LO INTER USE COST OF GAS RATE - 05/01/2022		COGsl	0.5580 /therm	
~~COM/IND LO INTER 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: ow Winter Use Ratio Summer	~~1.0465~~	0.9910				
Times: Correction actor	~~0.9867~~	1.0027				
Ad usted Demand Cost of Gas Rate	~~$ 0.2240~~	$ 0.1200				
Commodity Cost of Gas Rate	~~$ 0.1496~~	$ 0.2601				
Ad ustment Cost of Gas Rate	~~0.0938~~	0.1731				
Indirect Cost of Gas Rate	~~0.0083~~	0.0048				
Ad usted Com Ind ow Winter Use Cost of Gas Rate	~~$ 0.4591~~	$ 0.5580				

COM/IND HIGH INTER USE COST OF GAS RATE - 05/01/2021	COGsh	0.5593 /therm
~~COM/IND HIGH INTER 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 actor	~~0.9867~~	1.0027				
Ad usted Demand Cost of Gas Rate	~~$ 0.2123~~	$ 0.1213				
Commodity Cost of Gas Rate	~~$ 0.1496~~	$ 0.2601	Minimum			
Ad ustment Cost of Gas Rate	~~0.0938~~	0.1731	Maximum			
Indirect Cost of Gas Rate	~~0.0083~~	0.0048				
Ad usted Com Ind High Winter Use Cost of Gas Rate	~~$ 0.4474~~	$ 0.5593				

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

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

Issued by: ____________________
Neil Proudman
Title: President

Issued in compliance with NHPUC Order No. xx,xxx dated xxxx xx, 2021 in Docket DG 21-xxx.
~~Issued in compliance with NHPUC Order No. 26,419 dated October 31, 2020 in Docket DG 20-141~~

Li erty Utilities EnergyNorth Natural Gas Corp.

Off Pea 2022 Summer Cost of Gas Filing

Ta le of Contents

Ta	Title	Description
Summary	Summary	Summary
1	Schedule 1	Summary of Supply and Demand orecast
2	Schedule 2	Contracts Ranked on a per Unit Cost asis
3	Schedule 3	COG Over Under Cumulative Recovery alances and Interest Calculation
4	Schedule 4	Ad ustments to Gas Costs
5	Schedule 5A	Demand Costs
	Schedule 5	Demand olumes
	Schedule 5C	Demand Rates
6	Schedule 6	Supply and Commodity Costs, olumes and Rates
	Attachment	Pipeline Tariff Sheets
7	Schedule 7	N ME utures Henry Hub and Hedged Contracts
8	Schedule 8, Page 1	Annual ill Comparisons, May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3
	Schedule 8, Page 2	Annual ill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41
	Schedule 8, Page 3	Annual ill Comparisons, May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42
	Schedule 8, Page 4	Annual ill Comparisons, May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-52
	Schedule 8, Page 5	Residential Heating
9	Schedule 9	This schedule is no longer relevant
10	Schedule 10A Pages 1-2	Capacity Assignment Calculations 2020-2021 Derivation of Class Assignments and Weightings
	Schedule 10A Page 3	Correction actor Calculation
	Schedule 10	Off Peak 2022 Summer Cost of Gas iling
11	Schedule 11A	Normal and Design ear olumes Normal ear
	Schedule 11	Normal and Design ear olumes Design ear
	Schedule 11C	Capacity Utilization
12	Schedule 12, Page 1	Transportation Available for Pipeline Supply and Storage
	Schedule 12, Page 2	Agreements for Gas Supply and Transportation
13	Schedule 13	Storage Inventory

1	Li erty Utilities EnergyNorth Natural Gas Corp.		Updated Summary
2			Page 1 of 1
3	Off Pea 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 , 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 , 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 oss		$ -
21			
22			
23	Total Unad usted Cost of Gas		$ 10,330,821
24			
25	Ad ustments		
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 ln 193	222,837
29	Prior Period Ad ustments	Sch. 4, ln 24 col b	-
30	Refunds from Suppliers	Sch. 4, ln 24 col c	-
31	roker Revenue	Sch. 4, ln 24 col d	-
32	uel inancing	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	-
37	PO Premium - Collection		-
38	ixed Price Option Administrative Costs	Sch. 4, ln 24 col k	-
39			
40	Total Ad ustments		$ 4,695,023
41			
42	Total Anticipated Direct Costs	lns 23 40	$ 15,025,844
43			
44	Anticipated Indirect Cost of Gas		
45	or ing Capital		
46	Total Unad usted Anticipated Cost of Gas	n 23	$ 10,330,821
47	ead ag 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 or ing Capital Allo ance	lns 50 51	$ 4,555
54			
55	Bad De t		
56	Total Unad usted Anticipated Cost of Gas	ln 23	$ 10,330,821
57	ess 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	ad Debt Percentage	per GTC 17 f	0.70
62			
63	ad Debt Allowance	ln 60 ln 61	$ 103,653
64	Prior Period ad Debt Allowance	Sch. 3, col c , ln 163	23,159
65			
66	Total Bad De t Allo ance	lns 63 64	$ 126,812
67			
68	Production and Storage Capacity	per GTC17 f	$ -
69			
70	Miscellaneous Overhead	per GTC 17 f	$ -
71	Sales olume	Sch. 10 , ln 23 1000	23,366
72	Divided by Total Sales	Sch. 10 , 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	Pro ected Forecast Sales Therms	Sch. 3, col , ln 52	27,125,444

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2
3 Off Pea 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	or Month of:		May-22	un-22	ul-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 olumes Therms									
10										
11	A. Firm Demand olumes		87,054	267,289	220,723	223,909	335,525	722,212	855,832	
12	irm Gas Sales	Sch. 10 , 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	ost 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 olumes	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 olumes 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 - aseload	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	NG 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 one 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 olumes		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	NG apor	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	ess - Gas Refill:									
43	NG 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 irm Sendout olumes	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 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 Summary of Supply and Demand Forecast

REDACTED
Updated Schedule 1
Page 2 of 4

49										
50	II. Gas Costs									
51										
52	A. Demand Costs									
53	Supply									
54	Niagara Supply	Sch.5A, ln 12	[redacted]							
55	Subtotal Supply Demand									
56	ess Capacity Credit									
57	Net Pipeline Demand Costs									
58										
59	Pipeline:									
60	Iro uois Gas Trans Service RTS 470-0	Sch.5A, ln 16	[redacted]							
61	Tenn Gas Pipeline 95346 5- 6	Sch.5A, ln 17								
62	Tenn Gas Pipeline 2302 5- 6	Sch.5A, ln 18								
63	Tenn Gas Pipeline 8587 0- 6	Sch.5A, ln 19								
64	Tenn Gas Pipeline 8587 1- 6	Sch.5A, ln 20								
65	Tenn Gas Pipeline 8587 4- 6	Sch.5A, ln 21								
66	Tenn Gas Pipeline Dracut 42076 6- 6	Sch.5A, ln 22								
67	Tenn Gas Pipeline Dracut 358905 6- 7	Sch.5A, ln 23								
68	Tenn Gas Pipeline Concord ateral 6- 6	Sch.5A, ln 24								
69	Portland Natural Gas Trans Service	Sch.5A, ln 25								
70	ANE TransCanada via Union to Iro uois	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 4- 6 stg 632	Sch.5A, ln 29								
74	Tenn Gas Pipeline 4- 6 stg 11234	Sch.5A, ln 30								
75	Tenn Gas Pipeline 5- 6 stg 11234	Sch.5A, ln 31								
76	National uel ST 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	ess 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 ateral 6- 6	Sch.5A, ln 37	[redacted]							
83	Granite Ridge Demand	Sch.5A, ln 38								
84	DOMAC Demand NS 041	Sch.5A, ln 39								
85	Subtotal Peaking Demand									
86	ess 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 uel - Demand	Sch.5A, ln 52								
94	National uel - 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	ess 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	Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty								
2									
3	Off Pea 2022 Summer Cost of Gas Filing								
4	Summary of Supply and Demand Forecast								
105									REDACTED
106									Updated Schedule 1
107	B. Commodity Costs								Page 3 of 4
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 - aseload	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	NG Truck	Sch. 6, ln 18							
117	Portland Natural Gas	Sch. 6, ln 21							
118	PNGTS	Sch. 6, ln 20							
119	TGP Supply one 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	NG apor	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	ess Storage Refills:								
131	NG 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 olumetric Transportation Costs								
140	Dawn Supply	Sch. 6, ln 27	[redacted]						
141	Niagara Supply	Sch. 6, ln 28							
142	TGP Supply one 4	Sch. 6, ln 29							
143	Dracut Supply 1 - aseload	Sch. 6, ln 30							
144	Dracut Supply 2 - Swing	Sch. 6, ln 31							
145	Dracut Supply 3 - Swing	Sch. 6, ln							
146	Subtotal Pipeline olumetric 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 olumetric 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			THIS PAGE HAS BEEN REDACTED						
155									
156									

REDACTED
Updated Schedule 1
Page 4 of 4

1	Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty								
2									
3	Off Pea 2022 Summer Cost of Gas Filing								
4	Summary of Supply and Demand Forecast								
157	D. Supply and Demand Costs y Source								
158									
159									
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	ess 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	ess 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	ess Storage In . TGP Storage	ln 133							
177	ess Storage Transportation	ln 134							
178	ess NG Truck	ln 131							
179	ess 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	Su total 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 oss		$ -	$ -	$ -	$ -	$ -	$ -	$ -
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

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

REDACTED
Updated Schedule 2
Page 1 of 1

Off Pea 2022 Summer Cost of Gas Filing
Contracts Ran ed on a per Unit Cost Basis

Supplier	Contract	Contract Type	Contract Unit	Unit Dth MD /AC	Off Pea Cost per Unit Dth
a	b	c	d	e	f
Demand Costs					
ANE TransCanada via Union to Iro uois	Dawn - Parkway to Iro uois	Transportation	MD	4,047	[redacted]
Dominion - Capacity Reservation	GSS 300076	Storage	AC	102,700	
Tenn Gas Pipeline - Cap. Reservations	S-MA 523	Storage	AC	1,560,391	
National uel - Capacity Reservation	SS-1 2357	Storage	AC	670,800	
Tenn Gas Pipeline - Demand	S-MA 523	Storage	MD	21,844	
Dominion - Demand	GSS 300076	Storage	MD	934	
National uel - Demand	SS-1 2357	Storage	MD	6,098	
Tenn Gas Pipeline	42076 TA 6- 6	Transportation	MD	20,000	
Tenn Gas Pipeline	42076 TA 6- 6	Transportation	MD	40,000	
National uel	ST N02358	Transportation	MD	6,098	
Iro uois Gas Trans Service	RTS 470-01	Transportation	MD	4,047	
Honeoye - Demand	SS-N	Storage	MD	1,362	
Tenn Gas Pipeline	2302 5- 6	Transportation	MD	3,122	
Tenn Gas Pipeline short haul	11234 5- 6 stg	Transportation	MD	1,957	
Tenn Gas Pipeline short haul	8587 4- 6	Transportation	MD	3,811	
Tenn Gas Pipeline short haul	632 4- 6 stg	Transportation	MD	15,265	
Tenn Gas Pipeline short haul	11234 4- 6 stg	Transportation	MD	7,082	
Tenn Gas Pipeline Concord ateral 6- 6	irm Transportation	Transportation	MD	30,000	
Tenn Gas Pipeline	95346 5- 6	Transportation	MD	4,000	
TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MD	5,077	
Portland Natural Gas Trans Service	T-1999-001	Transportation	MD	1,000	
Tenn Gas Pipeline long haul	8587 1- 6	Transportation	MD	14,561	
Tenn Gas Pipeline long haul	8587 0- 6	Transportation	MD	7,035	
Portland Natural Gas	TN	Transportation	MD	5,000	
Supply Costs - Commodity					
NG Truck		Pipeline	Dkt	13,918	[redacted]
TGP Supply one 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 - aseload		Pipeline	Dkt	-	
TGP Supply Gulf		Pipeline	Dkt	39,745	
NG apor		Produced	Dkt	11,227	
Propane		Pipeline	Dkt	-	
Supply Costs - olumetric Transportation					
Dracut Supply 1 - aseload		Pipeline	Dkt	-	[redacted]
TGP Supply one 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	

THIS PAGE HAS BEEN REDACTED

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation
5
6

Updated Schedule 3
Page 1 of 3

7			Prior Period alance														
8			Plus Nov Collections	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	May-22	un-22	ul-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		k	l	m	n	o	p	
11	Account 8840-2-0000-10-1920-1741 formerly 175.40 COG Over /Under Balance - Interest Calculation																
12																	
13	Beginning Balance	Account 1920-1741 1	4 472 18	$ 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	orecast 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	Pro ected Revenues w o Int.	ln 54 ln 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	Pro ected Unbilled Revenue	ln 58 ln 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 Ad ustments with TGP Refund		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Gas Cost illed	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 alance	ln 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	
23																	
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		
25																	
26	Interest Applied	ln 22 ln 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
27																	
28	Over /Under Balance	ln 21 ln 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
29																	
30																	
31	Calculation of COG ith Interest																
32																	
33	Beginning Balance	ln 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	orecast Direct Gas Costs	ln 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	ln 15	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Pro ected Revenues with int.	ln 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	Pro ected Unbilled Revenue	ln 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 Ad ustments	ln 19	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	Gas Cost illed	ln 20	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Gas Cost Unbilled																
42	Reverse Prior Month Unbilled																
43	Add Interest	ln 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
45																	
46	Average Monthly alance			$ 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		
47																	
48	Interest Applied	ln 24 ln 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
49																	
50	Over /Under Balance	ln 43 ln 44 ln 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
51																	
52																	
53	orecast 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	ess orecast illing Therm Sales	Sch. 10 , ln 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	ess orecast Unaccounted or	Sch 1								53,988	29,666	24,501	25,149	36,419	78,230		247,952
56	ess orecast Company Use	Sch 1								3,081	1,693	1,398	1,435	2,079	4,465		14,152
57	Unbilled olumes									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	
59																	
60	eg alance									-	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 alance									4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587	4,436,728	
63																	
64	COG w o Interest	Sch. 3, pg. 4, ln 211 col. c								$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	$ 0.5702	
65																	
66	COG With Interest	Sch. 3, pg. 4, ln 211 col. d								$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	$ 0.5774	

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation

Updated Schedule 3
Page 2 of 3

Line			Prior Period alance Plus Nov Collections October 31, 2021	Nov-21	Dec-21	an-22	eb-22	Mar-22	Apr-22	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Nov-22	Off Peak Period Total
72		Days in Month		30	31	31	28	31	30	31	30	31	31	30	31	30	
74	a	b	c	d	e	f	g	h	i		k	l	m	n	o	p	
76	Account 8840-2-0000-10-11 3-1424 formerly 142.40 or ing 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 ag									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	orecast Working Capital	ln 34 ln 80 365 ln 81		-	-	-	-	-	-	-	-	-	-	-	-	-	-
84	Pro ected Revenues w o Int.	ln 123 ln 126		-	-	-	-	-	-	146	449	371	376	563	1,213	1,437	4,555
85	Pro ected 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 Ad ustments			-	-		-	-	-	-	-	-	-	-	-	-	-
90	Working Capital illed	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 alance	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 75	$ 3,864	$ 3,424	$ 3,062	$ 2,688	$ 2,139	$ 944	$ 199	199
103	Calculation of or ing Capital ith 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	orecast Working Capital	ln 82		-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Pro ected Rev. with interest	ln 123 ln 128		-	-	-	-	-	-	152	468	386	392	587	1,264	1,497	4,746
108	Pro ected 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 Ad ustments	ln 88	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Working Capital illed	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 alance			$ 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	orecast 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	

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 COG Over /Under Cumulative Recovery Balances and Interest Calculation

Updated Schedule 3
Page 3 of 3

Row	a	b	Prior Period alance Plus Nov Collections October 31, 2021 c	Nov-21 30 d	Dec-21 31 e	an-22 31 f	eb-22 28 g	Mar-22 31 h	Apr-22 30 i
137	Account 8840-2-0000-10-11 3-1754 formerly 175.54 Bad De t Over /Under Balance - Interest Calculation								
139	orecast Direct Gas Costs	ln 34		$ -	$ -	$ -	$ -	$ -	$ -
140	orecast Working Capital	ln 106 May includes prior period		-	-	-	-	-	-
141	Prior Period alance with Refund	ln 21 6							
142	Total orecast Direct Gas Costs	Working Capital		-	-	-	-	-	-
144	Beginning Balance	Account 1163-1754 1	23 159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
145		Oct Collections Un illed							
146	orecast ad Debt	ln 142 0.007		-	-	-	-	-	-
148	Pro ected Revenues w o int	ln 184 ln 187		-	-	-	-	-	-
149	Pro ected Unbilled Revenue	ln 185 ln 187							
150	Reverse Prior Month Unbilled								
152	ad Debt illed	Account 1163-1754 2			-		-	-	-
153	Add Net Ad ustments		-	-	-	-	-	-	-
155	Monthly Over Under Recovery		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
157	Average Monthly alance	ln 144 155 2		$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
159	Interest Rate	Prime Rate		5.25	5.25	5.25	5.25	5.25	5.25
161	Interest Applied	ln 157 ln 159 365 Days of Mo.		$ 100	$ 104	$ 104	$ 95	$ 105	$ 102
163	Over /Under Balance	ln 155 ln 161	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	23 7 8
166	Calculation of Bad De t ith Interest								
168	Beginning Balance		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
169	orecast ad Debt	ln 146		-	-	-	-	-	-
170	Pro ected Revenues with int.	ln 184 189		-	-	-	-	-	-
171	Pro ected Unbilled Revenue	ln 185 189							
172	Reverse Prior Month Unbilled								
173	ad Debt illed	ln 152	-		-	-	-	-	-
174	Add Interest	ln 161		-	-	-	-	-	-
175	Add Net Ad ustments	ln 153	-	-	-	-	-	-	-
176	Monthly Over Under Recovery		$ 23,159	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
178	Average Monthly alance	ln 168 176 2		$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666
180	Interest Applied	ln 159 ln 178 365 Days of Month		100	104	104	95	105	102
182	Over /Under Balance	-ln 174 ln 176 ln 180	$ 23,159	$ 23,259	$ 23,362	$ 23,467	$ 23,561	$ 23,666	$ 23,768
184	orecast Therm Sales	ln 53							
185	Unbilled Therm	ln 55							
187	COG Rate Without Interest	Sch. 3, pg. 4, ln 245 col. c							
189	COG With Interest	Sch. 3, pg. 4, ln 245 col. d							
193	Total Interest	lns 48 119 180		$ 19,417	$ 20,151	$ 20,241	$ 18,364	$ 20,413	$ 19,843

Row	a	May-22 31	un-22 30 k	ul-22 31 l	Aug-22 31 m	Sep-22 30 n	Oct-22 31 o	Nov-22 30 p	Off Peak Period Total
139	orecast Direct Gas Costs	$ 2,380,201	$ 1,465,677	$ 1,298,159	$ 1,280,664	$ 1,521,278	$ 3,048,645	$ -	10,994,623
140	orecast Working Capital	4,555	-	-	-	-	-		4,555
141	Prior Period alance with Refund	745,364	745,364	745,364	745,364	745,364	745,364		4,472,186
142	Total orecast Direct Gas Costs	3,130,120	2,211,041	2,043,523	2,026,028	2,266,642	3,794,009	-	10,999,178
144	Beginning Balance	$ 23,768	$ 21,839	$ 24,161	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 23,159
146	orecast ad Debt	21,911	15,477	14,305	14,182	15,866	26,558		108,300
148	Pro ected Revenues w o int	4,219	12,954	10,697	10,851	16,261	35,001	41,476	131,458
149	Pro ected Unbilled Revenue	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	ad Debt illed								-
153	Add Net Ad ustments	-	-	-	-	-	-	-	-
155	Monthly Over Under Recovery	$ 21,738	$ 24,161	$ 27,600	$ 30,746	$ 30,592	$ 22,591	$ 1,208	$ -
157	Average Monthly alance	$ 22,753	$ 23,000	$ 25,881	$ 29,231	$ 30,734	$ 26,658	$ 11,959	
159	Interest Rate	5.25	5.25	5.25	5.25	5.25	5.25		
161	Interest Applied	$ 101	$ 99	$ 115	$ 130	$ 133	$ 119		$ 1,307
163	Over /Under Balance	$ 21,839	$ 24,260	$ 27,716	$ 30,876	$ 30,725	$ 22,710	$ 11,959	1,307
168	Beginning Balance	$ 23,768	$ 16,906	$ 16,596	$ 17,879	$ 18,697	$ 15,167	$ 65	$ 23,159
169	orecast ad Debt	21,911	15,477	14,305	14,182	15,866	26,558	-	108,300
170	Pro ected Revenues with int.	5,086	15,617	12,896	13,082	19,604	42,196	50,003	158,484
171	Pro ected Unbilled Revenue	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	ad Debt illed								-
174	Add Interest	101	99	115	130	133	119		698
175	Add Net Ad ustments	-	-	-	-	-	-	-	-
176	Monthly Over Under Recovery	$ 16,917	$ 16,623	$ 17,917	$ 18,746	$ 15,226	$ 20	$ 25,988	$ 26,328
178	Average Monthly alance	$ 20,343	$ 16,765	$ 17,256	$ 18,312	$ 16,962	$ 7,593	$ 13,027	
180	Interest Applied	91	72	77	82	73	34	-	$ 1,038
182	Over /Under Balance	$ 16,906	$ 16,596	$ 17,879	$ 18,697	$ 15,167	$ 65	$ 25,988	$ 25,988
184	orecast Therm Sales	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	4,069,607	4,111,291	4,145,962	4,208,071	4,185,304	4,121,587		
187	COG Rate Without Interest	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	$0.0048	
189	COG With Interest	$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	$0.0058	
193	Total Interest	$ 19,566	$ 17,759	$ 18,213	$ 18,198	$ 16,705	$ 13,968	$ -	$ 222,837

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty

Updated Schedule 4
Page 1 of 1

2
3 Off Pea 2022 Summer Cost of Gas Filing
4 Ad ustments to Gas Costs
5

	Ad ustments	Prior Period Ad ustments	Refunds from Suppliers / Pipelines	Bro er Revenue	Fuel Financing	Transportation CGA Revenues	Interrupti le Sales Margin	Off System Sales Margin	Capacity Release Margin	Net Option Premiums	Fi ed Price Option Administrative Costs	Total Ad ustments
7	a	b	c	d	e	f	g	h	i		k	m
8												
9	Nov-19	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Dec-19	-	-	-	-	-	-	-	-	-	-	-
11	an-20	-	-	-	-	-	-	-	-	-	-	-
12	eb-20	-	-	-	-	-	-	-	-	-	-	-
13	Mar-20	-	-	-	-	-	-	-	-	-	-	-
14	Apr-20	-	-	-	-	-	-	-	-	-	-	-
15	May-20	-	-	-	-	-	-	-	149,464	-	-	149,464
16	un-20	-	-	-	-	-	-	-	141,180	-	-	141,180
17	ul-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

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

1	Li erty Utilities EnergyNorth Natural Gas Corp.										REDACTED
2											Updated Schedule 5A
3	Off Pea 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	un-22	ul-22	Aug-22	Sep-22	Oct-22	Total	Total
9	a	b	c	d	e	f	g	h	i		k
10											
11	Supply										
12	Niagara Supply		Sch 5 , ln 9 Sch 5C ln 9 x days	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Subtotal Supply Demand Reservation Charges			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14											
15	Pipeline										
16	Iro uois Gas Trans Service RTS 470-0		Sch 5 , ln 12 Sch 5C ln 12 x days	[redacted]							
17	Tenn Gas Pipeline 95346 5- 6		Sch 5 , ln 13 Sch 5C ln 14 x days								
18	Tenn Gas Pipeline 2302 5- 6		Sch 5 , ln 14 Sch 5C ln 16 x days								
19	Tenn Gas Pipeline 8587 0- 6		Sch 5 , ln 15 Sch 5C ln 18 x days								
20	Tenn Gas Pipeline 8587 1- 6		Sch 5 , ln 16 Sch 5C ln 20 x days								
21	Tenn Gas Pipeline 8587 4- 6		Sch 5 , ln 17 Sch 5C ln 22 x days								
22	Tenn Gas Pipeline Dracut 42076 6- 6		Sch 5 , ln 18 Sch 5C ln 24 x days								
23	Tenn Gas Pipeline Dracut 358905 6- 7		Sch 5 , ln Sch 5C ln 25 x days								
24	Tenn Gas Pipeline Concord ateral 6- 6		Sch 5 , ln 19 Sch 5C ln 28 x days								
25	Portland Natural Gas Trans Service		Sch 5 , ln 20 Sch 5C ln 30 x days								
26	Portland Natural Gas		Sch 5 , ln 21 Sch 5C ln 31 x days								
27	ANE TransCanada via Union to Iro uois		Sch 5 , ln 22 Sch 5C ln 48 x days								
28	TransCanada via Union to Portland		Sch 5 , ln 23 Sch 5C ln 49 x days								
29	Tenn Gas Pipeline 4- 6 stg 632	peak	Sch 5 , ln 24 Sch 5C ln 34 x days								
30	Tenn Gas Pipeline 4- 6 stg 11234	peak	Sch 5 , ln 25 Sch 5C ln 36 x days								
31	Tenn Gas Pipeline 5- 6 stg 11234	peak	Sch 5 , ln 26 Sch 5C ln 38 x days								
32	National uel ST 2358	peak	Sch 5 , 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	Pea ing Supply										
37	Tenn Gas Pipeline Concord ateral 6- 6	peak	Sch 5 , ln 30 Sch 5C ln 28 x days	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
38	Granite Ridge Demand	peak	Sch 5 , ln 31 Sch 5C ln 59 x days	-	-	-	-	-	-	-	-
39	DOMAC Demand NS 041	peak	Per Contract	-	-	-	-	-	-	-	
40	Subtotal Peaking Demand Charges			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
41											
42	Su total Supply Pipeline Pea ing		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	ess 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 Pea ing 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

THIS PAGE HAS BEEN REDACTED

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 Updated Schedule 5A
3 Off Pea 2022 Summer Cost of Gas Filing Page 2 of 2
4 Demand Costs

47											
48	Storage										
49	Dominion - Demand	peak	Sch 5 , 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 5 , 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 5 , ln 37	Sch 5C ln 67 x days	8,351	8,351	8,351	8,351	8,351	8,351	-	50,105
52	National uel - Demand	peak	Sch 5 , ln 39	Sch 5C ln 69 x days	16,053	16,053	16,053	16,053	16,053	16,053	-	96,318
53	National uel - Capacity	peak	Sch 5 , 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 5 , 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 5 , ln 42	Sch 5C ln 74 x days	27,931	27,931	27,931	27,931	27,931	27,931	-	167,586
56												
57	Su total Storage Demand Costs				$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ 116,105	$ -	$ 696,628
58												
59	ess 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 Pea 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 Pea Demand				$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ 506,708	$ -	$ 3,704,047

Line										
1	Li erty Utilities EnergyNorth Natural Gas Corp.									Updated Schedule 5
2										Page 1 of 1
3	Off Pea 2022 Summer Cost of Gas Filing									
4	Demand olumes									
5										
6			Peak	Reference	May-22	un-22	ul-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		Iro uois Gas Trans Service		RTS 470-01	4,047	4,047	4,047	4,047	4,047	4,047
13		Tenn Gas Pipeline		95346 5- 6	4,000	4,000	4,000	4,000	4,000	4,000
14		Tenn Gas Pipeline		2302 5- 6	3,122	3,122	3,122	3,122	3,122	3,122
15		Tenn Gas Pipeline long haul		8587 0- 6	7,035	7,035	7,035	7,035	7,035	7,035
16		Tenn Gas Pipeline long haul		8587 1- 6	14,561	14,561	14,561	14,561	14,561	14,561
17		Tenn Gas Pipeline short haul		8587 4- 6	3,811	3,811	3,811	3,811	3,811	3,811
18		Tenn Gas Pipeline		42076 TA 6- 6	20,000	20,000	20,000	20,000	20,000	20,000
		Tenn Gas Pipeline		358905 TA 6- 6	40,000	40,000	40,000	40,000	40,000	40,000
19		Tenn Gas Pipeline Concord ateral		irm Transportation	30,000	30,000	30,000	30,000	30,000	30,000
20		Portland Natural Gas Trans Service		T-1999-001	1,000	1,000	1,000	1,000	1,000	1,000
21		Portland Natural Gas		TN	5,000	5,000	5,000	5,000	5,000	5,000
22		ANE TransCanada via Union to Iro uois		Dawn - Parkway to Iro uois	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 4- 6 stg	15,265	15,265	15,265	15,265	15,265	15,265
25		Tenn Gas Pipeline short haul	peak	11234 4- 6 stg	7,082	7,082	7,082	7,082	7,082	7,082
26		Tenn Gas Pipeline short haul	peak	11234 5- 6 stg	1,957	1,957	1,957	1,957	1,957	1,957
27		National uel	peak	ST N02358	6,098	6,098	6,098	6,098	6,098	6,098
28										
29	Pea ing									
30		Tenn Gas Pipeline Concord ateral	peak		-	-	-	-	-	-
31		Granite Ridge Demand	peak		-	-	-	-	-	-
32		DOMAC i uid Demand Charge	peak	NS 041	-	-	-	-	-	-
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-N	1,362	1,362	1,362	1,362	1,362	1,362
38		Honeoye - Capacity	peak	SS-N	245,380	245,380	245,380	245,380	245,380	245,380
39		National uel - Demand	peak	SS-1 2357	6,098	6,098	6,098	6,098	6,098	6,098
40		National uel - Capacity Reservation	peak	SS-1 2357	670,800	670,800	670,800	670,800	670,800	670,800
41		Tenn Gas Pipeline - Demand	peak	S-MA 523	21,844	21,844	21,844	21,844	21,844	21,844
42		Tenn Gas Pipeline - Cap. Reservations	peak	S-MA 523	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391	1,560,391

Updated Schedule 5C
Page 1 of 1

					May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Nov-22	Nov-22	Dec-22	an-23	Fe -23	Mar-23	Apr-23
1	Li erty Utilities EnergyNorth Natural Gas Corp.																
2	d/ /a Li erty Utilities																
3	Off Pea 2022 Summer Cost of Gas Filing																
4	Demand Rates																
5																	
6	Tariff Rates				31	30	31	31	30	31	184	30	31	31	28	31	30
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate						
8	Supply																
9	Niagara Supply		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10																	
11	Pipeline																
12	Iro uois Gas	RTS 470-01	$ 5.2357	orth 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
13																	
14	Tenn Gas Pipeline	95346 5- 6	$ 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
15																	
16	Tenn Gas Pipeline	2302 5- 6	$ 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
17																	
18	Tenn Gas Pipeline	8587 0- 6	$ 20.3736	T-A 0 - 6	$ 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
19																	
20	Tenn Gas Pipeline	8587 1- 6	$ 18.0875	T-A 1 - 6	$ 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
21																	
22	Tenn Gas Pipeline	8587 4- 6	$ 7.1645	T-A 4 - 6	$ 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
23																	
24	TGP Dracut	42076 TA 6- 6	$ 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
25																	
26	TGP Dracut	358905 TA 6- 6	$ 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
27																	
28	TGP Concord ateral	irm 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
29																	
30	Portland Natural Gas	T-1999-001	$ 18.2633	Negot Dmd CMD Part 4.1 7	$ 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
31																	
32	Portland Natural Gas	TN	$ 22.8125	Negot Dmd CMD Part 4.1 7	$ 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
33																	
34	Tenn Gas Pipeline	632 4- 6 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
35																	
36	Tenn Gas Pipeline	11234 4- 6 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
37																	
38	Tenn Gas Pipeline	11234 5- 6 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
39																	
40	National uel	ST N02358	$ 4.5274	4.010 ersion 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
41																	
42	ANE Union Gas		$ 3.6665														
43	TransCanada Pipelines imited		$ 11.9842	Union Parkway to Iro uois													
44	Delivery Pressure Demand Charge		0.6083	Union Parkway to Iro uois													
45	Sub Total Demand Charges		16.2590														
46	Conversion rate G to MM TU		1.0551														
47	Conversion rate to US$		1.2589	1 0 1900													
48	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
49																	
50	Union Gas		$ 3.6665														
51	TransCanada Pipelines imited		$ 20.4218														
52	Delivery Pressure Demand Charge		$ 0.6083														
53	Sub Total Demand Charges		$ 24.6966														
54	Conversion rate G to MM TU		$ 1.0551														
55	Conversion rate to US$		$ 1.2589	$0.0000													
56	Demand Rate US$		$ 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
57																	
58	Pea ing																
59	Granite Ridge Demand		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
60	DOMAC Demand NS 041		$ -	Per Contract	$ -	$ -	$ -	$ -	$ -	$ -	$ -						
61																	
62	Storage																
63	Dominion - Demand	GSS 300076	$ 1.8716	GSS Settled,Tariff Rec 10.30	$ 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
64	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	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005	$ 0.0005
65			$ 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
66																	
67	Honeoye - Demand	SS-N	$ 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
68																	
69	National uel - Demand	SS-1 2357	$ 2.6325	4.020 ersion 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
70	National uel - Capacity	SS-1 2357	$ 0.0476	4.020 ersion 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
71			$ 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
72																	
73	Tenn Gas Pipeline	S-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 Li erty Utilities EnergyNorth Natural Gas Corp.
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 Supply and Commodity Costs olumes and Rates

REDACTED
Updated Schedule 6
Page 1 of 5

Line		Reference							Off-Peak
5									
6	or Month of:	Reference		May-22	un-22	ul-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	In 63	In 104	[redacted]						
13	Niagara Supply	In 64	In 109							
14	TGP Supply Gulf	In 65	In 129							
15	Dracut Supply 1 - aseload	In 66	In 114							
16	Dracut Supply 2 - Swing	In 67	In 119							
	Dracut Supply 3 - Swing									
17	City Gate Delivered Supply	In 68	In 135							
18	NG Truck	In 69	In 137							
19	Propane Truck	In 70	In 139							
20	PNGTS	In 71	In 144							
21	Portland Natural Gas									
22	TGP Supply one 4	In 73	In 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	olumetric Transportation Costs									
27	Dawn Supply	In 63	In 202	[redacted]						
28	Niagara Supply	In 64	In 213							
29	TGP Supply one 4	In 73	In 251							
30	Dracut Supply 1 - aseload	In 66	In 262							
31	Dracut Supply 2 - Swing	In 67	In 262							
	Dracut Supply 3 - Swing									
32	City Gate Delivered Supply	In 68	In 262							
33	TGP Storage - Withdrawals	In 78	In 177							
34										
35	Total olumetric Transportation Costs			$ 88,990	$ 71,093	$ 70,660	$ 70,003	$ 71,501	$ 87,078	$ 459,325
36										
37	Less - Gas Refill									
38	NG Truck	In 87	In 161	[redacted]						
39	Propane	In 88	In 162							
40	TGP Storage Refill	In 89	In 127							
41	Storage Refill Trans.	In 89	In 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	In 24	In 35 In 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	In 78	In 169	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49										
50	Produced Gas									
51	NG apor	In 81	In 156	[redacted]						
52	Propane	In 82	In 158							
53										
54	Total Produced Gas	In 51	In 52	$ 13,993	$ 13,159	$ 12,913	$ 12,877	$ 13,652	$ 15,911	$ 82,504
55										
56										
57	Total Commodity Gas Trans. Costs	In 45	In 48 In 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	Li erty Utilities EnergyNorth Natural Gas Corp.								
2									
3	Off Pea 2022 Summer Cost of Gas Filing								
4	Supply and Commodity Costs olumes and Rates								
59									Updated Schedule 6
60	olumes Therms								Page 2 of 5
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 - aseload		-	-	-	-	-	-	-
67	Dracut Supply 2 - Swing		-	-	-	-	-	436,185	436,185
	Dracut Supply 3 - Swing								
68	City Gate Delivered Supply		-	-	-	-	-	-	-
69	NG 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 one 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 olumes		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	NG apor		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	NG 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 olumes		4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820
94									
95									
96									

REDACTED
Updated Schedule 6
Page 3 of 5

									Average Rate
1 Li erty Utilities EnergyNorth Natural Gas Corp.									
2									
3 Off Pea 2022 Summer Cost of Gas Filing									
4 Supply and Commodity Costs olumes and Rates									
97									
98 Gas Costs and olumetric Transportation Rates									
99									
100 Pipeline Gas									
101 Da n Supply									
102 N ME Price	Sch 7, ln 10 10	[redacted]							
103 asis Differential									
104 Net Commodity Costs									
105									
106 Niagara Supply									
107 N ME Price	Sch 7, ln 10 10	[redacted]							
108 asis Differential									
109 Net Commodity Costs									
110									
111 Dracut Supply 1 - Baseload									
112 Commodity Costs - N ME Price	Sch 7, ln 10 10	[redacted]							
113 asis Differential									
114 Net Commodity Costs									
115									
116 Dracut Supply 2 - S ing									
117 Commodity Costs - N ME Price	Sch 7, ln 10 10	[redacted]							
118 asis Differential									
119 Net Commodity Costs									
120									
121 Dracut Supply 3 - S ing	Sch 7, ln 10 10								
122 Commodity Costs - N ME Price		[redacted]							
123 asis Differential									
124 Net Commodity Costs									
125									
126 TGP Supply Gulf									
127 N ME Price	Sch 7, ln 10 10	[redacted]							
128 asis Differential									
129 Net Commodity Costs									
130									
131									
132 TGP Citygate Supply									
133 N ME Price	Sch 7, ln 10 10	[redacted]							
134 asis Differential									
135 Net Commodity Costs									
136									
137 LNG Truc	Sch 7, ln 10 10	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
138									
139 Propane Truc	N ME - Propane	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
140									
141 PNGTS									
142 N ME Price	Sch 7, ln 10 10	[redacted]							
143 Additional Cost									
144 Net Commodity Cost									
145									
146 PNGTS E P									
147 N ME Price	Sch 7, ln 10 10	[redacted]							
148 asis Differential									
149 Net Commodity Cost									
150									
151 TGP Supply one 4									
152 N ME Price	Sch 7, ln 10 10	[redacted]							
153 asis Differential									
154 Net Commodity Cost		0.35 2	0.3524	0.3 20	0.3531	0.3135	0.3150	0.3420	
155									
156 LNG apor Storage	Sch 13, ln 97 10	0. 988	0.7258	0.7371	0.7371	0.7371	0.7723	0.7347	
157									
158 Propane	Sch 13, ln 67 10	1.1475	1.0155	0.9197	0.8429	0.7781	0.7194	0.9038	
159									
160 Storage Refill									
161 LNG Truc	ln 137	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
162 Propane	ln 139	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	
163									
164									

THIS PAGE HAS BEEN REDACTED

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 Supply and Commodity Costs olumes and Rates
165 REDACTED
166 Updated Schedule 6
167 Page 4 of 5

182	Per Unit olumetric Transportation Rates								
183	Da n Supply olumetric Transportation Charge								Average Rate
184	Commodity Costs	In 104	[redacted]						
185									
186	TransCanada - Commodity Rate G	Dawn - Parkway to Iro uois	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030	$0.00030
187	Conversion Rate G to MM TU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
188	Conversion Rate to US$	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 uel	Dawn - Parkway to Iro uois	0.74	0.67	0.00	0.00	0.00	0.00	0.23
191	TransCanada uel 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	0.0029	0.00040	0.00040	0.00040	0.00040	0.00130
193	IGTS - 1 RTS Commodity	orth Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
194	IGTS - 1 RTS ACA Rate Commodity	orth Revised Sheet No. 4	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012	$0.00012
195	IGTS - 1 RTS Deferred Asset Surcharge	orth Revised Sheet No. 4	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
196	Subtotal IGTS - Trans Charge - 1 RTS Commodity		0.0004	0.0004	0.0004	0.0004	0.0004	0.0004	0.0004
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 - uel Use actor - Percentage	orth Revised Sheet No. 4	1.00	1.00	1.00	1.00	1.00	1.00	1.00
199	IGTS - uel Use actor - uel Percentage	In 184 x In 198	0.00382	0.00384	0.00387	0.00385	0.00384	0.00385	0.00385
200	TGP TA uel Charge 5-6	17th Rev Sheet No. 32	0.86	0.86	0.86	0.86	0.86	0.86	0.86
201	TGP TA uel Percentage	In 184 x In 200	0.00329	0.00330	0.00333	0.00331	0.00330	0.00331	0.00331
202	Total olumetric Transportation Charge - Da n Supply		0.01092	0.010 8	0.00818	0.00814	0.00812	0.00814	0.00903
203									
204									
205	Niagara Supply olumetric Transportation Charge								
206	Commodity Costs	n 109	[redacted]						
207									
208	TGP TA - TA 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 TA - TA 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 TA - TA 5-6 Commodity Rate		0.00717	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
211	TGP TA uel Charge 5-6	17th Rev Sheet No. 32	0.86	0.86	0.86	0.86	0.86	0.86	0.86
212	TGP TA uel Percentage	In 206 x In 211	0.00311	0.00313	0.0031	0.00314	0.00313	0.00314	0.00314
213	Total olumetric Transportation Rate - Niagara Supply		0.01028	0.01030	0.01033	0.01031	0.01030	0.01031	0.01031
214									
215									
216		THIS PAGE HAS BEEN REDACTED							

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2
3 Off Pea 2022 Summer Cost of Gas Filing
4 Supply and Commodity Costs olumes and Rates

217								REDACTED
218								Updated Schedule 6
219								Page 5 of 5
220 TGP Direct olumetric Transportation Charge								Average Rate
221 Commodity Costs	n 127	[redacted]						
222								
223 TGP - Max Comm. ase Rate - 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 - 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 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 - 0-6		0.00875	0.00875	0.00875	0.00875	0.00875	0.00875	0.00875
228 TGP - Max Comm. ase Rate - 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 - 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 - 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 - 1-6		0.01579	0.01579	0.01579	0.01579	0.01579	0.01579	0.01579
233 TGP - uel Charge - 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 uel Charge - 0-6		1.52	1.52	1.52	1.52	1.52	1.52	1.52
236 TGP - uel Charge - 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 uel Charge - uel Charge - 1-6		2.74	2.74	2.74	2.74	2.74	2.74	2.74
239 TGP - uel Charge - 0-6	ln 221 x ln 235	0.00592	0.00597	0.00 04	0.00 05	0.00599	0.00599	0.00599
240 TGP - uel Charge - 1-6	ln 221 x ln 238	0.010	0.0107	0.01088	0.01089	0.01079	0.01078	0.01080
241 Total olumetric Transportation Rate - TGP Direct		0.04112	0.04128	0.0414	0.04148	0.04133	0.04131	0.04133
242								
243 TGP one 4 Purchase olumetric Transportation Charge								
244 Commodity Costs	n 127	[redacted]						
245								
246 TGP - Max Comm. ase Rate - 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 - 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 - 4-6		0.00940	0.00940	0.00940	0.00940	0.00940	0.00940	0.00940
249 TGP - uel Charge - 4-6	17th Rev Sheet No. 32	1.22	1.22	1.22	1.22	1.22	1.22	1.22
250 TGP - uel Charge	ln 244 x ln 249	0.00435	0.00430	0.00442	0.00431	0.00382	0.00384	0.00417
251 Total ol. Trans. Rate - TGP one		0.01375	0.01370	0.01382	0.01371	0.01322	0.01324	0.01357
252								
253								
254 TGP Dracut								
255 Commodity Costs - NYME Price	n 114	[redacted]						
256								
257 TGP - Trans Charge - Comm. - 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 - 6-6	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 - 6-6		0.00312	0.00312	0.00312	0.00312	0.00312	0.00312	0.00312
260 TGP - uel Charge - 6-6	17th Rev Sheet No. 32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
261 TGP - uel Charge	ln 255 x ln 260	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000
262 Total olumetric 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						

Updated Schedule 7
Page 1 of 1

1	Li erty Utilities EnergyNorth Natural Gas Corp.										
2											
3	Off Pea 2022 Summer Cost of Gas Filing										
4	NYME Futures Henry Hu										May - Oct
5											Off Peak
6	or Month of:		Reference		May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Strip Average
7		a	b		c	d	e	f	g	h	i
8	I. NYME Opening Prices as of										
9		Opening Prices		ine 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

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2 Off Pea 2022 Summer Cost of Gas Filing
3 Annual Bill Comparisons May 20 - Oct 20 vs May 21 - Oct 21 - Residential Heating Rate R-3

Updated Schedule 8
Page 1 of 5

Ln	Description	Rate	Rate	Nov	Dec	Jan	Feb	Mar	Apr	Winter	May	Jun	Jul	Aug	Sep	Oct	Summer	Total
4																		
5																		
6	Novem er 1 2021 - April 30 2022										May 1 2022 - Octo er 31 2022							
7	Residential Heating R3																	
8										inter							Summer	Total
9				Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov-Apr	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	May-Oct	Nov-Oct
10	Typical Usage Therms			62	110	123	148	132	92	667	51	28	16	14	14	21	144	811
11			8 1 2021 - Current															
12	inter																	
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	H Threshold		-															
17																		
18	Summer		8 1 2021 - Current															
19	Cust. Chg		$ 15.39								$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 15.39	$ 92.34	$ 184.68
20	Headblock		$ 0.5632								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Tailblock		$ 0.5632								$ 28.72	$ 15.77	$ 9.01	$ 7.88	$ 7.88	$ 11.83	$ 81.10	$ 456.76
22	H Threshold		-															
23																		
24	Total ase Rate Amount			$ 50.31	$ 77.34	$ 84.66	$ 98.74	$ 89.73	$ 67.20	$ 467.99	$ 44.11	$ 31.16	$ 24.40	$ 23.27	$ 23.27	$ 27.22	$ 173.44	$ 641.44
25																		
26	COG Rate - Seasonal			$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 1.1339	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 0.5587	$ 1.0318
27	COG amount			$ 70.30	$ 124.73	$ 139.47	$ 167.82	$ 149.67	$ 104.32	$ 756.31	$ 28.49	$ 15.64	$ 8.94	$ 7.82	$ 7.82	$ 11.73	$ 80.45	$ 836.76
28																		
29	DAC			$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444	$ 0.1444
30	DAC amount			$ 8.95	$ 15.89	$ 17.76	$ 21.37	$ 19.06	$ 13.29	$ 96.33	$ 7.37	$ 4.04	$ 2.31	$ 2.02	$ 2.02	$ 3.03	$ 20.80	$ 117.13
31																		
32	Total Bill			129.5	217.9	241.90	287.94	258.47	184.81	1 320. 3	79.97	50.85	35. 5	33.12	33.12	41.98	274. 9	1 595.32
33																		
34	Novem er 1 2020 - April 30 2021										May 1 2021 - Octo er 31 2021							
35	Residential Heating R3																	
36										inter							Summer	Total
37				Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	Nov-Apr	May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	May-Oct	Nov-Oct
38	Typical Usage Therms			62	110	123	148	132	92	667	51	28	16	14	14	21	144	811
39																		
40	inter	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	H Threshold	-	-	$ 34.53														
45																		
46	Summer	7 1 20 - 7 31 21	8 1 2021 - Current															
47	Cust. Chg	$ 15.50	$ 15.39								$15.50	$15.50	$15.50	$15.39	$15.39	$15.39	$ 92.67	$ 185.67
48	Headblock	$ 0.5678	$ 0.5632								$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	Tailblock	$ 0.5678	$ 0.5632								$ 28.96	$ 15.90	$ 9.08	$ 7.88	$ 7.88	$ 11.83	$ 81.54	$ 460.26
50	H Threshold	-	-															
51																		
52	Total ase Rate Amount			$ 50.70	$ 77.96	$ 85.34	$ 99.53	$ 90.45	$ 67.74	$ 471.72	$ 44.46	$ 31.40	$ 24.58	$ 23.27	$ 23.27	$ 27.22	$ 174.21	$ 645.93
53																		
54	COG Rate - Seasonal			$ 0.5571	$ 0.5571	$ 0.4664	$ 0.4276	$ 0.5156	$ 0.6050	$ 0.5100	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.3935	$ 0.4893
55	COG amount			$ 34.54	$ 61.28	$ 57.37	$ 63.28	$ 68.06	$ 55.66	$ 340.19	$ 20.07	$ 11.02	$ 6.30	$ 5.51	$ 5.51	$ 8.26	$ 56.66	$ 396.86
56																		
57	DAC			$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589	$ 0.0589
58	DAC amount			$ 3.65	$ 6.48	$ 7.24	$ 8.72	$ 7.77	$ 5.42	$ 39.29	$ 3.00	$ 1.65	$ 0.94	$ 0.82	$ 0.82	$ 1.24	$ 8.48	$ 47.77
59																		
60	Total Bill			88.90	145.72	149.95	171.54	1 .28	128.82	851.20	7.53	44.07	31.82	29. 1	29. 1	3 .72	239.35	1 090.55
61																		
62	DIFFERENCE																	
63	Total Bill			40. 7	72.24	91.95	11 .40	92.19	55.99	4 9.43	12.44	.78	3.83	3.51	3.51	5.27	35.34	504.77
64	Change			45.75	49.57	1.32	7.8	55.44	43.47	55.15	18.42	15.39	12.03	11.8	11.8	14.34	14.7	4 .29
65																		
66	Base Rate			$ 0.40	$ 0.62	$ 0.68	$ 0.79	$ 0.72	$ 0.53	$ 3.73	$ 0.34	$ 0.24	$ 0.18	$ -	$ -	$ -	$ 0.77	$ 4.50
67	Change			-0.78	-0.79	-0.79	-0.79	-0.79	-0.79	-0.79	-0.78	-0.76	-0.75	0.00	0.00	0.00	-0.44	-0.70
68																		
69	COG LDAC			$ 41.06	$ 72.86	$ 92.62	$ 117.19	$ 92.90	$ 56.53	$ 473.16	$ 12.79	$ 7.02	$ 4.01	$ 3.51	$ 3.51	$ 5.27	$ 36.10	$ 509.26
70	Change			107.52	107.52	143.35	162.76	122.51	92.55	124.69	55.42	55.42	55.42	55.42	55.42	55.42	55.42	114.54
	check			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 0.00	$ -	$ -	$ -	$ -	$ -	$ -

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
Off Pea 2022 Summer Cost of Gas Filing
Annual Bill Comparisons May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-41

Updated Schedule 8
Page 2 of 5

Novem er 1 2021 - April 30 2022 / May 1 2022 - Octo er 31 2022
Commercial Rate G-41

		Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	inter Nov-Apr	May-22	un-22	ul-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
inter	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								
H 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
H Threshold	20															
Total ase 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
DAC		$ 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
DAC 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	3 437.4	207.33	97.	85.15	92.85	84.19	88.04	55.20	4 092. 7

Novem er 1 2020 - April 30 2021 / May 1 2021 - Octo er 31 2021
Commercial Rate G-41

			Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	inter Nov-Apr	May-21	un-21	ul-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
inter	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								
H 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
H Threshold	20	20															
Total ase 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
DAC			$ 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
DAC 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	3 .09	3 2.52	2 144.09	17 .92	90.22	80.33	85.94	79.11	82.15	594. 7	2 738.7

DIFFERENCE

Total Bill	53.79	1 8.39	352.48	337.30	215.05	1 .3	1 293.37	30.40	7.44	4.82	.90	5.08	5.89	0.53	1 353.90
Change	34.99	51.07	71.28	77.10	58.74	45.89	0.32	17.18	8.25	.00	8.03	.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	$ -

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2 Off Pea 2022 Summer Cost of Gas Filing
4 Annual Bill Comparisons May 19 - Oct 19 vs May 20 - Oct 20 - Commercial Rate G-42
5
6

Updated Schedule 8
Page 3 of 5

7 Novem er 1 2021 - April 30 2022 | May 1 2022 - Octo er 31 2022
8 C I High inter Use Medium G-42

Row										inter							Summer	Total
10				Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	Nov-Apr	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	May-Oct	Nov-Oct
11	Typical Usage Therms			830	2,189	3,708	3,406	2,603	2,395	15,131	1,319	484	285	247	269	340	2,944	18,075
12																		
13	inter		8 1 2021 - Current															
14	Cust. Chg		$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14								
15	Headblock		$ 0.4261	$ 353.66	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 426.10	$ 2,484.16								
16	Tailblock		$ 0.2839	$ -	$ 337.56	$ 768.80	$ 683.06	$ 455.09	$ 396.04	$ 2,640.55								
17	H Threshold		1,000															
18																		
19	Summer		8 1 2021 - Current															
20	Cust. Chg		$ 171.19								$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
21	Headblock		$ 0.4261								$ 170.44	$ 170.44	$ 121.44	$ 105.25	$ 114.62	$ 144.87	$ 827.06	$ 3,311.22
22	Tailblock		$ 0.2839								$ 260.90	$ 23.85	$ -	$ -	$ -	$ -	$ 284.75	$ 2,925.31
23	H Threshold		400															
24																		
25	Total ase Rate Amount			$ 524.85	$ 934.85	$ 1,366.09	$ 1,280.35	$ 1,052.38	$ 993.33	$ 6,151.86	$ 602.53	$ 365.48	$ 292.63	$ 276.44	$ 285.81	$ 316.06	$ 2,138.95	$ 8,290.81
26																		
27	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	$ 1.0405
28	COG amount			$ 941.30	$ 2,482.54	$ 4,205.24	$ 3,862.74	$ 2,952.06	$ 2,716.17	$ 17,160.07	$ 737.72	$ 270.70	$ 159.40	$ 138.15	$ 150.45	$ 190.16	$ 1,646.58	$ 18,806.65
29																		
30	DAC			$ 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
31	DAC amount			$ 72.88	$ 192.21	$ 325.59	$ 299.07	$ 228.56	$ 210.30	$ 1,328.61	$ 115.82	$ 42.50	$ 25.02	$ 21.69	$ 23.62	$ 29.85	$ 258.50	$ 1,587.11
32																		
33	Total Bill			1 539.04	3 09. 0	5 89 .92	5 442.17	4 233.01	3 919.80	24 40.53	1 45 .07	78. 8	477.05	43 .27	459.88	53 .08	4 044.03	28 84.57

34
35 Novem er 1 2020 - April 30 2021 | May 1 2021 - Octo er 31 2021
36 C I High inter Use Medium G-42

Row										inter							Summer	Total
38				Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	Nov-Apr	May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	May-Oct	Nov-Oct
39	Typical Usage Therms			830	2,189	3,708	3,406	2,603	2,395	15,131	1,319	484	285	247	269	340	2,944	18,075
40																		
41	inter	7 1 20 - 7 31 21	8 1 2021 - Current															
42	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34								
43	Headblock	$ 0.4284	$ 0.4261	$ 355.57	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 428.40	$ 2,497.57								
44	Tailblock	$ 0.2855	$ 0.2839	$ -	$ 339.46	$ 773.13	$ 686.91	$ 457.66	$ 398.27	$ 2,655.44								
45	H Threshold	1,000	1,000															
46		-	-															
47	Summer	7 1 20 - 7 31 21	8 1 2021 - Current															
48	Cust. Chg	$ 172.39	$ 171.19								$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
49	Headblock	$ 0.4284	$ 0.4261								$ 171.36	$ 171.36	$ 122.09	$ 105.25	$ 114.62	$ 144.87	$ 829.56	$ 3,327.13
50	Tailblock	$ 0.2855	$ 0.2839								$ 262.37	$ 23.98	$ -	$ -	$ -	$ -	$ 286.36	$ 2,941.79
51	H Threshold	400	400															
52																		
53	Total ase Rate Amount			$ 527.96	$ 940.25	$ 1,373.92	$ 1,287.70	$ 1,058.45	$ 999.06	$ 6,187.35	$ 606.12	$ 367.73	$ 294.48	$ 276.44	$ 285.81	$ 316.06	$ 2,146.65	$ 8,334.00
54																		
55	COG Rate - Seasonal			$ 0.5552	$ 0.5552	$ 0.4645	$ 0.4257	$ 0.5137	$ 0.6031	$ 0.5043	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.3886	$ 0.4854
56	COG amount			$ 460.82	$ 1,215.33	$ 1,722.37	$ 1,449.93	$ 1,337.16	$ 1,444.42	$ 7,630.03	$ 512.56	$ 188.08	$ 110.75	$ 95.98	$ 104.53	$ 132.12	$ 1,144.04	$ 8,774.07
57																		
58	DAC			$ 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
59	DAC amount			$ 46.07	$ 121.49	$ 205.79	$ 189.03	$ 144.47	$ 132.92	$ 839.77	$ 73.20	$ 26.86	$ 15.82	$ 13.71	$ 14.93	$ 18.87	$ 163.39	$ 1,003.16
60																		
61	Total Bill			1 034.84	2 277.07	3 302.08	2 92 . 7	2 540.07	2 57 .41	14 57.15	1 191.89	582. 8	421.05	38 .13	405.27	4 7.0	3 454.08	18 111.24
62																		
63	DIFFERENCE																	
64	Total Bill			504.19	1 332.53	2 594.84	2 515.50	1 92.93	1 343.39	9 983.38	2 4.18	9 .00	5 .00	50.14	54. 1	9.02	589.95	10 573.33
65	Change			48.72	58.52	78.58	85.95	. 5	52.14	8.11	22.1	1 .48	13.30	12.99	13.47	14.78	17.08	58.38
66																		
67	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
68	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
69																		
70	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
71	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

1 Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
2 Off Pea 2022 Summer Cost of Gas Filing
4 Annual Bill Comparisons May 21 - Oct 21 vs May 22 - Oct 22 - Commercial Rate G-52
5
6

Updated Schedule 8
Page 4 of 5

7 Novem er 1 2021 - April 30 2022 | May 1 2022 - Octo er 31 2022
8 Commercial Rate G-52

Line		8 1 2021 - Current	Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	inter Nov-Apr	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Summer May-Oct	Total Nov-Oct
11	Typical Usage Therms		1,352	1,866	2,284	2,160	1,886	1,760	11,308	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
12																	
13	inter	8 1 2021 - Current															
14	Cust. Chg	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14								
15	Headblock	$ 0.2428	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 242.80	$ 1,456.80								
16	Tailblock	$ 0.1617	$ 56.92	$ 140.03	$ 207.62	$ 187.57	$ 143.27	$ 122.89	$ 858.30								
17	H Threshold	1,000															
18																	
19	Summer	8 1 2021 - Current															
20	Cust. Chg	$ 171.19								$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 171.19	$ 1,027.14	$ 2,054.28
21	Headblock	$ 0.1749								$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 174.90	$ 156.89	$ 1,031.39	$ 2,488.19
22	Tailblock	$ 0.1000								$ 49.70	$ 12.80	$ 3.20	$ 2.50	$ 5.00	$ -	$ 73.20	$ 931.50
23	H Threshold	1,000															
24																	
25	Total ase Rate Amount		$ 470.91	$ 554.02	$ 621.61	$ 601.56	$ 557.26	$ 536.88	$ 3,342.24	$ 395.79	$ 358.89	$ 349.29	$ 348.59	$ 351.09	$ 328.08	$ 2,131.73	$ 5,473.97
26																	
27	COG Rate - Seasonal		$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 1.1324	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.5580	$ 0.9201
28	COG amount		$ 1,531.00	$ 2,113.06	$ 2,586.40	$ 2,445.98	$ 2,135.71	$ 1,993.02	$ 12,805.18	$ 835.33	$ 629.42	$ 575.86	$ 571.95	$ 585.90	$ 500.53	$ 3,698.98	$ 16,504.16
29																	
30	DAC		$ 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
31	DAC amount		$ 118.72	$ 163.85	$ 200.55	$ 189.66	$ 165.60	$ 154.54	$ 992.92	$ 131.45	$ 99.05	$ 90.62	$ 90.00	$ 92.20	$ 78.76	$ 582.07	$ 1,574.99
32																	
33	Total Bill		2 120. 3	2 830.93	3 408.57	3 237.21	2 858.57	2 84.45	17 140.34	1 3 2.5	1 087.3	1 015.7	1 010.54	1 029.19	907.3	412.78	23 553.12

34

35 Novem er 1 2020 - April 30 2021 | May 1 2021 - Octo er 31 2021
36 Commercial Rate G-52

Line		7 1 20 - 7 31 21	8 1 2021 - Current	Nov-20	Dec-20	an-21	Fe -21	Mar-21	Apr-21	inter Nov-Apr	May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Summer May-Oct	Total Nov-Oct
39	Typical Usage Therms			1,352	1,866	2,284	2,160	1,886	1,760	11,308	1,497	1,128	1,032	1,025	1,050	897	6,629	17,937
40																		
41	inter	7 1 20 - 7 31 21	8 1 2021 - Current															
42	Cust. Chg	$ 172.39	$ 171.19	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 172.39	$ 1,034.34								
43	Headblock	$ 0.2439	$ 0.2428	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 243.90	$ 1,463.40								
44	Tailblock	$ 0.1624	$ 0.1617	$ 57.16	$ 140.64	$ 208.52	$ 188.38	$ 143.89	$ 123.42	$ 862.02								
45	H Threshold	1,000	1,000															
46		-	-															
47	Summer	7 1 20 - 7 31 21	8 1 2021 - Current															
48	Cust. Chg	$ 172.39	$ 171.19								$ 172.39	$ 172.39	$ 172.39	$ 171.19	$ 171.19	$ 171.19	$ 1,030.74	$ 2,065.08
49	Headblock	$ 0.1767	$ 0.1749								$ 176.70	$ 176.70	$ 176.70	$ 174.90	$ 174.90	$ 156.89	$ 1,036.79	$ 2,500.19
50	Tailblock	$ 0.1004	$ 0.1000								$ 49.90	$ 12.85	$ 3.21	$ 2.50	$ 5.00	$ -	$ 73.46	$ 935.48
51	H Threshold	1,000	1,000															
52																		
53	Total ase Rate Amount			$ 473.45	$ 556.93	$ 624.81	$ 604.67	$ 560.18	$ 539.71	$ 3,359.76	$ 398.99	$ 361.94	$ 352.30	$ 348.59	$ 351.09	$ 328.08	$ 2,140.99	$ 5,500.75
54																		
55	COG Rate - Seasonal			$ 0.5660	$ 0.5660	$ 0.4753	$ 0.4365	$ 0.5245	$ 0.6139	$ 0.5235	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.3999	$ 0.4778
56	COG amount			$ 765.23	$ 1,056.16	$ 1,085.59	$ 942.84	$ 989.21	$ 1,080.46	$ 5,919.48	$ 598.65	$ 451.09	$ 412.70	$ 409.90	$ 419.90	$ 358.71	$ 2,650.94	$ 8,570.42
57																		
58	DAC			$ 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
59	DAC amount			$ 75.04	$ 103.56	$ 126.76	$ 119.88	$ 104.67	$ 97.68	$ 627.59	$ 83.08	$ 62.60	$ 57.28	$ 56.89	$ 58.28	$ 49.78	$ 367.91	$ 995.50
60																		
61	Total Bill			1 313.72	1 71 . 5	1 837.1	1 7.39	1 54.0	1 717.8	9 90 .84	1 080.72	875. 3	822.28	815.38	829.2	73 .57	5 159.83	15 0 . 7
62																		
63	DIFFERENCE																	
64	Total Bill			80 .91	1 114.28	1 571.41	1 5 9.82	1 204.51	9 .59	7 233.51	281.84	211.73	193.49	195.17	199.93	170.80	1 252.95	8 48 .45
65	Change			1.42	4.91	85.53	94.15	72.82	5 .27	73.02	2 .08	24.18	23.53	23.94	24.11	23.19	24.28	5 .33
66																		
67	Base Rate			$ 2.55	$ 2.91	$ 3.20	$ 3.11	$ 2.92	$ 2.83	$ 17.52	$ 3.20	$ 3.05	$ 3.01	$ -	$ -	$ -	$ 9.26	$ 26.78
68	Change			-0.54	-0.52	-0.51	-0.51	-0.52	-0.52	-0.52	-0.80	-0.84	-0.86	0.00	0.00	0.00	-0.43	-0.49
69																		
70	COG LDAC			$ 809.45	$ 1,117.19	$ 1,574.61	$ 1,572.93	$ 1,207.43	$ 969.42	$ 7,251.02	$ 285.04	$ 214.78	$ 196.50	$ 195.17	$ 199.93	$ 170.80	$ 1,262.21	$ 8,513.23
71	Change			96.33	96.33	129.88	148.01	110.38	82.28	110.75	41.81	41.81	41.81	41.81	41.81	41.81	41.81	89.00
	check			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Li erty Utilities EnergyNorth Natural Gas Corp. d/ /a Li erty
Off Pea 2022 Summer Cost of Gas Filing
Residential Heating

	Summer 2021	Summer 2022
Customer Charge	$ 15.50	$ 15.39
irst 20 Therms	$ 0.5678	$ 0.5632
Excess 20 Therms	$ 0.5678	$ 0.5632
DAC	$ 0.0589	$ 0.1444
COG	$ 0.5587	$ 0.5587
Total Ad ust	$ 0.6176	$ 0.7031

		Summer 2021 COG	Summer 2022 Cog	Total Impact	Impact	Base Rate Impact	Impact	COG Impact	Impact	LDAC 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

Li erty Utilities EnergyNorth Natural Gas Corp.

Updated Schedule 10A
Page 1 of 3

2022 Summer Cost of Gas Filing
Capacity Assignment Calculations 2020-2021
Derivation of Class Assignments and eightings

asic assumptions:
1 Residential class pays average seasonal gas cost rate using M A method to allocate costs to seasons
2 Residual gas costs are allocated to C I H and classes based on M A method
3 The M A 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 ase 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. Dekatherm	Ad usted Design Day Demand, Dt	Percent of Total		Avg Daily ase Use oad, 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				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. 07		3,719	69,396
14	Total				75,211	82,510	48.083		2,626	79,885
15	H 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 reakdown									
19	Total								2,626	79,885
20	H Total								4,232	11,745
21	Total								6,858	91,630
22										
23	C I reakdown Percentage									
24	Total								38.291	87.182
25	H Total								61.709	12.818
26	Total								100.0	100.0
27										
28					Capacity Cost	MD , 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 ateral 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	MD , Dt	$ Dt-Mo.			
38	Pipeline - aseload				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	MD , Dt	$ Dt-Mo.			
46	Pipeline - ase	ine 38	ine 13 Col C	42. 07	615,228	4,506	$11.3770			
47	Pipeline - Remaining	ine 39	ine 13 Col C	42. 07	6,348,623	46,502	$11.3770			
48	Storage	ine 40	ine 13 Col C	42. 07	1,755,962	11,979	$12.2156			
49	Peaking	ine 41	ine 13 Col C	42. 07	1,754,952	10,127	$14.4412			
50	Total			42. 07	10,474,751	73,114	$11.9388			
51										

Line	Description							
52	Li erty 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 eightings							
57								
58								Ratios for COG
59	C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
60	Pipeline - ase	ine 38 -	ine 46		828,730	6,070	$11.3770	
61	Pipeline - Remaining	ine 39 -	ine 47		8,551,745	62,640	$11.3769	
62	Storage	ine 40 -	ine 48		2,365,348	16,136	$12.2157	
63	Peaking	ine 41 -	ine 49		2,364,048	13,642	$14.4410	
64	Total			57.393	14,109,870	98,488	$11.9388	1.0000
65								
66								
67	- C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
68	Pipeline - ase	ine 60	ine 24 Col E		317,329	2,324	$11.3787	
69	Pipeline - Remaining	ine 61	ine 24 Col		7,455,589	54,610	$11.3770	
70	Storage	ine 62	ine 24 Col		2,062,160	14,068	$12.2154	
71	Peaking	ine 63	ine 24 Col		2,061,026	11,893	$14.4415	
72	Total			48.3884	11,896,104	82,895	$11.9590	1.0017
73				38.291	84			ine 72 ine 64
74								
75	H - C I Allocation				Capacity Cost	MD , Dt	$ Dt-Mo.	
76	Pipeline - ase	ine 60 -	ine 68		511,401	3,746	$11.3766	
77	Pipeline - Remaining	ine 61 -	ine 69		1,096,156	8,030	$11.3756	
78	Storage	ine 62 -	ine 70		303,188	2,068	$12.2174	
79	Peaking	ine 63 -	ine 71		303,022	1,749	$14.4379	
80	Total			9.0047	2,213,767	15,593	$11.8310	0.9910
81								ine 80 ine 64
82								
83	Unit Cost				Residential	C I	H 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	oad Makeup				Residential	LLF C I	HLF C I	
92								
93	Pipeline				69.77	8. 8	75.52	
94	Storage				16.38	1 .97	13.2	
95	Peaking				13.85	14.35	11.22	
96	Total				100.00	100.00	100.00	
97								
98								
99	Supply Makeup				Residential	C I	H 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	Li erty 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								
7		d	e	f	g	h	i	
8	Data Source: Schedule 10							Total
9		May	une	uly	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	ow 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								
26	Total Sales				10,442,120			
27	ow Winter Use				4,333,380			
28	Summer Ratio for ow 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 actor	Total Sales	ow Winter Use x Winter Ratio for		ow Winter Use	High Winter Use x Winter Ratio for High Winter Use		
33	Correction actor				100.2748			
34								
35								
36	Allocation Calculation for Miscellaneous Overhead							
37								
38	Pro ected Winter Sales olume				11 1 21- 4 30 22		91,676,680	Sch.10 , ln 23
39	Pro ected Annual Sales olume				11 1 21 - 10 31 22		115,042,810	Sch.10 , ln 23
40	Percentage of Winter Sales to Annual Sales						79.69	

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Docket No. DG 21-130
Exhibit 2

1 Li erty Utilities EnergyNorth Natural Gas Corp.
2 d/ /a Li erty Utilities
3 Off Pea 2022 Summer Cost of Gas Filing
4 2022 Summer Cost of Gas Filing

U dated Schedule 10
Page 1 of 1

5															
6	Dry Therms														
7 Firm Sales							Su total							Su total	
8	Nov-21	Dec-21	an-22	Fe -22	Mar-22	Apr-22	P 21-22	May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	OP 22	Total
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 olume	11 723 720	17 742 350	20 7 1 510	17 503 20	14 92 0 0	9 019 420	91 7 80	5 274 850	2 751 830	2 28 170	2 318 030	3 434 190	7 301 0 0	23 3 130	115 042 810
24															
25 Transportation Sales															
26															
27 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
28 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
29 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
30 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
31 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
32 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
33 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
34															
35 Total Trans. Sales	33 940	7 828 880	8 811 910	7 357 300	7 024 370	5 224 390	42 583 790	4 28 130	3 488 290	3 399 230	3 558 2 0	3 951 180	5 184 130	23 8 7 220	451 010
36															
37 Total All Sales	18 0 0 0	25 571 230	29 573 420	24 8 0 920	21 950 430	14 243 810	134 2 0 470	9 5 0 980	240 120	5 85 400	5 87 290	7 385 370	12 485 190	47 233 350	181 493 820

1	Li erty Utilities EnergyNorth Natural Gas Corp.							Updated Schedule 11A
2								Page 1 of 1
3	Off Pea 2022 Summer Cost of Gas Filing							
4	Normal and Design Year olumes							
5								
6								
7	olumes Therms	Normal Year						
8								
9	For the Months of May 22 -Octo er 22							
10								
11								Off Pea
12		May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	May - Oct
13	Pipeline Gas:							
14	Dawn Supply	739,535	95,658	-	-	206,295	636,518	1,678,006
15	Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
16	TGP Supply Gulf	13,120	-	-	-	-	384,326	397,446
17	Dracut Supply 1 - aseload	-	-	-	-	-	-	0
18	Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
19	Dracut Supply 3 - Swing	-	-	-	-	-	-	-
20	Constellation Combo	-	-	-	-	-	-	0
21	NG Truck	44,883	18,131	-	-	55,566	20,602	139,181
22	Propane Truck	79,409	71,899	69,472	69,279	73,449	81,696	445,204
23	PNGTS	205,081	146,300	119,612	125,908	176,916	218,093	991,910
24	Portland Natural Gas	152,602	3,126	-	-	2,555	574,003	732,286
25	TGP Supply 4	5,386,659	4,708,479	4,708,982	4,696,535	4,819,522	5,546,088	29,866,267
26		7,289,702	5,584,403	5,440,551	5,437,523	5,925,726	8,585,177	38,263,081
27								
28	Storage Gas:							
29		-	-	-	-	-	-	0
30								
31	Produced Gas:							
32	NG apor	20,025	18,131	17,519	17,470	18,522	20,602	112,269
33	Propane	-	-	-	-	-	-	0
34		20,025	18,131	17,519	17,470	18,522	20,602	112,269
35								
36	ess - Gas Refills:							
37	NG Truck	44,883	18,131	-	-	55,566	20,602	139,181
38	Propane	79,409	71,899	69,472	69,279	73,449	81,696	445,204
39	TGP Storage Refill	2,188,222	2,766,568	3,120,796	3,057,929	2,444,250	1,262,380	14,840,145
40		2,312,514	2,856,598	3,190,268	3,127,208	2,573,265	1,364,677	15,424,530
41								
42	Total Sendout olumes	4,997,212	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,950,820
43								

1 Li erty Utilities EnergyNorth Natural Gas Corp. — Updated Schedule 11B
2 — Page 1 of 1
3 Off Pea 2022 Summer Cost of Gas Filing

44 Normal and Design Year olumes
45
46
47 olumes Therms — Design Year
48
49 For the Months of May 22 -Octo er 22
50

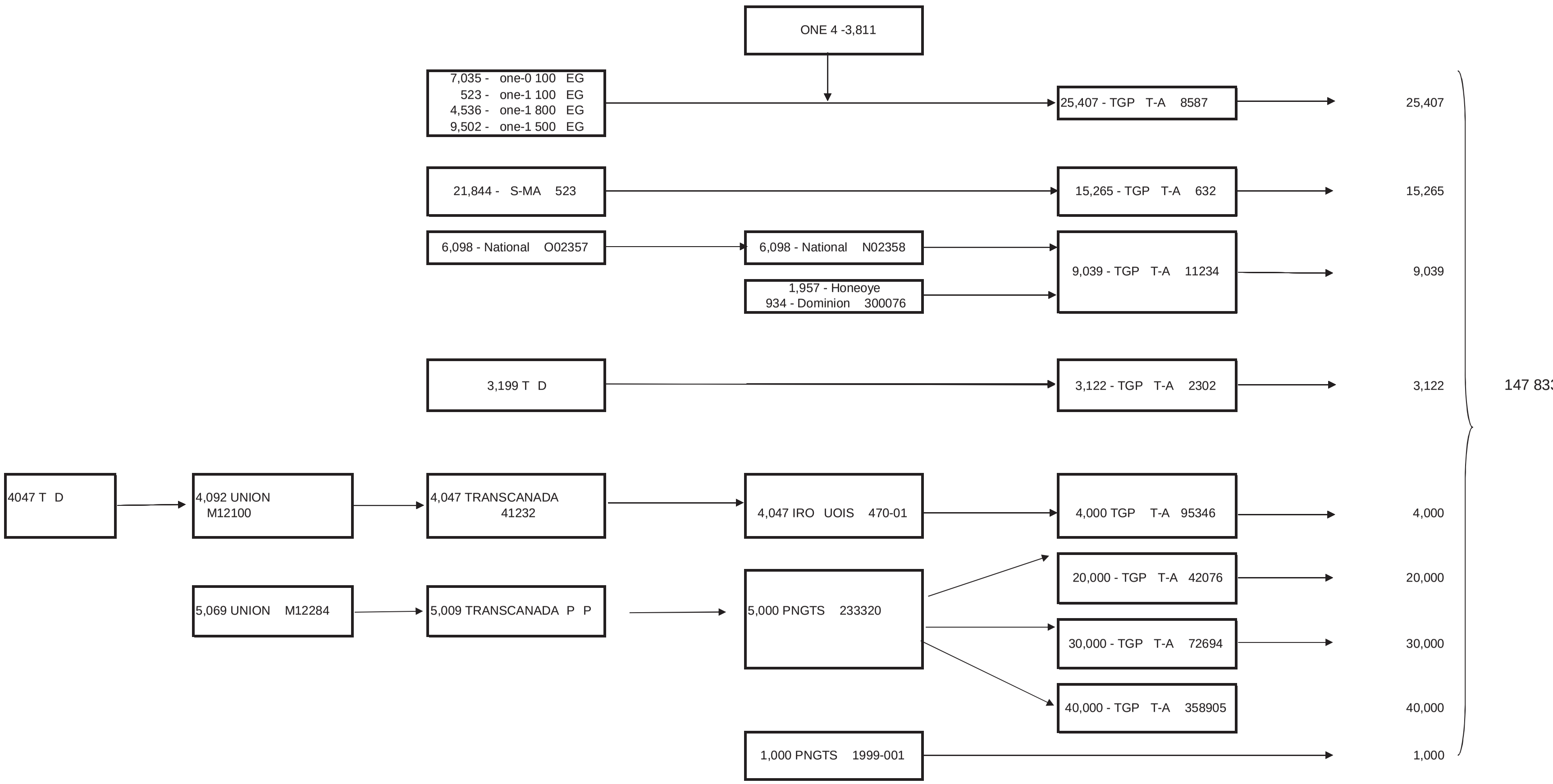
#		May-22	un-22	ul-22	Aug-22	Sep-22	Oct-22	Off Pea May - Oct
53	Pipeline Gas:							
54	Dawn Supply	738,844	49,392	-	-	102,190	658,540	1,548,966
55	Niagara Supply	668,413	540,809	542,484	545,801	591,423	687,667	3,576,596
56	TGP Supply Gulf	12,429	-	-	-	-	384,326	396,755
57	Dracut Supply 1 - aseload	-	-	-	-	-	-	0
58	Dracut Supply 2 - Swing	-	-	-	-	-	436,185	436,185
	Dracut Supply 3 - Swing	-	-	-	-	-	-	-
59	Constellation Combo	-	-	-	-	-	-	0
60	NG 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 4	5,536,500	4,925,428	4,951,832	4,939,917	5,049,449	5,697,403	31,100,529
65	Subtotal Pipeline olumes	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	NG apor	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	ess - Gas Refills:							
76	NG 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 olumes	4,974,426	2,745,936	2,267,802	2,327,785	3,370,983	7,241,101	22,928,033

Line	Description	Off-Peak Period Normal ear Use Therms	MD MM tu day	Seasonal uantity Therms	Utilization Rate	Off-Peak Period Design ear Use Therms	MD MM tu day	Seasonal uantity Therms	Utilization Rate
1	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 11C
2									Page 1 of 1
3	Off Pea 2022 Summer Cost of Gas Filing								
4	Capacity Utili ation								
5	olumes Therms								
6									
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	NG 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 4	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 olumes	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	NG apor	112,269				112,269			
29	Propane	-				-			
30									
31	Subtotal Produced Gas	112,269				112,269			
32									
33	Less - Gas Refills								
34	NG 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 olumes	22,950,820				22,928,033			

Li erty Utilities EnergyNorth Natural Gas Corp.

Off Pea 2022 Summer Cost of Gas Filing
Transportation Availa le for Pipeline Supply and Storage
MMBtu

Updated Schedule 12
Page 1 of 2



Li erty Utilities EnergyNorth Natural Gas Corp.

Off Pea 2022 Summer Cost of Gas Filing
Agreements for Gas Supply and Transportation

Updated Schedule 12
Page 2 of 2

SOURCE	RATE SCHEDULE	CONTRACT NUMBER	TYPE	MD MMBTU	MA MMBTU	E PIRATION DATE	NOTIFICATION DATE	RENE AL OPTIONS
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N A	Terminates
Constellation	CS		irm Combination i uid and apor Svc	Up to 7 trucks	630,000	3 31 2022 Peak Only	N A	Terminates
Dracut or	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-N	11234	Storage	1,957	245,380	3 31 2023	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	SS	O02358	Storage	6,098	670,800	3 31 2023	3 31 2022	Evergreen Provision
National Fuel Gas Supply Corporation	SST	N02358	Transportation	6,098	670,800	3 31 2023	3 31 2022	Evergreen Provision
Iro uois Gas Transmission System	RTS	47001	Transportation	4,047	1,477,155	11 1 2022	11 1 2021	Evergreen Provision
Portland Natural Gas Transmission System	T 1999-01	1999-001	Transportation	1,000	365,000	11 30 2032	11 31 2031	Evergreen Provision
Portland Natural Gas Transmission System	T	P P	Transportation	4,432	1,617,680	10 31 2040	10 31 2039	Precedent Agreement
Tennessee Gas Pipeline Company	S-MA	523	Storage	21,844	1,560,391	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	8587	Transportation	25,407	9,273,555	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	2302	Transportation	3,122	1,139,530	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	632	Transportation	15,265	5,571,725	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	11234	Transportation	9,039	3,299,235	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	72694	Transportation	30,000	10,950,000	10 31 2029	10 31 2028	Evergreen Provision
Tennessee Gas Pipeline Company	TA	95346	Transportation	4,000	1,460,000	11 30 2022	11 30 2021	Evergreen Provision
Tennessee Gas Pipeline Company	TA	42076	Transportation	20,000	7,300,000	10 31 2025	10 31 2024	Evergreen Provision
Tennessee Gas Pipeline Company	TA	358905	Transportation	40,000	14,600,000	10 31 2041	10 31 2040	Evergreen Provision
TransCanada Pipeline	T	41232	Transportation	4,047	1,477,155	10 31 2026	10 31 2024	Evergreen Provision
TransCanada Pipeline	T	P P	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	P P	Transportation	4,432	1,617,680	10 31 2040		Precedent Agreement

MA is calculated on a 365 day calendar year.

Ln			May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Total
1	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 13
2									Page 1 of 3
3	Off Pea 2022 Summer Cost of Gas Filing								
4	Storage Inventory								
5									
6	Underground Storage Gas								
7			May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Total
8			Actual	Actual	Estimate	Estimate	Estimate	Estimate	
9	eginning alance MM tu		1,895,479	1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	1,951,935
10									
11	In ections MM tu	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 MM tu	Sch 11A ln 29 10	5,270	150	-	-	-	-	1,368,064
18									
19	Ending alance MM tu		1,901,645	1,929,241	1,929,241	1,929,241	2,113,358	2,297,475	2,545,701
20									
21									
22	eginning alance		$ 9,092,272	$ 9,085,950	$ 9,164,894	$ 9,164,894	$ 9,164,894	$ 9,772,963	$ 3,609,668
23									
24	In ections	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 alance		$ 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 or Withdrawals ln 22 ln 9		$ 4.7779	$ 4.7501	$ 4.7505	$ 4.7505	$ 4.6244	$ 4.5204	
35									
36	TGP Storage Rate for In ections	Actual or N ME plus TGP Transportation	$ 1.6490	$ 2.8452	$ -	$ -	$ 3.3026	$ 3.3267	

Line	Description	Reference	May-21 Actual	un-21 Actual	ul-21 Estimate	Aug-21 Estimate	Sep-21 Estimate	Oct-21 Estimate	Total
37	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 13
38									Page 2 of 3
39	Off Pea 2022 Summer Cost of Gas Filing								
40									
41	Li uid Propane Gas LPG								
42			May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Total
43			Actual	Actual	Estimate	Estimate	Estimate	Estimate	
44	eginning alance		93,824	93,828	94,844	94,844	94,844	94,844	96,655
45									
46	In ections	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	Ad ustment for change in temperature		-	-	-	-	-	-	-
53	Ad ustment for Transfer		-	-	-	-	-	-	-
54	Ending alance		93,828	94,844	94,844	94,844	94,844	94,844	84,454
55									
56									
57	eginning alance		$ 1,382,938	$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,193,497
58									
59	In ections	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 alance		$ 1,382,997	$ 1,396,098	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 1,406,774	$ 599,211
66									
67	Average Rate or Withdrawals		$ 14.7397	$ 14.7199	$ 14.7199	$ 14.8325	$ 14.8325	$ 14.8325	
68									
69	Propane Rate for In ections	Actual or Sch. 6, ln 162 10	$ -	$ -	$ -	$ -	$ -	$ -	

70	Li erty Utilities EnergyNorth Natural Gas Corp.								Updated Schedule 13
71									Page 3 of 3
72	Off Pea 2022 Summer Cost of Gas Filing								
74	Li uid Natural Gas LNG		May-21	un-21	ul-21	Aug-21	Sep-21	Oct-21	Total
75			Actual	Actual	Estimate	Estimate	Estimate	Estimate	
76	eginning alance		7,885	5,928	10,583	10,583	10,583	10,583	12,057
78	In ections	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 alance		5,928	10,583	10,583	10,583	10,583	10,583	16,216
87	eginning alance		$ 34,430	$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 135,659
89	In ections	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 alance		$ 25,885	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 42,850	$ 36,451
97	Average Rate or Withdrawals		$ 4.3665	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	$ 4.0490	
99	NG Rate for In ections	Actual or Sch. 6, ln 161 10	$ 4.3665	$ 3.7546	$ 11.2630	$ 11.1000	$ -	$ -	

EnergyNorth inter 2021/2022 Cost of Gas and Summer 2022 Cost of Gas
Summary of Changes from the Original filing to the Updated Filing

	INTER RATE	INTER IMPACT	SUMMER RATE	SUMMER IMPACT
Original Filing Residential COG Rates e cluding GAP R-4	0.905		0.5002	
Update Production Storage Capacity Tab Pk Info and Rates Cell 29 to remove the portion that is attributable to eene of $208,129. ound in the Settlement Agreement for DG 20-105 Exhibit 49, ates 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 29 to remove the portion that is attributable to eene of $208,129. ound in the Settlement Agreement for DG 20-105 Exhibit 49, ates 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 29 to remove the portion that is attributable to eene of $208,129. ound in the Settlement Agreement for DG 20-105 Exhibit 49, ates 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 29 to remove the portion that is attributable to eene of $208,129. ound in the Settlement Agreement for DG 20-105 Exhibit 49, ates 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 PO Rate, as letters were issued prior to the market changes.

LDAC Ad ustments				
Original Filing Total LDAC Rate	$	0.1733		
Updated Filing Total LDAC Rate	$	0.1444	$	0.0289
Removed the prior year decoupling ad ustment				
1. Removed lines relating to the RDA ad ustment on Tab Pk Tab 19 RDA Page 1				
2. Removed tab Pk Tab 19 RDA Page 4 as it was sole related to the RDA Ad ustment				
3. Renumbered Schedules to indicate page n of 3 instead of pg. n of 4				
Updated the environmental rate calculation to exclude the lue 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 RDA Ad ustments				
1. Removed lines relating to the RDA ad ustment on Tab Pk Tab 19 RDA Page 1				
2. Removed tab Pk Tab 19 RDA Page 4 as it was sole related to the RDA Ad ustment				
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 DAC rate and the RDA Component of the DAC rate				
Original Filing Environmental component of the LDAC Rate	$	0.0155		
Updated Filing Environmental component of the LDAC Rate this impacts oth Residential and Commercial	$	0.0155	$	-
Updated the environmental rate calculation to exclude the lue Chip invoice for $1,062 identified in the Environmental Audit.				
Total Environmental Component Rate Change				-
This change resulted in no change in the DAC rate and the RDA Component of the DAC 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 DAC rate and the RDA Component of the DAC rate				
Updated the environmental rate calculation to exclude the lue Chip invoice identified in the Environmental Audit.				

Ties to total rate change for DAC

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
8	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
9	**I. Gas Volumes (Therms)**										
10										1,523,054	1.7%
11	**A. Firm Demand Volumes**										
12	Firm Gas Sales	Sch. 10B, ln 23	-	1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
13	Lost Gas (Unaccounted for)		-	154,267	268,126	327,942	293,688	236,282	128,807		1,409,112
14	Company Use		-	12,474	21,681	26,518	23,748	19,106	10,415		113,942
15	Unbilled Therms		-	7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)	(5,414,970)	(15,684)
16											
17	**Total Firm Volumes**	Sch. 6, ln 94	-	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
18											
19	**B. Supply Volumes (Therms)**										
20	Pipeline Gas:										
21	Dawn Supply	Sch. 6, ln 64	-	796,342	878,932	897,468	806,735	883,624	543,941		4,807,042
22	Niagara Supply	Sch. 6, ln 65	-	625,459	690,589	705,153	633,501	694,276	636,296		3,985,274
23	TGP Supply (Direct)	Sch. 6, ln 66	-	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382		16,183,681
24	Dracut Supply 1 - Baseload	Sch. 6, ln 67	-	-	2,648,210	4,507,009	3,037,758	-	-		10,192,978
25	Dracut Supply 2 - Swing	Sch. 6, ln 68	-	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232		11,732,071
26	ENGIE COMBO	Sch. 6, ln 69	-	-	945,993	1,229,648	1,264,827	734,441	-		4,174,908
27	LNG Truck	Sch. 6, ln 70	-	18,690	289,648	685,485	1,029,982	145,597	-		2,169,402
28	Propane Truck	Sch. 6, ln 71	-	-	-	356,219	91,328	-	-		447,548
29	PNGTS	Sch. 6, ln 72	-	198,251	197,617	108,541	146,415	191,500	201,686		1,044,010
30	Portland Natural Gas	Sch. 6, ln 73		345,771	381,679	389,728	350,092	383,716	260,087		2,111,074
31	TGP Supply (Z4)	Sch. 6, ln 74	-	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079		12,999,054
32	Subtotal Pipeline Volumes		-	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703		69,847,042
33											
34	Storage Gas:										
35	TGP Storage	Sch. 6, ln 79	-	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558		19,841,326
36											
37	Produced Gas:										
38	LNG Vapor	Sch. 6, ln 82	-	18,690	289,648	777,271	1,029,982	64,550	19,014		2,199,156
39	Propane	Sch. 6, ln 83	-	-	-	859,588	91,328	-	-		950,916
40	Subtotal Produced Gas		-	18,690	289,648	1,636,859	1,121,310	64,550	19,014		3,150,073
41											
42	Less - Gas Refill:										
43	LNG Truck	Sch. 6, ln 88	-	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-		(2,169,402)
44	Propane	Sch. 6, ln 89	-	-	-	(356,219)	(91,328)	-	-		(447,548)
45	TGP Storage Refill	Sch. 6, ln 90	-	(2,262,867)	-	-	-	-	-		(2,262,867)
46	Subtotal Refills		-	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-		(4,879,817)
47											
48	Total Firm Sendout Volumes	lns 32 + 35 + 40 + 46	-	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
49											

#			Peak Costs May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Peak Period Nov - Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Summary of Supply and Demand Forecast**										
5											
6											
7	For Month of:										
50	**II. Gas Costs**										**REDACTED**
51											
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 (Concord Lateral) Z6-Z6	Sch.5A, ln 23									
68	Portland Natural Gas Trans Service	Sch.5A, ln 24									
69	Portland Natural Gas										
70	ANE (TransCanada via Union to Iroquois)	Sch.5A, ln 26									
71	TransCanada via Union to Portland	Sch.5A, ln 27									
72	Tenn Gas Pipeline Z4-Z6 stg 632	Sch.5A, ln 28									
73	Tenn Gas Pipeline Z4-Z6 stg 11234	Sch.5A, ln 29									
74	Tenn Gas Pipeline Z5-Z6 stg 11234	Sch.5A, ln 30									
75	National Fuel FST 2358	Sch.5A, ln 31									
76	Subtotal Pipeline Demand		$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
77	Less Capacity Credit		(524,979)	(406,202)	(406,202)	(406,202)	(406,202)	(406,202)	(406,202)		(2,962,189)
78	Net Pipeline Demand Costs		$ 786,485	$ 998,368	$ 998,368	$ 998,368	$ 998,368	$ 998,368	$ 998,368		$ 6,776,696
79											
80	Peaking Supply:										
81	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Sch.5A, ln 36	[redacted]								
82	ENGIE Demand FLS	Sch.5A, ln 37									
83	ENGIE Demand	Sch.5A, ln 38									
84	Subtotal Peaking Demand		$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -		$ 4,968,750
85	Less Capacity Credit		-	(287,393)	(287,393)	(287,393)	(287,393)	(287,393)	-		(1,436,963)
86	Net Peaking Supply Demand Costs		$ -	$ 706,358	$ 706,358	$ 706,358	$ 706,358	$ 706,358	$ -		$ 3,531,788
87											
88	Storage:										
89	Dominion - Demand	Sch.5A, ln 48	[redacted]								
90	Dominion - Storage	Sch.5A, ln 49									
91	Honeoye - Demand	Sch.5A, ln 50									
92	National Fuel - Demand	Sch.5A, ln 51									
93	National Fuel - Capacity	Sch.5A, ln 52									
94	Tenn Gas Pipeline - Demand	Sch.5A, ln 53									
95	Tenn Gas Pipeline - Capacity	Sch.5A, ln 54									
96	Subtotal Storage Demand		$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
97	Less Capacity Credit		(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
98	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
99											
100	Total Demand Charges	lns 55 + 76 + 84 + 96	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887		$ 16,115,438
101	Total Capacity Credit	lns 56 + 77 + 85 + 97	(806,751)	(727,522)	(727,522)	(727,522)	(727,522)	(727,522)	(440,130)		(4,884,492)
102	Net Demand Charges		$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
103											
104											

REDACTED

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5
6

			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
105	**B. Commodity Costs**										**REDACTED**
106	Pipeline:										
107	Dawn Supply	Sch. 6, ln 12	[redacted]								
108	Niagara Supply	Sch. 6, ln 13									
109	TGP Supply (Direct)	Sch. 6, ln 14									
110	Dracut Supply 1 - Baseload	Sch. 6, ln 15									
111	Dracut Supply 2 - Swing	Sch. 6, ln 16									
112	ENGIE COMBO	Sch. 6, ln 17									
113	LNG Truck	Sch. 6, ln 18									
114	Propane Truck	Sch. 6, ln 19									
115	PNGTS	Sch. 6, ln 20									
116	Portland Natural Gas	Sch. 6, ln 21									
117	TGP Supply (Z4)	Sch. 6, ln 22									
118	Subtotal Pipeline Commodity Costs		$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
119											
120	Storage:										
121	TGP Storage - Withdrawals	Sch. 6, ln 48	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
122											
123	Produced Gas Costs:										
124	LNG Vapor	Sch. 6, ln 51	[redacted]								
125	Propane	Sch. 6, ln 52									
126	Subtotal Produced Gas Costs		$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
127											
128	Less Storage Refills:										
129	LNG Truck	Sch. 6, ln 38	[redacted]								
130	Propane	Sch. 6, ln 39									
131	TGP Storage Refill	Sch. 6, ln 40									
132	Storage Refill (Trans.)	Sch. 6, ln 41									
133	Subtotal Storage Refill		$ -	$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -		$ (2,372,341)
134											
135	Total Supply Commodity Costs		$ -	$ 2,797,420	$ 9,907,525	$ 14,220,800	$ 12,557,476	$ 6,390,132	$ 2,115,961		$ 47,989,313
136											
137	**C. Supply Volumetric Transportation Costs**										
138	Dawn Supply	Sch. 6, ln 27	[redacted]								
139	Niagara Supply	Sch. 6, ln 28									
140	TGP Supply (Direct)	Sch. 6, ln 29									
141	Dracut Supply 1 - Baseload	Sch. 6, ln 30									
142	Dracut Supply 2 - Swing	Sch. 6, ln 31									
143	Subtotal Pipeline Volumetric Trans. Costs		$ -	$ 190,287	$ 153,041	$ 162,184	$ 144,561	$ 146,577	$ 38,525		$ 835,174
144											
145	TGP Storage - Withdrawals	Sch. 6, ln 33	$ -	$ 25,361	$ 60,588	$ 75,479	$ 75,113	$ 54,742	$ 449		$ 291,733
146											
147	Total Supply Volumetric Trans. Costs	lns 143 + 145	$ -	$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974		$ 1,126,907
148											
149	Total Commodity Gas & Trans. Costs	lns 135 + 147	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221

150
151 **REDACTED**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Summary of Supply and Demand Forecast**
5

			Peak Costs								Peak Period
6			Peak Costs								Peak Period
7	For Month of:		May 16 - Oct 16	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Nov - Apr
152	**D. Supply and Demand Costs by Source**										**REDACTED**
153											
154	Purchased Gas Demand Costs										
155	Pipeline Gas Demand Costs	lns 55 + 76	$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570		$ 9,738,885
156	Peaking Gas Demand Costs	ln 84	-	993,750	993,750	993,750	993,750	993,750	-		4,968,750
157	Subtotal Purchased Gas Demand Costs		$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570		$ 14,707,635
158	Less Capacity Credit	lns 56 + 77 + 85	(524,979)	(693,594)	(693,594)	(693,594)	(693,594)	(693,594)	(406,202)		(4,399,152)
159	Net Purchased Gas Demand Costs		$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368		$ 10,308,483
160											
161	Storage Gas Demand Costs										
162	Storage Demand	ln 96	$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317		$ 1,407,802
163	Less Capacity Credit	ln 97	(281,772)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)	(33,928)		(485,340)
164	Net Storage Demand Costs		$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389		$ 922,462
165											
166	**Total Demand Costs**	lns 159 + 164	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
167											
168	Purchased Gas Supply										
169	Commodity Costs	ln 118	$ -	$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499		$ 42,563,780
170	Less Storage Inj.(TGP Storage)	ln 131	[redacted]								
171	Less Storage Transportation	ln 132									
172	Less LNG Truck	ln 129									
173	Less Propane Truck	ln 130									
174	Plus Transportation Costs	ln 143									
175	Subtotal Purchased Gas Supply		$ -	$ 2,527,981	$ 8,837,950	$ 11,224,354	$ 10,752,485	$ 5,545,818	$ 2,138,024		$ 41,026,613
176											
177	Storage Commodity Costs										
178	Commodity Costs	ln 121	$ -	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894		$ 5,125,663
179	Transportation Costs	ln 145	-	25,361	60,588	75,479	75,113	54,742	449		291,733
180	Subtotal Storage Commodity Costs		$ -	$ 470,947	$ 1,125,101	$ 1,401,627	$ 1,394,830	$ 1,016,547	$ 8,344		$ 5,417,397
181											
182	Produced Gas Commodity Costs	ln 126	$ -	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567		$ 2,672,211
183											
184	**Subtotal Commodity Costs**	lns 175 + 180 + 182	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
185											
186	Hedge Contract (Savings)/Loss	Sch 7, ln 32	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ -
187											
188	**Total Commodity Costs**	lns 184 + 186	$ -	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935		$ 49,116,221
189											
190	**Total Demand Costs**	ln 102	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757		$ 11,230,946
191	**Total Supply Costs**	ln 188	-	3,013,068	10,121,153	14,458,463	12,777,150	6,591,451	2,154,935		49,116,221
192											
193	**Total Direct Gas Costs**	lns 190 + 191	$ 1,208,615	$ 4,801,183	$ 11,909,268	$ 16,246,578	$ 14,565,265	$ 8,379,566	$ 3,236,692		$ 60,347,167
194											
195											

REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**					
2						
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**					
4	**Contracts Ranked on a per Unit Cost Basis**					**Peak Period**
5				**Contract**	**Unit Dth**	**Cost per**
6	**Supplier**	**Contract**	**Contract Type**	**Unit**	**(MDQ/ACQ)**	**Unit Dth**
7	(a)	(b)	(c)	(d)	(e)	(f)
8						
9	**Demand Costs**					
10	ENGIE Demand FLS		Peaking	MDQ	3,000	[redacted]
11	Niagara Supply		Supply	MDQ	3,199	
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	Iroquois Gas Trans Service	RTS 470-01	Transportation	MDQ	4,047	
21	Honeoye - Demand	SS-NY	Storage	MDQ	1,362	
22	Tenn Gas Pipeline	2302 Z5-Z6	Transportation	MDQ	3,122	
23	Tenn Gas Pipeline	95346 Z5-Z6	Transportation	MDQ	4,000	
24	Tenn Gas Pipeline (short haul)	11234 Z5-Z6(stg)	Transportation	MDQ	1,957	
25	Tenn Gas Pipeline (short haul)	11234 Z4-Z6(stg)	Transportation	MDQ	7,082	
26	Tenn Gas Pipeline (short haul)	8587 Z4-Z6	Transportation	MDQ	3,811	
27	Tenn Gas Pipeline (short haul)	632 Z4-Z6 (stg)	Transportation	MDQ	15,265	
28	Tenn Gas Pipeline (Concord Lateral) Z6-Z6	Firm Transportation	Transportation	MDQ	30,000	
29	ANE (TransCanada via Union to Iroquois)	Union Parkway to Iroquois	Transportation	MDQ	4,047	
30	TransCanada via Union to Portland	Union Parkway to Portland	Transportation	MDQ	1,784	
31	Tenn Gas Pipeline (long haul)	8587 Z1-Z6	Transportation	MDQ	14,561	
32	Tenn Gas Pipeline (long haul)	8587 Z0-Z6	Transportation	MDQ	7,035	
33	Portland Natural Gas Trans Service	FTN-ENN0005	Transportation	MDQ	1,000	
34	Portland Natural Gas	FTN	Transportation	MDQ	1,784	
35	ENGIE Demand	NSB041	Peaking	MDQ	10,000	
36						
37	**Supply Costs - Commodity**					
38	TGP Supply (Z4)		Pipeline	Dkt	1,299,905	[redacted]
39	Niagara Supply		Pipeline	Dkt	398,527	
40	ENGIE COMBO		Pipeline	Dkt	417,491	
41	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	
42	Dawn Supply		Pipeline	Dkt	480,704	
43	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	
44	TGP Storage		Storage	Dkt	1,984,133	
45	PNGTS		Pipeline	Dkt	104,401	
46	Propane Truck		Pipeline	Dkt	44,755	
47	LNG Truck		Pipeline	Dkt	216,940	
48	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
49	Propane		Produced	Dkt	95,092	
50	LNG Vapor (Storage)		Produced	Dkt	219,916	
51						
52	**Supply Costs - Volumetric Transportation**					
53	Dracut Supply 1 - Baseload		Pipeline	Dkt	1,019,298	[redacted]
54	Dracut Supply 2 - Swing		Pipeline	Dkt	1,173,207	
55	Niagara Supply		Pipeline	Dkt	398,527	
56	Dawn Supply		Pipeline	Dkt	480,704	
57	TGP Storage - Withdrawals		Pipeline	Dkt	1,984,133	
58	TGP Supply (Direct)		Pipeline	Dkt	1,618,368	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 2019 Winter Cost of Gas Filing
COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

Schedule 3
Page 1 of 2

(a)	Days in Month (b)	Prior Period Bal Apr-18 Ending Bal Plus May Billings (c)	May-18 31 (d)	Jun-18 30 (e)	Jul-18 31 (f)	Aug-18 31 (g)	Sep-18 30 (h)	Oct-18 31 (i)	Nov-18 30 (j)	Dec-18 31 (k)	Jan-19 31 ( )	Feb-19 28 (m)	Mar-19 31 (n)	Apr-19 30 (o)	May-19 31 (p)	Peak Period Total (q)
Account 1920 1740 COG (Over)/Under Balance Interest Calculation																
Beginning Balance	Account 1920-1740 1/	$ 2,599,354	$ 2,599,354	$ 2,809,963	$ 3,021,267	$ 1,170,522	$ 1,376,547	$ 1,583,143	$ 1,790,657	$ (79,923)	$ 171,838	$ 2,647,667	$ 5,581,094	$ 3,681,093	$ 1,307,916	$ 2,599,354
Fcst Direct Gas Costs(Inc U/G Hedges)	Schedule 5A		201,436	201,436	201,436	201,436	201,436	201,436	4,801,183	11,909,268	16,246,578	14,565,265	8,379,566	3,236,692	-	60,347,166
Production & Storage & Misc Overhead			-	-	-	-	-	-	331,852	331,852	331,852	331,852	331,852	331,852		1,991,109
Projected Revenues w/o Int.	ln 52 * 59		-	-	-	-	-	-	(1,215,530)	(8,859,482)	(12,569,565)	(13,494,227)	(11,477,743)	(7,974,343)	(3,714,669)	(59,305,560)
Projected Unbilled Revenue									(5,275,947)	(7,699,104)	(8,929,195)	(7,793,217)	(6,258,130)	(3,703,910)		(39,659,503)
Reverse Prior Month Unbilled										5,275,947	7,699,104	8,929,195	7,793,217	6,258,130	3,703,910	39,659,503
Adjustment				-	(2,059,732)				-							(2,059,732)
Add Net Adjustments	Schedule 4		-	-	-	-	-	-	(515,120)	(706,884)	(307,129)	383,528	(682,508)	(528,763)	-	(2,356,877)
Gas Cost Billed	Account 1920-1740 2/	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Monthly (Over)/Under Recovery		$ 2,599,354	$ 2,800,790	$ 3,011,398	$ 1,162,971	$ 1,371,958	$ 1,577,983	$ 1,784,579	$ (82,906)	$ 171,673	$ 2,643,482	$ 5,570,062	$ 3,667,347	$ 1,300,750	$ 1,297,157	$ 1,215,460
Average Monthly Balance	(ln 12 + 21)/2		$ 2,700,072	$ 2,910,681	$ 2,092,119	$ 1,271,240	$ 1,477,265	$ 1,683,861	$ 853,875	$ 45,875	$ 1,407,660	$ 4,108,865	$ 4,624,221	$ 2,490,921	$ 1,302,536	
Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Interest Applied	ln 22 * ln 24 / 365 * Days of Month		$ 9,173	$ 9,868	$ 7,552	$ 4,589	$ 5,160	$ 6,078	$ 2,983	$ 166	$ 4,184	$ 11,032	$ 13,746	$ 7,166	$ -	$ 81,696
(Over)/Under Balance	ln 21 + ln 26	$ 2,599,354	$ 2,809,963	$ 3,021,267	$ 1,170,522	$ 1,376,547	$ 1,583,143	$ 1,790,657	$ (79,923)	$ 171,838	$ 2,647,667	$ 5,581,094	$ 3,681,093	$ 1,307,916	$ 1,297,157	1,297,157
Calculation of COG with Interest																
Beginning Balance	ln 12	$ 2,599,354	$ 2,599,354	$ 2,809,963	$ 3,021,267	$ 1,170,522	$ 1,376,547	$ 1,583,143	$ 1,790,657	$ (81,814)	$ 166,646	$ 2,638,436	$ 5,568,246	$ 3,665,323	$ 1,290,529	$ 2,599,354
Fcst Direct Gas Costs(Inc U/G Hedges)	ln 13		201,436	201,436	201,436	201,436	201,436	201,436	4,801,183	11,909,268	16,246,578	14,565,265	8,379,566	3,236,692	-	60,347,166
Prod Storage & Misc Overhead	ln 14		-	-	-	-	-	-	331,852	331,852	331,852	331,852	331,852	331,852	-	1,991,109
Projected Revenues with int.	ln 52 * ln 61		-	-	-	-	-	-	(1,215,885)	(8,862,065)	(12,573,229)	(13,498,161)	(11,481,090)	(7,976,668)	(3,715,752)	(59,322,850)
Projected Unbilled Revenue									(5,277,485)	(7,701,349)	(8,931,798)	(7,795,489)	(6,259,955)	(3,704,990)		(39,671,065)
Reverse Prior Month Unbilled										5,277,485	7,701,349	8,931,798	7,795,489	6,259,955	3,704,990	39,671,065
Add Net Adjustments	ln 19		-	-	(2,059,732)	-	-	-	(515,120)	(706,884)	(307,129)	383,528	(682,508)	(528,763)	-	(4,416,609)
Gas Cost Billed	ln 20	-		-	-	-	-	-	-	-	-	-	-	-	-	-
Add Interest	ln 26		-	-	-	-	-	-	2,983	166	4,184	11,032	13,746	7,166	-	39,276
(Over)/Under Balance		$ 2,599,354	$ 2,800,790	$ 3,011,398	$ 1,162,971	$ 1,371,958	$ 1,577,983	$ 1,784,579	$ (81,816)	$ 166,658	$ 2,638,451	$ 5,568,261	$ 3,665,345	$ 1,290,566	$ 1,279,766	$ 1,237,446
Average Monthly Balance			$ 2,700,072	$ 2,910,681	$ 2,092,119	$ 1,271,240	$ 1,477,265	$ 1,683,861	$ 854,421	$ 42,422	$ 1,402,548	$ 4,103,348	$ 4,616,795	$ 2,477,945	$ 1,285,148	
Interest Applied	ln 24 * ln 44 / 365 * Days of Month		9,173	9,868	7,552	4,589	5,160	6,078	2,985	153	4,169	11,017	13,724	7,128	-	81,596
(Over)/Under Balance	-ln 41 +ln 42 + ln 46	$ 2,599,354	$ 2,809,963	$ 3,021,267	$ 1,170,522	$ 1,376,547	$ 1,583,143	$ 1,790,657	$ (81,814)	$ 166,646	$ 2,638,436	$ 5,568,246	$ 3,665,323	$ 1,290,529	$ 1,279,766	1,279,766
Forecast Sendout Therms	Sch 1								9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276		87,958,623
Less Forecast Billing Therm Sales	Sch. 10B, ln 23 Nov - May								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
Less Forecast Unaccounted For	Sch 1								154,267	268,126	327,942	293,688	236,282	128,807		1,409,112
Less Forecast Company Use	Sch 1								12,474	21,681	26,518	23,748	19,106	10,415		113,942
Unbilled Volumes									7,690,884	3,532,300	1,793,136	-1,655,946	-2,237,735	-3,723,353	-5,414,970	(15,684)
Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286	-15,684	
COB w/o Interest	Sch. 3, pg. 4, ln 209 col. (c)								$0.6860	$0.6860	$0.6860	$0.6860	$0.6860	$0.6860	$0.6860	
COG With Interest	Sch. 3, pg. 4, ln 209 col. (d)								$0.6862	$0.6862	$0.6862	$0.6862	$0.6862	$0.6862	$0.6862	

1/ Beginning Balance for Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 31, April 2010 column.
2/ Gas Cost Billed Acct 1920-1740. See Tab 18, Schedule 1, page 1, line 15, May 2010 column.

(a)	Days in Month (b)	Prior Period Bal Apr-18 Ending Bal + May Collections	May-18 31 (c)	Jun-18 30 (d)	Jul-18 31 (e)	Aug-18 31 (f)	Sep-18 30 (g)	Oct-18 31 (h)	Nov-18 30 (i)	Dec-18 31 ( )	Jan-19 31 (k)	Feb-19 28 (l)	Mar-19 31 (m)	Apr-19 30 (n)	May-19 31 (o)	Peak Period Total (p)
Account 1163 1422 Working Capital (Over)/Under Balance Interest Calculation																
Beginning Balance	Account 1163-1422 1/	$ 4,305	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 4,305
Days Lag			0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391	0.0391		
Prime Rate			4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Forecast Working Capital	ln 34 * 0.091%		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
Projected Revenues w/o Int.	ln 119 * ln 123		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
Projected Unbilled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
Add Net Adjustments			-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
Working Capital Billed	Account 1163-1422 2/	-														-
Monthly (Over)/Under Recovery		$ 4,305	$ 4,620	$ 4,960	$ (3,270)	$ (2,932)	$ (2,608)	$ (2,283)	$ 9	$ 9,930	$ 20,114	$ 29,284	$ 32,123	$ 31,903	$ 31,986	$ 31,673
Average Monthly Balance	(ln 76 + ln 90)/2		$ 4,463	$ 4,798	$ 853	$ (3,099)	$ (2,776)	$ (2,451)	$ (1,141)	$ 4,967	$ 15,030	$ 24,721	$ 30,737	$ 32,059	$ 31,991	
Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
Interest Applied	ln 92 * ln 94 / 365 * Days of Month		$ 15	$ 16	$ 3	$ (11)	$ (10)	$ (9)	$ (4)	$ 18	$ 45	$ 66	$ 91	$ 92	$ -	$ 313
(Over)/Under Balance	ln 90 + ln 96	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,986	31,986

1 Liberty Utilities (EnergyNorth Natural Gas) Corp.
2 d/b/a Liberty Utilities
3 Peak 2018 2019 Winter Cost of Gas Filing
4 COG (Over)/Under Cumulative Recovery Balances and Interest Calculation

Schedule 3
Page 2 of 2

101	**Calculation of Working Capital with Interest**																
103	**Beginning Balance**	ln 76	$ 4,305	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 4,305
104	Forecast Working Capital	ln 80		315	325	335	335	335	335	7,979	19,792	22,236	19,935	11,469	4,430	-	87,820
105	Projected Rev. with interest	ln 119 * ln 125		-	-	-	-	-	-	(1,063)	(7,749)	(10,994)	(11,803)	(10,039)	(6,975)	(3,249)	(51,871)
106	Projected Unb lled Revenue									(4,615)	(6,734)	(7,810)	(6,816)	(5,474)	(3,240)		(34,688)
107	Reverse Prior Month Unbilled										4,615	6,734	7,810	6,816	5,474	3,240	34,688
108	Add Net Adjustments	ln 86	-	-	-	(8,581)	-	-	-	-	-	-	-	-	-	-	(8,581)
109	Working Capital Billed	ln 88	-	-	-	-	-	-	-								-
110	Add Interest	ln 96		-	-	-	-	-	-	(4)	18	45	66	91	92	-	309
111	Monthly (Over)/Under Recovery		$ 4,305	$ 4,620	$ 4,960	$ (3,270)	$ (2,932)	$ (2,608)	$ (2,283)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,987	$ 31,981
113	Average Monthly Balance			$ 4,463	$ 4,798	$ 853	$ (3,099)	$ (2,776)	$ (2,451)	$ (1,143)	$ 4,976	$ 15,053	$ 24,754	$ 30,782	$ 32,105	$ 31,991	
115	Interest Applied	ln 94 * ln 113 / 365 * Days of Month		15	16	3	(11)	(10)	(9)	(4)	18	45	66	92	92	-	$ 314
117	**(Over)/Under Balance**	-ln 110 +ln 111 + ln 115	$ 4,305	$ 4,635	$ 4,976	$ (3,267)	$ (2,943)	$ (2,618)	$ (2,292)	$ 5	$ 9,947	$ 20,158	$ 29,350	$ 32,214	$ 31,996	$ 31,987	$ 31,987
119	Forecast Therm Sales	ln 52								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
120	Unbilled Therm	ln 55								7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)		
121	Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286		
123	Working Cap. Rate w/out Int.	Sch. 3, pg. 4, ln 226 col. (c)								$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	$0.0006	
125	Working Capital Rate w/ Int	Sch 3 pg 4 ln 226 col (d)								$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	$0 0006	
126	1/ Beginning Balance for Acct 1163-1422. See Tab 18 Schedule 5, page 1, line 18, April 2010 column.																
127	2/ Working Capital Billed Acct 1163-1422. See Tab 18, Schedule 5, page 1, line 8, May 2010 column.																
128			Prior Period Bal														
129			Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	May-19	DemandPeriod
130		Days in Month	Ending Bal	31	30	31	31	30	31	30	31	31	28	31	30	31	Total
131	(a)	(b)	+ May Collections	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	( )	(m)	(n)	(o)	(p)
133	**Account 1920 1743 Bad Debt (Over)/Under Balance Interest Calculation**																
135	Forecast Direct Gas Costs	ln 34		$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 201,436	$ 4,801,183	$11,909,268	$16,246,578	$14,565,265	$ 8,379,566	$ 3,236,692	$ -	60,347,166
136	Forecast Working Capital	ln 104		315	325	335	335	335	335	12,284	19,792	22,236	19,935	11,469	4,430		92,125
137	Prior Period Balance	ln 42								433,226	433,226	433,226	433,226	433,226	433,226		2,599,354
138	Total Forecast Direct Gas Costs & Working Capital			201,751	201,761	201,771	201,771	201,771	201,771	5,246,693	12,362,286	16,702,039	15,018,425	8,824,260	3,674,348	-	60,439,291
140	**Beginning Balance**	Account 1920-1743 1/	$ (144,328)	$ (144,328)	$ (141,289)	$ (138,240)	$ (160,372)	$ (157,422)	$ (154,442)	$ (151,471)	$ (339,874)	$ (610,930)	$ (915,007)	$(1,187,048)	$ (1,464,476)	$ (1,637,860)	$ (144,328)
142	Forecast Bad Debt	ln 138 * 0.0174597638738471		3,523	3,523	3,523	3,523	3,523	3,523	91,606	215,843	291,614	262,218	154,069	64,153		1,100,640
144	Projected Revenues w/o int	ln 181 * ln 185		-	-	-	-	-	-	(52,271)	(380,984)	(540,528)	(580,291)	(493,576)	(342,920)	(159,742)	(2,550,312)
145	Projected Unb lled Revenue									(226,881)	(331,084)	(383,981)	(335,131)	(269,118)	(159,279)		(1,705,474)
146	Reverse Prior Month Unbilled										226,881	331,084	383,981	335,131	269,118	159,279	1,705,474
148	Bad Debt Billed	Account 1920-1743 2/	-		-	-	-	-	-		-	-	-	-	-	-	-
150	Add Net Adjustments		-	-	-	(25,117)	-	-	-		-	-	-	-	-	-	(25,117)
152	Monthly (Over)/Under Recovery		$ (144,328)	$ (140,805)	$ (137,767)	$ (159,834)	$ (156,849)	$ (153,899)	$ (150,920)	$ (339,017)	$ (609,218)	$ (912,742)	$ (1,184,229)	$(1,460,541)	$ (1,633,404)	$ (1,638,323)	$ (1,619,117)
154	Average Monthly Balance	(ln 140 + ln 152)/2		$ (142,566)	$ (139,528)	$ (149,037)	$ (158,610)	$ (155,660)	$ (152,681)	$ (245,244)	$ (474,546)	$ (761,836)	$ (1,049,618)	$(1,323,794)	$ (1,548,940)	$ (1,638,091)	
156	Interest Rate	Prime Rate		4.00%	4.13%	4.25%	4.25%	4.25%	4.25%	4.25%	4.25%	3.50%	3.50%	3.50%	3.50%		
158	Interest Applied	ln 154 * ln 156 / 365 * Days of Month		$ (484)	$ (473)	$ (538)	$ (573)	$ (544)	$ (551)	$ (857)	$ (1,713)	$ (2,265)	$ (2,818)	$ (3,935)	$ (4,456)		$ (19,206)
160	**(Over)/Under Balance**	ln 152 + ln 158	$ (144 328)	$ (141 289)	$ (138 240)	$ (160 372)	$ (157 422)	$ (154 442)	$ (151 471)	$ (339 874)	$ (610 930)	$ (915 007)	$ (1 187 048)	$(1 464 476)	$ (1 637 860)	$ (1 638 323)	(1 638 323)
163	**Calculation of Bad Debt with Interest**																
165	**Beginning Balance**	ln 140	$ (144,328)	$ (144,328)	$ (141,289)	$ (138,240)	$ (135,210)	$ (132,168)	$ (129,101)	$ (126,038)	$ (314,354)	$ (585,321)	$ (889,398)	$(1,161,438)	$ (1,438,867)	$ (1,612,251)	$ (144,328)
166	Forecast Bad Debt	ln 142		3,523	3,523	3,523	3,523	3,523	3,523	91,606	215,843	291,614	262,218	154,069	64,153	-	1,100,640
167	Projected Revenues with int.	ln 181 * ln 187		-	-	-	-	-	-	(52,271)	(380,984)	(540,528)	(580,291)	(493,576)	(342,920)	(159,742)	(2,550,312)
168	Projected Unb lled Revenue									(226,881)	(331,084)	(383,981)	(335,131)	(269,118)	(159,279)		(1,705,474)
169	Reverse Prior Month Unbilled										226,881	331,084	383,981	335,131	269,118	159,279	1,705,474
170	Bad Debt Billed	ln 148	-		-	-	-	-	-	-	-	-	-	-	-	-	0
171	Add Interest	ln 158		-	-	-	-	-	-	(857)	(1,713)	(2,265)	(2,818)	(3,935)	(4,456)	-	(16,043)
172	Add Net Adjustments	ln 150	-							-	-	-	-	-	-	-	0
173	Monthly (Over)/Under Recovery		$ (144 328)	$ (140 805)	$ (137 767)	$ (134 717)	$ (131 687)	$ (128 646)	$ (125 578)	$ (314 441)	$ (585 410)	$ (889 398)	$ (1 161 438)	$(1 438 867)	$ (1 612 251)	$ (1 612 714)	$ (1 610 043)
175	Average Monthly Balance			$ (142,566)	$ (139,528)	$ (136,478)	$ (133,448)	$ (130,407)	$ (127,340)	$ (220,239)	$ (449,882)	$ (737,359)	$ (1,025,418)	$(1,300,153)	$ (1,525,559)	$ (1,612,482)	
177	Interest Applied	ln 156 * ln 175 / 365 * Days of Month		(484)	(473)	(493)	(482)	(456)	(460)	(769)	(1,624)	(2,265)	(2,818)	(3,935)	(4,456)	-	$ (18,714)
179	**(Over)/Under Balance**	-ln 171 +ln 173 + ln 177	$ (144,328)	$ (141,289)	$ (138,240)	$ (135,210)	$ (132,168)	$ (129,101)	$ (126,038)	$ (314,354)	$ (585,321)	$ (889,398)	$ (1,161,438)	$(1,438,867)	$ (1,612,251)	$ (1,612,714)	$ (1,612,714)
181	Forecast Term Sales	ln 52								1,771,910	12,914,697	18,322,981	19,670,884	16,731,404	11,624,407	5,414,970	86,451,254
182	Unbilled Therm	ln 55								7,690,884	3,532,300	1,793,136	(1,655,946)	(2,237,735)	(3,723,353)		
183	Gross Unbilled									7,690,884	11,223,184	13,016,320	11,360,374	9,122,639	5,399,286		
185	COG Rate Without Interest	Sch. 3, pg. 4, ln 243 col. (c)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	
187	COG With Interest	Sch. 3, pg. 4, ln 243 col. (d)								$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	$0.0295	
188	1/ Beginning Balance for Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 20, April 2010 column.																
189	2/ Bad Debt B lled Acct 1920-1743. See Tab 18, Schedule 1, page 3, line 10, May 2010 column.																
191	**Total Interest**	lns 46 + 115 + 177	$ -	$ 8,704	$ 9,412	$ 7,062	$ 4,096	$ 4,695	$ 5,610	$ 2,211	$ (1,453)	$ 1,949	$ 8,266	$ 9,880	$ 2,765	$ -	$ 63,196

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Adjustments to Gas Costs**
5

			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
6	Adjustments												
7	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(m)
8													
9	May-18		$ -	$ -	-	$ -	$ -	$ -	[redacted]		$ -	$ -	$ -
10	Jun-18		-	-	-	-	-	-			-	-	-
11	Jul-18	1/	-	-	-	-	-	-			-	-	-
12	Aug-18	1/	-	-	-	-	-	-			-	-	-
13	Sep-18	1/	-	-	-	-	-	-			-	-	-
14	Oct-18	1/	-	-	-	-	-	-			-	-	-
15	Nov-18	1/	-	-	(227,504)	-	(3,273)	-			-	45,000	(515,120)
16	Dec-18	1/	-	-	(368,407)	-	(4,111)	-			-	-	(706,884)
17	Jan-19	1/	-	-	(17,997)	-	(5,091)	-			-	-	(307,129)
18	Feb-19	1/	-	-	703,749	-	(5,254)	-			-	-	383,528
19	Mar-19	1/	-	-	(369,992)	-	(4,696)	-			-	-	(682,508)
20	Apr-19	1/	-	-	(217,609)	-	(3,956)	-			-	-	(528,763)
21													
22	Subtotal May 18 - Oct 18		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23													
24	Subtotal Nov 18 - Apr 19		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
25													
26	Total Peak Period		$ -	$ -	$ (497,759)	$ -	$ (26,381)	$ -	$ -	$ (1,877,737)	$ -	$ 45,000	$ (2,356,877)
27													

1/ Estimates are based on prior years actual, except transportation revenue is calculated on Schedule 17.

Ln											
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										**REDACTED**
2	**d/b/a Liberty Utilities**										**Schedule 5A**
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										**Page 1 of 1**
4	**Demand Costs**										
5											
6				Deferred							Peak
7				to Peak							Nov-Apr
8		Peak	Reference	May 18 -Oct 18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	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	[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		Sch 5B, ln 18 * Sch 5C ln 24 x days								
23	Tenn Gas Pipeline (Concord Lateral) Z6-Z6		Sch 5B, ln 19 * Sch 5C ln 26 x days								
24	Portland Natural Gas Trans Service		Sch 5B, ln 20 * Sch 5C ln 28 x days								
25	Portland Natural Gas		Sch 5B, ln 21 * Sch 5C ln 29 x days								
26	ANE (TransCanada via Union to Iroquois)		Sch 5B, ln 22 * Sch 5C ln 30 x days								
27	TransCanada via Union to Portland		Sch 5B, ln 23 * Sch 5C ln 31 x days								
28	Tenn Gas Pipeline Z4-Z6 stg 632	peak	Sch 5B, ln 24 * Sch 5C ln 32 x days								
29	Tenn Gas Pipeline Z4-Z6 stg 11234	peak	Sch 5B, ln 25 * Sch 5C ln 34 x days								
30	Tenn Gas Pipeline Z5-Z6 stg 11234	peak	Sch 5B, ln 26 * Sch 5C ln 36 x days								
31	National Fuel FST 2358	peak	Sch 5B, ln 27 * Sch 5C ln 38 x days								
32											
33	Subtotal Pipeline Demand Charges			$ 1,311,464	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 1,404,570	$ 9,738,885
34											
35	**Peaking Supply**										
36	Tenn Gas Pipeline (Concord Latera) Z6-Z6	peak	Sch 5B, ln 30 * Sch 5C ln 26 x days	[redacted]							
37	ENGIE Demand FLS	peak	Per Contract								
38	ENGIE Demand	peak	Per Contract								
39	Subtotal Peaking Demand Charges			$ -	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ 993,750	$ -	$ 4,968,750
40											
41	**Subtotal Supply, Pipeline & Peaking**		ln 13 + ln 33 + ln 39	$ 1,311,464	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 2,398,320	$ 1,404,570	$ 14,707,635
42											
43	Less Transportation Capacity Credit			$ (524,979)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (693,594)	$ (406,202)	$ (4,399,152)
44											
45	**Total Supply, Pipeline & Peaking Demand**			$ 786,485	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 1,704,726	$ 998,368	$ 10,308,483
46											
47											
48	Dominion - Demand	peak	Sch 5B, ln 35 * Sch 5C ln 61 x days	$ 10,464	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 1,744	$ 20,928
49	Dominion - Storage	peak	Sch 5B, ln 36 * Sch 5C ln 62 x days	8,935	1,489	1,489	1,489	1,489	1,489	1,489	17,870
50	Honeoye - Demand	peak	Sch 5B, ln 37 * Sch 5C ln 65 x days	52,466	8,744	8,744	8,744	8,744	8,744	8,744	104,933
51	National Fuel - Demand	peak	Sch 5B, ln 39 * Sch 5C ln 67 x days	90,980	15,163	15,163	15,163	15,163	15,163	15,163	181,959
52	National Fuel - Capacity	peak	Sch 5B, ln 40 * Sch 5C ln 68 x days	153,345	25,557	25,557	25,557	25,557	25,557	25,557	306,690
53	Tenn Gas Pipeline - Demand	peak	Sch 5B, ln 41 * Sch 5C ln 71 x days	195,783	32,631	32,631	32,631	32,631	32,631	32,631	391,567
54	Tenn Gas Pipeline - Capacity	peak	Sch 5B, ln 42 * Sch 5C ln 72 x days	191,928	31,988	31,988	31,988	31,988	31,988	31,988	383,856
55											
56	**Subtotal Storage Demand Costs**			$ 703,901	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 117,317	$ 1,407,802
57											
58	Less Transportation Capacity Credit			$ (281,772)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (33,928)	$ (485,340)
59											
60	**Total Storage Demand Costs**		ln 56 + ln 58	$ 422,129	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 83,389	$ 922,462
61											
62	**Total Demand Charges**		ln 41 + ln 56	$ 2,015,366	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 2,515,637	$ 1,521,887	$ 16,115,438
63											
64	Total Transportation Capacity Credit		ln 43 + ln 58	$ (806,751)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (727,522)	$ (440,130)	$ (4,884,492)
65											
66	**Total Demand Charges less Cap. Cr.**		ln 62 + ln 64	$ 1,208,615	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,788,115	$ 1,081,757	$ 11,230,946
67											
68							REDACTED				

Line			Peak	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**									
2	**d/b/a Liberty Utilities**									
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**									
4	**Demand Volumes**									
5										
6			Peak	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
7		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
8	**Supply**									
9		Niagara Supply			3,199	3,199	3,199	3,199	3,199	3,199
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
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		FTN-ENN0005	1,000	1,000	1,000	1,000	1,000	1,000
21		Portland Natural Gas		FTN	1,784	1,784	1,784	1,784	1,784	1,784
22		ANE (TransCanada via Union to Iroquois)		Union 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	1,784	1,784	1,784	1,784	1,784	1,784
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		0	0	0	0	0	0
31		ENGIE Demand FLS	peak		3,000	3,000	3,000	3,000	3,000	0
32		ENGIE Demand	peak	NSB041	7,000	7,000	7,000	7,000	7,000	0
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-O02357	6,098	6,098	6,098	6,098	6,098	6,098
40		National Fuel - Capacity Reservation	peak	FSS-O02357	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

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**Demand Rates**										
5					**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Nov - Apr**
6	**Tariff Rates**				30	31	31	28	31	30	181
7					Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Unit Rate	Avg Rate
8	**Supply**										
9	Niagara Supply		[redacted]	Per Contract	[redacted]						
10											
11	**Pipeline**										
12	Iroquois Gas Trans Service	RTS 470-01	$5.5997	First Revised Sheet No. 4	$0.1867	$0.1806	$0.1806	$0.2000	$0.1806	$0.1867	$0.1859
13											
14	Tenn Gas Pipeline	95346 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
15											
16	Tenn Gas Pipeline	2302 Z5-Z6	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0.2386	$0.2376
17											
18	Tenn Gas Pipeline	8587 Z0-Z6	$23.2175	FT-A (Z0 - Z6)	$0.7739	$0.7490	$0.7490	$0.8292	$0.7490	$0.7739	$0.7706
19											
20	Tenn Gas Pipeline	8587 Z1-Z6	$20.6094	FT-A (Z1 - Z6)	$0.6870	$0.6648	$0.6648	$0.7361	$0.6648	$0.6870	$0.6841
21											
22	Tenn Gas Pipeline	8587 Z4-Z6	$8.1481	FT-A (Z4 - Z6)	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
23											
24	TGP Dracut	42076 FTA Z6-Z6	$4.7453	11th Rev Sheet No. 14	$0.1582	$0.1531	$0.1531	$0.1695	$0.1531	$0.1582	$0.1575
25											
26	TGP Concord Lateral	Firm Transportatio	$12.1916	Per contract	$0.4064	$0 3933	$0.3933	$0.4354	$0.3933	$0.4064	$0.4047
27											
28	Portland Natural Gas	FTN-ENN0005	$18.2633	Dmd is Negot/CMDY=Part 4.1 \	$0.6088	$0 5891	$0.5891	$0.6523	$0.5891	$0.6088	$0.6062
29											
30	Portland Natural Gas	FTN	$22.8125	Dmd is Negot/CMDY=Part 4.1 \	$0.7604	$0.7359	$0.7359	$0.8147	$0.7359	$0.7604	$0.7572
31											
32	Tenn Gas Pipeline	632 Z4-Z6 (stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0.2716	$0.2705
33											
34	Tenn Gas Pipeline	11234 Z4-Z6(stg)	$8.1481	11th Rev Sheet No. 14	$0.2716	$0 2628	$0.2628	$0.2910	$0.2628	$0 2716	$0.2705
35											
36	Tenn Gas Pipeline	11234 Z5-Z6(stg)	$7.1569	11th Rev Sheet No. 14	$0.2386	$0 2309	$0.2309	$0.2556	$0.2309	$0 2386	$0.2376
37											
38	National Fuel	FST N02358	$3.6874	4.010 Version 21.0.1 Pg 1	$0.1229	$0.1189	$0.1189	$0.1317	$0.1189	$0.1229	$0.1224
39											
40	ANE Union Gas		$3.7160								
41	TransCanada Pipelines Limited		$13 34166	Union Parkway to Iroquois							
42	Delivery Pressure Demand Charge		0.6704	Union Parkway to Iroquois							
43	Sub Total Demand Charges		17.7280								
44	Conversion rate GJ to MMBTU		1.0551								
45	Conversion rate to US$		1.2851	updated 7/6/18							
46	Demand Rate/US$		$14.5544		$0.4851	$0.4695	$0.4695	$0.5198	$0.4695	$0.4851	$0.4831
47											
48	Union Gas		$3.7160								
49	TransCanada Pipelines Limited		$22.4898	Union Parkway to Portland							
50	Delivery Pressure Demand Charge		$0.6704	Union Parkway to Portland							
51	Sub Total Demand Charges		26.8762								
52	Conversion rate GJ to MMBTU		1.0551								
53	Conversion rate to US$		1.2851	updated 7/6/18							
54	Demand Rate/US$		$22.0649		$0.7355	$0.7118	$0.7118	$0.7880	$0.7118	$0.7355	$0.7324
55											
56	**Peaking**										
57	ENGIE Demand FLS		[redacted]	Per Contract	[redacted]						
58	Subtotal Peaking Demand Charges			Per Contract							
59											
60	**Storage**										
61	Dominion - Demand	GSS 300076	$1.8672	GSS Settled,Tariff Rec #10.30 \	$0.0622	$0.0602	$0.0602	$0.0667	$0.0602	$0.0622	$0.0619
62	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
63			$1.8817		$0.0627	$0.0607	$0.0607	$0.0672	$0.0607	$0.0627	$0.0624
64											
65	Honeoye - Demand	SS-NY	$6.4187	Sub 1st Rev Sheet No. 5	$0.2140	$0 2071	$0.2071	$0.2292	$0.2071	$0.2140	$0.2129
66											

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Demand Rates**

Line	Description	Rate Schedule	Rate	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov - Apr
5											
67	National Fuel - Demand	FSS-O02357	$2.4866	4.020 Version 16.0.0 Pg 1	$0.0829	$0.0802	$0.0802	$0.0888	$0.0802	$0.0829	$0.0825
68	National Fuel - Capacity	FSS-O02357	$0.0381	4.020 Version 16.0.0 Pg 1	$0.0013	$0.0012	$0.0012	$0.0014	$0.0012	$0.0013	$0.0013
69			$2.5247		$0.0842	$0.0814	$0.0814	$0.0902	$0.0814	$0.0842	$0.0837
70											
71	Tenn Gas Pipeline	FS-MA 523	$1.4938	14th Rev Sheet No.61	$0.0498	$0.0482	$0.0482	$0.0534	$0.0482	$0.0498	$0.0495
72	Tenn Gas Pipeline - Space	FS-MA 523	$0.0205	14th Rev Sheet No.61	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007	$0.0007
73			$1.5143		$0.0505	$0.0488	$0.0488	$0.0541	$0.0488	$0.0505	$0.0502
74											
75											

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

FY 2017 GAS ANNUAL CHARGES
CORRECTION FOR ANNUAL CHARGES UNIT CHARGE
June 26, 2018

The annual charges unit charge (ACA) to be applied to in fiscal year 2019 for recovery of FY 2018 Current year and 2017 True-Up is **$0.0013** per Dekatherm (Dth). The new ACA surcharge will become effective October 1, 2018.

The following calculations were used to determine the FY 2018 unit charge:

2018 CURRENT:

Estimated Program Cost $66,791,000 divided by 49,985,774,086 Dth	=	0.0013362002

2017 TRUE-UP:

Debit/Credit Cost ($316,993) divided by 47,717,356,257 Dth	=	(0.0000066431)
TOTAL UNIT CHARGE	=	0.0013295571

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

PUBLIC

Dominion Energy Transmission, Inc.
FERC Gas Tariff
Fifth Revised Volume No. 1

GSS, GSS-E & ISS Rates - Settled Parties
Tariff Record No. 10.30.
Version 2.0.0
Superseding Version 1.0.0

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 Schedule	Rate Component	Base Tariff Rate [1]	Current Acct 858 Base	Current EPCA Base	TCRA [5] Surcharge	EPCA [6] Surcharge	Current Rate [7]	FERC ACA
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
GSS [2], [4]								
	Storage Demand	$1.7984	$0.0665	$0.0052	($0.0050)	$0.0021	$1.8672	-
	Storage Capacity	$0.0145	-	-	-	-	$0.0145	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	GSS-TE Surcharge [3]	-	$0.0046	-	($0.0003)	-	$0.0043	-
	From Customers Balance	$0.6163	$0.0143	$0.0011	($0.0010)	$0.0004	$0.6311	[8]
GSS-E [2], [4]								
	Storage Demand	$2.2113	$0.0665	$0.0052	($0.0050)	$0.0021	$2.2801	-
	Storage Capacity	$0.0369	-	-	-	-	$0.0369	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	Authorized Overruns	$1.0657	$0.0143	$0.0011	($0.0010)	$0.0004	$1.0805	[8]
ISS [2]								
	ISS Capacity	$0.0736	$0.0022	$0.0002	($0.0002)	$0.0001	$0.0759	-
	Injection Charge	$0.0154	-	$0.0136	$0.0001	($0.0001)	$0.0290	-
	Withdrawal Charge	$0.0154	-	-	$0.0001	($0.0001)	$0.0154	[8]
	Authorized Overrun/from Cust. Bal	$0.6163	$0.0143	$0.0011	($0.0010)	$0.0004	$0.6311	[8]
	Excess Injection Charge	$0.2245	-	$0.0136	$0.0001	($0.0001)	$0.2381	-

[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 $0.6157. Daily Capacity Release Rate for GSS-E per Dt is $1.0651
[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 (http://www.ferc.gov/industries/gas/annual-charges.asp).

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

Third Revised Sheet No. 4
Superseding
Second Revised Sheet No. 4

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

	Minimum	Maximum		
		Effective 9/1/2016	Effective 9/1/2017	Effective 9/1/2018
RTS DEMAND (Monthly):				
Zone 1	$0.0000	$ 6.1928	$ 5.9982	$ 5.5997
Zone 2	$0.0000	$ 5.3381	$ 5.1678	$ 4.7998
Inter-Zone	$0.0000	$10.4755	$ 9.8672	$ 8.8026
RTS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.0034	$ 0.0034	$ 0.0034
Zone 2	$0.0022	$ 0.0022	$ 0.0022	$ 0.0022
Inter-Zone	$0.0056	$ 0.0056	$ 0.0056	$ 0.0056
ITS COMMODITY (Daily):				
Zone 1	$0.0034	$ 0.2070	$ 0.2006	$ 0.1875
Zone 2	$0.0022	$ 0.1777	$ 0.1721	$ 0.1600
Inter-Zone	$0.0056	$ 0.3500	$ 0.3300	$ 0.2950
VOLUMETRIC CAPACITY RELEASE (Daily) 2/:				
Zone 1	$0.0000	$ 0.2036	$ 0.1972	$ 0.1841
Zone 2	$0.0000	$ 0.1755	$ 0.1699	$ 0.1578
Inter-Zone	$0.0000	$ 0.3444	$ 0.3244	$ 0.2894

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

(Footnotes continued on Sheet 4.01)

Issued On: November 3, 2016

Effective On: September 1, 2016

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

Third Revised Sheet No. 4.01
Superseding
Second Revised Sheet No. 4.01

1/ Transporter's Settlement dated August 18, 2016, in Docket No. RP16-301-000, which was approved by Commission order issued October 20, 2016, established new base tariff recourse rates referred to as "Settlement Rates" and a moratorium on changes to the Settlement Rates until September 1, 2020. All recourse Maximum and Minimum Rates listed on Sheet Nos. 4, 4B, 4C, and 5A are Settlement Rates subject to the moratorium.

2/ No rate cap shall apply to any capacity releases with terms of less than or equal to one year pursuant to FERC Order Nos. 712 et al.

Issued On: November 3, 2016

Effective On: September 1, 2016

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

Fifth Revised Sheet No. 4A
Superseding
Fourth Revised Sheet No. 4A

To the extent applicable, the following adjustments apply:

ACA ADJUSTMENT:
Commodity 1/

MEASUREMENT VARIANCE/FUEL USE FACTOR:

Minimum	0.00%
Maximum (Non-Eastchester Shipper)	1.00%
Maximum (Eastchester Shipper)	4.50%
Maximum (Brookfield Shipper)	1.20%

1/ The ACA ADJUSTMENT Commoditiy rate shall be the applicable FERC ACA unit charge incorporated by reference pursuant to Section 12.2 in the General Terms and Conditions of Transporter's FERC Gas Tariff.

RATES FOR PART 284 STORAGE SERVICES

Rate Sch. (1)	Rate Component [1/] (2)		Rate [2/] (3)
ESS	Demand	(Max)	$2.4921 [7/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0388 [8/]
		(Min)	$0.0000
	Injection/	(Max)	$0.0411plus ACA [3]
	Withdrawal	(Min)	$0.0000
	Max. Volumetric Dem. Rate [4]		$0.0853plus ACA [3/]
	Max. Volumetric Cap. Rate [5/]		$0.0013
	Storage Balance Transfer	(Max)[6/]	$3.8600
		(Min)[6/]	$0.0000
ISS	Injection	(Max)	$0.9923plus ACA [3/]
		(Min)	$0.0000
	Storage Balance Transfer	(Max)[6/]	$3.8600
		(Min)[6/]	$0.0000
FSS	Demand	(Max)	$2.3833 [7/]
		(Min)	$0.0000
	Capacity	(Max)	$0.0366 [8/]
		(Min)	$0.0000
	Injection/	(Max)	$0.0391plus ACA [3/]
	Withdrawal	(Min)	$0.0000
	Max. Volumetric Dem. Rate [4/]		$0.0816plus ACA [3/]
	Max. Volumetric Cap. Rate [5/]		$0.0013
	Storage Balance Transfer	(Max)[6]	$3.8600
		(Min)[6]	$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 0.89%.
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/ Assessed per dekatherm injected/withdrawn. Exclusive of Injection/Withdrawal charge.
5/ Assessed per dekatherm per day on storage balance.
6/ Rate per nomination.
7/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.1033 shall be added as a Storage PS/GHG Demand/Deliverability Surcharge, in addition to the specified rate.
8/ Pursuant to Section 42 of the General Terms and Conditions, per Dth charge of $0.0015 shall be added as a Storage PS/GHG Capacity Surcharge, in addition to the specified rate.

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)	$3.6293	-	-	$3.6293 [4/]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA [3/]
EFT	Reservation	(Max)	3.8067	0.0000	0.0000	$3.8067 [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)	0.1452	-	-	$0.1452 plus ACA[3/]
		(Min)	0.0148	-	-	$0.0148 plus ACA[3/]
	Maximum Volumetric Rate		0.1452	0.0000	0.0000	$0.1452 plus ACA[3/]
FST	Reservation	(Max)	3.6293	-	-	$3.6293 [4/]
		(Min)	0.0000	-	-	$0.0000
	Commodity	(Max)	0.0135	-	-	$0.0135 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Overrun	(Max)	0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0135	-	-	$0.0135 plus ACA [3/]
	Maximum Volumetric Rate		0.1378	-	-	$0.1378 plus ACA [3/]
IT	Commodity	(Max)	$0.1378	-	-	$0.1378 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]
	Overrun	(Max)	0.1378	-		$0.1378 plus ACA [3/]
		(Min)	0.0000	-	-	$0.0000 plus ACA [3/]

The NA15 Retention is 1.25% 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 0.79% and the Transportation LAUF Retention for all applicable rate schedules is 0.00%. 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, per Dth charge of $0.0581 shall be added as a Transmission PS/GHG Surcharge, in addition to the specified rate.

Effective On: April 1, 2018

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/
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:

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

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.

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

Eleventh Revised Sheet No. 14
Superseding
Tenth 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	$5.5411		$11.5794	$15.5758	$15.8514	$17.4175	$18.4879	$23.1959
L		$4.9193						
1	$8.3417		$7.9962	$10.6413	$15.0745	$14.8460	$16.7429	$20.5878
2	$15.5759		$10.5774	$5.5014	$5.1427	$6.5803	$9.0504	$11.6830
3	$15.8514		$8.3784	$5.5458	$4.0009	$6.1457	$11.1149	$12.8437
4	$20.1259		$18.5544	$7.0708	$10.7456	$5.2598	$5.6884	$8.1265
5	$23.9973		$16.8625	$7.4172	$8.9748	$5.8432	$5.4810	$7.1353
6	$27.7603		$19.3678	$13.3296	$14.6845	$10.3726	$5.4568	$4.7237

Daily Base
Reservation Rate 1/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.1822		$0.3807	$0.5121	$0.5211	$0.5726	$0.6078	$0.7626
L		$0.1617						
1	$0.2742		$0.2629	$0.3499	$0.4956	$0.4881	$0.5505	$0.6769
2	$0.5121		$0.3478	$0.1809	$0.1691	$0.2163	$0.2975	$0.3841
3	$0.5211		$0.2755	$0.1823	$0.1315	$0.2021	$0.3654	$0.4223
4	$0.6617		$0.6100	$0.2325	$0.3533	$0.1729	$0.1870	$0.2672
5	$0.7890		$0.5544	$0.2439	$0.2951	$0.1921	$0.1802	$0.2346
6	$0.9127		$0.6367	$0.4382	$0.4828	$0.3410	$0.1794	$0.1553

Maximum Reservation
Rates 2 /, 3 /

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$5.5627		$11.6010	$15.5974	$15.8730	$17.4391	$18.5095	$23.2175
L		$4.9409						
1	$8.3633		$8.0178	$10.6629	$15.0961	$14.8676	$16.7645	$20.6094
2	$15.5975		$10.5990	$5.5230	$5.1643	$6.6019	$9.0720	$11.7046
3	$15.8730		$8.4000	$5.5674	$4.0225	$6.1673	$11.1365	$12.8653
4	$20.1475		$18.5760	$7.0924	$10.7672	$5.2814	$5.7100	$8.1481
5	$24.0189		$16.8841	$7.4388	$8.9964	$5.8648	$5.5026	$7.1569
6	$27.7819		$19.3894	$13.3512	$14.7061	$10.3942	$5.4784	$4.7453

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 $0.0216.

Issued: September 29, 2017
Effective: November 1, 2017

Docket No. RP17-1118-000
Accepted: October 26, 2017

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

Thirteenth Revised Sheet No. 15
Superseding
Twelveth 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	$0.2668	$0.2546	$0.3030
L		$0.0012						
1	$0.0042		$0.0081	$0.0147	$0.0179	$0.2269	$0.2313	$0.2641
2	$0.0167		$0.0087	$0.0012	$0.0028	$0.0734	$0.1178	$0.1305
3	$0.0207		$0.0169	$0.0026	$0.0002	$0.0982	$0.1358	$0.1482
4	$0.0250		$0.0205	$0.0087	$0.0105	$0.0454	$0.0642	$0.1041
5	$0.0284		$0.0256	$0.0100	$0.0118	$0.0639	$0.0633	$0.0787
6	$0.0346		$0.0300	$0.0143	$0.0163	$0.0984	$0.0533	$0.0324

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	$0.0041		$0.0124	$0.0186	$0.0228	$0.2677	$0.2555	$0.3039
L		$0.0021						
1	$0.0051		$0.0090	$0.0156	$0.0188	$0.2278	$0.2322	$0.2650
2	$0.0176		$0.0096	$0.0021	$0.0037	$0.0743	$0.1187	$0.1314
3	$0.0216		$0.0178	$0.0035	$0.0011	$0.0991	$0.1367	$0.1491
4	$0.0259		$0.0214	$0.0096	$0.0114	$0.0463	$0.0651	$0.1050
5	$0.0293		$0.0265	$0.0109	$0.0127	$0.0648	$0.0642	$0.0796
6	$0.0355		$0.0309	$0.0152	$0.0172	$0.0993	$0.0542	$0.0333

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 $0.0009.

Issued: September 27, 2016
Effective: November 1, 2016

Docket No. RP16-1251-000
Accepted: October 13, 2016

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

Fourteenth Revised Sheet No. 61
Superseding
Thirteenth 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	$2.0334	$2.0334 1/		
Space Rate	$0.0207	$0.0207 1/		
Injection Rate	$0.0073	$0.0073	1.51%	$0.0000
Withdrawal Rate	$0.0073	$0.0073		
Overrun Rate	$0.2441	$0.2441 1/		
FIRM STORAGE SERVICE (FS) - MARKET AREA				
Deliverability Rate	$1.4938	$1.4938 1/		
Space Rate	$0.0205	$0.0205 1/		
Injection Rate	$0.0087	$0.0087	1.51%	$0.0000
Withdrawal Rate	$0.0087	$0.0087		
Overrun Rate	$0.1793	$0.1793 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 -0.09%.

Issued: March 1, 2018
Effective: April 1, 2018

Docket No. RP18-531-000
Accepted: March 29, 2018

FUEL AND EPCR

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

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	0.51%		1.54%	2.28%	2.86%	3.33%	3.75%	4.44%
L		0.26%						
1	0.63%		1.12%	1.92%	2.31%	2.82%	3.41%	3.88%
2	2.33%		1.19%	0.25%	0.46%	0.85%	1.43%	1.93%
3	2.86%		2.31%	0.46%	0.14%	1.17%	1.69%	2.20%
4	3.33%		2.62%	1.19%	1.41%	0.48%	0.73%	1.24%
5	3.88%		3.41%	1.44%	1.69%	0.72%	0.71%	0.91%
6	4.63%		4.02%	1.93%	2.20%	1.17%	0.57%	0.30%

EPCR 3/, 4/

RECEIPT ZONE	DELIVERY ZONE 0	L	1	2	3	4	5	6
0	$0.0039		$0.0151	$0.0233	$0.0290	$0.0350	$0.0398	$0.0477
L		$0.0013						
1	$0.0053		$0.0105	$0.0193	$0.0236	$0.0293	$0.0359	$0.0412
2	$0.0233		$0.0113	$0.0012	$0.0034	$0.0076	$0.0138	$0.0190
3	$0.0290		$0.0236	$0.0034	$0.0000	$0.0111	$0.0164	$0.0219
4	$0.0350		$0.0271	$0.0113	$0.0137	$0.0036	$0.0063	$0.0118
5	$0.0398		$0.0359	$0.0138	$0.0164	$0.0062	$0.0061	$0.0082
6	$0.0477		$0.0412	$0.0190	$0.0219	$0.0110	$0.0046	$0.0017

1/ Included in the above F&LR is the Losses component of the F&LR equal to 0.10%.
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 0.10%.
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.

Interim Mainline 2018 Transportation Tolls and 2018 Abandonment Surcharges (TGI-003-2017)

Storage Transportation 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)
1	Centram MDA	5.10726	0.1679	0.30417	0.0100
2	Union WDA	34.53326	1.1353	2.87711	0.0946
3	Union NDA	14.71771	0.4839	1.05728	0.0348
4	Union EDA	10.29604	0.3385	0.65092	0.0214
5	KPUC EDA	9.90367	0.3256	0.61503	0.0202
6	GMIT EDA	16.93265	0.5567	1.26047	0.0414
7	Enbridge CDA	5.26756	0.1732	0.18919	0.0062
8	Enbridge EDA	13.18532	0.4335	0.91645	0.0301
9	Cornwall	13.37938	0.4399	0.93410	0.0307
10	Iroquois	12.57212	0.4133	0.86018	0.0283
11	Philipsburg	16.97676	0.5581	1.26473	0.0416

Firm Transportation - Short Notice

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)	Abandonment Surcharge ($/GJ/Month)	Daily Equivalent Abandonment Surcharge ($/GJ)
	(a)	(b)	(c)	(d)	(e)
12	Kirkwall to Thorold CDA	6.06965	0.1996	0.21292	0.0070
13	Union Parkway Belt to Goreway CDA	4.51931	0.1486	0.08213	0.0027
14	Union Parkway Belt to Victoria Square #2 CDA	5.33691	0.1755	0.15208	0.0050
15	Union Parkway Belt to Schomberg #2 CDA	5.28368	0.1737	0.14600	0.0048
16	Union Parkway Belt to Napanee #2 EDA	10.18928	0.3350	0.54446	0.0179

Dawn Long Term Fixed Price

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
17	For All Dawn LTFP Contract Demand except any portion subject to a reduced term for the final 24 months of such reduced term	23.42083	0.7700
18	Any portion of Contract Demand reduced in term by 12 months for months 85 through 108	26.46250	0.8700
19	Any portion of Contract Demand reduced in term by 24 months for months 73 through 96	28.89583	0.9500
20	Any portion of Contract Demand reduced in term by 36 months for months 61 through 84	30.41667	1.0000
21	Any portion of Contract Demand reduced in term by 48 months for months 49 through 72	31.63333	1.0400
22	Any portion of Contract Demand reduced in term by 60 months for months 37 through 60	31.93750	1.0500

Notes: The tolls are inclusive of Delivery Pressure Toll and Abandonment Surcharge.
The Abandonment Surcharges are the same as the Empress to Emerson 2 Abandonment Surcharges for FT service.

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)
1	Union Parkway Belt to Union EDA	11.32565	0.3724	0.65092	0.0214

Delivery Pressure

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
2	Average Delivery Pressure Toll	0.67038	0.0220

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, STFT and SSS.

Union Dawn Receipt Point Surcharge

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
3	Union Dawn Receipt Point Surcharge	0.14587	0.0048

Short Notice Balancing (SNB) Service

Line No.	Particulars	Monthly Toll ($/GJ/Month)	Daily Equivalent ($/GJ)
	(a)	(b)	(c)
4	SNB Toll	3.43648	0.1130

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)
5	Western Section	1.4886
6	Eastern Section	0.3640

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	-	0.3946	-	0.0343
2	Union NDA	Enbridge Parkway CDA	-	0.3986	-	0.0348
3	Union NDA	Enbridge EDA	-	0.4283	-	0.0381
4	Union NDA	KPUC EDA	-	0.5045	-	0.0466
5	Union NDA	GMIT EDA	-	0.5546	-	0.0521
6	Union NDA	Enbridge SWDA	-	0.5278	-	0.0492
7	Union NDA	Union SWDA	-	0.5299	-	0.0494
8	Union NDA	Chippawa	-	0.4756	-	0.0433
9	Union NDA	Cornwall	-	0.4586	-	0.0414
10	Union NDA	East Hereford	-	0.6614	-	0.0641
11	Union NDA	Emerson 1	-	0.9288	-	0.0992
12	Union NDA	Emerson 2	-	0.9288	-	0.0992
13	Union NDA	Iroquois	-	0.4397	-	0.0393
14	Union NDA	Kirkwall	-	0.4204	-	0.0372
15	Union NDA	Napierville	-	0.5461	-	0.0512
16	Union NDA	Niagara Falls	-	0.4742	-	0.0432
17	Union NDA	North Bay Junction	-	0.1848	-	0.0120
18	Union NDA	Philipsburg	-	0.5561	-	0.0523
19	Union NDA	Spruce	-	0.8519	-	0.0902
20	Union NDA	St. Clair	-	0.5149	-	0.0507
21	Union NDA	Welwyn	-	1.0634	-	0.1150
22	Union NDA	Dawn Export	-	0.5278	-	0.0492
23	Union Parkway Belt	Empress	63.22226	2.0785	5.51241	0.1812
24	Union Parkway Belt	TransGas SSDA	54.10243	1.7787	4.67474	0.1537
25	Union Parkway Belt	Centram SSDA	50.36574	1.6559	4.33164	0.1424
26	Union Parkway Belt	Centram MDA	44.71341	1.4700	3.81243	0.1253
27	Union Parkway Belt	Centrat MDA	44.27389	1.4556	3.77197	0.1240
28	Union Parkway Belt	Union WDA	34.53326	1.1353	2.87711	0.0946
29	Union Parkway Belt	Nipigon WDA	30.53408	1.0039	2.50998	0.0825
30	Union Parkway Belt	Union NDA	14.71771	0.4839	1.05728	0.0348
31	Union Parkway Belt	Calstock NDA	23.58052	0.7753	1.87123	0.0615
32	Union Parkway Belt	Tunis NDA	18.10674	0.5953	1.36845	0.0450
33	Union Parkway Belt	GMIT NDA	14.03851	0.4615	0.99463	0.0327
34	Union Parkway Belt	Union SSMDA	21.07662	0.6929	1.64128	0.0540
35	Union Parkway Belt	Union NCDA	7.38395	0.2428	0.38355	0.0126
36	Union Parkway Belt	Union CDA	4.79732	0.1577	0.14600	0.0048
37	Union Parkway Belt	Union ECDA	3.75676	0.1235	0.05049	0.0017
38	Union Parkway Belt	Union EDA	10.29604	0.3385	0.65092	0.0214
39	Union Parkway Belt	Union Parkway Belt	3.51465	0.1156	0.02798	0.0009
40	Union Parkway Belt	Enbridge CDA	5.26756	0.1732	0.18919	0.0062
41	Union Parkway Belt	Enbridge Parkway CDA	3.51465	0.1156	0.02798	0.0009
42	Union Parkway Belt	Enbridge EDA	13.18532	0.4335	0.91645	0.0301
43	Union Parkway Belt	KPUC EDA	9.90367	0.3256	0.61503	0.0202
44	Union Parkway Belt	GMIT EDA	16.93265	0.5567	1.26047	0.0414
45	Union Parkway Belt	Enbridge SWDA	8.28428	0.2724	0.46629	0.0153
46	Union Parkway Belt	Union SWDA	8.35972	0.2748	0.47328	0.0156
47	Union Parkway Belt	Chippawa	6.35435	0.2089	0.28896	0.0095
48	Union Parkway Belt	Cornwall	13.37938	0.4399	0.93410	0.0307
49	Union Parkway Belt	East Hereford	20.86766	0.6861	1.62212	0.0533
50	Union Parkway Belt	Emerson 1	41.71007	1.3713	3.53655	0.1163
51	Union Parkway Belt	Emerson 2	41.71007	1.3713	3.53655	0.1163
52	Union Parkway Belt	Iroquois	12.48908	0.4106	0.85258	0.0280
53	Union Parkway Belt	Kirkwall	4.31795	0.1420	0.10190	0.0034
54	Union Parkway Belt	Napierville	16.60963	0.5461	1.23096	0.0405
55	Union Parkway Belt	Niagara Falls	6.30416	0.2073	0.28440	0.0094
56	Union Parkway Belt	North Bay Junction	11.07136	0.3640	0.72209	0.0237
57	Union Parkway Belt	Philipsburg	16.97676	0.5581	1.26473	0.0416
58	Union Parkway Belt	Spruce	44.27389	1.4556	3.77197	0.1240
59	Union Parkway Belt	St. Clair	8.78494	0.2888	0.51222	0.0168
60	Union Parkway Belt	Welwyn	50.36574	1.6559	4.33164	0.1424
61	Union Parkway Belt	Dawn Export	8.28428	0.2724	0.46629	0.0153
62	Union SSMDA	Empress	-	1.2649	-	0.1386
63	Union SSMDA	TransGas SSDA	-	1.0300	-	0.1111
64	Union SSMDA	Centram SSDA	-	0.9338	-	0.0998
65	Union SSMDA	Centram MDA	-	0.7882	-	0.0827
66	Union SSMDA	Centrat MDA	-	0.7876	-	0.0827
67	Union SSMDA	Union WDA	-	1.0598	-	0.1146
68	Union SSMDA	Nipigon WDA	-	1.1416	-	0.1241
69	Union SSMDA	Union NDA	-	0.8315	-	0.0878
70	Union SSMDA	Calstock NDA	-	1.0598	-	0.1146
71	Union SSMDA	Tunis NDA	-	0.9188	-	0.0980
72	Union SSMDA	GMIT NDA	-	0.8140	-	0.0857
73	Union SSMDA	Union SSMDA	-	0.0905	-	0.0009
74	Union SSMDA	Union NCDA	-	0.6757	-	0.0656
75	Union SSMDA	Union CDA	-	0.5678	-	0.0536
76	Union SSMDA	Union ECDA	-	0.5774	-	0.0547
77	Union SSMDA	Union EDA	-	0.7545	-	0.0744
78	Union SSMDA	Union Parkway Belt	-	0.5709	-	0.0540
79	Union SSMDA	Enbridge CDA	-	0.6123	-	0.0586
80	Union SSMDA	Enbridge Parkway CDA	-	0.5709	-	0.0540
81	Union SSMDA	Enbridge EDA	-	0.8328	-	0.0832

uniongas

Effective
2018-04-01
Rate M12
Page 1 of 4

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 – Fuel and Commodity Charge Rate/GJ	Shipper Supplied Fuel – Fuel Ratio %	AND	Shipper Supplied Fuel – Commodity Charge Rate/GJ
Firm Transportation (1), (5)					
Dawn to Parkway	$3.716	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	$3.154				
Kirkwall to Parkway	$0.561				
M12-X Firm Transportation					
Between Dawn, Kirkwall and Parkway	$4.590	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	$8.918	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	$8.918				
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)	n/a	n/a	0.158%		
Cap-and-Trade Facility-Related Charges (applied to all quantities transported)					
Dawn to Kirkwall / Lisgar		$0.006			$0.006
Dawn to Parkway		$0.006			$0.006
Kirkwall to Parkway / Lisgar		$0.006			$0.006
Parkway to Dawn / Kirkwall		$0.006			$0.006
Kirkwall to Dawn		$0.006			$0.006
Parkway (TCPL / EGT) to Parkway (Cons) / Lisgar (2)		$0.006			$0.006

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**REDACTED**
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	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 64 * ln 104	[redacted]						
13	Niagara Supply	ln 65 * ln 109							
14	TGP Supply (Direct)	ln 66 * ln 125							
15	Dracut Supply 1 - Baseload	ln 67 * ln 114							
16	Dracut Supply 2 - Swing	ln 68 * ln 119							
17	ENG E COMBO	ln 69 * ln 131							
18	LNG Truck	ln 70 * ln 133							
19	Propane Truck	ln 71 * ln 135							
20	PNGTS	ln 72 * ln 140							
21	Portland Natural Gas	ln 73 * ln 145							
22	TGP Supply (Z4)	ln 74 * ln 150							
23									
24	Subtotal Pipeline Gas Costs		$ 3,103,274	$ 8,816,534	$ 11,872,037	$ 11,207,935	$ 5,464,501	$ 2,099,499	$ 42,563,780
25									
26	**Volumetric Transportation Costs**								
27	Dawn Supply	ln 64 * ln 197	[redacted]						
28	Niagara Supply	ln 65 * ln 208							
29	TGP Supply (Direct)	ln 66 * ln 235							
30	Dracut Supply 1 - Baseload	ln 67 * ln 256							
31	Dracut Supply 2 - Swing	ln 68 * ln 256							
32	ENG E COMBO	ln 69 * ln 256							
33	TGP Storage - Withdrawals	ln 79 * ln 172							
34									
35	**Total Volumetric Transportation Costs**		$ 215,648	$ 213,629	$ 237,663	$ 219,674	$ 201,319	$ 38,974	$ 1,126,907
36									
37	**Less - Gas Refill**								
38	LNG Truck	ln 88 * ln 157	[redacted]						
39	Propane	ln 89 * ln 158							
40	TGP Storage Refill	ln 90 * ln 123							
41	Storage Refill (Trans.)	ln 90 * ln 235							
42									
43	Subtotal Refills		$ (765,580)	$ (131,625)	$ (809,867)	$ (600,010)	$ (65,260)	$ -	$ (2,372,341)
44									
45	**Total Supply & Pipeline Commodity Costs**	ln 24 + ln 35 + ln 43	$ 2,553,342	$ 8,898,538	$ 11,299,833	$ 10,827,598	$ 5,600,561	$ 2,138,473	$ 41,318,346
46									
47	**Storage Gas**								
48	TGP Storage - Withdrawals	ln 79 * ln 164	$ 445,586	$ 1,064,513	$ 1,326,148	$ 1,319,717	$ 961,805	$ 7,894	$ 5,125,663
49									
50	**Produced Gas**								
51	LNG Vapor	ln 82 * ln 152	[redacted]						
52	Propane	ln 83 * ln 154							
53									
54	**Total Produced Gas**	ln 51 + ln 52	$ 14,140	$ 158,102	$ 1,832,482	$ 629,835	$ 29,085	$ 8,567	$ 2,672,211
55									
56									
57	**Total Commodity Gas & Trans. Costs**	ln 45 + ln 48 + ln 54	$ 3,013,068	$ 10,121,153	$ 14,458,463	$ 12,777,150	$ 6,591,451	$ 2,154,935	$ 49,116,221
58									$ 87,958,623
59						**REDACTED**			

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
60									
61	**Volumes (Therms)**								
62									
63	**Pipeline Gas**	See Schedule 11A							
64	Dawn Supply		796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
65	Niagara Supply		625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
66	TGP Supply (Direct)		4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
67	Dracut Supply 1 - Baseload		-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
68	Dracut Supply 2 - Swing		2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
69	ENG E COMBO		-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
70	LNG Truck		18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
71	Propane Truck		-	-	356,219	91,328	-	-	447,548
72	PNGTS		198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
73	Portland Natural Gas		345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
74	TGP Supply (Z4)		1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
75									
76	Subtotal Pipeline Volumes		10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
77									
78	**Storage Gas**								
79	TGP Storage		1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
80									
81	**Produced Gas**								
82	LNG Vapor		18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
83	Propane		-	-	859,588	91,328	-	-	950,916
84									
85	Subtotal Produced Gas		18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
86									
87	**Less - Gas Refill**								
88	LNG Truck		(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
89	Propane		-	-	(356,219)	(91,328)	-	-	(447,548)
90	TGP Storage Refill		(2,262,867)	-	-	-	-	-	(2,262,867)
91									
92	Subtotal Refills		(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
93									
94	**Total Sendout Volumes**		9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623
95									
96									
97									

REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
98	**Gas Costs and Volumetric Transportation Rates**								
99									
100	**Pipeline Gas**								
101	**Dawn Supply**								Average Rate
102	NYMEX Price	Sch 7, ln 10/10	[redacted]						
103	Basis Differential								
104	**Net Commodity Costs**								
105									
106	**Niagara Supply**								
107	NYMEX Price	Sch 7, ln 10/10	[redacted]						
108	Basis Differential								
109	**Net Commodity Costs**								
110									
111	**Dracut Supply 1 - Baseload**								
112	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
113	Basis Differential								
114	**Net Commodity Costs**								
115									
116	**Dracut Supply 2 - Swing**								
117	Commodity Costs - NYMEX Price	Sch 7, ln 10 / 10	[redacted]						
118	Basis Differential								
119	**Net Commodity Costs**								
120									
121									
122	**TGP Supply (Direct)**								
123	NYMEX Price	Sch 7, ln 10/10	[redacted]						
124	Basis Differential								
125	**Net Commodity Costs**								
126									
127									
128	**ENGIE COMBO**								
129	NYMEX Price	Sch 7, ln 10/10	[redacted]						
130	Basis Differential								
131	**Net Commodity Costs**								
132									
133	**LNG Truck**	Sch 7, ln 10/10	[redacted]						
134									
135	**Propane Truck**	Propane WACOG	[redacted]						
136									
137	**PNGTS**								
138	NYMEX Price	Sch 7, ln 10/10	[redacted]						
139	Basis Differential								
140	**Net Commodity Cost**								
141									
142	**PNGTS EXP**								
143	NYMEX Price	Sch 7, ln 10/10	[redacted]						
144	Basis Differential								
145	**Net Commodity Cost**								
146									
147	**TGP Supply (Z4)**								
148	NYMEX Price	Sch 7, ln 10/10	[redacted]						
149	Basis Differential								
150	**Net Commodity Cost**								
151									
152	**LNG Vapor (Storage)**	Sch 16, ln 95 /10	[redacted]						
153									
154	**Propane**	Sch 16, ln 66 /10	[redacted]						
155									
156	**Storage Refill**								
157	**LNG Truck**	ln 133	[redacted]						
158	**Propane**	ln 135							
159									

REDACTED

REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									Peak
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
160									
161									
162	**TGP Storage**								Average Rate
163	**Commodity Costs - Storage withdrawal**	Sch 16, In 34 /10	$0.2583	$0 2583	$0 2583	$0.2583	$0.2583	$0.2583	$0.2583
164									
165	TGP - Max Commodity - Z 4-6	13th Rev Sheet No. 15	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050	$0.01050
166	TGP - Max Comm. ACA Rate - Z 4-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
167	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 4-6		$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063	$0.01063
168	TGP - Fuel Charge % - Z 4-6	13th Rev Sheet No. 32	1.24%	1.24%	1.24%	1 24%	1.24%	1 24%	1.24%
169	TGP - Fuel Charge % - Z 4-6 - (NYMEX * Percentage)		$0.00320	$0.00320	$0.00320	$0.00320	$0.00320	$0.00320	$0.00320
170	TGP - Withdrawal Charge	14th Rev Sheet No.61	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087	$0.00087
171	**Total Volumetric Transportation Rate - TGP (Storage)**		$0.01470	$0.01470	$0.01470	$0.01470	$0.01470	$0.01470	$0.01470
172									
173	**Total TGP - Comm. & Vol. Trans. Rate**	In 164 + In 172	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**	**$0.27304**
174									
175									
176	**Per Unit Volumetric Transportation Rates**								
177	**Dawn Supply Volumetric Transportation Charge**								
178	**Commodity Costs**	In 104	**$0.2977**	**$0.3162**	**$0.3306**	**$0.3269**	**$0.3056**	**$0.2519**	**$0.3048**
179									
180	TransCanada - Commodity Rate/GJ	Union Parkway to Iroquois	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060	$0.00060
181	Conversion Rate GL to MMBTU		1.0551	1.0551	1.0551	1.0551	1.0551	1.0551	1.0551
182	Conversion Rate to US$	updated 7/6/18	1 2851	1 2851	1 2851	1.2851	1.2851	1.2851	1.2851
183	Commodity Rate/US$	In 181 x In 182 x In 183	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081	$0.00081
184	TransCanada Fuel %	Union Parkway to Iroquois	1.95%	2.01%	2.20%	2.17%	1.78%	2 20%	2.05%
185	TransCanada Fuel * Percentage	In 179 x In 185	$0.00581	$0.00634	$0.00726	$0.00708	$0.00545	$0.00553	$0.00625
186	Subtotal TransCanada		**$0.00663**	**$0.00715**	**$0.00808**	**$0.00790**	**$0.00626**	**$0.00635**	**$0.00706**
187	IGTS - Z1 RTS Commodity	First Revised Sheet No. 4	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034	$0.00034
188	IGTS - Z1 RTS ACA Rate Commodity	Fifth Revised Sheet 4A	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
189	IGTS - Z1 RTS Deferred Asset Surcharge	Fifth Revised Sheet 4A	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000	$0.00000
190	Subtotal IGTS - Trans Charge - Z1 RTS Commodity		**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**	**$0.00047**
191	TGP NET-NE - Comm. Segments 3 & 4	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
192	IGTS -Fuel Use Factor - Percentage	Fifth Revised Sheet 4A	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%	1.00%
193	IGTS -Fuel Use Factor - Fuel * Percentage	In 179 x In 193	**$0.00298**	**$0.00316**	**$0.00331**	**$0.00327**	**$0.00306**	**$0.00252**	**$0.00305**
194	TGP FTA Fuel Charge % Z 5-6	13th Rev Sheet No. 32	0.91%	0.91%	0.91%	0 91%	0.91%	0 91%	0.91%
195	TGP FTA Fuel * Percentage	In 179 x In 195	**$0.00271**	**$0.00288**	**$0.00301**	**$0.00297**	**$0.00278**	**$0.00229**	**$0.00277**
196	**Total Volumetric Transportation Charge - Dawn Supply**		**$0.01291**	**$0.01379**	**$0.01499**	**$0.01474**	**$0.01270**	**$0.01176**	**$0.01348**
197									
198									
199	**Niagara Supply Volumetric Transportation Charge**								
200	**Commodity Costs**	Ln 109	[redacted]						
201									
202	TGP FTA - FTA Z 5-6 Comm. Rate	13th Rev Sheet No. 15	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796	$0.00796
203	TGP FTA - FTA Z 5-6 - ACA Rate	13th Rev Sheet No. 15	$0.00013	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001	$0.0001
204	Subtotal TGP FTA - FTA Z 5-6 Commodity Rate		**$0.00809**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**	**$0.0081**
205	TGP FTA Fuel Charge % Z 5-6	13th Rev Sheet No. 32	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%	0.91%
206	TGP FTA Fuel * Percentage	In 201 x In 206	[redacted]						
207	**Total Volumetric Transportation Rate - Niagara Supply**								
208									
209									
210									

REDACTED

REDACTED

Line	Description	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov- Apr
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								
2	**d/b/a Liberty Utilities**								
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Supply and Commodity Costs, Volumes and Rates**								
5									
6	For Month of:	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Nov- Apr
7	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
211									
212									
213	**TGP Direct Volumetric Transportation Charge**								Average Rate
214	**Commodity Costs**	Ln 123	[redacted]						
215									
216	TGP - Max Comm. Base Rate - Z 0-6	13th Rev Sheet No. 15	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039	$0.03039
217	TGP - Max Commodity ACA Rate - Z 0-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
218	Subtotal TGP - Max Comm. Rate Z 0-6		$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052	$0.03052
219	Prorated Percentage		32.60%	32.60%	32.60%	32.60%	32.60%	32.60%	32.60%
220	Prorated TGP - Max Commodity Rate - Z 0-6		**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**	**$0.00995**
221	TGP - Max Comm. Base Rate - Z 1-6	13th Rev Sheet No. 15	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650	$0.02650
222	TGP - Max Commodity ACA Rate - Z 1-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
223	Subtotal TGP - Max Commodity Rate - Z 1-6		$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663	$0.02663
224	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
225	Prorated TGP - Trans Charge - Max Commodity Rate - Z 1-6		**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**	**$0.01795**
226	TGP - Fuel Charge % - Z 0 -6	13th Rev Sheet No. 32	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%	4.44%
227	Prorated Percentage		32.6%	32.6%	32.6%	32.6%	32.6%	32.6%	32.6%
228	Prorated TGP Fuel Charge % - Z 0-6		1.45%	1.45%	1.45%	1.45%	1.45%	1.45%	1.45%
229	TGP - Fuel Charge % - Z 1 -6	13th Rev Sheet No. 32	3.88%	3.88%	3.88%	3 88%	3.88%	3.88%	3.88%
230	Prorated Percentage		67.40%	67.40%	67.40%	67.40%	67.40%	67.40%	67.40%
231	Prorated TGP Fuel Charge - Fuel Charge % - Z 1-6		2.62%	2.62%	2.62%	2.62%	2.62%	2.62%	2.62%
232	TGP - Fuel Charge % - Z 0-6	In 215 x In 229	**$0.00427**	**$0.00440**	**$0.00453**	**$0.00447**	**$0.00432**	**$0.00387**	**$0.00431**
233	TGP - Fuel Charge % - Z 1-6	In 215 x In 232	**$0.00771**	**$0.00796**	**$0.00818**	**$0.00808**	**$0.00781**	**$0.00699**	**$0.00779**
234	**Total Volumetric Transportation Rate - TGP (Direct)**		**$0.03987**	**$0.04026**	**$0.04060**	**$0.04045**	**$0.04003**	**$0.03876**	**$0.04000**
235									
236	**TGP (Zone 6 Purchase) Volumetric Transportation Charge**								
237	**Commodity Costs**	Ln 123	[redacted]						
238									
239	TGP - Max Comm. Base Rate - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
240	TGP - Max Commodity ACA Rate - Z 6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
241	Subtotal TGP - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
242	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
243	TGP - Fuel Charge	In 238 x In 243	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**	**$0.00003**
244	**Total Vol. Trans. Rate - TGP (Zone 6)**		**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**	**$0.00349**
245									
246									
247	**TGP Dracut**								
248	**Commodity Costs - NYMEX Price**	Ln 114	[redacted]						
249									
250	TGP - Trans Charge - Comm. - Z 6-6	13th Rev Sheet No. 15	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333	$0.00333
251	TGP - Trans Charge - ACA Rate - Z6-6	13th Rev Sheet No. 15	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013	$0.00013
252	Subtotal TGP - Trans Charge - Max Commodity Rate - Z 6-6		**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**	**$0.00346**
253	TGP - Fuel Charge % - Z 6-6	13th Rev Sheet No. 32	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
254	TGP - Fuel Charge	In 249 x In 254	[redacted]						
255	**Total Volumetric Transportation Rate - TGP Dracut**								
256									
257									

REDACTED

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**										
2	**d/b/a Liberty Utilities**										
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**										
4	**NYMEX Futures @ Henry Hub**										
5											Peak
6	For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19		Strip Average
7	(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)		(i)
8	**I. NYMEX Opening Prices as of**										
9	Opening Prices (15 day average)			2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$	2.9782
10	NYMEX		**Filed COG**	2.9479	3.0421	3.1275	3.0909	2.9866	2.6741	$	2.9782

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
NYMEX Futures @ Henry Hub

For Month of:	Reference		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Strip Average
(a)	(b)		(c)	(d)	(e)	(f)	(g)	(h)	(i)
NYMEX Settlement - 15 Day Average									
	Days	Date							
	1	21-Aug	2 9910	3.0830	3.1670	3.1310	3.0270	2.7090	
	2	20-Aug	2 9660	3.0610	3.1450	3.1090	3.0060	2.7010	
	3	17-Aug	2 9860	3.0820	3.1680	3.1320	3.0280	2.7080	
	4	16-Aug	2 9500	3.0460	3.1340	3.1000	2.9980	2.6930	
	5	15-Aug	2 9850	3.0780	3.1650	3.1280	3.0220	2.7060	
	6	14-Aug	3.0020	3.0920	3.1760	3.1380	3.0320	2.7130	
	7	13-Aug	2 9710	3.0590	3.1450	3.1090	3.0040	2.6980	
	8	10-Aug	2 9820	3.0670	3.1510	3.1130	3.0080	2.6910	
	9	9-Aug	2 9920	3.0770	3.1620	3.1250	3.0220	2.6980	
	10	8-Aug	2 9890	3.0770	3.1630	3.1240	3.0190	2.6910	
	11	7-Aug	2 9350	3.0310	3.1170	3.0800	2.9740	2.6570	
	12	6-Aug	2 9030	3.0030	3.0900	3.0520	2.9470	2.6340	
	13	3-Aug	2 8980	2.9980	3.0820	3.0450	2.9410	2.6260	
	14	2-Aug	2 8570	2.9580	3.0430	3.0060	2.9030	2.6050	
	15	1-Aug	2 8110	2.9190	3.0050	2.9710	2.8680	2 5820	
		15 Day Average	2 9479	3.0421	3.1275	3.0909	2.9866	2.6741	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
1 **d/b/a Liberty Utilities**
2 **Peak 2018 - 2019 Winter Cost of Gas Filing**
3 **Annual Bill Comparisons, Nov 17 - Apr 18 vs Nov 18 - Apr 19 - Residential Heating Rate R-3**
4
5

6	**November 1, 2018 - April 30, 2019**										**May 1, 2018 - October 31, 2018**						
7	**Residential Heating (R3)**																
8	**PROPOSED**									**Winter**							**Summer**	**Total**
9				**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Nov-Apr**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**May-Oct**	**Nov-Oct**
10	**average Usage (Therms)**			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
11		5/1/2018	7/1/2018															
12	**Winter:**																	
13	Cust. Chg	$24.43	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$15.02	$90.12								
14	Headblock	$0.3863	$0.5631	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00								
15	Tailblock	$0.3197	$0.5631	$21.33	$53.70	$88.19	$78.12	$60.12	$56.40	$357.86								
16	HB Threshold	100	-															
17																		
18	**Summer:**																	
19	Cust. Chg	$14.88	$15.02								$14.88	$14.88	$15.02	$15.02	$15.02	$15.02	$89.84	$179.96
20	Headblock	$0.5580	$0.5631								$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
21	Tailblock	$0.5580	$0.5631								$30.99	$11.84	$9.43	$8.47	$8.80	$10.15	$79.67	$437.53
22	HB Threshold	-	-															
23																		
24	Total Base Rate Amount			$36.35	$68.72	$103.21	$93.14	$75.14	$71.42	$447.98	$45.87	$26.72	$24.45	$23.49	$23.82	$25.17	$169.51	$617.49
25																		
26	COG Rate - (Seasonal)			$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.7411	$0.3133	$0.3916	$0.3127	$0.3665	$0.3916	$0.3916	$0.3491	$0.6694
27	COG amount			$28.07	$70.68	$116.07	$102.82	$79.12	$74.23	$470.98	$17.40	$8.31	$5.24	$5.51	$6.12	$7.06	$49.63	$520.62
28																		
29	LDAC			$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0836	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0945	$0.0856
30	LDAC amount			$3.17	$7.98	$13.10	$11.60	$8.93	$8.38	$53.15	$5.25	$2.00	$1.58	$1.42	$1.48	$1.70	$13.44	$66.59
31																		
32	**Total Bill**			**$67.58**	**$147.37**	**$232.37**	**$207.57**	**$163.19**	**$154.03**	**$972.12**	**$68.51**	**$37.03**	**$31.27**	**$30.42**	**$31.42**	**$33.93**	**$232.58**	**$1,204.70**
33																		
34	**November 1, 2017 - April 30, 2018**										**May 1, 2017 - October 31, 2017**							
35	**Residential Heating (R3)**																	
36	**CURRENT**									**Winter**							**Summer**	**Total**
37				**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**Nov-Apr**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**May-Oct**	**Nov-Oct**
38	**average Usage (Therms)**			38	95	157	139	107	100	636	56	21	17	15	16	18	142	778
39																		
40	**Winter:**	5/1/2017	7/1/2017															
41	Cust. Chg	$22.10	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$24.43	$146.58								
42	Headblock	$0.3495	$0.3863	$14.63	$36.84	$38.63	$38.63	$38.63	$38.63	$205.99								
43	Tailblock	$0.2892	$0.3197	$0.00	$0.00	$18.10	$12.39	$2.16	$0.05	$32.70								
44	HB Threshold	100	100															
45																		
46	**Summer:**																	
47	Cust. Chg	$22.10	$24.43								$22.10	$22.10	$24.43	$24.43	$24.43	$24.43	$141.92	$288.50
48	Headblock	$0.3495	$0.3863								$6.99	$6.99	$6.47	$5.81	$6.04	$6.96	$39.26	$245.25
49	Tailblock	$0.2892	$0.3197								$10.27	$0.35	$0.00	$0.00	$0.00	$0.00	$10.63	$43.32
50	HB Threshold	20	20															
51																		
52	Total Base Rate Amount			$39.06	$61.27	$81.16	$75.45	$65.22	$63.11	$385.27	$39.36	$29.44	$30.90	$30.24	$30.47	$31.39	$191.81	$577.08
53																		
54	COG Rate - (Seasonal)			$0.6445	$0.6445	$0.6445	$0.8056	$0.8056	$0.8056	$0.7321	$0.4368	$0.4368	$0.4368	$0.4725	$0.4725	$0.4725	$0.4490	$0.6804
55	COG amount			$24.41	$61.46	$100.94	$111.77	$86.01	$80.69	$465.28	$24.26	$9.27	$7.31	$7.11	$7.39	$8.52	$63.84	$529.12
56																		
57	LDAC			$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	$0.0856	0.0856	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0640	$0.0817
58	LDAC amount			$3.24	$8.16	$13.41	$11.88	$9.14	$8.57	$54.40	$3.55	$1.36	$1.07	$0.96	$1.00	$1.15	$9.10	$63.50
59																		
60	**Total Bill**			**$66.71**	**$130.90**	**$195.50**	**$199.09**	**$160.37**	**$152.38**	**$904.95**	**$67.17**	**$40.07**	**$39.28**	**$38.31**	**$38.85**	**$41.07**	**$264.75**	**$1,169.70**
61																		
62	**DIFFERENCE:**																	
63	**Total Bill**			**$0.87**	**$16.48**	**$36.87**	**$8.48**	**$2.82**	**$1.65**	**$67.17**	**$1.34**	**($3.04)**	**($8.02)**	**($7.89)**	**($7.43)**	**($7.13)**	**($32.17)**	**$35.00**
64	% Change			**1.30%**	**12.59%**	**18.86%**	**4.26%**	**1.76%**	**1.08%**	**7.42%**	**1.99%**	**-7.58%**	**-20.41%**	**-20.59%**	**-19.13%**	**-17.37%**	**-12.15%**	**2.99%**
65																		
66	**Base Rate**			($2.71)	$7.45	$22.05	$17.70	$9.92	$8.31	$62.71	$6.50	($2.72)	($6.45)	($6.75)	($6.65)	($6.22)	($22.29)	$40.42
67	% Change			-6.95%	12.16%	27.17%	23.46%	15.20%	13.17%	16.28%	16.51%	-9.25%	-20.87%	-22.33%	-21.81%	-19.82%	-11.62%	7.00%
68																		
69	**COG & LDAC**			$3.58	$9.03	$14.82	($9.22)	($7.10)	($6.66)	$4.46	($5.16)	($0.31)	($1.57)	($1.14)	($0.79)	($0.91)	($9.88)	($5.42)
70	% Change			14.68%	14.68%	14.68%	-8.25%	-8.25%	-8.25%	0.96%	-21.29%	-3.37%	-21.43%	-15.98%	-10.67%	-10.67%	-15.47%	-1.02%
	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 Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-41

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
Commercial Rate (G-41)

PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			89	277	504	457	331	297	1,954	153	39	26	34	25	29	306	2,260
Winter:	7/1/2018	5/1/2018															
Cust. Chg	$56.58	$53.45	$56.58	$56.58	$56.58	$56.58	$56.58	$56.58	$339.48								
Headblock	$0.4639	$0.4383	$41.15	$46.39	$46.39	$46.39	$46.39	$46.39	$273.10								
Tailblock	$0.3116	$0.2944	$0.00	$55.19	$125.84	$111.12	$71.93	$61.33	$425.41								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$56.58	$56.07								$56.07	$56.07	$56.58	$56.58	$56.58	$56.58	$338.47	$677.95
Headblock	$0.4639	$0.4597								$9.19	$9.19	$9.28	$9.28	$9.28	$9.28	$55.50	$328.60
Tailblock	$0.3116	$0.3088								$40.99	$5.78	$1.96	$4.23	$1.58	$2.87	$57.41	$482.82
HB Threshold	20	20															
Total Base Rate Amount			$97.73	$158.16	$228.81	$214.09	$174.90	$164.30	$1,037.99	$106.25	$71.05	$67.82	$70.09	$67.44	$68.73	$451.38	$1,489.37
COG Rate - (Seasonal)			$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.3084	$0.3855	$0.3066	$0.3604	$0.3855	$0.3855	$0.3374	$0.6858
COG amount			$65.67	$205.16	$373.01	$338.04	$244.91	$219.74	$1,446.51	$47.11	$14.93	$8.06	$12.10	$9.66	$11.26	$103.11	$1,549.63
LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0770
LDAC amount			$6.84	$21.38	$38.88	$35.23	$25.53	$22.90	$150.76	$11.65	$2.95	$2.00	$2.56	$1.91	$2.23	$23.32	$174.08
Total Bill			**$170.24**	**$384.70**	**$640.69**	**$587.36**	**$445.33**	**$406.94**	**$2,635.27**	**$165.01**	**$88.93**	**$77.88**	**$84.75**	**$79.02**	**$82.22**	**$577.81**	**$3,213.08**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
Commercial Rate (G-41)

CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			89	277	504	457	331	297	1,954	153	39	26	34	25	29	306	2,260
Winter:	7/1/2017	5/1/2017															
Cust. Chg	$53.45	$48.36	$53.45	$53.45	$53.45	$53.45	$53.45	$53.45	$320.70								
Headblock	$0.4383	$0.3965	$38.88	$43.83	$43.83	$43.83	$43.83	$43.83	$258.03								
Tailblock	$0.2944	$0.2663	$5.45	$52.15	$118.90	$104.99	$67.96	$57.94	$407.38								
HB Threshold	100	100															
Summer:																	
Cust. Chg	$53.45	$48.36								$48.36	$48.36	$53.45	$53.45	$53.45	$53.45	$310.52	$631.22
Headblock	$0.4383	$0.3965								$7.93	$7.93	$8.77	$8.77	$8.77	$8.77	$50.94	$308.97
Tailblock	$0.2944	$0.2663								$27.20	$7.84	$2.20	$1.08	$0.86	$6.66	$45.84	$453.22
HB Threshold	20	20															
Total Base Rate Amount			$97.78	$149.43	$216.18	$202.27	$165.24	$155.22	$986.11	$83.49	$64.13	$64.42	$63.30	$63.08	$68.88	$407.30	$1,393.41
COG Rate - (Seasonal)			$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7325	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4309	$0.6917
COG amount			$57.06	$178.28	$324.13	$367.17	$266.02	$238.67	$1,431.33	$64.24	$16.29	$11.05	$15.32	$11.44	$13.33	$131.67	$1,563.00
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0644
LDAC amount			$5.98	$18.68	$33.96	$30.78	$22.30	$20.01	$131.70	$6.87	$1.74	$1.18	$1.51	$1.13	$1.31	$13.75	$145.45
Total Bill			**$160.82**	**$346.38**	**$574.27**	**$600.21**	**$453.55**	**$413.90**	**$2,549.14**	**$154.61**	**$82.16**	**$76.65**	**$80.13**	**$75.65**	**$83.52**	**$552.72**	**$3,101.86**

DIFFERENCE:

Total Bill	**$9.42**	**$38.32**	**$66.43**	**($12.85)**	**($8.22)**	**($6.97)**	**$86.13**	**$10.41**	**$6.77**	**$1.22**	**$4.62**	**$3.37**	**($1.30)**	**$25.09**	**$111.22**
% Change	**5.86%**	**11.06%**	**11.57%**	**-2.14%**	**-1.81%**	**-1.68%**	**3.38%**	**6.73%**	**8.24%**	**1.60%**	**5.77%**	**4.46%**	**-1.56%**	**4.54%**	**3.59%**
Base Rate	($0.05)	$8.74	$12.64	$11.82	$9.66	$9.08	$51.88	$22.76	$6.92	$3.40	$6.79	$4.36	($0.15)	$44.08	$95.97
% Change	-0.05%	5.85%	5.85%	5.85%	5.85%	5.85%	5.26%	27.27%	10.79%	5.27%	10.73%	6.91%	-0.21%	10.82%	6.89%
COG & LDAC	$9.47	$29.59	$53.79	($24.68)	($17.88)	($16.04)	$34.25	($12.36)	($0.15)	($2.17)	($2.17)	($0.99)	($1.15)	($18.99)	$15.26
% Change	16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.39%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-14.42%	0.98%
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

Liberty Utilities (EnergyNorth Natural Gas) Corp.
d/b/a Liberty Utilities
Peak 2018 - 2019 Winter Cost of Gas Filing
Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-42

November 1, 2018 - April 30, 2019 / **May 1, 2018 - October 31, 2018**
C&I High Winter Use Medium G-42

PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
	7/1/2018	5/1/2018															
Winter:																	
Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50								
Headblock	$0.4219	$0.3986	$350.20	$421.90	$421.90	$421.90	$421.90	$421.90	$2,459.70								
Tailblock	$0.2811	$0.2655	$0.00	$334.13	$761.08	$676.27	$450.55	$392.11	$2,614.13								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$169.75	$168.21								$160.36	$160.36	$169.75	$169.75	$169.75	$169.75	$999.72	$2,018.22
Headblock	$0.4219	$0.4181								$167.24	$167.24	$120.07	$104.03	$113.31	$143.61	$815.50	$3,275.21
Tailblock	$0.2811	$0.2785								$255.94	$23.42	$0.00	$0.00	$0.00	$0.00	$279.36	$2,893.49
HB Threshold	400	400															
Total Base Rate Amount			$519.95	$925.78	$1,352.73	$1,267.92	$1,042.20	$983.76	$6,092.33	$583.54	$351.02	$289.82	$273.78	$283.06	$313.36	$2,094.59	$8,186.92
COG Rate - (Seasonal)			$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.7403	$0.3084	$0.3855	$0.3066	$0.3604	$0.3855	$0.3855	$0.3412	$0.6753
COG amount			$614.49	$1,620.25	$2,744.67	$2,521.30	$1,926.86	$1,772.94	$11,200.51	$406.78	$186.62	$87.26	$88.87	$103.54	$131.22	$1,004.28	$12,204.79
LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0770
LDAC amount			$64.04	$168.87	$286.06	$262.78	$200.82	$184.78	$1,167.36	$100.64	$36.94	$21.71	$18.81	$20.49	$25.97	$224.57	$1,391.93
Total Bill			**$1,198.49**	**$2,714.89**	**$4,383.46**	**$4,052.00**	**$3,169.88**	**$2,941.48**	**$18,460.21**	**$1,090.97**	**$574.57**	**$398.79**	**$381.46**	**$407.09**	**$470.55**	**$3,323.43**	**$21,783.64**

November 1, 2017 - April 30, 2018 / **May 1, 2017 - October 31, 2017**
C&I High Winter Use Medium G-42

CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
average Usage (Therms)			830	2,189	3,708	3,406	2,603	2,395	15,130	1,319	484	285	247	269	340	2,943	18,073
	5/1/2017	7/1/2017															
Winter:																	
Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
Headblock	$0.3606	$0.3986	$330.86	$398.60	$398.60	$398.60	$398.60	$398.60	$2,323.86								
Tailblock	$0.2402	$0.2655	$0.00	$315.58	$718.84	$638.74	$425.54	$370.34	$2,469.05								
HB Threshold	1,000	1,000															
Summer:																	
Cust. Chg	$145.08	$160.36								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
Headblock	$0.3606	$0.3986								$144.24	$144.24	$113.44	$98.29	$107.06	$135.68	$742.94	$3,066.80
Tailblock	$0.2402	$0.2655								$220.75	$28.09	$0.00	$0.00	$0.00	$0.00	$248.84	$2,717.89
HB Threshold	400	400															
Total Base Rate Amount			$491.22	$874.54	$1,277.80	$1,197.70	$984.50	$929.30	$5,755.08	$510.07	$317.41	$273.80	$258.65	$267.42	$296.04	$1,923.37	$7,678.45
COG Rate - (Seasonal)			$0.6433	$0.6433	$0.6433	$0.8041	$0.8041	$0.8041	$0.7326	$0.4206	$0.4206	$0.4206	$0.4563	$0.4563	$0.4563	$0.4310	$0.6835
COG amount			$533.98	$1,407.95	$2,385.04	$2,738.59	$2,092.92	$1,925.74	$11,084.22	$554.78	$203.61	$119.70	$112.51	$122.55	$155.32	$1,268.47	$12,352.68
LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0638
LDAC amount			$55.95	$147.51	$249.89	$229.55	$175.43	$161.42	$1,019.74	$59.36	$21.78	$12.81	$11.10	$12.09	$15.32	$132.45	$1,152.19
Total Bill			**$1,081.15**	**$2,430.01**	**$3,912.73**	**$4,165.84**	**$3,252.85**	**$3,016.46**	**$17,859.03**	**$1,124.20**	**$542.80**	**$406.30**	**$382.26**	**$402.05**	**$466.67**	**$3,324.29**	**$21,183.32**

DIFFERENCE:

	Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
Total Bill	**$117.35**	**$284.88**	**$470.73**	**($113.84)**	**($82.97)**	**($74.98)**	**$601.17**	**($33.23)**	**$31.77**	**($7.51)**	**($0.79)**	**$5.04**	**$3.88**	**($0.85)**	**$600.32**
% Change	**10.85%**	**11.72%**	**12.03%**	**-2.73%**	**-2.55%**	**-2.49%**	**3.37%**	**-2.96%**	**5.85%**	**-1.85%**	**-0.21%**	**1.25%**	**0.83%**	**-0.03%**	**2.83%**
Base Rate	$28.73	$51.23	$74.93	$70.22	$57.69	$54.45	$337.25	$73.48	$33.61	$16.02	$15.14	$15.65	$17.32	$171.21	$508.47
% Change	5.85%	5.86%	5.86%	5.86%	5.86%	5.86%	5.86%	14.41%	10.59%	5.85%	5.85%	5.85%	5.85%	8.90%	6.62%
COG & LDAC	$88.61	$233.65	$395.80	($184.06)	($140.66)	($129.43)	$263.92	($106.71)	($1.84)	($23.54)	($15.93)	($10.61)	($13.45)	($172.07)	$91.85
% Change	16.60%	16.60%	16.60%	-6.72%	-6.72%	-6.72%	2.38%	-19.23%	-0.90%	-19.66%	-14.16%	-8.66%	-8.66%	-13.56%	0.74%
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.

1 **d/b/a Liberty Utilities**
2 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Annual Bill Comparisons, Nov 16 - Apr 17 vs Nov 17 - Apr 18 - Commercial Rate G-52**

7 **November 1, 2018 - April 30, 2019** — **May 1, 2018 - October 31, 2018**
8 **Commercial Rate (G-52)**

#	PROPOSED			Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Winter Nov-Apr	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Summer May-Oct	Total Nov-Oct
11	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,306	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
12																		
13	**Winter:**	7/1/2018	5/1/2018															
14	Cust. Chg	$169.75	$160.36	$169.75	$169.75	$169.75	$169.75	$169.75	$169.75	$1,018.50								
15	Headblock	$0.2401	$0.2268	$240.10	$240.10	$240.10	$240.10	$240.10	$240.10	$1,440.60								
16	Tailblock	$0.1600	$0.1511	$56.28	$138.55	$205.37	$185.54	$141.69	$121.61	$849.04								
17	HB Threshold	1,000	1,000															
18																		
19	**Summer:**																	
20	Cust. Chg	$169.75	$168.21								$168.21	$168.21	$169.75	$169.75	$169.75	$169.75	$1,015.42	$2,033.92
21	Headblock	$0.1740	$0.1724								$172.40	$172.40	$174.00	$174.00	$174.00	$156.04	$1,022.84	$2,463.44
22	Tailblock	$0.0989	$0.0980								$49.15	$12.63	$3.16	$2.48	$4.92	$0.00	$72.35	$921.38
23	HB Threshold	1,000	1,000															
24																		
25	Total Base Rate Amount			$466.13	$548.40	$615.22	$595.39	$551.54	$531.46	$3,308.14	$389.76	$353.24	$346.91	$346.23	$348.67	$325.79	$2,110.61	$5,418.74
26																		
27	COG Rate - (Seasonal)			$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.7456	$0.3299	$0.4124	$0.3335	$0.3873	$0.4124	$0.4124	$0.3776	$0.6096
28	COG amount			$1,007.86	$1,391.23	$1,702.65	$1,610.22	$1,405.86	$1,312.30	$8,430.11	$493.86	$465.08	$344.16	$397.00	$432.94	$369.83	$2,502.87	$10,932.98
29																		
30	LDAC			$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	$0.0772	0.0772	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0763	$0.0768
31	LDAC amount			$104.30	$143.97	$176.19	$166.63	$145.48	$135.80	$872.37	$114.22	$86.05	$78.74	$78.21	$80.10	$68.42	$505.74	$1,378.11
32																		
33	**Total Bill**			**$1,578.29**	**$2,083.59**	**$2,494.07**	**$2,372.23**	**$2,102.88**	**$1,979.56**	**$12,610.61**	**$997.85**	**$904.37**	**$769.80**	**$821.44**	**$861.71**	**$764.05**	**$5,119.22**	**$17,729.83**

35 **November 1, 2017 - April 30, 2018** — **May 1, 2017 - October 31, 2017**
36 **Commercial Rate (G-52)**

#	CURRENT			Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	Winter Nov-Apr	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Summer May-Oct	Total Nov-Oct
39	**average Usage (Therms)**			1,352	1,866	2,284	2,160	1,886	1,760	11,306	1,497	1,128	1,032	1,025	1,050	897	6,628	17,935
40																		
41	**Winter:**	5/1/2017	7/1/2017															
42	Cust. Chg	$145.08	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$160.36	$962.16								
43	Headblock	$0.2052	$0.2268	$226.80	$226.80	$226.80	$226.80	$226.80	$226.80	$1,360.80								
44	Tailblock	$0.1367	$0.1511	$53.15	$130.84	$193.95	$175.22	$133.81	$114.84	$801.81								
45	HB Threshold	1,000	1,000															
46																		
47	**Summer:**																	
48	Cust. Chg	$145.08	$160.36								$145.08	$145.08	$160.36	$160.36	$160.36	$160.36	$931.60	$1,893.76
49	Headblock	$0.1487	$0.1644								$148.70	$148.70	$164.40	$164.40	$164.40	$147.43	$938.03	$2,298.83
50	Tailblock	$0.0845	$0.0934								$32.97	$7.82	$2.98	$2.34	$4.65	$0.00	$50.76	$852.57
51	HB Threshold	1,000	1,000															
52																		
53	Total Base Rate Amount			$440.31	$518.00	$581.11	$562.38	$520.97	$502.00	$3,124.77	$326.75	$301.60	$327.74	$327.10	$329.41	$307.79	$1,920.40	$5,045.16
54																		
55	COG Rate - (Seasonal)			$0.6560	$0.6560	$0.6560	$0.8171	$0.8200	$0.8200	$0.7397	$0.4574	$0.4574	$0.4574	$0.4931	$0.4931	$0.4931	$0.4734	$0.6413
56	COG amount			$886.74	$1,224.04	$1,498.04	$1,764.63	$1,546.14	$1,443.25	$8,362.84	$684.73	$515.83	$472.01	$505.45	$517.65	$442.21	$3,137.88	$11,500.72
57																		
58	LDAC			$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	$0.0674	0.0674	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0450	$0.0591
59	LDAC amount			$91.11	$125.76	$153.91	$145.56	$127.09	$118.63	$762.06	$67.37	$50.75	$46.44	$46.13	$47.24	$40.36	$298.27	$1,060.33
60																		
61	**Total Bill**			**$1,418.16**	**$1,867.80**	**$2,233.06**	**$2,472.57**	**$2,194.19**	**$2,063.88**	**$12,249.67**	**$1,078.85**	**$868.18**	**$846.20**	**$878.68**	**$894.31**	**$790.35**	**$5,356.55**	**$17,606.22**

63 **DIFFERENCE:**

#		Nov	Dec	Jan	Feb	Mar	Apr	Winter Nov-Apr	May	Jun	Jul	Aug	Sep	Oct	Summer May-Oct	Total Nov-Oct
64	**Total Bill**	**$160.13**	**$215.79**	**$261.00**	**($100.33)**	**($91.32)**	**($84.32)**	**$360.95**	**($81.00)**	**$36.19**	**($76.39)**	**($57.24)**	**($32.60)**	**($26.30)**	**($237.34)**	**$123.61**
65	% Change	**11.29%**	**11.55%**	**11.69%**	**-4.06%**	**-4.16%**	**-4.09%**	**2.95%**	**-7.51%**	**4.17%**	**-9.03%**	**-6.51%**	**-3.64%**	**-3.33%**	**-4.43%**	**0.70%**
66																
67	**Base Rate**	$25.82	$30.40	$34.11	$33.01	$30.57	$29.45	$183.37	$63.01	$51.64	$19.17	$19.13	$19.26	$18.00	$190.21	$373.58
68	% Change	5.86%	5.87%	5.87%	5.87%	5.87%	5.87%	5.87%	19.28%	17.12%	5.85%	5.85%	5.85%	5.85%	9.90%	7.40%
69																
70	**COG & LDAC**	$134.31	$185.39	$226.89	($133.34)	($121.89)	($113.78)	$177.58	($144.01)	($15.45)	($95.56)	($76.37)	($51.86)	($44.30)	($427.55)	($249.97)
71	% Change	15.15%	15.15%	15.15%	-7.56%	-7.88%	-7.88%	2.12%	-21.03%	-3.00%	-20.24%	-15.11%	-10.02%	-10.02%	-13.63%	-2.17%
	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.

1	**d/b/a Liberty Utilities**		
2	**Peak 2018 - 2019 Winter Cost of Gas Filing**		
3	**Residential Heating**		
4		Winter 2017-18	Winter 2018-19
5	Customer Charge	$24.43	$15.02
6	First 100 Therms	$0.3863	$0.5631
7	Excess 100 Therms	$0.3197	$0.5631
8	LDAC	$0.0856	$0.0836
9	COG	$0.7321	$0.7411
10	Total Adjust	$0.8177	$0.8247
11			
12			
13			

					Total		Base Rate		COG		LDAC	
14												
15			Winter 2017-18 COG @	Winter 2018-19 COG @	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact	$ Impact	% Impact
16			$0.8177	$0.8247	$0.01	1%						
17												
18	Cooking alone	5	$30.45	$30.49	$0.04	0%	$0.00	0%	$0.04	0%	-$0.01	0%
19												
20		10	$36.47	$36.54	$0.07	0%	$0.00	0%	$0.09	0%	-$0.02	0%
21												
22		20	$48.51	$48.65	$0.14	0%	$0.00	0%	$0.18	0%	-$0.04	0%
23												
24	Water Heating alone	30	$60.55	$60.76	$0.21	0%	$0.00	0%	$0.27	0%	-$0.06	0%
25												
26		45	$78.61	$78.93	$0.32	0%	$0.00	0%	$0.40	1%	-$0.09	0%
27												
28		50	$84.63	$84.98	$0.35	0%	$0.00	0%	$0.45	1%	-$0.10	0%
29												
30	Heating Alone	80	$114.73	$115.26	$0.53	0%	$0.00	0%	$0.67	1%	-$0.15	0%
31												
32		125	$182.37	$183.30	$0.93	1%	$0.00	0%	$1.19	1%	-$0.26	0%
33												
34		150	$201.70	$202.76	$1.05	1%	$0.00	0%	$1.35	1%	-$0.29	0%
35												
36		200	$258.57	$259.98	$1.40	1%	$0.00	0%	$1.80	1%	-$0.39	0%
37												

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Variance Analysis of the Components of the Winter 2017-18 Actual Results vs Proposed Winter 2018-19 Cost of Gas Rate**

Line		WINTER 2017-18 ACTUAL RESULTS (6 months actual)			WINTER 2018-19 (6 months Proposed)		
11	Therm Sales (COG)	83,403,894			86,451,254		
12-14		THERM SENDOUT	COSTS	EFFECT ON COST OF GAS	THERM SENDOUT	COSTS	EFFECT ON COST OF GAS
16	Demand Charges		$ 8,996,827	$ 0.1079		$ 11,230,946	$ 0.1299
18	Purchased Gas		$ 51,743,743	0.6204	64,967,225	$ 41,318,346	0.4779
20	Storage/Produced Gas		$ 921,553	0.0110	22,991,399	$ 7,797,874	0.0902
22	Hedging (Gain)/Loss		0	0.0000		0	0.0000
25	Total Volumes and Cost	92,177,230	$ 61,662,124	$ 0.7393	87,958,623	$ 60,347,167	$ 0.6980
27	Direct Costs						
28	Prior Period Balance		$ 724,939	$ 0.0087		2,599,354	$ 0.0301
29	Interest		115,162	0.0014		63,196	0.0007
30	Prior Period Adjustment		-	-		351,017	0.0041
31	Broker Revenues		(497,759)	(0.0060)		(497,759)	(0.0058)
32	Refunds from Suppliers		1,054	0.0000		-	-
33	Fuel Financing		-	-		-	-
34	Transportation CGA Revenues		(59,496)	(0.0007)		(26,381)	(0.0003)
35	280 Day Margin		-	-		-	-
36	Interruptible Sales Margin		-	-		-	-
37	Capacity Release and Off System Sales Margins		(1,877,737)	(0.0225)		(1,877,737)	(0.0217)
38	Hedging Costs		-	-		-	-
39	FPO Admin Costs		-	-		45,000	0.0005
40	Indirect Costs		-	-			
41	Misc Overhead		10,737	0.0001		10,681	0.0001
42	Occupant Disallowance/Credits		-			-	-
43	Production & Storage		1,980,428	0.0237		1,980,428	0.0229
44	Bad Debt Adjustment %		227,016	0.0027		1,079,135	0.0125
45	Cashout, Broker penalty, Canadian Managed,…		-	-		0	0
46	Total Adjusted Cost		$ 62,286,467	**$ 0.7468**		$ 64,074,101	**$ 0.7412**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2018 - 2019 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
Derivation of Class Assignments and Weightings

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			575	578	0.4%		109	469
2	RATE R-3-Resi Htg			71,486	71,889	43.7%		4,189	67,700
3	RATE G-41 (T)			30,310	30,485	18 5%		1,045	29,440
4	RATE G-51 (S)			2,545	2,556	1 6%		670	1,886
5	RATE G-42 (V)			37,598	37,813	23 0%		1,566	36,248
6	RATE G-52			5,360	5,381	3 3%		1,846	3,535
7	RATE G-43			7,427	7,468	4 5%		587	6,881
8	RATE G-53			3,878	3,893	2.4%		1,412	2,480
9	RATE G-54			4,483	4,507	2.7%		382	4,126
10									
11	Total			163,661	164,571	100 0%		11,806	152,765
12									-
13	Residential Total			72,061	72,467	**44.034%**		4,298	68,169
14	LLF Total			75,334	75,766	**46.038%**		3,198	72,568
15	HLF Total			16,266	16,338	**9.927%**		4,310	12,027
16	Total			163,661	164,571	100 0%		11,806	152,765
17									
18	C&I Breakdown								
19	LLF Total							3,198	72,568
20	HLF Total							4,310	12,027
21	Total							7,508	84,595
22									
23	C&I Breakdown Percentage								
24	LLF Total							42.590%	85.783%
25	HLF Total							57.410%	14.217%
26	Total							**100.0%**	**100.0%**
27									
28				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
29	Pipeline			$12,671,205	79,718	$13 2459			
30	Storage			$4,394,284	28,115	$13 0247			
31									
32	Peaking			$4,969,000					
33	Peaking Additional Costs			$0					
34	Subtotal Peaking Costs			$4,969,000	56,738	$7 2982			
35	Total			$22,034,489	164,571	$11.1575			
36									
37				Capacity Cost	MDQ, Dt	$/Dt-Mo.			
38	Pipeline - Baseload			1,876,633	11,806	$13 2459			
39	Pipeline - Remaining			10,794,572	67,912	$13 2459			
40	Storage			4,394,284	28,115	$13 0247			
41	Peaking			4,969,000	56,738	$7 2982			
42	Total			22,034,489	164,571	$11.1575			
43									
44									
45	Residential Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.			
46	Pipeline - Base	Line 38 * Line 13 Col C	**44.034%**	826,357	5,199	$13 2459			
47	Pipeline - Remaining	Line 39 * Line 13 Col C	**44.034%**	4,753,297	29,904	$13 2459			
48	Storage	Line 40 * Line 13 Col C	**44.034%**	1,934,974	12,380	$13 0247			
49	Peaking	Line 41 * Line 13 Col C	**44.034%**	2,188,059	24,984	$7 2982			
50	Total		**44.034%**	9,702,631	72,467	$11.1575			

Liberty Utilities (EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Peak 2018 - 2019 Winter Cost of Gas Filing
Capacity Assignment Calculations 2016-2017
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		1,050,276	6,608	$13 2459	
55	Pipeline - Remaining	Line 39 - Line 47		6,041,275	38,007	$13 2458	
56	Storage	Line 40 - Line 48		2,459,310	15,735	$13 0248	
57	Peaking	Line 41 - Line 49		2,780,941	31,754	$7 2981	
58	Total		**55.966%**	12,331,802	92,104	$11.1575	**1.0000**
59							
60							
61	LLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
62	Pipeline - Base	Line 54 * Line 24 Col E		447,308	2,814	$13 2465	
63	Pipeline - Remaining	Line 55 * Line 24 Col F		5,182,374	32,604	$13 2458	
64	Storage	Line 56 * Line 24 Col F		2,109,664	13,498	$13 0245	
65	Peaking	Line 57 * Line 24 Col F		2,385,568	27,239	$7 2983	
66	Total		**45.9503%**	10,124,914	76,155	$11 0793	**0.9930**
67			42.590%	82%			(Line 66 / Line 58)
68							
69	HLF - C&I Allocation			Capacity Cost	MDQ, Dt	$/Dt-Mo.	
70	Pipeline - Base	Line 54 - Line 62		602,968	3,794	$13 2439	
71	Pipeline - Remaining	Line 55 - Line 63		858,901	5,403	$13 2473	
72	Storage	Line 56 - Line 64		349,646	2,237	$13 0251	
73	Peaking	Line 57 - Line 65		395,373	4,515	$7 2974	
74	Total		**10.0156%**	2,206,888	15,949	$11 5310	**1.0335**
75							(Line 74 / Line 58)
76							
77	Unit Cost			Residential	LLF C&I	HLF C&I	
78							
79	Pipeline			$ 13 2459	$ 13.2459	$ 13.2459	
80	Storage			$ 13 0247	$ 13.0247	$ 13.0247	
81	Peaking			$ -	$ -	$ -	
82	Total			$ 11.1575	$ 11.0793	$ 11.5310	
83							
84							
85	Load Makeup			Residential	**LLF C&I**	**HLF C&I**	
86							
87	Pipeline			48.44%	**46.51%**	**57.67%**	
88	Storage			17.08%	**17.72%**	**14.03%**	
89	Peaking			34.48%	**35.77%**	**28.31%**	
90	Total			100.00%	**100.00%**	**100.00%**	
91							
92							
93	Supply Makeup			Residential	LLF C&I	HLF C&I	Total
94							
95	Pipeline			44.03%	44.43%	11.54%	100.00%
96	Storage			44.03%	48.01%	7.96%	100.00%
97	Peaking			44.03%	48.01%	7.96%	100.00%

1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**							
2	**d/b/a Liberty Utilities**							
3	**2017-2018 Winter Calculation**							
4	**Correction Factor Calculation**							
5								
6								
7		d	e	f	g	h	i	
8	Data Source: Schedule 10B							Total
9		Nov	Dec	Jan	Feb	Mar	Apr	Sales
10								
11	G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429
12	G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213
13	G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015
14	High Winter Use	2,577,497	4,375,729	5,981,900	6,511,221	5,470,068	3,802,241	28,718,657
15								
16	G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220
17	G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252
18	G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652
19	G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923
21	Low Winter Use	462,782	635,054	1,084,797	1,002,328	924,009	780,077	4,889,046
22								
23	Gross Total	3,040,279	5,010,783	7,066,697	7,513,549	6,394,077	4,582,318	33,607,703
24								
25								
26	Total Sales				33,607,703			
27	Low Winter Use				4,889,046			
28	Winter Ratio for Low Winter Use				**1.0335**	Schedule 10A p 2, ln 74		
29	High Winter Use				28,718,657			
30	Winter Ratio for High Winter Use				**0.9930**	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 =				**100.1110%**			
34								
35								
36	**Allocation Calculation for Miscellaneous Overhead**							
37								
38	Projected Winter Sales Volume				11/1/18 - 4/30/19		86,628,921	Sch.10B, ln 23
39	Projected Annual Sales Volume				11/1/18 - 10/31/19		106,815,146	Sch.10B, ln 23
40	Percentage of Winter Sales to Annual Sales						81.10%	

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **2018 - 2019 Winter Cost of Gas Filing**
5
6 **Dry Therms**

	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Subtotal PK 18-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Subtotal OP 19	Total
7 **Firm Sales**															
8															
9 R-1	58,148	73,323	85,127	87,489	80,107	60,928	445,123	44,082	30,039	23,238	24,503	31,923	43,218	197,003	642,126
10 R-3	4,041,030	7,405,866	10,502,345	11,246,925	9,528,683	6,407,575	49,132,423	3,690,099	1,773,275	1,006,300	981,527	1,481,613	2,659,147	11,591,962	60,724,385
11 R-4	225,090	424,725	668,812	822,921	728,538	573,586	3,443,671	361,052	178,352	90,516	79,349	97,393	150,109	956,771	4,400,443
12 Total Residential.	4 324 268	7 903 914	11 256 284	12 157 335	10 337 327	7 042 089	53 021 218	4 095 234	1 981 666	1 120 055	1 085 379	1 610 929	2 852 473	12 745 736	65 766 954
13															
14 G-41	1,321,101	2,319,276	3,165,299	3,498,870	2,926,465	1,918,416	15,149,429	800,746	362,796	221,001	168,493	181,679	460,013	2,194,729	17,344,157
15 G-42	895,704	1,551,977	2,083,542	2,176,169	1,812,337	1,285,485	9,805,213	748,675	460,256	231,012	116,114	74,965	227,916	1,858,939	11,664,152
16 G-43	360,692	504,475	733,059	836,182	731,266	598,340	3,764,015	304,113	197,948	134,668	105,947	121,390	192,087	1,056,153	4,820,168
17 G-51	135,964	177,998	217,956	227,659	210,007	162,636	1,132,220	115,160	74,244	56,098	56,385	71,155	94,990	468,032	1,600,252
18 G-52	146,420	183,177	224,756	238,484	224,688	178,727	1,196,252	131,291	88,424	68,817	68,840	84,354	107,862	549,588	1,745,840
19 G-53	156,779	249,279	616,066	508,733	461,553	413,241	2,405,652	291,255	205,865	165,249	156,854	172,243	202,036	1,193,502	3,599,154
20 G-54	23,619	24,600	26,018	27,451	27,760	25,474	154,923	23,468	19,194	16,830	17,609	20,668	21,777	119,546	274,468
21 Total C/I	3 040 279	5 010 783	7 066 697	7 513 549	6 394 077	4 582 318	33 607 703	2 414 708	1 408 727	893 675	690 242	726 454	1 306 681	7 440 489	41 048 192
22															
23 **Sales Volume**	**7,364,547**	**12,914,697**	**18,322,981**	**19,670,884**	**16,731,404**	**11,624,407**	**86,628,921**	**6,509,942**	**3,390,393**	**2,013,730**	**1,775,621**	**2,337,384**	**4,159,155**	**20,186,225**	**106,815,146**
24															
25 Transportation Sales															
26															
27 G-41	575,879	819,379	1,110,280	1,198,083	994,081	780,156	5,477,859	419,152	223,968	126,739	130,012	177,081	307,285	1,384,236	6,862,094
28 G-42	1,709,642	2,476,139	3,396,451	3,680,772	3,051,299	2,391,810	16,706,114	1,277,699	653,670	331,128	308,102	424,112	829,661	3,824,373	20,530,487
29 G-43	916,199	1,344,906	1,729,807	1,910,992	1,765,170	1,398,691	9,065,765	1,166,024	718,428	474,845	407,575	463,279	699,961	3,930,112	12,995,877
30 G-51	42,394	46,822	55,046	63,877	60,806	58,506	327,451	77,824	67,235	64,233	77,040	88,667	80,334	455,334	782,784
31 G-52	222,033	234,604	257,794	277,352	269,034	248,554	1,509,370	283,695	260,424	264,769	323,847	380,983	356,910	1,870,628	3,379,999
32 G-53	465,205	609,368	785,673	886,023	881,490	807,226	4,434,985	739,996	529,662	363,450	297,063	282,627	351,494	2,564,292	6,999,276
33 G-54	2,364,482	2,375,492	2,456,766	2,089,499	2,011,618	1,925,018	13,222,874	1,781,763	1,808,656	1,788,616	1,955,455	2,061,440	2,219,044	11,614,976	24,837,850
34															
35 Total Trans. Sales	**6,295,834**	**7,906,710**	**9,791,817**	**10,106,599**	**9,033,498**	**7,609,960**	**50,744,418**	**5,746,154**	**4,262,044**	**3,413,780**	**3,499,094**	**3,878,188**	**4,844,690**	**25,643,949**	**76,388,368**
36															
37 Total All Sales	**13,660,381**	**20,821,407**	**28,114,798**	**29,777,484**	**25,764,902**	**19,234,367**	**137,373,339**	**12,256,096**	**7,652,437**	**5,427,510**	**5,274,715**	**6,215,572**	**9,003,844**	**45,830,174**	**183,203,513**

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
4 **Normal and Design Year Volumes** — **Schedule 11A**
5 **Page 1 of 1**
6
7 **Volumes (Therms)** — **Normal Year**
8
9 **For the Months of November 18 - April 19**
10

Line		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Peak Nov - Apr
11								
12								
13	Pipeline Gas:							
14	Dawn Supply	796,342	878,932	897,468	806,735	883,624	543,941	4,807,042
15	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
16	TGP Supply (Gulf)	4,139,245	2,920,023	2,991,075	2,713,035	2,906,921	513,382	16,183,681
17	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
18	Dracut Supply 2 - Swing	2,403,712	1,843,474	1,013,294	1,480,101	3,337,257	1,654,232	11,732,071
19	ENGIE Combo	-	945,993	1,229,648	1,264,827	734,441	-	4,174,908
20	LNG Truck	18,690	289,648	685,485	1,029,982	145,597	-	2,169,402
21	Propane Truck	-	-	356,219	91,328	-	-	447,548
22	PNGTS	198,251	197,617	108,541	146,415	191,500	201,686	1,044,010
23	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	260,087	2,111,074
24	TGP Supply (Z4)	1,640,078	1,819,931	1,858,313	1,670,006	1,829,646	4,181,079	12,999,054
25	Subtotal Pipeline Volumes	10,167,550	12,616,098	14,741,933	13,223,780	11,106,978	7,990,703	69,847,042
26								
27	Storage Gas:							
28	TGP Storage	1,724,852	4,120,707	5,133,488	5,108,595	3,723,126	30,558	19,841,326
29								
30	Produced Gas:							
31	LNG Vapor	18,690	289,648	777,271	1,029,982	64,550	19,014	2,199,156
32	Propane	-	-	859,588	91,328	-	-	950,916
33	Subtotal Produced Gas	18,690	289,648	1,636,859	1,121,310	64,550	19,014	3,150,073
34								
35	Less - Gas Refills:							
36	LNG Truck	(18,690)	(289,648)	(685,485)	(1,029,982)	(145,597)	-	(2,169,402)
37	Propane	-	-	(356,219)	(91,328)	-	-	(447,548)
38	TGP Storage Refill	(2,262,867)	-	-	-	-	-	(2,262,867)
39	Subtotal Refills	(2,281,558)	(289,648)	(1,041,704)	(1,121,310)	(145,597)	-	(4,879,817)
40								
41	Total Sendout Volumes	9,629,535	16,736,804	20,470,576	18,332,374	14,749,057	8,040,276	87,958,623
42								

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **d/b/a Liberty Utilities**
3 **Peak 2018 - 2019 Winter Cost of Gas Filing**
43 **Normal and Design Year Volumes** — **Schedule 11B**
44 **Page 1 of 1**
45
46 **Volumes (Therms)** **Design Year**
47
48 **For the Months of November 18 - April 19**
49

50								**Peak**
51		**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**Nov - Apr**
52	Pipeline Gas:							
53	Dawn Supply	796,342	878,932	897,468	806,735	883,624	617,960	4,881,061
54	Niagara Supply	625,459	690,589	705,153	633,501	694,276	636,296	3,985,274
55	TGP Supply (Gulf)	4,154,598	2,956,407	3,018,756	2,713,035	2,876,080	584,686	16,303,562
56	Dracut Supply 1 - Baseload	-	2,648,210	4,507,009	3,037,758	-	-	10,192,978
57	Dracut Supply 2 - Swing	3,107,938	3,496,465	3,388,088	3,348,710	4,354,285	2,136,377	19,831,864
58	ENGIE Combo	-	1,277,020	1,048,260	1,113,337	730,137	-	4,168,754
59	LNG Truck	19,358	54,220	759,788	885,016	452,570	-	2,170,952
60	Propane Truck	-	-	303,770	144,966	-	-	448,735
61	PNGTS	198,251	219,020	115,097	158,013	205,844	201,686	1,097,911
62	Portland Natural Gas	345,771	381,679	389,728	350,092	383,716	311,697	2,162,684
63	TGP Supply (Z4)	1,641,413	1,819,931	1,858,313	1,670,006	1,829,646	4,234,727	13,054,036
64	Subtotal Pipeline Volumes	10,889,131	14,422,474	16,991,430	14,861,168	12,410,180	8,723,428	78,297,812
65								
66	Storage Gas:							
67	TGP Storage	1,371,738	4,289,074	5,080,310	4,651,952	3,946,183	155,509	19,494,766
68								0
69	Produced Gas:							0
70	LNG Vapor	18,690	54,933	851,575	885,016	371,524	19,014	2,200,752
71	Propane	-	-	807,138	144,966	-	-	952,104
72	Subtotal Produced Gas	18,690	54,933	1,658,713	1,029,982	371,524	19,014	3,152,857
73								
74	Less - Gas Refills:							
75	LNG Truck	(19,358)	(54,220)	(759,788)	(885,016)	(452,570)	-	-2,170,952
76	Propane	-	-	(303,770)	(144,966)	-	-	-448,735
77	TGP Storage Refill	(1,843,002)	-	-	-	-	-	-1,843,002
78	Subtotal Refills	(1,862,360)	(54,220)	(1,063,558)	(1,029,982)	(452,570)	-	(4,462,690)
79								
80	Total Sendout Volumes	10,417,200	18,712,261	22,666,896	19,513,121	16,275,316	8,897,951	96,482,745

Line		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
1	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**								**Schedule 11C**
2	**d/b/a Liberty Utilities**								**Page 1 of 1**
3	**Peak 2018 - 2019 Winter Cost of Gas Filing**								
4	**Capacity Utilization**								
5	**Volumes (Therms)**								
6									
7									
8									
9									
10									
11	**Pipeline Gas:**								
12	Dawn Supply	4,807,042	4,000	7,240,000	66%	4,881,061	4,000	7,240,000	67%
13	Niagara Supply	3,985,274	3,122	5,650,820	71%	3,985,274	3,122	5,650,820	71%
14	TGP Supply (Gulf + Z4)	29,182,735	21,596	39,088,760	75%	29,357,598	21,596	39,088,760	75%
15	Dracut Supply 1 & 2	21,925,049	50,000	90,500,000	24%	30,024,841	50,000	90,500,000	33%
16	LNG Truck	2,169,402	-	-	-	2,170,952	-	-	-
17	Propane Truck	447,548	-	-	-	448,735	-	-	-
18	PNGTS	1,044,010	1,000	1,810,000	58%	1,097,911	1,000	1,810,000	61%
19	Portland Natural Gas	2,111,074	1,784	3,229,040	65%	2,162,684	1,784	3,229,040	67%
20	Engie Vapor	4,174,908	7,000	6,300,000	66%	4,168,754	7,000	6,300,000	66%
21									
22									
23	Subtotal Pipeline Volumes	69,847,042				78,297,812			
24									
25	**Storage Gas:**								
26	TGP Storage	19,841,326		25,791,710	77%	19,494,766		25,791,710	76%
27									
28	**Produced Gas:**								
29	LNG Vapor	2,199,156				2,200,752			
30	Propane	950,916.4				952,104			
31									
32	Subtotal Produced Gas	3,150,073				3,152,857			
33									
34	**Less - Gas Refills:**								
35	LNG Truck	(2,169,402)				(2,170,952)			
36	Propane	(447,548)				(448,735)			
37	TGP Storage Refill	(2,262,867)				(1,843,002)			
38									
39	Subtotal Refills	(4,879,817)				(4,462,690)			
40									
41	Total Sendout Volumes	87,958,623				96,482,745			

Liberty Utilities (EnergyNorth Natural Gas) Corp. **Schedule 11D**
d/b/a Liberty Utilities **Page 1 of 1**
Peak 2018 - 2019 Winter Cost of Gas Filing

Forecast of Upcoming Winter Period
Design Day Report
2018 / 19 Heating Season
(Therms)

EnergyNorth Natural Gas, Inc.
d/b/a Liberty Utilities

Requirements	
Firm Sales	1,188,091
Interruptible Sales	0
Firm Transportation	457,618
Interruptible Transportation	0
Total Requirements	1,645,709
Resources	
Purchased Pipeline Gas	797,180
Underground Storage Gas	281,150
Propane Air Production	269,379
LNG Produced Gas	228,000
Third-Party Supply	70,000
Total Resources	1,645,709

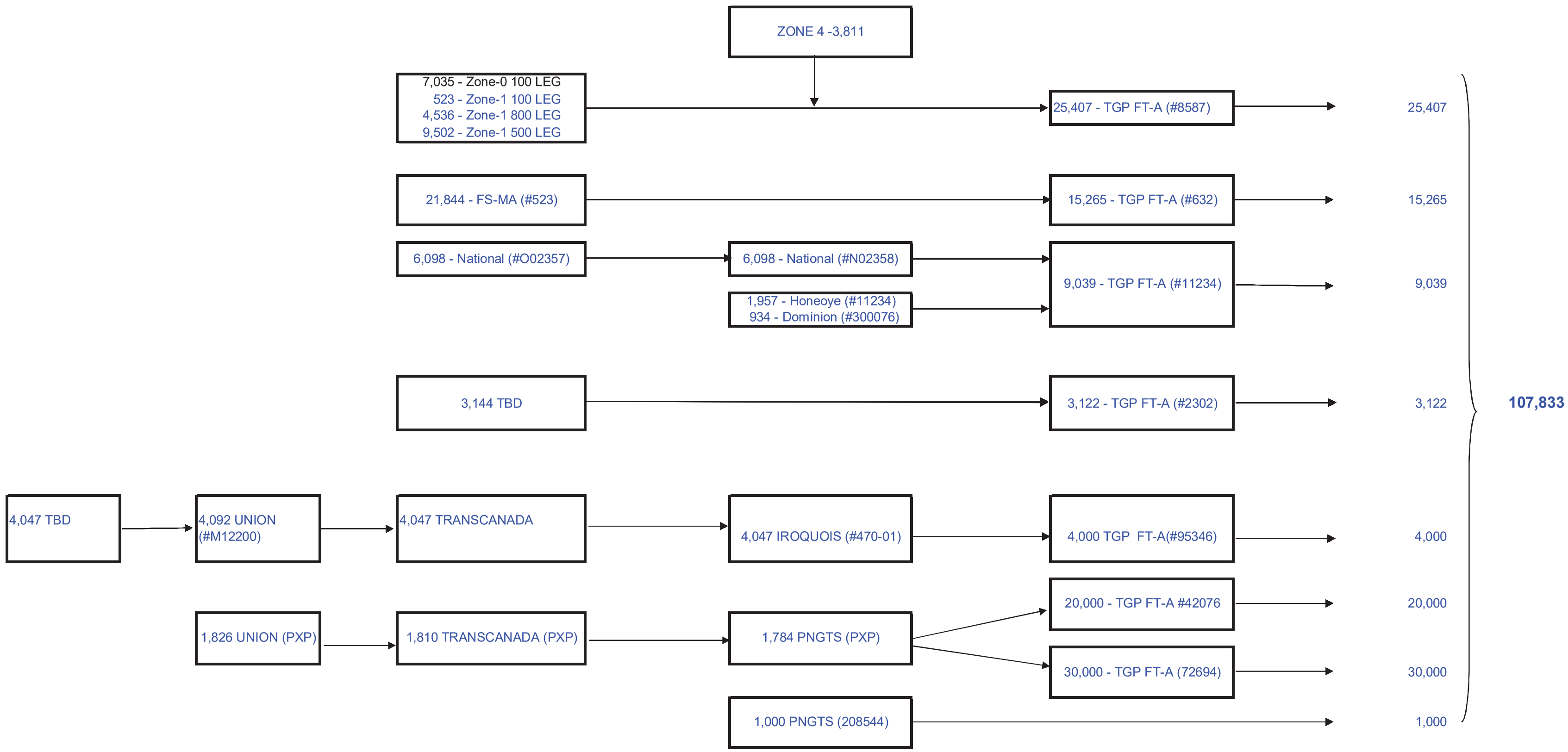
Please refer to the ENNGI 2013 IRP filing (DG 13-313) for a complete description of the methodology and assumptions used in the derivation of this data.

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 2018 - 2019 Winter Cost of Gas Filing
Transportation Available for Pipeline Supply and Storage
(MMBtu)



LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
Peak 2018 - 2019 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
Niagara	NA	NA	Supply	3,147	1,148,655	3/31/2019	N/A	Terminates
ANE	NA	NA	Supply	4,047	611,097	Peak Only	N/A	Terminates
ENGIE	FCS		Firm Combination Liquid and Vapor Svc	Up to 10 trucks	730,000	3/31/2019 Peak Only	N/A	Terminates
Dracut or Z6	NA	NA	Supply	Up to 20,000 / day	1,412,000	2/28/2019	N/A	Terminates
TGP Long-Haul	NA	NA	Supply	21,596	3,908,876	4/30/2019	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	3/31/2021	3/31/2019	Mutually agreed upon
Honeoye Storage Corporation	SS-NY	11234	Storage	1,957	245,380	3/31/2020	12 months notice	Evergreen Provision
National Fuel Gas Supply Corporation	FSS	O02358	Storage	6,098	670,800	3/31/2020	3/31/2019	Evergreen Provision
National Fuel Gas Supply Corporation	FSST	N02358	Transportation	6,098	670,800	3/31/2020	3/31/2019	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	10/31/2019	10/31/2018	Evergreen Provision
Portland Natural Gas Transmission System	FT	PXP	Transportation	1,784	651,160	11/1/2019		Precedent Agreement
Tennessee Gas Pipeline Company	FS-MA	523	Storage	21,844	1,560,391	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	8587	Transportation	25,407	9,273,555	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	2302	Transportation	3,122	1,139,530	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	632	Transportation	15,265	5,571,725	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	11234	Transportation	9,039	3,299,235	10/31/2020	10/31/2019	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	72694	Transportation	30,000	10,950,000	10/31/2029	10/31/2029	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	95346	Transportation	4,000	1,460,000	11/30/2021	11/30/2020	Evergreen Provision
Tennessee Gas Pipeline Company	FTA	42076	Transportation	20,000	7,300,000	10/31/2020	10/31/2019	Evergreen Provision
TransCanada Pipeline	FT	41232	Transportation	4,047	1,477,155	10/31/2022	10/31/2021	Evergreen Provision
TransCanada Pipeline	FT	PXP	Transportation	1,810	660,650	11/1/2019		Precedent Agreement
Union Gas Limited	M12	M12200	Transportation	4,092	1,493,580	10/31/2022	10/31/2020	Evergreen Provision
Union Gas Limited	M12	PXP	Transportation	1,826	666,490	11/1/2019		Precedent Agreement

* MAQ is calculated on a 365 day calendar year.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

May 2017 - Apr 2018 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	17,503,533	44.21%	74.78%
G-42	12,021,109	30.36%	37.32%
G-43	2,980,868	7.53%	26.68%
G-51	2,767,315	6.99%	72.79%
G-52	2,732,036	6.90%	29.44%
G-53	1,147,046	2.90%	10.71%
G-54	437,495	1.11%	2.32%
Total C/I	39,589,403	100.00%	

	Annual Transportation	% of Total by Class	% of Transportation to Total Volume by Class
G-41	5,901,802	8.45%	25.22%
G-42	20,192,111	28.90%	62.68%
G-43	8,191,717	11.72%	73.32%
G-51	1,034,372	1.48%	27.21%
G-52	6,549,487	9.37%	70.56%
G-53	9,561,069	13.68%	89.29%
G-54	18,439,622	26.39%	97.68%
Total C/I	69,870,180	100.00%	

Sales & Transportation	Total	% of Total by Class	
G-41	23,405,335	21.38%	100.00%
G-42	32,213,221	29.43%	100.00%
G-43	11,172,585	10.21%	100.00%
G-51	3,801,687	3.47%	100.00%
G-52	9,281,523	8.48%	100.00%
G-53	10,708,114	9.78%	100.00%
G-54	18,877,117	17.25%	100.00%
Total C/I	109,459,584	100.00%	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 Winter Cost of Gas Filing

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

	Off-Peak May 17 - Oct 17 (Therms)	Peak Nov 17-Apr 18 (Therms)	Total May 17 - Apr 18 (Therms)	
Pipeline Deliveries	17,319,900	88,967,680	106,287,580	
All Others	96,140	2,172,350	2,268,490	
	17,416,040	91,140,030	108,556,070	
				Ratio
Total Winter Supplies				91,140,030
Total Pipeline Deliveries				106,287,580
Ratio Winter Supplies to Pipeline Supplies				0.857

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**

2 **Peak 2018 - 2019 Winter Cost of Gas Filing**

3

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

5

6

Line	C&I Sales Normalized (Therms)	Jul-17	Aug-17	Jul - Aug Total	Total Annual	% of Jul-Aug to Total
9	(a)	(b)	(c)	(e)=(c)+(d)	(f)	(g)=(e)/(f)
10	G-41	178,096	235,365	413,461	17,503,533	2.36%
11	G-42	172,926	162,076	335,002	12,021,109	2.79%
12	G-43	46,398	59,648	106,045	2,980,868	3.56%
13	G-51	150,703	147,994	298,696	2,767,315	10.79%
14	G-52	143,061	156,081	299,142	2,732,036	10.95%
15	G-53	33,168	61,611	94,779	1,147,046	8.26%
16	G-54	25,839	35,035	60,874	437,495	13.91%
17						
18						
19	Total C/I	750,191	857,809	1,608,000	39,589,403	4.06%
20						
21						

1 **Liberty Utilities (EnergyNorth Natural Gas) Corp.**
2 **Peak 2018 - 2019 Winter Cost of Gas Filing**
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-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
9	Beginning Balance (MMBtu)		488,910	744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	488,910
11	Injections (MMBtu)	Sch 11A ln 38 /10	261,143	221,871	271,295	250,468	250,468	250,468	226,287	-	-	-	-	-	1,731,999
13	Subtotal		750,053	966,045	1,232,745	1,478,020	1,728,487	1,978,955	2,205,242	2,032,757	1,620,686	1,107,337	596,478	224,165	
15	Storage Sale/Adjustments		(3,639)	(4,595)	(5,193)			-							
17	Withdrawals (MMBtu)	Sch 11A ln 28 /10	(2,240)	-		-	-	-	(172,485)	(412,071)	(513,349)	(510,859)	(372,313)	(3,056)	(1,986,373)
19	Ending Balance (MMBtu)		744,174	961,450	1,227,552	1,478,020	1,728,487	1,978,955	2,032,757	1,620,686	1,107,337	596,478	224,165	221,109	234,536
22	Beginning Balance		$ 1,154,733	$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	1,154,733
24	Injections	ln 11 * ln 36	$ 662,826	$ 532,338	$ 708,595	$ 674,472	$ 674,472	$ 674,472	$ 627,674	$ -	$ -	$ -	$ -	$ -	$ 4,554,849
26	Subtotal		$ 1,817,559	$ 2,344,415	$ 3,049,262	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,696,861	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	
28	Storage Sale/Adjustments		$ (28)	$ (3,747)	$ (3,491)			$ -							
30	Withdrawals	ln 17 * ln 34	$ (5,454)		$ -	$ -	$ -	$ -	$ (445,586)	$ (1,064,513)	$ (1,326,148)	$ (1,319,717)	$ (961,805)	$ (7,894)	(5,131,118)
32	Ending Balance		$ 1,812,077	$ 2,340,667	$ 3,045,771	$ 3,720,243	$ 4,394,715	$ 5,069,186	$ 5,251,275	$ 4,186,762	$ 2,860,614	$ 1,540,897	$ 579,091	$ 571,197	$ 578,464
34	Average Rate For Withdrawals	ln 22 /ln 9	$2.4232	$2.4268	$2.4736	$2.5170	$2.5425	$2.5615	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	$2.5833	
36	TGP Storage Rate for Injections	Actual or NYMEX plus TGP Transportation	$2.5382	$2.3993	$2.6119	$2.6928	$2.6928	$2.6928	$2.7738	$2.8701	$2.9440	$2.9077	$2.8132	$2.6365	

Ln	Description	Reference	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
38	For Informational Purposes		Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
39	Summer Hedge Contracts - Vols Dth		-	-	-	-	-	-	-
40	Average Hedge Price		$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	
41	NYMEX		$2.9479	$3.0421	$3.1275	$3.0909	$2.9866	$2.6741	
43	Hedged Volumes at Hedged Price		$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Less Hedged Volumes at NYMEX		-	-	-	-	-	-	-
45	Hedge (Savings)/Loss		$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ln	Description	Reference	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19
47	Month Dollar Average	ln (22 + ln 32) /2	$ 3,383,007	$ 4,057,479	$ 4,731,951	$ 5,160,231	$ 4,719,018	$ 3,523,688	$ 2,200,755	$ 1,059,994	$ 575,144
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%
51	Inventory Finance Charge	ln 47 * ln 49	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
52	Financial Expenses		0	0	0	0	0	0	0	0	0
53	Total Inventory Finance Charges		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Ln	Liquid Propane Gas (LPG)		May-18 (Actual)	Jun-18 (Actual)	Jul-18 (Actual)	Aug-18 (Estimate)	Sep-18 (Estimate)	Oct-18 (Estimate)	Nov-18 (Estimate)	Dec-18 (Estimate)	Jan-19 (Estimate)	Feb-19 (Estimate)	Mar-19 (Estimate)	Apr-19 (Estimate)	Total
43	Beginning Balance		94,161	93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	94,161
45	Injections	Sch 11A ln 37 /10	-	-	42	-	-	-	-	-	35,622	9,133	-	-	44,797
47	Subtotal		94,161	93,982	93,945	93,945	93,945	93,945	93,945	93,945	129,567	52,741	43,608	43,608	
49	Withdrawals	Sch 11A ln 32 /10	(179)	(79)	-	-	-	-	-	-	(85,959)	(9,133)	-	-	(95,350)
51	Adjustment for change in temperature		-	-	-	-	-	-	-	-	-	-	-	-	-
52	Adjustment for Transfer		-	-	-	-	-	-	-	-	-	-	-	-	-
53	Ending Balance		93,982	93,903	93,945	93,945	93,945	93,945	93,945	93,945	43,608	43,608	43,608	43,608	43,608
56	Beginning Balance		$ 1,299,502	$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 1,299,502
58	Injections	ln 45 * ln 68	-	-	580	-	-	-	-	-	491,582	126,033	-	-	618,195
60	Subtotal		$ 1,299,502	$ 1,297,032	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,788,103	$ 727,852	$ 601,814	$ 601,814	
62	Withdrawals	ln 51 * ln 66	(2,470)	(1,090)	-	-	-	-	-	-	(1,186,284)	(126,038)	-	-	(1,315,883)
64	Ending Balance		$ 1,297,032	$ 1,295,941	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 601,819	$ 601,814	$ 601,814	$ 601,814	$ 601,814
66	Average Rate For Withdrawals		$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8009	$13.8006	$13.8005	$13.8005	$13.8005	
68	Propane Rate for Injections	Actual or Sch. 6, ln 158 * 10	$13.8009	$13.8009	$13.8009	$0.0000	$0.0000	$0.0000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	$13.8000	
71	Month Dollar Average	ln (56 + ln 64) /2				$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 1,296,521	$ 949,170	$ 601,817	$ 601,814	$ 601,814	
73	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%	
75	Inventory Finance Charge	ln 71 * ln 73				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

			May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
71															
72	**Liquid Natural Gas (LNG)**		May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Jan-19	Feb-19	Mar-19	Apr-19	Total
73			(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
74	Beginning Balance		10,658	9,572	10,498	9,787	10,713	11,639	12,565	12,565	12,565	3,386	3,386	11,491	10,658
75															
76	Injections	Sch 11A ln 36 /10	839	2,657	2,001	2,657	2,657	2,657	1,869	28,965	68,548	102,998	14,560	-	230,408
77															
78	Subtotal		11,497	12,229	12,499	12,444	13,370	14,296	14,434	41,530	81,113	106,385	17,946	11,491	
79															
80	Withdrawals	Sch 11A ln 31 /10	(1,925)	(1,731)	(2,712)	(1,731)	(1,731)	(1,731)	(1,869)	(28,965)	(77,727)	(102,998)	(6,455)	(1,901)	(231,477)
81															
82	Ending Balance		9,572	10,498	9,787	10,713	11,639	12,565	12,565	12,565	3,386	3,386	11,491	9,590	9,590
83															
84															
85	Beginning Balance		$ 54,633	$ 54,814	$ 65,051	$ 65,700	$ 78,110	$ 89,787	$ 100,915	$ 95,062	$ 68,585	$ 16,151	$ 15,601	$ 51,776	$ 54,633
86															
87	Injections	ln 76 * ln 97	11,205	20,961	18,851	25,031	25,031	25,031	8,287	131,625	318,284	473,977	65,260	-	1,123,541
88															
89	Subtotal		$ 65,838	$ 75,775	$ 83,901	$ 90,731	$ 103,141	$ 114,818	$ 109,202	$ 226,687	$ 386,869	$ 490,128	$ 80,861	$ 51,776	
90															
91	Withdrawals	ln 80 * ln 95	(11,024)	(10,724)	(18,201)	(12,621)	(13,354)	(13,902)	(14,140)	(158,102)	(370,718)	(474,527)	(29,085)	(8,567)	(1,134,966)
92															
93	Ending Balance		$ 54,814	$ 65,051	$ 65,700	$ 78,110	$ 89,787	$ 100,915	$ 95,062	$ 68,585	$ 16,151	$ 15,601	$ 51,776	$ 43,209	$ 43,209
94															
95	Average Rate For Withdrawals		$5.7265	$6.1963	$6.7127	$7.2911	$7.7143	$8.0315	$7.5656	$5.4584	$4.7695	$4.6071	$4.5058	$4.5058	
96															
97	LNG Rate for Injections	Actual or Sch. 6, ln 157 * 10	$13.3552	$7.8889	$9.4207	$9.4207	$9.4207	$9.4207	$4.4339	$4.5443	$4.6432	$4.6018	$4.4822	$0.0000	
98															
99															
100	Month Dollar Average	ln (85 + ln 93) /2				$ 71,905	$ 83,949	$ 95,351	$ 97,989	$ 81,823	$ 42,368	$ 15,876	$ 33,689	$ 47,492	
101															
102	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%	
103															
104	Inventory Finance Charge	ln 100 * ln 102				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
105															
106															
107	Total Fuel Financing	lns 53 + 75 + 104				$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Peak 2018 - 2019 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-18	6,295,834	$0.0005	$ 3,273
Dec-18	7,906,710	0.0005	4,111
Jan-19	9,791,817	0.0005	5,091
Feb-19	10,106,599	0.0005	5,254
Mar-19	9,033,498	0.0005	4,696
Apr-19	7,609,960	0.0005	3,956
Total	**50,744,418**		**$ 26,381**

1/ Per Schedule 10B, line 35. Excludes special contract volumes subject to transportation cost of gas.

2/ Refer to Proposed First Revised Page 94 for calculation of rate.

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Local Distribution Adjustment Charge (LDAC) increase due to Rate Case Expense and Recoupment
For LDAC effective November 1, 2018 - October 31, 2019

1	Rate Case Expense Remaining from Docket No. DG 14-180	$51,485
2	Rate Case Expense Through June 2018 in Docket No. DG 17-048	$578,477
3	Rate Case Expense for Docket No. DG 17-048 Currently Approved for $530,000	($48,477)
4	Remaining Recoupment from DG 14-180 & DG 17-048	$1,633,854
5	July 1, 2018 Balance	$2,215,339
6	Minus November 2019 & December 2019 Recoupment	($233,408)
7	Minus Estimated Recoveries from July 2018 through October 2018	($312,077)
8	Total Estimated Remaining Recovery As Of November 1, 2018	$1,669,854
9	Estimated November 2018 - October 2019 Interest	$36,303
10	Total Remaining Recovery	$1,706,158
11	Estimated November 2018 - October 2019 Sales (therms)	184,654,874
12	RCE & Recoupment rate per therm November 2018 - October 2019	$0.0092

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
RATE CASE EXPENSE AND RECOUPMENT PROJECTION

		(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
2	**DAYS IN MONTH**	**31**	**31**	**30**	**31**	**30**	**31**	**31**	**28**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	**30**	
3	Beginning Balance	$ 2,215,339	$ 2,152,980	$ 2,092,394	$ 2,018,719	$ 1,907,454	$ 1,770,590	$ 1,557,222	$ 1,265,114	$ 954,071	$ 684,545	$ 483,022	$ 354,966	$ 275,250	$ 218,798	$ 163,706	$ 98,381	$ 9,733,120
4																		
5	Add Actual Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6																		
7	Less Collected Revenue	(71,614)	(69,582)	(82,105)	(119,584)	(144,406)	(220,419)	(298,088)	(315,291)	(272,886)	(203,997)	(129,775)	(81,051)	(57,499)	(55,876)	(65,880)	(95,294)	(1,940,462)
8																		
9	Add Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10																		
11	Ending Balance Pre-Interest	$ 2,143,725	$ 2,083,399	$ 2,010,289	$ 1,899,135	$ 1,763,048	$ 1,550,171	$ 1,259,134	$ 949,823	$ 681,185	$ 480,548	$ 353,247	$ 273,915	$ 217,751	$ 162,922	$ 97,826	$ 3,087	**$ 7,792,658**
12																		
13	Month's Average Balance	$ 2,179,532	$ 2,118,190	$ 2,051,341	$ 1,958,927	$ 1,835,251	$ 1,660,381	$ 1,408,178	$ 1,107,468	$ 817,628	$ 582,547	$ 418,135	$ 314,440	$ 246,501	$ 190,860	$ 130,766	$ 50,734	
14																		
15	Interest Rate	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%	
16																		
17	Interest Applied	$ 9 256	$ 8 995	$ 8 430	$ 8 319	$ 7 542	$ 7 051	$ 5 980	$ 4 248	$ 3 360	$ 2 474	$ 1 718	$ 1 335	$ 1 047	$ 784	$ 555	$ 208	**36,303**
18																		
19	Ending Balance	**$ 2,152,980**	**$ 2,092,394**	**$ 2,018,719**	**$ 1,907,454**	**$ 1,770,590**	**$ 1,557,222**	**$ 1,265,114**	**$ 954,071**	**$ 684,545**	**$ 483,022**	**$ 354,966**	**$ 275,250**	**$ 218,798**	**$ 163,706**	**$ 98,381**	**$ 3,296**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Uitilities
Lost Revenue Adjustment Factor (LRAM)
For LDAC effective November 1, 2018 - October 31, 2019

	Residential	
1	October 31, 2018 Projected Balance (LRAM true-up)	$18,706
2	Calculated Lost Distr bution Revenue - November 2018 through October 2019	$0
3	Calculated Interest - November 2018 through October 2019	$957
4		
5	Total to be recovered	$19,663
6		
7	Estimated November 2018 - October 2019 Sales (therms)	66,050,202
8		
9	LRAM residential rate per therm November 2018 - October 2019	$0.0003
	Commercial & Industrial	
10	October 31, 2018 Projected Balance (LRAM true-up)	$13,218
11	Calculated Lost Distr bution Revenue - November 2018 through October 2019	$0
12	Calculated Interest - November 2018 through October 2019	$676
13		
14	Total to be recovered	$13,894
15		
16	Estimated November 2018 - October 2019 Sales (therms)	118,604,671
17		
18	LRAM C&I rate per therm November 2018 - October 2019	$0.0001

Schedule 19
LRAM
Page 2 of 2

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2018 THROUGH OCTOBER 2019
Lost Revenue Adjustment Mechanism

		(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-18**	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**28**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
	RESIDENTIAL													
3	Beginning Balance (LRAM true-up)	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	**$ 229,669**
4														
5	Add: Lost Distribution Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	**$ 229,669**
12														
13	Month's Average Balance	$ 18,706	$ 18,783	$ 18,863	$ 18,943	$ 19,015	$ 19,096	$ 19,175	$ 19,256	$ 19,335	$ 19,417	$ 19,500	$ 19,580	
14														
15	Interest Rate	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 77	$ 80	$ 80	$ 73	$ 81	$ 78	$ 81	$ 79	$ 82	$ 82	$ 80	$ 83	**957**
18														
19	Ending Balance	**$ 18,783**	**$ 18,863**	**$ 18,943**	**$ 19,015**	**$ 19,096**	**$ 19,175**	**$ 19,256**	**$ 19,335**	**$ 19,417**	**$ 19,500**	**$ 19,580**	**$ 19,663**	
	COMMERCIAL & INDUSTRIAL													
3	Beginning Balance	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	**$ 162,283**
4														
5	Add: Lost Distribution Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-
6														
7	Less: Lost Distribution Revenue Collections	-	-	-	-	-	-	-	-	-	-	-	-	-
8														
9	Add: Other	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	**$ 162,283**
12														
13	Month's Average Balance	$ 13,218	$ 13,272	$ 13,328	$ 13,385	$ 13,436	$ 13,493	$ 13,549	$ 13,606	$ 13,662	$ 13,720	$ 13,778	$ 13,835	
14														
15	Interest Rate	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 54	$ 56	$ 57	$ 51	$ 57	$ 55	$ 58	$ 56	$ 58	$ 58	$ 57	$ 59	**676**
18														
19	Ending Balance	**$ 13,272**	**$ 13,328**	**$ 13,385**	**$ 13,436**	**$ 13,493**	**$ 13,549**	**$ 13,606**	**$ 13,662**	**$ 13,720**	**$ 13,778**	**$ 13,835**	**$ 13,894**	

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities
Revenue Decoupling Adjustment Clause (RDAC)
Benchmark Revenue Per Customer effective November 1, 2018 - October 31, 2019

Schedule 19
RDAC
Page 1 of 1

EnergyNorth Natural Gas Inc

2016 Customers (Equivalent Bills)

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16	S&T Total	S&T Winter	S&T Summer
R-1	3,744	3,378	3,449	4,027	3,010	3,634	3,658	3,457	3,579	4,017	2,993	3,746	42,693	21,338	21,354
R-3	76,501	70,269	71,991	75,178	68,613	73,366	74,096	70,010	70,749	71,998	68,057	74,878	865,706	436,874	428,832
R-4	5,629	5,175	5,301	5,515	5,072	5,405	5,462	5,162	5,214	5,293	5,032	5,519	63,778	32,171	31,607
Total Resid.	**85,874**	**78,822**	**80,741**	**84,721**	**76,695**	**82,405**	**83,216**	**78,628**	**79,542**	**81,308**	**76,081**	**84,144**	**972,177**	**490,383**	**481,794**
G-41	9,712	8,893	9,107	9,817	8,436	9,306	9,383	8,871	8,994	9,400	8,360	9,482	109,763	55,371	54,392
G-42	1,856	1,708	1,749	1,830	1,665	1,783	1,802	1,705	1,723	1,758	1,653	1,820	21,055	10,618	10,437
G-43	51	47	48	49	47	49	50	47	47	47	47	50	579	293	286
G-51	1,435	1,309	1,335	1,484	1,218	1,385	1,399	1,324	1,350	1,453	1,207	1,419	16,319	8,189	8,129
G-52	345	316	323	346	302	331	335	316	320	333	299	338	3,903	1,967	1,936
G-53	34	31	32	33	30	32	33	31	31	32	30	33	382	192	190
G-54	28	25	26	27	25	26	27	25	26	26	25	27	314	159	155
G-63	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total C/I	**13,462**	**12,330**	**12,621**	**13,587**	**11,723**	**12,912**	**13,030**	**12,318**	**12,492**	**13,050**	**11,620**	**13,169**	**152,314**	**76,789**	**75,525**
Total All	**99,336**	**91,153**	**93,361**	**98,308**	**88,418**	**95,317**	**96,246**	**90,947**	**92,034**	**94,358**	**87,701**	**97,312**	**1,124,491**	**567,172**	**557,319**

2016 Calendar BF Base Normal Revenue Adjusted

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16	S&T Total	S&T Winter	S&T Summer
R-1	$ 99,555	$ 88,904	$ 84,658	$ 87,561	$ 63,153	$ 71,014	$ 67,806	$ 63,843	$ 67,363	$ 83,474	$ 71,184	$ 96,733	$ 945,249	$ 528,595	$ 416,654
R-3	$ 6,925,912	$ 6,006,068	$ 5,267,976	$ 3,465,023	$ 2,308,483	$ 1,894,274	$ 1,686,231	$ 1,601,723	$ 1,797,279	$ 2,621,900	$ 4,000,612	$ 5,910,427	$ 43,485,908	$ 31,576,019	$ 11,909,890
R-4	$ 191,604	$ 163,736	$ 153,105	$ 109,479	$ 66,579	$ 56,646	$ 50,195	$ 48,023	$ 51,492	$ 74,427	$ 112,783	$ 166,171	$ 1,244,239	$ 896,878	$ 347,362
Total Resid.	**$ 7,217,070**	**$ 6,258,708**	**$ 5,505,739**	**$ 3,662,064**	**$ 2,438,215**	**$ 2,021,934**	**$ 1,804,232**	**$ 1,713,589**	**$ 1,916,134**	**$ 2,779,801**	**$ 4,184,580**	**$ 6,173,330**	**$ 45,675,396**	**$ 33,001,491**	**$ 12,673,906**
G-41	$ 2,084,709	$ 1,824,070	$ 1,593,272	$ 1,184,307	$ 760,116	$ 682,994	$ 636,636	$ 598,503	$ 651,545	$ 868,129	$ 1,183,786	$ 1,783,044	$ 13,851,112	$ 9,653,189	$ 4,197,923
G-42	$ 2,376,642	$ 2,026,762	$ 1,748,029	$ 1,273,283	$ 799,478	$ 633,411	$ 536,535	$ 496,294	$ 605,841	$ 946,447	$ 1,380,050	$ 2,082,157	$ 14,904,929	$ 10,886,922	$ 4,018,006
G-43	$ 445,762	$ 366,776	$ 321,395	$ 215,283	$ 99,097	$ 72,082	$ 63,481	$ 61,834	$ 74,272	$ 72,723	$ 310,606	$ 382,910	$ 2,486,221	$ 2,042,733	$ 443,489
G-51	$ 190,836	$ 167,526	$ 157,125	$ 150,462	$ 117,288	$ 120,789	$ 121,237	$ 115,727	$ 121,591	$ 147,973	$ 141,856	$ 183,563	$ 1,735,974	$ 991,369	$ 744,605
G-52	$ 232,548	$ 208,796	$ 195,007	$ 180,976	$ 114,350	$ 113,547	$ 116,020	$ 113,151	$ 117,269	$ 146,165	$ 190,559	$ 227,888	$ 1,956,276	$ 1,235,774	$ 720,502
G-53	$ 184,285	$ 170,488	$ 174,839	$ 156,845	$ 75,894	$ 70,319	$ 71,880	$ 73,973	$ 72,595	$ 92,579	$ 156,563	$ 211,648	$ 1,511,909	$ 1,054,669	$ 457,240
G-54	$ 123,294	$ 94,963	$ 76,772	$ 90,647	$ 50,657	$ 62,751	$ 64,406	$ 66,555	$ 74,341	$ 87,455	$ 111,999	$ 137,467	$ 1,041,309	$ 635,143	$ 406,166
G-63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total C/I	**$ 5,638,076**	**$ 4,859,381**	**$ 4,266,440**	**$ 3,251,804**	**$ 2,016,880**	**$ 1,755,893**	**$ 1,610,194**	**$ 1,526,037**	**$ 1,717,455**	**$ 2,361,472**	**$ 3,475,420**	**$ 5,008,678**	**$ 37,487,730**	**$ 26,499,799**	**$ 10,987,931**
Total All	**$ 12,855,147**	**$ 11,118,089**	**$ 9,772,179**	**$ 6,913,867**	**$ 4,455,095**	**$ 3,777,827**	**$ 3,414,426**	**$ 3,239,626**	**$ 3,633,589**	**$ 5,141,273**	**$ 7,659,999**	**$ 11,182,008**	**$ 83,163,126**	**$ 59,501,290**	**$ 23,661,837**

Base Revenue Per Customer

	S&T Jan-16	S&T Feb-16	S&T Mar-16	S&T Apr-16	S&T May-16	S&T Jun-16	S&T Jul-16	S&T Aug-16	S&T Sep-16	S&T Oct-16	S&T Nov-16	S&T Dec-16
R-1	$ 26.589	$ 26 316	$ 24.543	$ 21.741	$ 20.979	$ 19.542	$ 18 534	$ 18.470	$ 18.823	$ 20.783	$ 23.785	$ 25 821
R-3	$ 90.533	$ 85.472	$ 73.176	$ 46.091	$ 33.645	$ 25.819	$ 22.757	$ 22 878	$ 25.404	$ 36.416	$ 58.783	$ 78 934
R-4	$ 34.041	$ 31.639	$ 28.884	$ 19.850	$ 13.127	$ 10.481	$ 9.190	$ 9 304	$ 9 875	$ 14.060	$ 22.415	$ 30.106
Total Resid.	**$ 84.043**	**$ 79.403**	**$ 68.190**	**$ 43.225**	**$ 31.791**	**$ 24.537**	**$ 21.681**	**$ 21.794**	**$ 24.090**	**$ 34.189**	**$ 55.001**	**$ 73.367**
G-41	$ 214.643	$ 205.102	$ 174.951	$ 120.636	$ 90.099	$ 73 391	$ 67 847	$ 67.468	$ 72.441	$ 92.350	$ 141.604	$ 188.055
G-42	$ 1,280.188	$ 1,186 317	$ 999.487	$ 695.694	$ 480.054	$ 355 242	$ 297.683	$ 291.098	$ 351.520	$ 538.337	$ 834.753	$ 1,143.792
G-43	$ 8,803.769	$ 7,748 822	$ 6,658.698	$ 4,355.038	$ 2,128.057	$ 1,483.170	$ 1,280.724	$ 1,315.618	$ 1,576.904	$ 1,533.165	$ 6,655.855	$ 7,622.644
G-51	$ 132.941	$ 127 993	$ 117.720	$ 101.392	$ 96.328	$ 87.191	$ 86.636	$ 87.436	$ 90.047	$ 101.832	$ 117.551	$ 129 325
G-52	$ 673.394	$ 660 268	$ 603.678	$ 523.102	$ 378.311	$ 343 526	$ 346.774	$ 358 299	$ 366.393	$ 439.111	$ 637.600	$ 675.157
G-53	$ 5,463.060	$ 5,529 375	$ 5,401.786	$ 4,719.552	$ 2,563.988	$ 2,172 593	$ 2,154 233	$ 2,353 335	$ 2,354.440	$ 2,893.096	$ 5,307.204	$ 6,505 579
G-54	$ 4,392.936	$ 3,788.457	$ 2,919.066	$ 3,300.283	$ 2,034.434	$ 2,398.153	$ 2,367 866	$ 2,683.658	$ 2,877.719	$ 3,372.308	$ 4,534.380	$ 5,060.135
G-63	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Total C/I	**$ 418.808**	**$ 394.103**	**$ 338.054**	**$ 239.324**	**$ 172.048**	**$ 135.986**	**$ 123.577**	**$ 123.882**	**$ 137.487**	**$ 180.958**	**$ 299.101**	**$ 380.345**
Total All	**$ 129.411**	**$ 121.972**	**$ 104.670**	**$ 70.329**	**$ 50.387**	**$ 39.634**	**$ 35.476**	**$ 35.621**	**$ 39.481**	**$ 54.487**	**$ 87.342**	**$ 114.908**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Residential Low Income Assistance Program (RLIAP)

		Customer Charge	First Block	Last Block	Total	
1	**Peak Period**					
2	R-3 Base Rates	$ 15.0200	$ 0.5631	$ 0.5631		
3	R-4 Rate at 40% of R-3	$ 6.0000	$ 0.2252	$ 0.2252		
4	Program Subsidy	$ 9.0200	$ 0.3379	$ 0.3379		
5	Average Annual Therms		488	177	666	
6						
7	Peak Period RLIAP Subsidy	$ 54.12	$ 164.96	$ 59.95	$ 279.03	
8						
9	**Off Peak Period**					
10	R-3 Base Rates	$ 15.0200	$ 0.5631	$ 0.5631		
11	R-4 Rate at 40% of R-3	$ 6.0000	$ 0.2252	$ 0.2252		
12	Program Subsidy	$ 9.0200	$ 0.3379	$ 0.3379		
13	Average Annual Therms		86	19	105	
14						
15	Off Peak Period RLIAP Subsidy	$ 54.12	$ 29.01	$ 6.52	$ 89.66	
16						
17	Estimated Annual Subsidy	$ 108.24	$ 193.97	$ 66.47	$ 368.69	
18						
19	Number of Estimated 2018/19 Participants				5,056	1/
20						
21	Annual Subsidy times Number of Participants (Ln 17 * Ln 19)				$ 1,864,087	
22	Prior Year Ending Balance - RLIAP Page 2				545,077	
23	Estimated Annual Administrative Costs				-	
24	Total Program Costs				$ 2,409,164	
25						
26	Estimated weather normalized firm therms billed for the					
27	twelve months ended 10/31/19 sales and transportation				184,654,874	
28						
29	**Total Residential Low Income Program Charge**				**$ 0.0130**	

1/
Estimated number of participants for 2018/19 is based on the actual number participants as of July 2018.

Liberty Utilities (EnergyNorth Natural Gas) Corp.

NOVEMBER 2017 THROUGH OCTOBER 2018
RESIDENTIAL LOW INCOME ASSISTANCE PROGRAM RECONCILIATION
ACCOUNT 175.6

		(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Actual)	(Estimate)	(Estimate)	(Estimate)	(Estimate)	
1	**FOR THE MONTH OF:**	**Nov-17**	**Dec-17**	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Total**
2	**DAYS IN MONTH**	**30**	**31**	**31**	**29**	**31**	**30**	**31**	**30**	**31**	**31**	**30**	**31**	
3	Beginning Balance	$ 274,360	$ 312,789	$ 322,168	$ 301,407	$ 300,711	$ 329,018	$ 389,796	$ 452,669	$ 486,283	$ 513,560	$ 536,461	$ 550,354	$ 274,360
4														
5	Add: Actual Costs	109,422 7	197,516 7	264,588 9	251,523 7	230,439 8	256,731 6	184,560 1	108,030 1	76,084	70,157	70,050	77,440	1,896,544
6														
7	Less: Collected Revenue	(72,016 8)	(189,281 6)	(286,473 3)	(253,200 1)	(203,333 3)	(197,354 2)	(123,328 7)	(76,245 4)	(50,926)	(49,480)	(58,385)	(85,038)	(1,645,062)
8														
9	Add: Administrative and Start Up Costs	-	-	-	-	-	-	-	-	-	-	-	-	-
10														
11	Ending Balance Pre-Interest	$ 311,766	$ 321,024	$ 300,284	$ 299,731	$ 327,817	$ 388,396	$ 451,028	$ 484,454	$ 511,441	$ 534,236	$ 548,126	$ 542,756	**$ 525,841**
12														
13	Month's Average Balance	$ 293,063	$ 316,907	$ 311,226	$ 300,569	$ 314,264	$ 358,707	$ 420,412	$ 468,561	$ 498,862	$ 523,898	$ 542,293	$ 546,555	
14														
15	Interest Rate	4 25%	4 50%	4 50%	4 50%	4 75%	4 75%	4 75%	5 00%	5 00%	5 00%	5 00%	5 00%	
16														
17	Interest Applied	$ 1,024	$ 1,144	$ 1,123	$ 980	$ 1,201	$ 1,400	$ 1,641	$ 1,829	$ 2,118	$ 2,225	$ 2,229	$ 2,321	**19,236**
18														
19	Ending Balance	**$ 312,789**	**$ 322,168**	**$ 301,407**	**$ 300,711**	**$ 329,018**	**$ 389,796**	**$ 452,669**	**$ 486,283**	**$ 513,560**	**$ 536,461**	**$ 550,354**	**$ 545,077**	**$ 545,077**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential Non-Heating and Heating Classes
November 1, 2018 - October 31, 2019
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 18	Actual	(2,240,400)	($0.0516)	(227,299)	265,627	169,251	35,820	12,775	(2,249,854)	(2,245,127)	4.75%	(6,227)	(2,256,081)	3,349,634	4,405,040	31
June 18	Actual	(2,256,081)	($0.0516)	(92,112)	265,627	148,594	32,579	12,775	(2,154,245)	(2,205,163)	4.75%	(6,267)	(2,160,512)	1,984,898	1,785,463	30
July 18	Forecast	(2,160,512)	($0.0516)	(64,816)	265,627	101,545	8,281	12,775	(2,102,728)	(2,131,620)	5.00%	(3,349)	(2,106,077)	1,252,661	1,256,417	31
August 18	Forecast	(2,106,077)	($0.0516)	(54,524)	265,627	0	0		(1,894,974)	(2,000,525)	5.00%	(8,495)	(1,903,469)	1,056,675	0	31
September 18	Forecast	(1,903,469)	($0.0516)	(58,985)	265,627	0	0		(1,696,827)	(1,800,148)	5.00%	(7,398)	(1,704,225)	1,143,113	0	30
October 18	Forecast	(1,704,225)	($0.0516)	(87,386)	265,627	0	0		(1,525,984)	(1,615,104)	5.00%	(6,859)	(1,532,843)	1,693,533	0	31
November 18	Forecast	(1,532,843)	($0.0450)	(195,314)	265,627	0	0		(1,462,529)	(1,497,686)	5.00%	(6,155)	(1,468,684)	4,340,302	0	30
December 18	Forecast	(1,468,684)	($0.0450)	(357,114)	265,627	0	0		(1,560,171)	(1,514,428)	5.00%	(6,431)	(1,566,602)	7,935,861	0	31
January 19	Forecast	(1,566,602)	($0.0450)	(509,038)	404,158	0	0		(1,671,483)	(1,619,043)	5.00%	(6,875)	(1,678,358)	11,311,961	0	31
February 19	Forecast	(1,678,358)	($0.0450)	(549,085)	404,158	0	0		(1,823,286)	(1,750,822)	5.00%	(6,715)	(1,830,001)	12,201,886	0	28
March 19	Forecast	(1,830,001)	($0.0450)	(467,012)	404,158	0	0		(1,892,856)	(1,861,428)	5.00%	(7,905)	(1,900,760)	10,378,048	0	31
April 19	Forecast	(1,900,760)	($0.0450)	(318,535)	404,158	0	0		(1,815,138)	(1,857,949)	5.00%	(7,635)	(1,822,773)	7,078,549	0	30
May 19	Forecast	(1,822,773)	($0.0450)	(184,988)	404,158	0	0		(1,603,603)	(1,713,188)	5.00%	(7,275)	(1,610,878)	4,110,836	0	31
June 19	Forecast	(1,610,878)	($0.0450)	(89,586)	404,158	0	0		(1,296,307)	(1,453,593)	5.00%	(5,974)	(1,302,280)	1,990,802	0	30
July 19	Forecast	(1,302,280)	($0.0450)	(50,671)	404,158	0	0		(948,794)	(1,125,537)	5.00%	(4,780)	(953,574)	1,126,024	0	31
August 19	Forecast	(953,574)	($0.0450)	(49,093)	404,158	0	0		(598,509)	(776,041)	5.00%	(3,296)	(601,805)	1,090,959	0	31
September 19	Forecast	(601,805)	($0.0450)	(72,834)	404,158	0	0		(270,481)	(436,143)	5.00%	(1,792)	(272,273)	1,618,528	0	30
October 19	Forecast	(272,273)	($0.0450)	(128,990)	404,158	0	0		2,894	(134,690)	5.00%	(572)	2,322	2,866,447	0	31
November 19	Forecast	2,322	($0.0450)	(195,314)	404,158	0	0		211,166	106,744	5.00%	439	211,605	4,340,302	0	30
December 19	Forecast	211,605	($0.0450)	(357,114)	404,158	0	0		258,648	235,127	5.00%	998	259,647	7,935,861	0	31

Estimated Residential Conservation Charge Effective November 1, 2018 - October 31, 2019		
Beginning Balance	$	(1,532,843)
Program Budget Nov 18-Oct 19		4,572,829
Projected Interest		(65,405)
Projected Budget with Interest	$	2,974,581
Total Charges	**$**	**2,974,581**
Projected Therm Sales		**66,050,202**
Residential Rate		**$0.0450**
Total Charges with Interest	**$**	**2,972,259**
Projected Therm Sales		**66,050,202**
Residential Rate		**$0.0450**

Estimated Residential Conservation Charge
Effective November 1, 2018 - October 31, 2019

Beginning Balance	$	(1,532,842.79)
Program Budget Nov 18-Oct 19	$	4,182,242.33
Projected Interest	$	(61,190.00)
Projected Budget with Interest	$	2,588,209.55
Total Charges	$	2,588,209.55

Residential Non Heating Therm Sales	0%	778,066	642,126	0%
Residential Heating Therm Sales	35%	65,862,804	65,408,076	35%
C&I Therm Sales	62%	115,871,154	118,604,671	64%
Total Therms	100%	**186,909,214**	**184,654,874**	100%
		Budget 2018	Budget 2019	
Low-Income Program Budget		$ 1,217,300	$ 1,310,342	
Other Refund		-	-	
Total Shared Budget		**$ 1,005,700**	**$ 1,310,342**	
Residential Program Budget		$ 2,362,534	$ 4,163,210	
Residential Program Incentive @ 70%		$ 196,891	$ 217,977	
Total Residential Program Budget		**$ 2,559,425**	**$ 4,381,187**	
Commercial/Industrial Program Budget		$ 3,580,741	$ 4,419,684	
Commercial/Industrial Program Incentive at 70%		$ 196,941	$ 205,958	
Total Commercial/Industrial Program Budget		**$ 3,777,682**	**$ 4,625,642**	
Total Program Budget		**$ 7,554,407**	**$ 10,317,171**	
Shared Expenses Allocation to Residential		$ 436,990	$ 468,703	
Shared Expenses Allocation to C&I		780,310	841,639	
Total Allocated Shared Expenses		**$ 1,217,300**	**$ 1,310,342**	
Total Residential (including allocation of Shared Budget)		$ 2,996,415	$ 4,849,890	
Total C&I (including allocation of Shared Budget)		4,557,992	5,467,281	
Total Budget		**$ 7,554,407**	**$ 10,317,171**	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Commercial/Industrial Classes
November 1, 2018 - October 31, 2019
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 18	Actual	(1,094,665)	($0.0219)	(158,066)	245,987	106,016	43,216	9,778	(1,093,721)	(1,094,193)	4.75%	(3,717)	(1,097,438)	6,537,363	7,299,008	31
June 18	Actual	(1,097,438)	($0.0219)	(131,661)	245,987	198,094	13,943	9,778	(1,007,284)	(1,052,361)	4.75%	(3,676)	(1,010,960)	5,092,563	6,011,635	30
July 18	Forecast	(1,010,960)	($0.0219)	(87,792)	245,987	0	0		(852,765)	(931,862)	5.00%	(3,957)	(856,722)	4,008,754	0	31
August 18	Forecast	(856,722)	($0.0219)	(84,349)	245,987	0	0		(695,084)	(775,903)	5.00%	(3,295)	(698,379)	3,851,567	0	31
September 18	Forecast	(698,379)	($0.0219)	(91,025)	245,987	0	0		(543,418)	(620,898)	5.00%	(2,552)	(545,969)	4,156,413	0	30
October 18	Forecast	(545,969)	($0.0219)	(109,234)	245,987	0	0		(409,216)	(477,593)	5.00%	(2,028)	(411,245)	4,987,864	0	31
November 18	Forecast	(411,245)	($0.0387)	(363,835)	245,987	0	0		(529,092)	(470,168)	5.00%	(1,932)	(531,025)	9,401,414	0	30
December 18	Forecast	(531,025)	($0.0387)	(504,619)	245,987	0	0		(789,657)	(660,341)	5.00%	(2,804)	(792,461)	13,039,253	0	31
January 19	Forecast	(792,461)	($0.0387)	(659,998)	455,607	0	0		(996,852)	(894,657)	5.00%	(3,799)	(1,000,651)	17,054,214	0	31
February 19	Forecast	(1,000,651)	($0.0387)	(688,909)	455,607	0	0		(1,233,953)	(1,117,302)	5.00%	(4,286)	(1,238,239)	17,801,261	0	28
March 19	Forecast	(1,238,239)	($0.0387)	(603,328)	455,607	0	0		(1,385,960)	(1,312,099)	5.00%	(5,572)	(1,391,532)	15,589,859	0	31
April 19	Forecast	(1,391,532)	($0.0387)	(477,319)	455,607	0	0		(1,413,244)	(1,402,388)	5.00%	(5,763)	(1,419,007)	12,333,818	0	30
May 19	Forecast	(1,419,007)	($0.0387)	(318,833)	455,607	0	0		(1,282,233)	(1,350,620)	5.00%	(5,736)	(1,287,969)	8,238,574	0	31
June 19	Forecast	(1,287,969)	($0.0387)	(221,442)	455,607	0	0		(1,053,803)	(1,170,886)	5.00%	(4,812)	(1,058,615)	5,722,003	0	30
July 19	Forecast	(1,058,615)	($0.0387)	(168,174)	455,607	0	0		(771,183)	(914,899)	5.00%	(3,885)	(775,068)	4,345,591	0	31
August 19	Forecast	(775,068)	($0.0387)	(163,556)	455,607	0	0		(483,018)	(629,043)	5.00%	(2,671)	(485,689)	4,226,257	0	31
September 19	Forecast	(485,689)	($0.0387)	(179,980)	455,607	0	0		(210,062)	(347,876)	5.00%	(1,430)	(211,492)	4,650,649	0	30
October 19	Forecast	(211,492)	($0.0387)	(240,009)	455,607	0	0		4,106	(103,693)	5.00%	(440)	3,666	6,201,778	0	31
November 19	Forecast	3,666	($0.0387)	(363,835)	455,607	0	0		95,437	49,552	5.00%	204	95,641	9,401,414	0	30
December 19	Forecast	95,641	($0.0387)	(504 619)	455,607	0	0		46 629	71,135	5.00%	302	46 931	13,039,253	0	31
Total 11/2018 - 10/2019				**$ (4,590,001)**	**$ 5,048,041**	0						**$ (43,130)**		118,604,671	0	

Estimated C&I Conservation Charge **November 1, 2018 - October 31, 2019**	
Beginning Balance	(411,245)
Program Budget Nov 18-Oct 19	**5,048,041**
Projected Interest	(43,107)
Program Budget with Interest	4,593,690
Total Charges	**$4,593,690**
Projected Therm Sales	**118,604,671**
C&I Rate	$0.0387
Total Charges with Interest	**$4,590,001**
Projected Therm Sales	**118,604,671**
C&I Rate	**$0.0387**
C&I Rate from Prior Programs	**$0.0000**
Combined C&I Rate	**$0.0387**

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Energy Efficiency Programs
For Residential and Commercial/Industrial Classes
November 1, 2018 - October 31, 2019
Energy Efficiency Charge

Month	Actual or Forecast	Beginning Balance (Over)/Under	DSM Rate Per Therm	DSM Collections	Forecasted DSM Expenditures	Actual DSM Expenditures Residential	C&I	Low-Income	Total	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
May 18	Actual	(3,335,065)	n/a	(385,365)	511,614	169,251	106,016	79,036	354,303	22,553	(3,343,575)	(3,339,320)	**4.75%**	(13,472)	(3,357,046)	9,886,997	11,704,048	31
June 18	Actual	(3,353,519)	n/a	(223,773)	511,614	148,594	198,094	46,522	393,210	22,553	(3,161,529)	(3,257,524)	4.75%	(12,718)	(3,174,247)	7,077,460	7,797,098	30
July 18	Forecast	(3,171,472)	n/a	(152,607)	511,614	101,545	0	8,281	109,825		(3,214,254)	(3,192,863)	5.00%	(13,559)	(3,227,813)	5,261,414	1,256,417	31
August 18	Forecast	(2,962,798)	n/a	(138,874)	511,614	0	0	0	0		(2,590,058)	(2,776,428)	5.00%	(11,790)	(2,601,848)	4,908,241	0	31
September 18	Forecast	(2,601,848)	n/a	(150,010)	511,614	0	0	0	0		(2,240,245)	(2,421,047)	5.00%	(9,950)	(2,250,194)	5,299,526	0	30
October 18	Forecast	(2,250,194)	n/a	(196,621)	511,614	0	0	0	0		(1,935,201)	(2,092,697)	5.00%	(8,887)	(1,944,087)	6,681,398	0	31
November 18	Forecast	(1,944,087)	n/a	(559,148)	511,614	0	0	0	0		(1,991,622)	(1,967,855)	5.00%	(8,087)	(1,999,709)	13,741,716	0	30
December 18	Forecast	(1,999,709)	n/a	(861,733)	511,614	0	0	0	0		(2,349,828)	(2,174,768)	5.00%	(9,235)	(2,359,063)	20,975,114	0	31
January 19	Forecast	(2,359,063)	n/a	(1,169,036)	859,764	0	0	0	0		(2,668,335)	(2,513,699)	5.00%	(10,675)	(2,679,010)	28,366,175	0	31
February 19	Forecast	(2,679,010)	n/a	(1,237,994)	859,764	0	0	0	0		(3,057,239)	(2,868,124)	5.00%	(11,001)	(3,068,240)	30,003,147	0	28
March 19	Forecast	(3,068,240)	n/a	(1,070,340)	859,764	0	0	0	0		(3,278,816)	(3,173,528)	5.00%	(13,477)	(3,292,292)	25,967,908	0	31
April 19	Forecast	(3,292,292)	n/a	(795,853)	859,764	0	0	0	0		(3,228,381)	(3,260,337)	5.00%	(13,399)	(3,241,780)	19,412,367	0	30
May 19	Forecast	(3,241,780)	n/a	(503,820)	859,764	0	0	0	0		(2,885,836)	(3,063,808)	5.00%	(13,011)	(2,898,847)	12,349,409	0	31
June 19	Forecast	(2,898,847)	n/a	(311,028)	859,764	0	0	0	0		(2,350,110)	(2,624,479)	5.00%	(10,786)	(2,360,896)	7,712,805	0	30
July 19	Forecast	(2,360,896)	n/a	(218,845)	859,764	0	0	0	0		(1,719,977)	(2,040,436)	5.00%	(8,665)	(1,728,642)	5,471,615	0	31
August 19	Forecast	(1,728,642)	n/a	(212,649)	859,764	0	0	0	0		(1,081,527)	(1,405,084)	5.00%	(5,967)	(1,087,494)	5,317,216	0	31
September 19	Forecast	(1,087,494)	n/a	(252,814)	859,764	0	0	0	0		(480,543)	(784,018)	5.00%	(3,222)	(483,765)	6,269,177	0	30
October 19	Forecast	(483,765)	n/a	(368,999)	859,764	0	0	0	0		7,000	(238,383)	5.00%	(1,012)	5,988	9,068,225	0	31
November 19	Forecast	5,988	n/a	(559,149)	859,764	0	0	0	0		306,603	156,296	5.00%	642	307,246	13,741,716	0	30
December 19	Forecast	307,246	n/a	(861,733)	859,764	0	0	0	0		305,277	306,261	5.00%	1,301	306,578	20,975,114	0	31

Total 11/2018 - 10/2019

Residential (R-1 & R-3) and C & I Conservation Charge **November 1, 2018 - October 31, 2019**		
Beginning Balance	$	(1,944,087)
Program Budget Nov 18-Oct 19	$	9,620,871
Projected Interest	$	(108,512)
Program Budget with Interest	$	7,568,271
Total Charges		**$7,568,271**

Environmental Surcharge - Manufactured Gas Plants

Manufactured Gas Plants		
Required annual Environmental increase	$2,970,867	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,970,867	
Overall Annual Net Increase to Rates	$2,970,867	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/19 - sales and transportation	184,654,874	therms
Surcharge per therm	$0.0161	per therm
Total Environmental Surcharge	$0.0161	

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

NASHUA FORMER MGP

LINE
NO.

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), 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.

   - 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.

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

NASHUA FORMER MGP

LINE
NO.

- 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.

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

NASHUA FORMER MGP

LINE
NO.

- 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.

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

NASHUA FORMER MGP

LINE
NO.

- 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

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

NASHUA FORMER MGP

LINE
NO.

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.

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

NASHUA FORMER MGP

LINE
NO.

- 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.

- 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.

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

NASHUA FORMER MGP

LINE
NO.

- 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 5 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.

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

NASHUA FORMER MGP

LINE
NO.

- 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.

- 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.

- 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.

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 progressing, and when the design is completed it will be submitted to NHDES for approval. The cap construction and site paving are now planned for 2019 construction season.

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

NASHUA FORMER MGP

LINE
NO.

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.

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

NASHUA FORMER MGP

LINE
NO.

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.

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

MANCHESTER FORMER MGP

LINE
NO.

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) 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.

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

MANCHESTER FORMER MGP

LINE
NO.

- 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

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

MANCHESTER FORMER MGP

LINE
NO.

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

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

MANCHESTER FORMER MGP

LINE
NO.

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 exceedences 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.

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

MANCHESTER FORMER MGP

LINE
NO.

- 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 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 during June 2014. 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.

- ENGI removed material from a tar-separator and other subsurface structures, installed three new monitoring wells and an extraction well on-site, prior to property paving in Fall 2017. Further removals from subsurface structures are planned for 2018.

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

MANCHESTER FORMER MGP

LINE
NO.

- 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.

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.

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 attorneys 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

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

MANCHESTER FORMER MGP

LINE
NO.

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 attorneys 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 attorneys 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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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), 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 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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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 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, involving 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

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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 Ground Water Management Permit received on May 10, 2017. 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.

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.

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

LACONIA FORMER MGP AND LIBERTY HILL DISPOSAL AREA

LINE
NO.

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 UTILITIES

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) 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.

   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

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

CONCORD FORMER MGP

LINE
NO.

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.

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

CONCORD FORMER MGP

LINE
NO.

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." ENGI has evaluated damage to the roof and structure of the holder, and will be using this information to determine whether the holder will be restored or razed.

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 and productive conversations took place with the developer. If the property is transferred, the purchaser's future use design would be taken into account when the final design of the engineered cap is being developed. This site developer has not contacted ENGI since the fall of 2017, and appears to have lost interest in the redevelopment project.

Concord Pond: 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 and 2012, 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

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

CONCORD FORMER MGP

LINE
NO.

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. During 2017, NHDES required active hazardous waste sites managed by the NHDES Hazardous Waste

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

CONCORD FORMER MGP

LINE
NO.

Remediation Bureau to include Per- and Polyfluoroalkyl Substances (PFAS) in one of their sampling rounds.

During May 19, 2009 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.

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, is to be provided to NHDES by the end of 2015.

Concord Pond: 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

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

CONCORD FORMER MGP

LINE
NO.

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, however ENGI has received no response from the City after numerous attempts to begin the implementation

A renewal application for the Groundwater Management Permit was submitted on July 20, 2012, and the renewed permit was granted by NHDES on December 11, 2012. Groundwater and surface water monitoring continues under this permit every May and November.

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

2018 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	-	130,096.96	-	-	8,604.02	138,700.98	[redacted]		127,356.38
2	Concord MGP	DEF077	2,124.00	57,893.99	-	-	10,983.48	71,001.47			57,559.09
3	Laconia/Liberty Hill	DEF086	-	30,546.25	-	-	3,493.97	34,040.22			34,040.22
4	Manchester MGP	DEF057	-	252,823.90	203,552.41	-	14,348.50	470,724.81			346,043.49
5	Nashua MGP	DEF054	-	60,516.43	-	-	961.72	61,478.15			15,523.24
6	General Expenses	DEF064	-	-	-	-	10,799.27	10,799.27			10,799.27
	Total Pool Activity		**2,124.00**	**531,877.53**	**534,001.53**	**-**	**49,190.96**	**786,744.90**	**-**	**(195,423.21)**	**591,321.69**

REDACTED

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
[redacted]											
2	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 0717					188.26	188.26			188.26
3	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12623		4,750.99				4,750.99			4,750.99
4	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12646		2,298.90				2,298.90			2,298.90
5	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12674		1,170.49				1,170.49			1,170.49
[redacted]											
7	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12700		1,390.91				1,390.91			1,390.91
8	NH DEPT OF ENVIRONMENTAL SERVICES	199810022 1017					494.19	494.19			494.19
9	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12721		2,796.34				2,796.34			2,796.34
10	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12748		2,349.28				2,349.28			2,349.28
11	GZA GEOENVIRONMENTAL INC	751199		1,545.20				1,545.20			1,545.20
12	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12773		2,101.91				2,101.91			2,101.91
13	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12801		8,516.27				8,516.27			8,516.27
[redacted]											
15	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12827		6,201.08				6,201.08			6,201.08
[redacted]											
17	INNOVATIVE ENGINEERING SOLUTIONS, INC.	12853		2,262.06				2,262.06			2,262.06
18	GZA GEOENVIRONMENTAL INC	754590		890.00				890.00			890.00
19	MARY CASEY - MILEAGE	JC10420					30.98	30.98			30.98
20	6/30/18 ACCRUAL			24,243.00				24,243.00			24,243.00
21								0.00			0.00
22								0.00			0.00
23	Environmental Staff Time						248.29	248.29			248.29
	Total Pool Activity		**-**	**60,516.43**	**-**	**-**	**961.72**	**61,478.15**	**-**	**(45,954.91)**	**15,523.24**

REDACTED

159

0607

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

			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 EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	ANCHOR QEA LLC	52780		4,417.00				4,417.00			4,417.00
2	NH DEPT OF ENVIRONMENTAL SERVICES	199212014 0717					2,800.40	2,800.40			2,800.40
3	CITY OF CONCORD	2017-50460144					1,020.00	1,020.00			1,020.00
4	GEI CONSULTANTS, INC.	3023173		10,873.95				10,873.95			10,873.95
5	ANCHOR QEA LLC	53274		2,732.28				2,732.28			2,732.28
6	GEI CONSULTANTS, INC.	3024117		7,153.51				7,153.51			7,153.51
7	ANCHOR QEA LLC	53684		3,267.25				3,267.25			3,267.25
8	GEI CONSULTANTS, INC.	3026036		2,449.16				2,449.16			2,449.16
9	CLEAN HARBORS	1002010768					918.07	918.07			918.07
10	ANCHOR QEA LLC	53983		1,874.00				1,874.00			1,874.00
11	CLEAN HARBORS	1002066623					277.20	277.20			277.20
12	GEI CONSULTANTS, INC.	3028085		2,441.58				2,441.58			2,441.58
13	MARY CASEY - MILEAGE	MILEAGE					69.84	69.84			69.84
14	ANCHOR QEA LLC	54929		18,327.36				18327.36			18,327.36
15	GEI CONSULTANTS, INC.	3027117		2,283.34				2283.34			2,283.34
16	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT CONCORD					270.00	270.00			270.00
17	GEI CONSULTANTS, INC.	3030430		5,924.48				5,924.48			5,924.48
18	ANCHOR QEA LLC	55234		7,664.89				7,664.89			7,664.89
19	[redacted]										
20											
21	ANCHOR QEA LLC	55820		1,948.00				1,948.00			1,948.00
22	GEI CONSULTANTS, INC.	3031191		11,010.86				11,010.86			11,010.86
23	GEI CONSULTANTS, INC.	3032434		2,195.36				2,195.36			2,195.36
24	ANCHOR QEA LLC	56204		984.75				984.75			984.75
25	GEI CONSULTANTS, INC.	3033558		1,481.46				1,481.46			1,481.46
26	ANCHOR QEA LLC	56882		8,053.75				8,053.75			8,053.75
27	GEI CONSULTANTS, INC.	3034922		3,509.84				3,509.84			3,509.84
28	CITY OF CONCORD	2018-50460122					1,020.00	1,020.00			1,020.00
29	[redacted]										
30	MARY CASEY - MILEAGE	MILEAGE					110.08	110.08			110.08
31	ANCHOR QEA LLC	54495		661.04				661.04			661.04
32	ANCHOR QEA LLC	57441		762.00				762.00			762.00
33	CLEAN HARBORS	1002347764					1,539.23	1,539.23			1,539.23
34	GEI CONSULTANTS, INC.	3036309		3,736.92				3,736.92			3,736.92
35	GEI CONSULTANTS, INC.	3037273		8,574.18				8,574.18			8,574.18
36	MARY CASEY - MILEAGE	MILEAGE					22.80	22.80			22.80
37	Environmental Staff Time			17,770.00			0.00	17,770.00			17,770.00
38	6/30/18 ACCRUAL						556.40	556.40			556.40
	Total Pool Activity		**0.00**	**130,096.96**	**0.00**	**0.00**	**8,604.02**	**138,700.98**	**0.00**	**(11,344.60)**	**127,356.38**

REDACTED

160

0608

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

			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	CLEAN HARBORS	1002010900					530.46	530.46			530.46
2	CLEAN HARBORS	1002009730					277.20	277.20			277.20
[redacted]											
4	GZA GEOENVIRONMENTAL INC	744589		26,730.07				26,730.07			26,730.07
5	PLANT INSPECTORS FOR REMEDIATION ACTIVITIES				3,753.43			3,753.43			3,753.43
6	ESMI OF NH	1015191			90,828.00			90,828.00			90,828.00
7	MARY CASEY - MILEAGE	JC8825					53.93	53.93			53.93
8	MARY CASEY - MILEAGE	JC8825					166.72	166.72			166.72
9	CLEAN HARBORS	1002057075					8,308.52	8,308.52			8,308.52
10	T FORD COMPANY, INC	1806-1			90,930.00			90,930.00			90,930.00
11	CLEAN HARBORS	1002064356					277.20	277.20			277.20
12	ESMI OF NH	1015242			2,590.08			2,590.08			2,590.08
13	CLEAN HARBORS	1002139193					2,204.40	2,204.40			2,204.40
14	GZA GEOENVIRONMENTAL INC	750011		48,029.02				48,029.02			48,029.02
15	NH DEPT OF ENVIRONMENTAL SERVICES	200003011 0118					839.09	839.09			839.09
[redacted]											
18	GZA GEOENVIRONMENTAL INC	749333		17,521.62				17,521.62			17,521.62
19	ESMI OF NH	1015428			10,368.40			10,368.40			10,368.40
20	ESMI OF NH	1015617			3,030.10			3,030.10			3,030.10
21	GZA GEOENVIRONMENTAL INC	753031		28,062.90				28,062.90			28,062.90
22	ESMI OF NH	1015717			2,052.40			2,052.40			2,052.40
23	GZA GEOENVIRONMENTAL INC	749019		78,038.61				78,038.61			78,038.61
[redacted]											
25	GZA GEOENVIRONMENTAL INC	755534		11,812.55				11,812.55			11,812.55
26	MARY CASEY - MILEAGE	JC10420					31.23	31.23			31.23
27	GZA GEOENVIRONMENTAL INC	757697		6,629.13				6,629.13			6,629.13
[redacted]											
29	6/30/18 ACCRUAL			36,000.00				36,000.00			36,000.00
30	Environmental Staff Time						$ 1,659.75	1,659.75			1,659.75
	Total Pool Activity		**0.00**	**252,823.90**	**203,552.41**	**0.00**	**14,348.50**	**470,724.81**	**0.00**	**(124,681.32)**	**346,043.49**

REDACTED

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	ALLEGRA MARKETING PRINT MAIL	31130					180.00	180.00			180.00
2	MARY CASEY - MILEAGE	JC8825					49.69	49.69			49.69
3	MARY CASEY - MILEAGE	LABOR					50.37	50.37			50.37
4								0.00			0.00
5								0.00			0.00
6	Environmental Staff Time						10,519.21	10,519.21			10,519.21
	Total Pool Activity		**0.00**	**0.00**	**0.00**	**0.00**	**10,799.27**	**10,799.27**	**0.00**	**0.00**	**10,799.27**

162

0610

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

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	CITY OF CONCORD	2017-50460144					1,020.00	1,020.00			1,020.00
3	CITY OF CONCORD GSD	410184001 0617					9.76	9.76			9.76
4	CITY OF CONCORD GSD	410184001 0717					9.76	9.76			9.76
5	ORR & RENO, P.A.	108290	2,124.00					2,124.00			2,124.00
6	CITY OF CONCORD GSD	410184001 0817					9.62	9.62			9.62
7	CLEAN HARBORS	1002010746					2,645.39	2,645.39			2,645.39
8	CLEAN HARBORS	1002010768					513.03	513.03			513.03
9	GZA GEOENVIRONMENTAL INC	744553		16,727.48				16,727.48			16,727.48
10	GZA GEOENVIRONMENTAL INC	744590		3,452.78				3,452.78			3,452.78
11	JOE GAUCI LANDSCAPING LLC	2017-8-3576					1,438.00	1,438.00			1,438.00
12	CITY OF CONCORD GSD	410184001 0917					9.76	9.76			9.76
13	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 1017					141.21	141.21			141.21
14	JOE GAUCI LANDSCAPING LLC	2017-9-3576					474.00	474.00			474.00
15	GZA GEOENVIRONMENTAL INC	736983		354.55				354.55			354.55
16	MARY CASEY - MILEAGE	JC8825					70.81	70.81			70.81
17	JOE GAUCI LANDSCAPING LLC	3576					509.00	509.00			509.00
18	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT					270.00	270.00			270.00
19	GZA GEOENVIRONMENTAL INC	748974		2,107.50				2,107.50			2,107.50
20	CITY OF CONCORD	410184-001					19.52	19.52			19.52
21	GZA GEOENVIRONMENTAL INC	750012		2,320.30				2,320.30			2,320.30
22	GZA GEOENVIRONMENTAL INC	748973		11,791.42				11,791.42			11,791.42
23	NH DEPT OF ENVIRONMENTAL SERVICES	198904063 0118					70.59	70.59			70.59
[redacted]											
26	CITY OF CONCORD GSD	410184-001 1217					29.43	29.43			29.43
27	CITY OF CONCORD GSD	410184-001 0218					29.58	29.58			29.58
28	GZA GEOENVIRONMENTAL INC	753234		4,677.00				4,677.00			4,677.00
29	GZA GEOENVIRONMENTAL INC	749326		6,936.38				6,936.38			6,936.38
30	CITY OF CONCORD	2018-50460122					1,020.00	1,020.00			1,020.00
[redacted]											
32	GZA GEOENVIRONMENTAL INC	755027		1,060.75				1,060.75			1,060.75
33	JOE GAUCI LANDSCAPING LLC	2018-5-3576					597.00	597.00			597.00
34	CLEAN HARBORS	1002347764					1,833.59	1,833.59			1,833.59
35	GZA GEOENVIRONMENTAL INC	757698		4,965.83				4,965.83			4,965.83
36	6/30/18 ACCRUAL			3,500.00				3,500.00			3,500.00
37	Environmental Staff Time						263.43	263.43			263.43
	Total Pool Activity		**2,124.00**	**57,893.99**	**0.00**	**0.00**	**10,983.48**	**71,001.47**	**0.00**	**(13,442.38)**	**57,559.09**

REDACTED

163

0611

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

			1101	1102	1105	1106	1107		1108	1109	
LINE NO.	VENDOR	REF NO.	LEGAL EXPENSES	CONSULTING EXPENSES	REMEDIATION EXPENSES	SETTLEMENT EXPENSES	OTHER EXPENSES	SUB-TOTAL EXPENSES	INSURANCE & THIRD PARTY EXPENSES	INSURANCE & THIRD PARTY RECOVERIES	TOTAL SUBMITTED
1	MULLER'S LAWN & LANDSCAPING, LLC	4403					800.00	800.00			800.00
2	GEI CONSULTANTS, INC.	3027116		25,493.60				25,493.60			25,493.60
3	CLEAN HARBORS	1002031388					519.20	519.20			519.20
4	MULLER'S LAWN & LANDSCAPING, LLC	4489					800.00	800.00			800.00
5	GEI CONSULTANTS, INC.	3028084		3,769.44				3,769.44			3,769.44
6	NH DEPT OF ENVIRONMENTAL SERVICES	SQG SELFCERT LIB HIL					270.00	270.00			270.00
7	GEI CONSULTANTS, INC.	3030427		1,283.21				1,283.21			1,283.21
8	BLUE CHIP FILMS LLC	1438					675.00	675.00			675.00
9	BLUE CHIP FILMS LLC	1468					300.00	300.00			300.00
10								-			-
11								-			-
23	Environmental Staff Time						129.77	129.77			129.77
	Total Pool Activity		0.00	30,546.25	0.00	0.00	3,493.97	34,040.22			34,040.22

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 95

Concord Pond

DEF056

	(thru 9/99) pool #1 #3	(9/99 9/00) pool #4	(9/03 9/04) pool #5	(9/04 9/05) pool #6	(9/05 9/06) pool #7	(9/06 9/07) pool #8	(9/07 9/08) pool #9	(9/08 9/09) pool #10	(9/09 9/10) pool #11	(9/10 9/11) pool #12	(9/11 9/12) pool #13	(9/12 6/13) pool #14	(7/13 6/14) pool #15	(7/14 6/15) pool #16	(7/15 6/16) pool #17	(7/16 6/17) pool #18	(7/17 6/18) pool #19	subtotal
1 Remediation costs (i.o. 500061)	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
Remediation costs (i.o. 500005)	-	-																-
A Subtotal - remediation costs	5,420,852	129,002	60,293	21,613	96,293	155,796	95,374	128,187	143,000	249,160	86,412	78,387	40,314	89,626	43,204	102,196	138,701	7,078,409
																		-
Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)			(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,204,671)
Cash recoveries (i.o. 500004)	(445,985)	-																(445,985)
Recovery costs (i.o. 500004)	623,784	-				-	-	-	-	-	-	-	-	-	-	-	-	623,784
Transfer Credit from Gas Restructuring																		-
B Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	(14,314)	(13,446)	-	(12,608)	(6,064)	(32,417)	(5,173)	(19,318)	(7,990)	(11,392)	(8,614)	(14,047)	(11,345)	(2,026,872)
																		-
A-B Total net expenses to recover	3,583,912	95,798	60,293	21,613	81,979	142,350	95,374	115,579	136,936	216,743	81,238	59,069	32,324	78,235	34,590	88,148	127,356	5,051,537
																		-
																		-
Surcharge revenue:																		-
Act June 1998 - October 1998	(54,889)	-																(54,889)
Act November 1998 - October 1999	(538,143)	-																(538,143)
Act November 1999 - October 2000	(760,871)	-																(760,871)
Act November 2000 - October 2001	(626,614)	(13,925)																(640,539)
Act November 2001 - October 2002	(600,600)	(24,514)																(625,114)
Act November 2002 - October 2003	(592,678)	(15,197)																(607,874)
Act November 2003 - October 2004	(291,340)	(14,567)																(305,907)
Act November 2004- October 2005	(56,719)	(14,180)	(14,180)															(85,078)
Act November 2005- October 2006	-	(6,875)	(6,875)															(13,750)
Act November 2006- October 2007	-	-	-	-	(14,091)													(14,091)
Act November 2007- October 2008																		-
Act November 2012- October 2013										(5,002)	(5,002)							(10,003)
Act November 2013- October 2014										(12,749)	(12,749)							(25,497)
Act Nov 2009-Oct 2010 Base Rate Rev										($4,423)								(4,423)
Act Nov 2010-Oct 2011 Base Rate Rev										($32,310)								(32,310)
Act Nov 2011-Oct 2012 Base Rate Rev										($28,448)								(28,448)
Act Nov 2012-Oct 2013 Base Rate Rev										($2,143)	($2,143)							(4,286)
Act Nov 2013-Oct 2014 Base Rate Rev																		-
Act Nov 2014-Oct 2015 Base Rate Rev																		
AES collections			(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(220,792)
Gas Street overcollection	(23,511)																	(23,511)
Prior Period Pool under/overcollection	21,038	38,548	45,088	50,734	60,721	116,708	246,787	-	-	-	-	-	-	-	-	-	-	
																		0
																		-
C Surcharge Subtotal	(3,524,326)	(50,710)	(9,559)	39,108	34,729	104,437	234,166	(12,904)	(13,145)	(98,295)	(33,631)	(13,725)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(3,995,526)
D Net balance to be recovered (A-B+C)	59,586	45,088	50,734	60,721	116,708	246,787	329,540	102,675	123,791	47,629	47,608	45,345	18,376	64,062	20,185	73,484	112,498	1,056,012
E Allocation of Litigated Recovery			-		-		(329,540)	(102,675)	(123,791)	(47,228)	-	-	-	-	-	-	-	(603,234)
Surcharge calculation																		
Unrecovered costs (D+E)	-	-	-	-	-	-	-	-	-	-	6,801	12,956	7,875	36,607	14,417.84	62,986.49	112,498.35	254,142
remaining life	-	-	24	36	48	60	72	84	84	84	12	24	36	48	60	72	84	
one year	-	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
F amortization	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
Required annual increase in rates:																		
smaller of D or F	-	-	-	-	-		-	-	-	-	6,801	6,478	2,625	9,152	2,884	10,498	16,071	54,508
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
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	$0.0001	$0.0001	$0.0003

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 95

Laconia & Liberty Hill

	i.o. no. 500005 (thru 9/01) pool #1 #3	(9/04 9/05) pool #4	(9/05 9/06) pool #5	(9/06 9/07) pool #6	(9/07 9/08) pool #7 Incl. Audit Corr	(9/08 9/09) pool #8 Incl. Audit Corr	(9/09 9/10) pool #9	(9/10 9/11) pool #10	(9/11 9/12) pool #11	(9/12 6/13) pool #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	DEF086 (7/17 6/18) pool #17	subtotal
1 Remediation costs (i.o. 500061)	-	-									[redacted]					
Remediation costs (i.o. 500005)	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
A Subtotal - remediation costs	5,241,032	9,702	2,330,555	2,089,199	428,225	607,876	262,678	210,532	269,281	642,986						
Cash recoveries (i.o. 500061)	-	-	-	-	-	-										
Cash recoveries (i.o. 500004)	-	-	-	-	-	-										
Recovery costs (i.o. 500004)	-			11,643	21,729	-	-									
Transfer Credit from Gas Restructuring					-	-										
B Subtotal - net recoveries	-	-	-	11,643	21,729	-	-	-	-	-						
A-B Total net expenses to recover	5,241,032	9,702	2,330,555	2,100,842	449,954	607,876	262,678	210,532	269,281	642,986						
Surcharge revenue:																
Act June 1998 - October 1998	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
Act November 1998 - October 1999	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-
Act November 1999 - October 2000	(151,933)	-	-		-	-	-	-	-	-	-	-	-	-	-	(151,933)
Act November 2000 - October 2001	(696,237)	-	-		-	-	-	-	-	-	-	-	-	-	-	(696,237)
Act November 2001 - October 2002	(796,714)	-	-		-	-	-	-	-	-	-	-	-	-	-	(796,714)
Act November 2002 - October 2003	(805,434)	-	-		-	-	-	-	-	-	-	-	-	-	-	(805,434)
Act November 2003 - October 2004	(699,215)															(699,215)
Act November 2004- October 2005	(652,264)															(652,264)
Act November 2005- October 2006	(691,159)	-	-		-	-	-	-	-	-	-	-	-	-	-	(691,159)
Act November 2006- October 2007	(648,174)	-	(309,996)													(958,171)
Act November 2007- October 2008																-
Act November 2012- October 2013									(20,006)							(20,006)
Act November 2013- October 2014									(25,497)	(76,491)						(101,988)
Act Nov 2009-Oct 2010 Base Rate Rev								($4,296)								(4,296)
Act Nov 2010-Oct 2011 Base Rate Rev								($31,384)								(31,384)
Act Nov 2011-Oct 2012 Base Rate Rev								($27,632)								(27,632)
Act Nov 2012-Oct 2013 Base Rate Rev								$0	($14,208)							(14,208)
Act Nov 2013-Oct 2014 Base Rate Rev									(28,433)	(28,433)	(28,433)					(85,298)
Act Nov 2014-Oct 2015 Base Rate Rev									(21,909)	(21,909)	(21,909)	(21,909)	-	-	-	(87,637)
AES collections																-
Gas Street overcollection																-
Prior Period Pool under/overcollection	21,391	111,336	121,038	2,141,596	4,242,438		-	-	(89,606)	-	-	-	-	-	-	
C Surcharge Subtotal	(5,119,739)	111,336	(188,958)	2,141,596	4,242,438	-	-	(63,313)	(199,659)	(126,833)	(50,342)	(21,909)	-	-	-	(5,823,577)
D Net balance to be recovered (A-B+C)	121,293	121,038	2,141,596	4,242,438	4,692,393	607,876	262,678	147,219	69,622	516,153	[redacted]					
E Allocation of Litigated Recovery					(4,692,393)	(607,876)	(262,678)	(236,825)	-	-						
Surcharge calculation																
Unrecovered costs (D+E)	-	-			-	-	-	-	9,946	147,472.25						
remaining life	-	36	48	60	72	84	84	48	12	24						
one year	-	12	12	12	12	12	12	12	12	12						
F amortization	-	-	-	-	-	-	-	-	9,946	73,736						
Required annual increase in rates:																
smaller of D or F	-	-	-		-	-	-	-	9,946	73,736	[redacted]					
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0001	$0.0004	[redacted]					

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 95

Manchester

		(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8 Incl. Audit Corr	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	DEF057 (7/17 6/18) pool #18	subtotal
1	1 Remediation costs (i.o. 500061)	-	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	10,598,402
2	Remediation costs (i.o. 500005)	825,092																825,092
3	A Subtotal - remediation costs	825,092	335,338	1,989,848	875,702	561,210	4,387,645	312,185	369,037	372,237	507,622	82,113	92,900	116,496	71,011	54,333	470,725	11,423,494
4																		
5	Cash recoveries (i.o. 500061)	-			(545,540)	(220,353)	(1,127,436)		(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(2,753,952)
6	Cash recoveries (i.o. 500004)	-																-
7	Recovery costs (i.o. 500004)	-	1,242,326			2,546	-											1,244,872
8	Transfer Credit from Gas Restructuring					-	-											-
9	B Subtotal - net recoveries	-	1,242,326	-	(545,540)	(217,807)	(1,127,436)	-	(40,359)	(234,648)	(65,324)	(270,732)	(31,690)	(41,057)	(48,322)	(3,810)	(124,681)	(1,509,080)
10																		
11	A-B Total net expenses to recover	825,092	1,577,664	1,989,848	330,162	343,402	3,260,209	312,185	328,678	137,589	442,298	(188,619)	61,210	75,440	22,690	50,523	346,043	9,914,414
12																		-
13																		-
14	Surcharge revenue:																	-
15	Act June 1998 - October 1998	-	-															-
16	Act November 1998 - October 1999	-	-															-
17	Act November 1999 - October 2000	-	-															-
18	Act November 2000 - October 2001	-	-															-
19	Act November 2001 - October 2002	(73,543)	-															(73,543)
20	Act November 2002 - October 2003	(75,984)	-															(75,984)
21	Act November 2003 - October 2004	(138,576)	-															(138,576)
22	Act November 2004- October 2005	(113,437)	(212,695)	-			-	-	-	-	-	-	-	-	-	-	-	(326,132)
23	Act November 2005- October 2006	(96,247)	(206,243)	(261,242)			-	-	-	-	-	-	-	-	-	-	-	(563,732)
24	Act November 2006- October 2007	(126,817)	(211,361)	(281,815)	(42,272)													(662,265)
25	Act November 2007- October 2008																	-
26	Act November 2012- October 2013										(40,012)							(40,012)
27	Act November 2013- October 2014										(50,994)							(50,994)
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									-	(23,337)							(23,337)
32	Act Nov 2013-Oct 2014 Base Rate Rev																	-
33	Act Nov 2014-Oct 2015 Base Rate Rev																	
34	AES collections																	-
35	Gas Street overcollection																	-
36	Prior Period Pool under/overcollection	394,600	276,881	1,224,246	2,671,037	2,958,927	3,302,330	-	-	-								
37																		
38																		
39	C Surcharge Subtotal	(230,004)	(353,418)	681,189	2,628,765	2,958,927	3,302,330	-	-	-	(114,343)	-	-	-	-	-	-	(1,954,576)
40																		
41																		
42	D Net balance to be recovered (A-B+C)	595,088	1,224,246	2,671,037	2,958,927	3,302,330	6,562,539	312,185	328,678	137,589	327,955	(188,619)	61,210	75,440	22,690	50,523	346,043	7,959,838
43																		
44	E Allocation of Litigated Recovery		-	-			(6,562,539)	(312,185)	(328,678)	(91,770)	-	-	-	-	-	-	-	(7,295,172)
45																		
46	Surcharge calculation																	
47	Unrecovered costs (D+E)	-	-	-	-		-	-	-	-	46,851	(53,891)	26,233	43,108	16,207	43,305	346,043	467,856
48	remaining life	-	24	36	48	60	70	84	84	12	12	24	36	48	60	72	84	
49	one year	-	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F amortization	-	-	-	-	-	-	-	-	-	46 851	(26 946)	8 744	10 777	3 241	7 218	49 435	
51																		
52	Required annual increase in rates:																	
53	smaller of D or F	-	-	-	-		-	-	-	-	46,851	(26,946)	8,744	10,777	3,241	7,218	49,435	99,320
54																		
55	forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																		
57	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0003	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0000	$0.0003	$0.0005

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 95

			Nashua															DEF054	
							Corrected per 2/08 Audit												
			(9/00 9/03) pool #1 #3	(9/03 9/04) pool #4	(9/04 9/05) pool #5	(9/05 9/06) pool #6	(9/06 9/07) pool #7	(9/07 9/08) pool #8	(9/08 9/09) pool #9	(9/09 9/10) pool #10	(9/10 9/11) pool #11	(9/11 9/12) pool #12	(9/12 6/13) pool #13	(7/13 6/14) pool #14	(7/14 6/15) pool #15	(7/15 6/16) pool #16	(7/16 6/17) pool #17	(7/17 6/18) pool #18	subtotal
1	1	Remediation costs (i.o. 500061)	-	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	1,620,044
2		Remediation costs (i.o. 500005)	1,771,567																1,771,567
3	A	Subtotal - remediation costs	1,771,567	10,841	206,367	23,354	9,737	107,605	78,535	162,729	65,118	399,400	119,095	63,397	105,917	106,129	100,342	61,478	3,391,611
4																			-
5		Cash recoveries (i.o. 500061)	-			(18,581)	(4,151)	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(566,063)
6		Cash recoveries (i.o. 500004)	-																-
7		Recovery costs (i.o. 500004)	-			5,449	12,938	-	-										18,388
8		Transfer Credit from Gas Restructuring					-	-	-										-
9	B	Subtotal - net recoveries	-	-		(13,131)	8,787	(10,414)	(62,246)	(63,753)	(31,767)	(2,990)	(199,336)	(27,447)	(40,699)	(43,694)	(15,029)	(45,955)	(547,675)
10																			-
11	A-B	Total net expenses to recover	1,771,567	10,841	206,367	10,223	18,524	97,191	16,289	98,975	33,351	396,411	(80,241)	35,950	65,217	62,435	85,314	15,523	2,843,936
12																			
13																			
14		Surcharge revenue:																	
15	Act	June 1998 - October 1998	-	-															-
16	Act	November 1998 - October 1999	-	-															-
17	Act	November 1999 - October 2000	-	-															-
18	Act	November 2000 - October 2001	-	-															-
19	Act	November 2001 - October 2002	(183,857)	-															(183,857)
20	Act	November 2002 - October 2003	(243,150)	-															(243,150)
21	Act	November 2003 - October 2004	(247,639)	-															(247,639)
22	Act	November 2004- October 2005	(241,054)	-															(241,054)
23	Act	November 2005- October 2006	(247,492)	-	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(274,991)
24	Act	November 2006- October 2007	(253,633)	-	(28,181)	-													(281,815)
25	Act	November 2007- October 2008																	-
26	Act	November 2012- October 2013										(40,012)							(40,012)
27	Act	November 2013- October 2014										(38,246)							(38,246)
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									-	(20,916)							(20,916)
32	Act	Nov 2013-Oct 2014 Base Rate Rev																	-
33	Act	Nov 2014-Oct 2015 Base Rate Rev																	
34		AES collections																	-
35		Gas Street overcollection																	-
36		Prior Period Pool under/overcollection	669,664	543,205	554,046	704,732	714,955	733,479	-	-	-	6,224	-	-	-	-	-	-	
37																			
38																			
39	C	Surcharge Subtotal	(747,161)	543,205	498,365	704,732	714,955	733,479	-	-	-	(92,950)	-	-	-	-	-	-	(1,571,680)
40																			
41																			
42	D	Net balance to be recovered (A-B+C)	1,024,405	554,046	704,732	714,955	733,479	830,669	16,289	98,975	33,351	303,461	(80,241)	35,950	65,217	62,435	85,314	15,523	1,272,256
43																			
44	E	Allocation of Litigated Recovery	-	-	-	-	-	(830,669)	(16,289)	(98,975)	(27,127)	-	-	-	-	-	-	-	(973,061)
45																			
46		Surcharge calculation																	
47		Unrecovered costs (D+E)	-	-	-	-		-	-	-		43,352	(22,926)	15,407	37,267	44,596	73,126	15,523	206,345
48		remaining life	12	24	36	48	60	72	84	84	72	12	24	36	48	60	72	84	
49		one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	
50	F	amortization	-	-	-	-	-	-	-	-	-	43 352	(11 463)	5 136	9 317	8 919	12 188	2 218	
51																			
52		Required annual increase in rates:																	
53		smaller of D or F	-	-	-	-		-	-	-	-	43,352	(11,463)	5,136	9,317	8,919	12,188	2,218	69,665
54																			
55		forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56																			
57		surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	($0.0001)	$0.0000	$0.0001	$0.0000	$0.0001	$0.0000	$0.0004

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 95

			Dover												
														DEF059	
			(9/02 9/03) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/17 6/18) pool #12	subtotal
1	1	Remediation costs (i.o. 500061)	-	18,854	2,288	-	-	-	-	-	-	-	-	-	21,142
2		Remediation costs (i.o. 500005)	181,066												181,066
3	A	Subtotal - remediation costs	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
4															
5		Cash recoveries (i.o. 500061)	-					-	-	-	-	-	-	-	-
6		Cash recoveries (i.o. 500004)	-												-
7		Recovery costs (i.o. 500004)	-												-
8		Transfer Credit from Gas Restructuring													-
9	B	Subtotal - net recoveries	-	-	-	-	-	-	-	-	-	-	-	-	-
10															
11	A-B	Total net expenses to recover	181,066	18,854	2,288	-	-	-	-	-	-	-	-	-	202,208
12															
13															
14		Surcharge revenue:													
15	Act	June 1998 - October 1998	-												-
16	Act	November 1998 - October 1999	-												-
17	Act	November 1999 - October 2000	-												-
18	Act	November 2000 - October 2001	-												-
19	Act	November 2001 - October 2002	-												-
20	Act	November 2002 - October 2003	-												-
21	Act	November 2003 - October 2004	(29,134)												(29,134)
22	Act	November 2004- October 2005	(28,359)												(28,359)
23	Act	November 2005- October 2006	(27,499)	-			-	-	-	-	-	-	-	-	(27,499)
24	Act	November 2006- October 2007	(28,181)	-	-										(28,181)
25	Act	November 2007- October 2008													-
26	Act	November 2012- October 2013													-
27	Act	November 2013- October 2014													-
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 2014 Base Rate Rev													-
33	Act	Nov 2014-Oct 2015 Base Rate Rev													
34		AES collections													-
35		Gas Street overcollection													-
36		Prior Period Pool under/overcollection		67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	
37															
38															
39	C	Surcharge Subtotal	(113,174)	67,892	86,746	89,034	89,034	-	-	-	-	-	-	-	(113,174)
40															
41															
42	D	Net balance to be recovered (A-B+C)	67,892	86,746	89,034	89,034	89,034	-	-	-	-	-	-	-	89,034
43															
44	E	Allocation of Litigated Recovery		-		-	(89,034)	-	-	-	-	-	-	-	(89,034)
45															
46		Surcharge calculation													
47		Unrecovered costs (D+E)	-	-	-		-	-	-	-	-	-	-	-	-
48		remaining life	24	36	48	60	72	84	84	84	84	84	84	84	
49		one year	12	12	12	12	12	12	12	12	12	12	12	12	
50	F	amortization	-	-	-	-	-	-	-	-	-	-	-	-	
51															
52		Required annual increase in rates:													
53		smaller of D or F	-	-	-		-	-	-	-	-	-	-	-	-
54															
55		forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
56															
57		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

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 95

		Keene												
												DEF055		
		(9/03 9/04) pool #1	(9/04 9/05) pool #2	(9/05 9/06) pool #3	(9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	subtotal
1	Remediation costs (i.o. 500061)	-										[redacted]		
	Remediation costs (i.o. 500005)	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
A	Subtotal - remediation costs	10,165	6,606	35,111	8,766	32	269	-	-	488	1,400			
	Cash recoveries (i.o. 500061)	-												
	Cash recoveries (i.o. 500004)	-												
	Recovery costs (i.o. 500004)			18,831	823	-	-	-	-					
	Transfer Credit from Gas Restructuring				-	-	-							
B	Subtotal - net recoveries	-		18,831	823	-	-	-	-	-	-			
A-B	Total net expenses to recover	10,165	6,606	53,942	9,589	32	269	-	-	488	1,400			
														-
														-
	Surcharge revenue:													-
Act	June 1998 - October 1998	-												-
Act	November 1998 - October 1999	-												-
Act	November 1999 - October 2000	-												-
Act	November 2000 - October 2001	-												-
Act	November 2001 - October 2002	-												-
Act	November 2002 - October 2003	-												-
Act	November 2003 - October 2004	-												-
Act	November 2004- October 2005	-	-				-	-	-	-	-	-	-	-
Act	November 2005- October 2006	-	-				-	-	-	-	-	-	-	-
Act	November 2006- October 2007	-	-	(14,091)										(14,091)
Act	November 2007- October 2008													-
Act	November 2012- October 2013													-
Act	November 2013- October 2014													-
Act	Nov 2009-Oct 2010 Base Rate Rev													-
Act	Nov 2010-Oct 2011 Base Rate Rev													-
Act	Nov 2011-Oct 2012 Base Rate Rev													-
Act	Nov 2012-Oct 2013 Base Rate Rev													-
Act	Nov 2013-Oct 2014 Base Rate Rev													-
Act	Nov 2014-Oct 2015 Base Rate Rev													
	AES collections													-
	Gas Street overcollection													-
	Prior Period Pool under/overcollection		10,165	16,771	56,622	66,211	-	-	-	-	-	-	-	
C	Surcharge Subtotal	-	10,165	2,680	56,622	66,211	-	-	-	-	-	-	-	(14,091)
D	Net balance to be recovered (A-B+C)	10,165	16,771	56,622	66,211	66,244	269	-	-	488	1,400	[redacted]		
E	Allocation of Litigated Recovery	-	-	-	-	(66,244)	(269)	-	-	-	-			
	Surcharge calculation													
	Unrecovered costs (D+E)	-	-	-			-	-	-	70	400			
	remaining life	24	36	48	60	72	84	84	84	12	24			
	one year	12	12	12	12	12	12	12	12	12	12			
F	amortization	-	-	-	-	-	-	-	-	70	200			
	Required annual increase in rates:													
	smaller of D or F	-	-	-			-	-	-	70	200	[redacted]		
	forecasted therm sales	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
	surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	[redacted]		

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 95

	Concord												DEF077		
	(9/03 9/05) pool #1 & #2	Corrected per 1/24/07 Audit (9/05 9/06) pool #3	Corrected per 2/08 Audit (9/06 9/07) pool #4	(9/07 9/08) pool #5	(9/08 9/09) pool #6	(9/09 9/10) pool #7	(9/10 9/11) pool #8	(9/11 9/12) pool #9	(9/12 6/13) pool #10	(7/13 6/14) pool #11	(7/14 6/15) pool #12	(7/15 6/16) pool #13	(7/16 6/17) pool #14	(7/17 6/18) pool #15	subtotal
1 Remediation costs (i.o. 500061)	-												[redacted]		
Remediation costs (i.o. 500005)	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
A Subtotal - remediation costs	243,123	44,345	109,642	8,006	77,063	49,403	179,732	289,103	84,256	135,673	192,525	114,749			
Cash recoveries (i.o. 500061)	-	(22,239)	(47,977)	(12,601)	16,623	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
Cash recoveries (i.o. 500004)	-														
Recovery costs (i.o. 500004)				1,432	(1,007)										
Transfer Credit from Gas Restructurin		-													
B Subtotal - net recoveries	-	(22,239)	(47,977)	(11,169)	15,616	(3,213)	(11,394)	(31,575)	(38,871)	(12,319)	(28,742)	(19,197)			
A-B Total net expenses to recover	243,123	22,106	61,665	(3,163)	92,679	46,190	168,338	257,528	45,384	123,355	163,783	95,553			
															-
															-
Surcharge revenue:															-
Act June 1998 - October 1998	-														-
Act November 1998 - October 1999	-														-
Act November 1999 - October 2000	-														-
Act November 2000 - October 2001	-														-
Act November 2001 - October 2002	-														-
Act November 2002 - October 2003	-														-
Act November 2003 - October 2004	-														-
Act November 2004- October 2005															-
Act November 2005- October 2006	(27,499)			-	-	-	-	-	-	-	-	-	-	-	(27,499)
Act November 2006- October 2007	(28,181)	-													(28,181)
Act November 2007- October 2008															-
Act November 2012- October 2013							(20,006)	(20,006)							(40,012)
Act November 2013- October 2014							(12,749)	(25,497)							(38,246)
Act Nov 2009-Oct 2010 Base Rate Rev							($1,891)								(1,891)
Act Nov 2010-Oct 2011 Base Rate Rev							($13,816)								(13,816)
Act Nov 2011-Oct 2012 Base Rate Rev							($12,164)								(12,164)
Act Nov 2012-Oct 2013 Base Rate Rev							($6,794)	($6,794)							(13,588)
Act Nov 2013-Oct 2014 Base Rate Rev															-
Act Nov 2014-Oct 2015 Base Rate Rev															
AES collections															-
Gas Street overcollection															-
Prior Period Pool under/overcollection	22,191	187,442	209,549	271,214	-	-	-	-	-	-	-	-	-	-	
C Surcharge Subtotal	(33,490)	187,442	209,549	271,214	-	-	(67,420)	(52,297)	-	-	-	-	-	-	(175,398)
D Net balance to be recovered (A-B+C)	209,633	209,549	271,214	268,051	92,679	46,190	100,919	205,231	45,384	123,355	163,783	95,553	[redacted]		
E Allocation of Litigated Recovery	-	-	-	(268,051)	(92,679)	(46,190)	(13,905)	-	-	-	-	-			
Surcharge calculation															
Unrecovered costs (D+E)	-	-		-	-	-	-	29,319	12,967	52,866	93,590	68,252			
remaining life	84	60		72	84	84	12	12	24	36	48	60			
one year	24	12		12	12	12	12	12	12	12	12	12			
F amortization	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650			
Required annual increase in rates:															
smaller of D or F	-	-		-	-	-	-	29,319	6,483	17,622	23,398	13,650	[redacted]		
forecasted therm sales	369,309,748	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874
surcharge per therm	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0002	$0.0000	$0.0001	$0.0001	$0.0001	[redacted]		

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 95

	General																
	(9/02 9/05) pool #1 #3	Corrected per 1/24/07 Audit (9/05 9/06) pool #4	(9/06 9/07) pool #5	(9/07 9/08) pool #6	(9/08 9/09) pool #7	(9/09 9/10) pool #8	(9/10 9/11) pool #9	(9/11 9/12) pool #10	(9/12 6/13) pool #11	(7/13 6/14) pool #12	(7/14 6/15) pool #13	(7/15 6/16) pool #14	(7/16 6/17) pool #15	DEF064 (7/17 6/18) pool #16	subtotal		2018 MGP Remediation subtotal
1 Remediation costs (i.o. 500061)	-														-		[redacted]
Remediation costs (i.o. 500005)	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
A Subtotal - remediation costs	750,239	34,355	22,017	(181,000)	(26,884)	4,199	69,286	93,034	75,204	13,139	16,612	11,879	6,547	10,799	899,427		
Cash recoveries (i.o. 500061)	-		-	-	-										-		
Cash recoveries (i.o. 500004)	-														-		
Recovery costs (i.o. 500004)		290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	322,270		
Transfer Credit from Gas Restructurin	(3,331)	-													(3,331)		
B Subtotal - net recoveries	(3,331)	290,155	31,826	16,012	23,953	-	-	(14,068)	(1,358)	-	(24,250)	-	-	-	318,939		
A-B Total net expenses to recover	746,908	324,511	53,844	(164,988)	(2,931)	4,199	69,286	78,967	73,846	13,139	(7,638)	11,879	6,547	10,799	1,218,366		
																	-
Surcharge revenue:																	
Act June 1998 - October 1998	-														-		(54,889)
Act November 1998 - October 1999	-														-		(538,143)
Act November 1999 - October 2000	-														-		(912,804)
Act November 2000 - October 2001	-														-		(1,336,776)
Act November 2001 - October 2002	-														-		(1,679,228)
Act November 2002 - October 2003	-														-		(1,732,442)
Act November 2003 - October 2004	(8,265)														(8,265)		(1,428,735)
Act November 2004- October 2005	(70,898)														(70,898)		(1,403,787)
Act November 2005- October 2006	(96,247)			-	-	-	-	-	-	-	-	-	-	-	(96,247)		(1,694,877)
Act November 2006- October 2007		(49,318)													(49,318)		(2,036,113)
Act November 2007- October 2008															-		-
Act November 2012- October 2013							(5,002)	(5,002)							(10,003)		(160,048)
Act November 2013- October 2014							(12,749)	(12,749)	(12,749)						(38,246)		(293,217)
Act Nov 2009-Oct 2010 Base Rate Rev															-		(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev															-		(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev															-		(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev															-		(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev																	(85,298)
Act Nov 2014-Oct 2015 Base Rate Rev																	(87,637)
AES collections	-														-		(220,792)
Gas Street overcollection															-		(23,511)
Prior Period Pool under/overcollection	296,594	457,429	732,622	786,465	-	-	-	-	-	-	-	-	-	-			
C Surcharge Subtotal	15,503	408,111	732,622	786,465	-	-	(17,750)	(17,750)	(12,749)	-	-	-	-	-	(272,977)		(13,920,997)
D Net balance to be recovered (A-B+C)	762,410	732,622	786,465	621,477	(2,931)	4,199	51,536	61,217	61,098	13,139	(7,638)	11,879	6,547	10,799	945,390	3,595,226	[redacted]
																-	
E Allocation of Litigated Recovery	-	-	-	(621,477)	2,931	(4,199)	(11,582)	-	-	-	-	-	-	-	(634,326)	(428,437)	
																-	
Surcharge calculation																-	
Unrecovered costs (D+E)	-	-		-	-	-	-	8,745	17,456	5,631	(4,364)	8,485	5,611	10,799	52,364	2,150,415	
remaining life	84	60	72	84	84	84	12	12	24	36	48	60	72	84			
one year	24	12	12	12	12	12	12	12	12	12	12	12	12	12			
F amortization	-	-	-	-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543			
Required annual increase in rates:																	
smaller of D or F	-	-		-	-	-	-	8,745	8,728	1,877	(1,091)	1,697	935	1,543	22,434	584,652	
forecasted therm sales	553,441,400	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874	184,654,874		**184,654,874**
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	$0.0001		**$0.0161**

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 95

Expense and Collection Summary per Year

	(thru 9/98)	(9/99 9/00)	(9/00 9/01)	(9/01 9/02)	(9/02 9/03)	(9/03 9/04)	(9/04 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)	(7/13 6/14)	(7/14 6/15)	(7/15 6/16)	(7/16 6/17)	(7/17 6/18)	Total
1 Remediation costs (i.o. 500061)	5,420,852	129,002	-	-	-	406,472	2,236,682	997,637	726,742	4,590,624	518,907	674,766	686,515	993,434	196,611	312,039	220,344	256,871	670,904	[redacted]
Remediation costs (i.o. 500005)	1,027,747	-	-	-	181,066	10,165	16,308	2,444,366	2,229,625	255,263	658,324	316,280	459,550	651,906	1,801,404	7,975,914	3,307,910	260,380	115,841	
A Subtotal - remediation costs	6,448,599	129,002	-	-	181,066	416,637	2,252,990	3,442,003	2,956,367	4,845,887	1,177,231	991,045	1,146,065	1,645,340	1,998,015	8,287,953	3,528,254	517,250	786,745	
Cash recoveries (i.o. 500061)	(2,014,740)	(33,204)	-	-	-	-	-	(600,673)	(285,927)	(1,150,452)	(58,231)	(113,390)	(310,226)	(105,062)	(79,446)	(121,889)	(119,826)	(53,116)	(195,423)	
Cash recoveries (i.o. 500004)	(445,985)	-	-	-	-	(4,765,500)	(1,779,370)	(3,288,281)	(11,935,301)	(1,033,751)	9,795	-	-	-	-	-	-	-	-	
Recovery costs (i.o. 500004)	623,784	-	-	-	-	5,622,795	1,905,791	2,350,722	377,106	678,985	(2,078,366)	-	-	(14,068)	2,500,000	2,475,750	-	-	-	
Transfer Credit from Gas Restructuring	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
B Subtotal - net recoveries	(1,836,941)	(33,204)	-	-	-	857,295	126,421	(1,538,231)	(11,844,123)	(1,505,218)	(2,126,802)	(113,390)	(310,226)	(119,129)	2,420,554	2,353,861	(119,826)	(53,116)	(195,423)	
A-B Total net expenses to recover	4,611,659	95,798	-	-	181,066	1,273,932	2,379,412	1,903,772	(8,887,756)	3,340,669	(949,571)	877,655	835,839	1,526,211	4,418,569.29	10,641,813.86	3,408,427.63	464,499.00	591,686.20	
Surcharge revenue:																				
Act June 1998 - October 1998	(54,889)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(54,889)
Act November 1998 - October 1999	(538,143)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(538,143)
Act November 1999 - October 2000	(912,804)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(912,804)
Act November 2000 - October 2001	(779,786)	(13,925)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(793,711)
Act November 2001 - October 2002	(759,943)	(24,514)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(784,457)
Act November 2002 - October 2003	(744,646)	(15,197)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(759,843)
Act November 2003 - October 2004	(422,442)	(14,567)	-	-	(29,134)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(466,143)
Act November 2004- October 2005	(184,336)	(14,180)	-	-	(28,359)	(226,875)	-	-	-	-	-	-	-	-	-	-	-	-	-	(453,749)
Act November 2005- October 2006	(141,176)	(6,875)	-	-	(27,499)	(213,118)	(288,741)	-	-	-	-	-	-	-	-	-	-	-	-	(677,409)
Act November 2006- October 2007	-	-	-	-	(28,181)	(211,361)	(309,996)	(429,768)	-	-	-	-			-	-	-	-	-	(979,307)
Act November 2007- October 2008													-	-	-	-	-	-	-	-
Act November 2012- October 2013									-	-	-	-	(30,009)	(130,039)	-	-	-	-	-	(160,048)
Act November 2013- October 2014													(38,246)	(165,731)	-	-	-	-	-	(203,977)
Act Nov 2009-Oct 2010 Base Rate Rev													(10,611)	-	-	-	-	-	-	(10,611)
Act Nov 2010-Oct 2011 Base Rate Rev													(77,509)	-	-	-	-	-	-	(77,509)
Act Nov 2011-Oct 2012 Base Rate Rev													(68,244)	-	-	-	-	-	-	(68,244)
Act Nov 2012-Oct 2013 Base Rate Rev													(8,937)	(67,398)	-	-	-	-	-	(76,335)
Act Nov 2013-Oct 2014 Base Rate Rev													-	(28,433)	(28,433)	-	-	-	-	(56,865)
Act Nov 2014-Oct 2015 Base Rate Rev													-	(21,909)	(21,909)	(21,909)	-	-	-	(65,728)
AES collections	-	-	-	-	-	(33,593)	(11,626)	(11,901)	(12,271)	(12,620)	(12,904)	(13,145)	(13,221)	(13,738)	(13,948)	(14,173)	(14,405)	(14,664)	(14,858)	(207,067)
Gas Street overcollection	(23,511)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(23,511)
Prior Period Pool under/overcollection																				
C Surcharge Subtotal	(4,561,677)	(89,257)	-	-	(113,174)	(684,947)	(610,364)	(441,669)	(12,271)	(12,620)	(12,904)	(13,145)	(246,777)	(427,248)	(64,290)	(36,082)	(14,405)	(14,664)	(14,858)	(7,370,353)
D Net balance to be recovered (A-B+C)	49,982	6,541	-	-	67,892	588,985	1,769,048	1,462,103	(8,900,027)	3,328,049	(962,475)	864,510	589,062	1,098,962	4,354,279	10,605,732	3,394,023	449,835	576,828	[redacted]
E Allocation of Litigated Recovery																				
Surcharge calculation																				
Unrecovered costs (D+E)																				
remaining life																				
one year																				
F amortization																				
Required annual increase in rates:																				
smaller of D or F																				
forecasted therm sales																				
surcharge per therm																				

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019

Rate: **$0.19 /MMBtu**

	Rate	Volume	Total	
Injection Cost	$0.0087	**393,727**	$3,425	
Fuel (1.51%)	$0.0368	**393,727**	$14,474	
Withdrawal Cost	$0.0087	**199,601**	$1,737	
Delivery Rate	$0.0491	199,601	$9,808	
FTA Demand Charge	$0.2680	199,601	$53,499	
FTA Commodity Charge	$0.1181	199,601	$23,573	
Fuel (1.24%)	$0.0302	199,601	$6,026	
		Total Cost	$112,541	
	Absolute Value of the	Sendout Error	**593,327**	MMBtu
		Rate	$ 0.19	/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	$1.4938	/ MMBtu per month
	$0.0491	/ MMBtu per day
TGP Z4-6 Demand Charge	$8.1481	/ MMBtu per month
	$0.2680	/ MMBtu per day
TGP Z4-6 Commodity Charge	$0.1181	/ MMBtu

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
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	760	737	23	1,752,809	1,715,381	37,429	79,740	58,584	21,155
Dec	1,233	1,228	5	2,570,842	2,562,788	8,054	78,927	43,490	35,437
Jan	1,241	1,211	30	2,583,728	2,535,405	48,323	109,532	78,927	30,604
Feb	881	867	14	1,968,944	1,945,717	23,226	81,213	52,220	28,994
Mar	904	849	55	2,178,809	2,071,641	107,168	134,447	120,807	13,640
Apr	417	422	-5	886,923	892,396	-5,473	36,119	15,323	20,796
May	277	290	-13	655,202	666,170	-10,968	31,217	10,124	21,092
Jun	46	50	-4	367,325	369,128	-1,803	5,409	1,803	3,606
Jul	15	16	-1	327,694	328,009	-315	315	0	315
Aug	11	12	-1	338,212	339,005	-793	3,965	1,586	2,379
Sep	60	65	-5	360,471	361,168	-697	2,369	836	1,533
Oct	198	208	-10	779,449	789,474	-10,025	30,075	10,025	20,050
Total	**6,043**	**5,955**	**88**	**14,770,409**	**14,576,283**	**194,126**	**593,327**	**393,727**	**199,601**

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Apr 1, 2017	31	31	0	48,280	48,280	0	0	0	0
Apr 2, 17	24	24	0	40,619	40,619	0	0	0	0
Apr 3, 17	21	17	4	37,335	32,957	4,378	4,378	4,378	0
Apr 4, 17	27	27	0	43,902	43,902	0	0	0	0
Apr 5, 17	25	24	1	41,713	40,619	1,095	1,095	1,095	0
Apr 6, 17	22	25	-3	38,430	41,713	-3,284	3,284	0	3,284
Apr 7, 17	21	22	-1	37,335	38,430	-1,095	1,095	0	1,095
Apr 8, 17	23	24	-1	39,524	40,619	-1,095	1,095	0	1,095
Apr 9, 17	11	11	0	26,390	26,390	0	0	0	0
Apr 10, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 11, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 12, 17	9	11	-2	24,201	26,390	-2,189	2,189	0	2,189
Apr 13, 17	16	18	-2	31,863	34,052	-2,189	2,189	0	2,189
Apr 14, 17	14	16	-2	29,674	31,863	-2,189	2,189	0	2,189
Apr 15, 17	3	3	0	17,634	17,634	0	0	0	0
Apr 16, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 17, 17	11	9	2	26,390	24,201	2,189	2,189	2,189	0
Apr 18, 17	21	20	1	37,335	36,241	1,095	1,095	1,095	0
Apr 19, 17	16	18	-2	31,863	34,052	-2,189	2,189	0	2,189
Apr 20, 17	12	14	-2	27,485	29,674	-2,189	2,189	0	2,189
Apr 21, 17	20	22	-2	36,241	38,430	-2,189	2,189	0	2,189
Apr 22, 17	19	21	-2	35,146	37,335	-2,189	2,189	0	2,189
Apr 23, 17	9	9	0	24,201	24,201	0	0	0	0
Apr 24, 17	10	7	3	25,296	22,012	3,284	3,284	3,284	0
Apr 25, 17	18	18	0	34,052	34,052	0	0	0	0
Apr 26, 17	12	10	2	27,485	25,296	2,189	2,189	2,189	0
Apr 27, 17	5	5	0	19,823	19,823	0	0	0	0
Apr 28, 17	0	0	0	14,351	14,351	0	0	0	0
Apr 29, 17	2	1	1	16,540	15,445	1,095	1,095	1,095	0
Apr 30, 17	15	15	0	30,768	30,768	0	0	0	0
May 1, 17	11	19	-8	22,877	29,627	-6,750	6,750	0	6,750
May 2, 17	8	10	-2	20,346	22,034	-1,687	1,687	0	1,687
May 3, 17	15	14	1	26,252	25,408	844	844	844	0
May 4, 17	10	10	0	22,034	22,034	0	0	0	0
May 5, 17	14	16	-2	25,408	27,096	-1,687	1,687	0	1,687
May 6, 17	7	7	0	19,503	19,503	0	0	0	0
May 7, 17	12	11	1	23,721	22,877	844	844	844	0
May 8, 17	19	20	-1	29,627	30,471	-844	844	0	844
May 9, 17	18	16	2	28,783	27,096	1,687	1,687	1,687	0
May 10, 17	13	12	1	24,565	23,721	844	844	844	0
May 11, 17	13	14	-1	24,565	25,408	-844	844	0	844
May 12, 17	12	13	-1	23,721	24,565	-844	844	0	844
May 13, 17	16	17	-1	27,096	27,940	-844	844	0	844
May 14, 17	18	18	0	28,783	28,783	0	0	0	0
May 15, 17	9	8	1	21,190	20,346	844	844	844	0
May 16, 17	0	0	0	13,597	13,597	0	0	0	0
May 17, 17	0	0	0	13,597	13,597	0	0	0	0
May 18, 17	0	0	0	13,597	13,597	0	0	0	0
May 19, 17	0	0	0	13,597	13,597	0	0	0	0
May 20, 17	6	4	2	18,659	16,972	1,687	1,687	1,687	0
May 21, 17	5	5	0	17,815	17,815	0	0	0	0
May 22, 17	12	13	-1	23,721	24,565	-844	844	0	844
May 23, 17	1	3	-2	14,440	16,128	-1,687	1,687	0	1,687
May 24, 17	3	4	-1	16,128	16,972	-844	844	0	844
May 25, 17	13	13	0	24,565	24,565	0	0	0	0
May 26, 17	11	9	2	22,877	21,190	1,687	1,687	1,687	0
May 27, 17	6	4	2	18,659	16,972	1,687	1,687	1,687	0
May 28, 17	3	5	-2	16,128	17,815	-1,687	1,687	0	1,687
May 29, 17	14	15	-1	25,408	26,252	-844	844	0	844
May 30, 17	7	7	0	19,503	19,503	0	0	0	0
May 31, 17	1	3	-2	14,440	16,128	-1,687	1,687	0	1,687
Jun 1, 17	1	0	1	12,004	11,553	451	451	451	0
Jun 2, 17	5	6	-1	13,807	14,258	-451	451	0	451
Jun 3, 17	7	6	1	14,708	14,258	451	451	451	0
Jun 4, 17	2	3	-1	12,455	12,905	-451	451	0	451
Jun 5, 17	12	13	-1	16,962	17,413	-451	451	0	451
Jun 6, 17	15	14	1	18,314	17,864	451	451	451	0
Jun 7, 17	2	1	1	12,455	12,004	451	451	451	0
Jun 8, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 9, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 10, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 11, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 12, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 13, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 14, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 15, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 16, 17	2	4	-2	12,455	13,356	-902	902	0	902
Jun 17, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 18, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 19, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 20, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 21, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 22, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 23, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 24, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 25, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 26, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 27, 17	0	3	-3	11,553	12,905	-1,352	1,352	0	1,352
Jun 28, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 29, 17	0	0	0	11,553	11,553	0	0	0	0
Jun 30, 17	0	0	0	11,553	11,553	0	0	0	0
Jul 1, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 2, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 3, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 4, 17	0	0	0	10,418	10,418	0	0	0	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jul 5, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 6, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 7, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 8, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 9, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 10, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 11, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 12, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 13, 17	5	5	0	11,993	11,993	0	0	0	0
Jul 14, 17	1	2	-1	10,733	11,048	-315	315	0	315
Jul 15, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 16, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 17, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 18, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 19, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 20, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 21, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 22, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 23, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 24, 17	7	7	0	12,623	12,623	0	0	0	0
Jul 25, 17	2	2	0	11,048	11,048	0	0	0	0
Jul 26, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 27, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 28, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 29, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 30, 17	0	0	0	10,418	10,418	0	0	0	0
Jul 31, 17	0	0	0	10,418	10,418	0	0	0	0
Aug 1, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 2, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 3, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 4, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 5, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 6, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 7, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 8, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 9, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 10, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 11, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 12, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 13, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 14, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 15, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 16, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 17, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 18, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 19, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 20, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 21, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 22, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 23, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 24, 17	0	0	0	10,629	10,629	0	0	0	0
Aug 25, 17	1	2	-1	11,422	12,215	-793	793	0	793
Aug 26, 17	1	1	0	11,422	11,422	0	0	0	0
Aug 27, 17	1	0	1	11,422	10,629	793	793	793	0
Aug 28, 17	2	2	0	12,215	12,215	0	0	0	0
Aug 29, 17	4	3	1	13,800	13,007	793	793	793	0
Aug 30, 17	0	2	-2	10,629	12,215	-1,586	1,586	0	1,586
Aug 31, 17	2	2	0	12,215	12,215	0	0	0	0
Sep 1, 17	8	9	-1	12,852	12,991	-139	139	0	139
Sep 2, 17	3	3	0	12,155	12,155	0	0	0	0
Sep 3, 17	7	7	0	12,713	12,713	0	0	0	0
Sep 4, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 5, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 6, 17	0	3	-3	11,737	12,155	-418	418	0	418
Sep 7, 17	1	3	-2	11,876	12,155	-279	279	0	279
Sep 8, 17	4	4	0	12,294	12,294	0	0	0	0
Sep 9, 17	5	3	2	12,434	12,155	279	279	279	0
Sep 10, 17	4	2	2	12,294	12,016	279	279	279	0
Sep 11, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 12, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 13, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 14, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 15, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 16, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 17, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 18, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 19, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 20, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 21, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 22, 17	1	0	1	11,876	11,737	139	139	139	0
Sep 23, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 24, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 25, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 26, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 27, 17	0	0	0	11,737	11,737	0	0	0	0
Sep 28, 17	5	4	1	12,434	12,294	139	139	139	0
Sep 29, 17	7	9	-2	12,713	12,991	-279	279	0	279
Sep 30, 17	15	18	-3	13,827	14,245	-418	418	0	418
Oct 1, 17	8	10	-2	26,760	28,765	-2,005	2,005	0	2,005
Oct 2, 17	6	8	-2	24,755	26,760	-2,005	2,005	0	2,005
Oct 3, 17	6	6	0	24,755	24,755	0	0	0	0
Oct 4, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 5, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 6, 17	2	3	-1	20,745	21,748	-1,003	1,003	0	1,003
Oct 7, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 8, 17	0	0	0	18,740	18,740	0	0	0	0

Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment - B Supplier Balancing Charge
Page 5 of 6

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Oct 9, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 10, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 11, 17	6	7	-1	24,755	25,758	-1,003	1,003	0	1,003
Oct 12, 17	14	17	-3	32,776	35,783	-3,008	3,008	0	3,008
Oct 13, 17	9	8	1	27,763	26,760	1,003	1,003	1,003	0
Oct 14, 17	1	1	0	19,743	19,743	0	0	0	0
Oct 15, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 16, 17	19	20	-1	37,788	38,791	-1,003	1,003	0	1,003
Oct 17, 17	15	16	-1	33,778	34,781	-1,003	1,003	0	1,003
Oct 18, 17	6	10	-4	24,755	28,765	-4,010	4,010	0	4,010
Oct 19, 17	4	2	2	22,750	20,745	2,005	2,005	2,005	0
Oct 20, 17	7	8	-1	25,758	26,760	-1,003	1,003	0	1,003
Oct 21, 17	3	4	-1	21,748	22,750	-1,003	1,003	0	1,003
Oct 22, 17	7	5	2	25,758	23,753	2,005	2,005	2,005	0
Oct 23, 17	1	2	-1	19,743	20,745	-1,003	1,003	0	1,003
Oct 24, 17	0	0	0	18,740	18,740	0	0	0	0
Oct 25, 17	4	3	1	22,750	21,748	1,003	1,003	1,003	0
Oct 26, 17	17	16	1	35,783	34,781	1,003	1,003	1,003	0
Oct 27, 17	15	17	-2	33,778	35,783	-2,005	2,005	0	2,005
Oct 28, 17	8	5	3	26,760	23,753	3,008	3,008	3,008	0
Oct 29, 17	4	4	0	22,750	22,750	0	0	0	0
Oct 30, 17	16	16	0	34,781	34,781	0	0	0	0
Oct 31, 17	20	20	0	38,791	38,791	0	0	0	0
Nov 1, 17	14	16	-2	39,984	43,238	-3,255	3,255	0	3,255
Nov 2, 17	4	3	1	23,710	22,083	1,627	1,627	1,627	0
Nov 3, 17	12	10	2	36,729	33,474	3,255	3,255	3,255	0
Nov 4, 17	18	17	1	46,493	44,866	1,627	1,627	1,627	0
Nov 5, 17	9	7	2	31,847	28,592	3,255	3,255	3,255	0
Nov 6, 17	16	14	2	43,238	39,984	3,255	3,255	3,255	0
Nov 7, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 8, 17	29	30	-1	64,394	66,021	-1,627	1,627	0	1,627
Nov 9, 17	24	22	2	56,257	53,003	3,255	3,255	3,255	0
Nov 10, 17	39	40	-1	80,667	82,295	-1,627	1,627	0	1,627
Nov 11, 17	35	37	-2	74,158	77,413	-3,255	3,255	0	3,255
Nov 12, 17	31	31	0	67,649	67,649	0	0	0	0
Nov 13, 17	29	30	-1	64,394	66,021	-1,627	1,627	0	1,627
Nov 14, 17	31	28	3	67,649	62,767	4,882	4,882	4,882	0
Nov 15, 17	29	29	0	64,394	64,394	0	0	0	0
Nov 16, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 17, 17	32	33	-1	69,276	70,903	-1,627	1,627	0	1,627
Nov 18, 17	20	24	-4	49,748	56,257	-6,509	6,509	0	6,509
Nov 19, 17	28	27	1	62,767	61,139	1,627	1,627	1,627	0
Nov 20, 17	30	28	2	66,021	62,767	3,255	3,255	3,255	0
Nov 21, 17	22	19	3	53,003	48,120	4,882	4,882	4,882	0
Nov 22, 17	31	29	2	67,649	64,394	3,255	3,255	3,255	0
Nov 23, 17	33	32	1	70,903	69,276	1,627	1,627	1,627	0
Nov 24, 17	25	25	0	57,885	57,885	0	0	0	0
Nov 25, 17	21	16	5	51,375	43,238	8,137	8,137	8,137	0
Nov 26, 17	32	28	4	69,276	62,767	6,509	6,509	6,509	0
Nov 27, 17	35	36	-1	74,158	75,785	-1,627	1,627	0	1,627
Nov 28, 17	26	26	0	59,512	59,512	0	0	0	0
Nov 29, 17	30	26	4	66,021	59,512	6,509	6,509	6,509	0
Nov 30, 17	25	24	1	57,885	56,257	1,627	1,627	1,627	0
Dec 1, 17	28	29	-1	63,965	65,576	-1,611	1,611	0	1,611
Dec 2, 17	29	32	-3	65,576	70,408	-4,832	4,832	0	4,832
Dec 3, 17	30	29	1	67,187	65,576	1,611	1,611	1,611	0
Dec 4, 17	28	27	1	63,965	62,354	1,611	1,611	1,611	0
Dec 5, 17	17	16	1	46,247	44,636	1,611	1,611	1,611	0
Dec 6, 17	30	30	0	67,187	67,187	0	0	0	0
Dec 7, 17	31	29	2	68,797	65,576	3,222	3,222	3,222	0
Dec 8, 17	34	31	3	73,630	68,797	4,832	4,832	4,832	0
Dec 9, 17	34	35	-1	73,630	75,240	-1,611	1,611	0	1,611
Dec 10, 17	35	33	2	75,240	72,019	3,222	3,222	3,222	0
Dec 11, 17	37	34	3	78,462	73,630	4,832	4,832	4,832	0
Dec 12, 17	34	37	-3	73,630	78,462	-4,832	4,832	0	4,832
Dec 13, 17	44	44	0	89,737	89,737	0	0	0	0
Dec 14, 17	48	47	1	96,180	94,569	1,611	1,611	1,611	0
Dec 15, 17	42	43	-1	86,516	88,126	-1,611	1,611	0	1,611
Dec 16, 17	44	43	1	89,737	88,126	1,611	1,611	1,611	0
Dec 17, 17	44	44	0	89,737	89,737	0	0	0	0
Dec 18, 17	34	38	-4	73,630	80,073	-6,443	6,443	0	6,443
Dec 19, 17	27	24	3	62,354	57,522	4,832	4,832	4,832	0
Dec 20, 17	37	35	2	78,462	75,240	3,222	3,222	3,222	0
Dec 21, 17	42	42	0	86,516	86,516	0	0	0	0
Dec 22, 17	39	43	-4	81,683	88,126	-6,443	6,443	0	6,443
Dec 23, 17	33	32	1	72,019	70,408	1,611	1,611	1,611	0
Dec 24, 17	36	38	-2	76,851	80,073	-3,222	3,222	0	3,222
Dec 25, 17	43	40	3	88,126	83,294	4,832	4,832	4,832	0
Dec 26, 17	51	50	1	101,012	99,402	1,611	1,611	1,611	0
Dec 27, 17	59	57	2	113,899	110,677	3,222	3,222	3,222	0
Dec 28, 17	63	63	0	120,342	120,342	0	0	0	0
Dec 29, 17	60	61	-1	115,509	117,120	-1,611	1,611	0	1,611
Dec 30, 17	57	59	-2	110,677	113,899	-3,222	3,222	0	3,222
Dec 31, 17	63	63	0	120,342	120,342	0	0	0	0
Jan 1, 18	63	65	-2	120,342	123,563	-3,222	3,222	0	3,222
Jan 2, 18	53	52	1	104,234	102,623	1,611	1,611	1,611	0
Jan 3, 18	47	47	0	94,569	94,569	0	0	0	0
Jan 4, 18	46	45	1	92,959	91,348	1,611	1,611	1,611	0
Jan 5, 18	63	60	3	120,342	115,509	4,832	4,832	4,832	0
Jan 6, 18	67	63	4	126,785	120,342	6,443	6,443	6,443	0
Jan 7, 18	51	49	2	101,012	97,791	3,222	3,222	3,222	0
Jan 8, 18	37	35	2	78,462	75,240	3,222	3,222	3,222	0
Jan 9, 18	41	34	7	84,905	73,630	11,275	11,275	11,275	0
Jan 10, 18	32	31	1	70,408	68,797	1,611	1,611	1,611	0
Jan 11, 18	18	17	1	47,857	46,247	1,611	1,611	1,611	0
Jan 12, 18	14	8	6	41,414	31,750	9,665	9,665	9,665	0

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Calculation of Supplier Balancing Charge
2018-2019
Estimated Daily Imbalances

Date	Predicted MAN HDD	Actual MAN HDD	Forecaster Error MAN HDD	Sendout (MMBtu) Calculated on Predicted MAN HDD	Calculated on Actual MAN HDD	Sendout Error (MMBtu)	Abs.Value Sendout Error (MMBtu)	Injections (MMBtu)	Withdrawals (MMBtu)
Jan 13, 18	46	47	-1	92,959	94,569	-1,611	1,611	0	1,611
Jan 14, 18	52	52	0	102,623	102,623	0	0	0	0
Jan 15, 18	48	46	2	96,180	92,959	3,222	3,222	3,222	0
Jan 16, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Jan 17, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Jan 18, 18	41	42	-1	84,905	86,516	-1,611	1,611	0	1,611
Jan 19, 18	35	34	1	75,240	73,630	1,611	1,611	1,611	0
Jan 20, 18	28	27	1	63,965	62,354	1,611	1,611	1,611	0
Jan 21, 18	30	30	0	67,187	67,187	0	0	0	0
Jan 22, 18	30	36	-6	67,187	76,851	-9,665	9,665	0	9,665
Jan 23, 18	24	32	-8	57,522	70,408	-12,886	12,886	0	12,886
Jan 24, 18	43	41	2	88,126	84,905	3,222	3,222	3,222	0
Jan 25, 18	47	44	3	94,569	89,737	4,832	4,832	4,832	0
Jan 26, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Jan 27, 18	22	18	4	54,300	47,857	6,443	6,443	6,443	0
Jan 28, 18	27	28	-1	62,354	63,965	-1,611	1,611	0	1,611
Jan 29, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Jan 30, 18	43	42	1	88,126	86,516	1,611	1,611	1,611	0
Jan 31, 18	37	36	1	78,462	76,851	1,611	1,611	1,611	0
Feb 1, 18	29	29	0	65,576	65,576	0	0	0	0
Feb 2, 18	50	52	-2	99,402	102,623	-3,222	3,222	0	3,222
Feb 3, 18	41	41	0	84,905	84,905	0	0	0	0
Feb 4, 18	27	26	1	62,354	60,743	1,611	1,611	1,611	0
Feb 5, 18	40	39	1	83,294	81,683	1,611	1,611	1,611	0
Feb 6, 18	40	40	0	83,294	83,294	0	0	0	0
Feb 7, 18	38	39	-1	80,073	81,683	-1,611	1,611	0	1,611
Feb 8, 18	45	47	-2	91,348	94,569	-3,222	3,222	0	3,222
Feb 9, 18	37	38	-1	78,462	80,073	-1,611	1,611	0	1,611
Feb 10, 18	25	25	0	59,133	59,133	0	0	0	0
Feb 11, 18	28	29	-1	63,965	65,576	-1,611	1,611	0	1,611
Feb 12, 18	38	35	3	80,073	75,240	4,832	4,832	4,832	0
Feb 13, 18	38	36	2	80,073	76,851	3,222	3,222	3,222	0
Feb 14, 18	27	29	-2	62,354	65,576	-3,222	3,222	0	3,222
Feb 15, 18	20	21	-1	51,079	52,690	-1,611	1,611	0	1,611
Feb 16, 18	32	31	1	70,408	68,797	1,611	1,611	1,611	0
Feb 17, 18	33	33	0	72,019	72,019	0	0	0	0
Feb 18, 18	34	35	-1	73,630	75,240	-1,611	1,611	0	1,611
Feb 19, 18	20	19	1	51,079	49,468	1,611	1,611	1,611	0
Feb 20, 18	9	16	-7	33,361	44,636	-11,275	11,275	0	11,275
Feb 21, 18	17	10	7	46,247	34,971	11,275	11,275	11,275	0
Feb 22, 18	35	35	0	75,240	75,240	0	0	0	0
Feb 23, 18	27	27	0	62,354	62,354	0	0	0	0
Feb 24, 18	27	25	2	62,354	59,133	3,222	3,222	3,222	0
Feb 25, 18	31	29	2	68,797	65,576	3,222	3,222	3,222	0
Feb 26, 18	28	25	3	63,965	59,133	4,832	4,832	4,832	0
Feb 27, 18	24	21	3	57,522	52,690	4,832	4,832	4,832	0
Feb 28, 18	18	14	4	47,857	41,414	6,443	6,443	6,443	0
Mar 1, 18	23	21	2	58,728	54,831	3,897	3,897	3,897	0
Mar 2, 18	28	24	4	68,470	60,676	7,794	7,794	7,794	0
Mar 3, 18	28	23	5	68,470	58,728	9,743	9,743	9,743	0
Mar 4, 18	29	28	1	70,419	68,470	1,949	1,949	1,949	0
Mar 5, 18	30	29	1	72,367	70,419	1,949	1,949	1,949	0
Mar 6, 18	32	31	1	76,264	74,316	1,949	1,949	1,949	0
Mar 7, 18	31	33	-2	74,316	78,213	-3,897	3,897	0	3,897
Mar 8, 18	34	35	-1	80,161	82,110	-1,949	1,949	0	1,949
Mar 9, 18	33	32	1	78,213	76,264	1,949	1,949	1,949	0
Mar 10, 18	32	30	2	76,264	72,367	3,897	3,897	3,897	0
Mar 11, 18	32	32	0	76,264	76,264	0	0	0	0
Mar 12, 18	31	28	3	74,316	68,470	5,846	5,846	5,846	0
Mar 13, 18	34	33	1	80,161	78,213	1,949	1,949	1,949	0
Mar 14, 18	31	29	2	74,316	70,419	3,897	3,897	3,897	0
Mar 15, 18	31	29	2	74,316	70,419	3,897	3,897	3,897	0
Mar 16, 18	37	34	3	86,007	80,161	5,846	5,846	5,846	0
Mar 17, 18	44	42	2	99,646	95,749	3,897	3,897	3,897	0
Mar 18, 18	44	41	3	99,646	93,801	5,846	5,846	5,846	0
Mar 19, 18	40	37	3	91,852	86,007	5,846	5,846	5,846	0
Mar 20, 18	33	30	3	78,213	72,367	5,846	5,846	5,846	0
Mar 21, 18	29	27	2	70,419	66,522	3,897	3,897	3,897	0
Mar 22, 18	28	24	4	68,470	60,676	7,794	7,794	7,794	0
Mar 23, 18	26	23	3	64,573	58,728	5,846	5,846	5,846	0
Mar 24, 18	28	26	2	68,470	64,573	3,897	3,897	3,897	0
Mar 25, 18	34	31	3	80,161	74,316	5,846	5,846	5,846	0
Mar 26, 18	30	28	2	72,367	68,470	3,897	3,897	3,897	0
Mar 27, 18	25	22	3	62,625	56,779	5,846	5,846	5,846	0
Mar 28, 18	19	19	0	50,934	50,934	0	0	0	0
Mar 29, 18	14	17	-3	41,191	47,037	-5,846	5,846	0	5,846
Mar 30, 18	17	18	-1	47,037	48,985	-1,949	1,949	0	1,949
Mar 31, 18	20	14	6	52,882	41,191	11,691	11,691	11,691	0
Apr	417	422	-5	886,923	892,396	-5,473	36,119	15,323	20,796
May	277	290	-13	655,202	666,170	-10,968	31,217	10,124	21,092
Jun	46	50	-4	367,325	369,128	-1,803	5,409	1,803	3,606
Jul	15	16	-1	327,694	328,009	-315	315	0	315
Aug	11	12	-1	338,212	339,005	-793	3,965	1,586	2,379
Sep	60	65	-5	360,471	361,168	-697	2,369	836	1,533
Oct	198	208	-10	779,449	789,474	-10,025	30,075	10,025	20,050
Nov	760	737	23	1,752,809	1,715,381	37,429	79,740	58,584	21,155
Dec	1,233	1,228	5	2,570,842	2,562,788	8,054	78,927	43,490	35,437
Jan	1,241	1,211	30	2,583,728	2,535,405	48,323	109,532	78,927	30,604
Feb	881	867	14	1,968,944	1,945,717	23,226	81,213	52,220	28,994
Mar	904	849	55	2,178,809	2,071,641	107,168	134,447	120,807	13,640
Total	6,043	5,955	88	14,770,409	14,576,283	194,126	593,327	393,727	199,601

Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Docket DE 98-124 Gas Restructuring
Peaking Demand Rate

Line	Description	Resource	Amount	Unit	Source:
1	Peak Day		164,571	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) 72694	30,000		
10			79,718	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		56,738	Dekatherm	Line 1 - Line 10 - Line 18
21					
22					
23	Peaking Costs				
23					
23	Gas Supply		$4,969,000		Attachment B Page 3 Line 11
25	Indirect Production & Storage Capacity		$1,980,428		Summary Page Line 68
26	Granite Ridge		$0		Attachment B Page 3 Line 1
27	Total		$6,949,428		Sum Line 24 - 26
28					
29	Annual Peaking Rate per MDQ		$122.48		Line 27 divided by Line 20
30					
31	**Monthly Peaking MDQ**		**$20.41**	**/Dekatherm**	Line 29 divided by 6 month

Liberty Utilities (EnergyNorth Natural Gas) Corp.

Tennessee Allocations

Resource Type	High Load Factor	Low Load Factor
Pipeline	59 0%	47 2%
Storage	13 6%	17 5%
Peaking	27 4%	35 3%
TOTAL:	100 00%	100 00%

Capacity Resources effective November 1, 2017

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		$14 5544		10/31/2022	
	Iroquois	RTS to Wright	470-01	4,047		$5 5997		11/1/2022	
	TGP	NET-NE (Z5-Z6)	95346	4,000		$7 1569		11/30/2021	
	TGP	FT-A (Z5-Z6)	2302	3,122		$7 1569		10/31/2020	
	TGP	FT-A (Z0-Z6)	8587	7,035		$23 2175		10/31/2020	
	TGP	FT-A (Z1-Z6)	8587	14,561		$20 6094		10/31/2020	
	TGP	FT-A (Z6-Z6)	42076	20,000		$4 7453		10/31/2020	
	TGP	FT-A (Z6-Z6)	72694	30,000		$12 1916		10/31/2029	
Storage									
	TGP	FS-MA (Storage)	523*	21,844	1,560,391	$1.4938	$0.0205	10/31/2020	
	TGP	FT-A (Z4-Z6)	632	15,265		$8.1481		10/31/2020	
	TGP	FT-A (Z4-Z6)	8587	3,811		$8.1481		10/31/2020	
	National Fuel	FSS-1 (Storage)	O02357*	6,098	670,800	$2.4329	$0.0373	3/31/2020	
	National Fuel	FST (Transport)	N02358	6,098		$3.7049		3/31/2020	
	TGP	FT-A (Z4-Z6)	11234	6,150		$8.1481		10/31/2020	
	Honeoye	SS-NY (Storage)	SS-NY**	1,957	245,380	$4.4683	$0.0000	4/1/2020	X
	TGP	FT-A (Z5-Z6)	11234	1,957		$7.1569		10/31/2020	
	Dominion	GSS (Storage)	300076*	934	102,700	$1 8683	$0.0145	3/31/2021	
	TGP	FT-A (Z4-Z6)	11234	932		$8.1481		10/31/2020	
Peaking									
	Energy North	LNG/Propane****		56,738	-	$20.4100	$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 11/01/18. 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
Schedule 21
2018 - 2019 Winter Cost of Gas Filing
Back Up Calculations to
III Delivery Terms and Conditions
Proposed First Revised Page 147
Attachment B - Peaking Demand Charge

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	Concord Lateral	[redacted]				
5	ENGIE					
6						
7	Subtotal					$4,969,000 *
8						
9	**Total**					**$4,969,000**
10						

* Contract currently being negotiated for an effective date of November 1, 2018

REDACTED

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	47.2%	17.5%	35.3%	100.0%
G-51	**LALW**	Low Annual C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-42	**MAHW**	Medium C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-52	**MALW**	Medium C&I - Low Winter Use	59.0%	13.6%	27.4%	100.0%
G-43	**HAHW**	High Annual C&I - High Winter Use	47.2%	17.5%	35.3%	100.0%
G-53	**HALW90**	High Annual C&I - LF < 90%	59.0%	13.6%	27.4%	100.0%
G-54	**HALWG90**	High Annual C&I - LF > 90%	59.0%	13.6%	27.4%	100.0%

HLF	High Load Factor	58.97%	13.60%	27.44%	100%
LLF	Low Load Factor	47.23%	17.48%	35.28%	100%
	Total	48.44%	17.08%	34.48%	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	71.386 Heat load	Total
HLF	R-1 RNSH	109	469	578
LLF	R-3 RSH	4,189	67,700	71,889
LLF	G-41 SL	1,045	29,440	30,485
HLF	G-51 SH	670	1,886	2,556
LLF	G-42 ML	1,566	36,248	37,813
HLF	G-52 MH	1,846	3,535	5,381
LLF	G-43 LL	587	6,881	7,468
HLF	G-53 LLL90	1,412	2,480	3,893
HLF	G-54 LLG90	382	4,126	4,507
	TOTAL	11,806	152,765	164,571

HLF	4,420	12,496	16,916
LLF	7,387	140,269	147,655
Total	11,806	152,765	164,571

Allocate Class Design Day Throughput to Supply Sources

	Base Pipeline	Remaining Pipeline	Sub-total Pipeline	Storage	Peaking	Total
R-1 RNSH	109	208	318	86	174.16	578
R-3 RSH	4,189	30,096	34,285	12,460	25,144	71,889
G-41 SL	1,045	13,087	14,133	5,418	10,934	30,485
G-51 SH	670	839	1,509	347	701	2,556
G-42 ML	1,566	16,114	17,680	6,671	13,463	37,813
G-52 MH	1,846	1,571	3,418	651	1,313	5,381
G-43 LL	587	3,059	3,646	1,266	2,556	7,468
G-53 LLL90	1,412	1,103	2,515	457	921	3,893
G-54 LLG90	382	1,834	2,216	759	1,532	4,507
TOTAL	11,806	67,912	79,718	28,115	56,738	164,571

HLF	4,420	5,555	9,975	2,300	4,641	16,916
LLF	7,387	62,356	69,743	25,815	52,097	147,655
Total	11,806	67,912	79,718	28,115	56,738	164,571

% of Peak Day Requirement

	Pipeline	Storage	Peaking	Total
R-1 RNSH	54 9%	14.9%	30.1%	100.0%
R-3 RSH	47.7%	17.3%	35.0%	100.0%
G-41 SL	46.4%	17.8%	35 9%	100.0%
G-51 SH	59.0%	13.6%	27.4%	100.0%
G-42 ML	46 8%	17.6%	35.6%	100.0%
G-52 MH	63 5%	12.1%	24.4%	100.0%
G-43 LL	48 8%	17.0%	34 2%	100.0%
G-53 LLL90	64.6%	11.7%	23.7%	100.0%
G-54 LLG90	49 2%	16.8%	34.0%	100.0%
TOTAL	48.4%	17.1%	34 5%	100.0%

High Load Factor	58.97%	13.60%	27.44%	100%
Low Load Factor	47.23%	17.48%	35.28%	100%
Total	48.44%	17.08%	34.48%	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) — **Allocate Design Day Sendout to Rate Classes**

Design DD 71.386

	Daily Baseload * 1000	March Heating Factor * 1000	Heat load (Heating Factor * Design DD)	Total	Baseload as % of Total Class Load	Heat Load as % of Total	Base Load	Heat Load	Total
R-1 RNSH	109	6.530	466	575	19%	0.307%	109	469	578
R-3 RSH	4,189	942.720	67,297	71,486	6%	44.317%	4,189	67,700	71,889
G-41 SL	1,045	409.946	29,264	30,310	3%	19.271%	1,045	29,440	30,485
G-51 SH	670	26.266	1,875	2,545	26%	1.235%	670	1,886	2,556
G-42 ML	1,566	504.747	36,032	37,598	4%	23.728%	1,566	36,248	37,813
G-52 MH	1,846	49.223	3,514	5,360	34%	2.314%	1,846	3,535	5,381
G-43 LL	587	95.816	6,840	7,427	8%	4.504%	587	6,881	7,468
G-53 LLL90	1,412	34.540	2,466	3,878	36%	1.624%	1,412	2,480	3,893
G-54 LLG90	382	57.448	4,101	4,483	9%	2.701%	382	4,126	4,507
TOTAL	11,806	2,294.712	151,855	163,661		100.000%	11,806	152,765	164,571

HLF	4,420	174	12,422	16,841
LLF	7,387	2,121	139,433	146,820
Total	11,806	2,295	151,855	163,661

Design Day from 2018-2019 COG	**164,571**
Design Day from Billing Calculation	163,661
Variance	910

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

CALCULATION OF NORMAL SALES VOLUMES

Actual Volumes

Total Core Sales Volumes(000's) MMBTU

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total	Monthly Baseload (Jul+Aug)/2	Daily Baseload
HLF	R-1 RNSH	5	7	9	10	9	8	6	6	4	3	3	4	73	3 385	0 109
LLF	R-3 RSH	319	689	1,132	1,127	939	780	467	217	144	115	120	161	6,212	129 864	4 189
LLF	G-41 SL	104	263	487	490	384	308	170	63	27	37	28	38	2,399	32 400	1 045
HLF	G-51 SH	26	36	47	47	43	38	35	32	21	21	22	25	394	20 777	0 670
LLF	G-42 ML	169	359	581	593	482	387	235	109	48	49	54	83	3,147	48 536	1 566
HLF	G-52 MH	74	88	108	109	99	88	76	80	58	56	57	74	968	57 235	1 846
LLF	G-43 LL	30	59	122	143	100	82	72	32	22	15	12	24	714	18 191	0 587
HLF	G-53 LLL90	52	59	74	94	73	67	67	59	44	43	47	60	739	43 783	1 412
HLF	G-54 LLL110	(1)	12	25	42	24	(1)	34	116	14	12	11	38	326	11 791	0 380
HLF	G-63 LLG110	0	0	21	63	37	0	0	0	0	0	0	0	122	0 036	0 001
	TOTAL	777	1,572	2,606	2,719	2,191	1,757	1,162	714	382	352	353	506	15,092	367 304	11 849
	HLF	156	202	284	366	286	200	218	293	141	136	139	201	2,622	137 007	4 462
	LLF	622	1,371	2,322	2,353	1,905	1,557	944	420	242	216	214	305	12,471	228 991	7 387

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

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
		30	31	31	28	31	30	31	30	31	31	30	31	365
HLF	R-1 RNSH	3	3	3	3	3	3	3	3	4	3	3	3	40
LLF	R-3 RSH	126	130	130	117	130	126	130	126	144	115	120	130	1,529
LLF	G-41 SL	31	32	32	29	32	31	32	31	27	37	28	32	381
HLF	G-51 SH	20	21	21	19	21	20	21	20	21	21	20	21	245
LLF	G-42 ML	47	49	49	44	49	47	49	47	48	49	47	49	571
HLF	G-52 MH	55	57	57	52	57	55	57	55	58	56	55	57	674
LLF	G-43 LL	18	18	18	16	18	18	18	18	22	15	12	18	214
HLF	G-53 LLL90	42	44	44	40	44	42	44	42	44	43	42	44	516
HLF	G-54 LLL110	(1)	12	12	11	12	(1)	12	11	14	12	11	12	139
HLF	G-63 LLG110	0	0	0	0	0	0	0	0	0	0	0	0	0
	TOTAL	372	397	397	359	397	371	397	384	413	383	369	397	4,325
	HLF	120	137	137	124	137	120	137	133	141	136	132	137	1,613
	LLF	222	229	229	207	229	222	229	222	242	216	207	229	2,696

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Schedule 22
Page 5 of 6

Heating Volumes (= Actual Volumes - Baseload)

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	R-1 RNSH	1	3	6	7	6	5	3	2	0	0	0	1	33
LLF	R-3 RSH	193	559	1,003	1,010	809	655	338	92	0	0	0	31	4,683
LLF	G-41 SL	73	231	454	460	352	277	138	31	0	0	0	6	2,017
HLF	G-51 SH	6	15	26	28	23	18	15	12	0	0	2	5	149
LLF	G-42 ML	122	310	532	549	433	340	186	62	0	0	7	34	2,575
HLF	G-52 MH	19	31	51	57	42	33	19	25	0	0	1	17	295
LLF	G-43 LL	12	41	104	127	82	64	54	14	0	0	0	6	499
HLF	G-53 LLL90	10	15	30	54	30	24	23	17	0	0	4	16	223
HLF	G-54 LLL110	0	0	13	32	12	0	22	105	0	0	0	26	187
HLF	G-63 LLG110	0	0	21	63	37	0	0	0	0	0	0	0	121
	TOTAL	406	1,175	2,209	2,360	1,794	1,385	765	330	(31)	(31)	(16)	109	10,768

	Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	36	65	147	242	149	80	81	161	0	0	7	64	1,008
LLF	400	1,142	2,093	2,146	1,676	1,335	715	199	0	0	7	76	9,775
Actual BDD	**472.5**	**982.5**	**1219.5**	**1028.5**	**858.0**	**730.5**	**339.0**	**83.0**	**33.0**	**14.0**	**38.5**	**136.5**	5935 5

Heat Factors

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total	AVG	AVG Peak
HLF	R-1 RNSH	0 0031	0 0033	0 0046	0 0066	0 0065	0 0063	0 0086	0 0286	0 0000	0 0000	0 0000	0 0044	0 0063	0 0060	0 0051
LLF	R-3 RSH	0 4085	0 5692	0 8221	0 9820	0 9427	0 8961	0 9957	1 1053	0 0000	0 0000	0 0000	0 2264	0 8961	0 5790	0 7701
LLF	G-41 SL	0 1538	0 2350	0 3724	0 4476	0 4099	0 3786	0 4063	0 3754	0 0000	0 0000	0 0000	0 0420	0 3786	0 2351	0 3329
HLF	G-51 SH	0 0117	0 0155	0 0215	0 0277	0 0263	0 0249	0 0430	0 1467	0 0000	0 0000	0 0422	0 0338	0 0249	0 0328	0 0213
LLF	G-42 ML	0 2579	0 3158	0 4363	0 5337	0 5047	0 4652	0 5501	0 7434	0 0000	0 0000	0 1809	0 2501	0 4652	0 3532	0 4189
HLF	G-52 MH	0 0392	0 0316	0 0417	0 0559	0 0492	0 0449	0 0557	0 2994	0 0000	0 0000	0 0338	0 1217	0 0449	0 0644	0 0438
LLF	G-43 LL	0 0263	0 0420	0 0854	0 1235	0 0958	0 0881	0 1580	0 1706	0 0000	0 0000	0 0000	0 0404	0 0881	0 0692	0 0768
HLF	G-53 LLL90	0 0213	0 0154	0 0247	0 0527	0 0345	0 0334	0 0674	0 2015	0 0000	0 0000	0 1092	0 1175	0 0334	0 0565	0 0303
HLF	G-54 LLL110	0 0000	0 0001	0 0110	0 0308	0 0140	0 0000	0 0646	1 2605	0 0000	0 0000	0 0000	0 1925	0 0000	0 1311	0 0093
HLF	G-63 LLG110	0 0000	0 0000	0 0169	0 0614	0 0435	0 0000	0 0003	0 0000	0 0000	0 0000	0 0000	0 0001	0 0000	0 0102	0 0203
	TOTAL	0 8584	1 1963	1 8112	2 2947	2 0911	1 8965	2 2581	3 9700	-0 9394	-2 2143	-0 4130	0 8015		1 1343	1 6914

Liberty Utilities (EnergyNorth Natural Gas) Corp

Calculation of Capacity Allocators
Docket No DE 98-124

Actual BillingDD	472.5	982.5	1,219.5	1,028.5	858.0	730.5	339.0	83.0	33.0	14.0	38.5	136.5	5935.5
Norm Billing DD	560.7	879.5	1134.3	1129.5	971.5	706.1	372.8	142.0	29.2	8.3	62.1	265.1	6261.0

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

		Nov-17	Dec-17	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-17	Aug-17	Sep-17	Oct-17	Total
HLF	R-1 RNSH	5	6	9	10	10	8	7	7	4	3	3	5	76
LLF	R-3 RSH	355	630	1,062	1,226	1,046	758	501	283	144	115	120	190	6,431
LLF	G-41 SL	118	239	455	535	431	299	184	85	27	37	28	44	2,480
HLF	G-51 SH	27	34	45	50	46	38	37	41	21	21	23	30	412
LLF	G-42 ML	192	326	543	647	539	375	254	153	48	49	58	115	3,298
HLF	G-52 MH	77	85	105	115	105	87	78	98	58	56	57	89	1,011
LLF	G-43 LL	32	55	115	156	111	80	77	42	22	15	12	29	746
HLF	G-53 LLL90	54	57	72	99	77	66	69	71	44	43	49	75	777
HLF	G-54 LLL110	(1)	12	24	45	25	(1)	36	190	14	12	11	63	431
HLF	G-63 LLG110	0	0	19	69	42	0	0	0	0	0	0	0	131
	TOTAL	853	1,449	2,451	2,950	2,428	1,711	1,239	948	386	365	343	609	15,733

HLF	162	195	274	389	306	197	226	408	141	136	144	262	2,839
LLF	696	1,251	2,176	2,564	2,127	1,512	1,016	562	242	216	218	377	12,956

Docket No. DG 22-041
Exhibit 1

Docket No. DG 22-___
Attachment ELM-1

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2018 - 2019 Winter Cost of Gas Filing
Fixed Price Option

Schedule 23
Page 1 of 1

		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	$ 943.37	$ 926 93	$ 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	$ 679.85	$ 672 22	$ 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	$ 816.25	$ 916.09	$ (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	$ 790.65	$ 760 55	$ 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	$ 128,046	$0.5553	$0.5758	$ 821.32	$ 840.44	$ (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	$ 552,331	$0.8597	$0.8220	$ 1,115.55	$ 1,080.46	$ 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	$0.8925	$0.9425	$ 1,142.96	$ 1,189 55	$ (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	$ 518,882	$1.2951	$1.1342	$ 1,526.01	$ 1,376.01	$ 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	$ 262,714	$1.2664	$1.1656	$ 1,509.79	$ 1,415 80	$ 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	$1.2043	$1.1746	$ 1,433.09	$ 1,405.40	$ 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	$ 260,827	$1.2835	$1.0888	$ 1,555.31	$ 1,373 85	$ 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	$0.9863	$0.9416	$ 1,250.80	$ 1,209.12	$ 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	$0.8420	$0.8029	$ 1,175.03	$ 1,138 58	$ 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	$ 156,704	$0.8126	$0.7309	$ 1,165.61	$ 1,089.44	$ 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	$0.6919	$0.7680	$ 743.03	$ 792.48	$ (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	$ 178,616	$0.9095	$1.1011	$ 857.72	$ 981 21	$ (123.49)	-12 59%	$0 9108	$1.1057	$ 2,736 57	$ 3,117.48	$ (380 92)	-12 22%
17	Nov 14 - Apr 15	15.1%	$0.0795	8,779,742	$ 697,989	$1.2425	$0.7321	$ 1,127.66	$ 948.07	$ 179.59	18 94%	$0.6312	$0.7403	$ 2,422.09	$ 2,635.27	$ (213.18)	-8.09%
18	Nov 15 - Apr 16	15.3%	$0.0200	4,941,157	$ 98,823	$0.7716	$0.7516	$ 869.15	$ 712.73	$ 156.42	21 95%						
19	Nov 16 - Apr 17	11.5%	$0.0106	5,419,967	$ 57,452	$0.7268	$0.7162	$ 827.14	$ 812 38	$ 14.76	1 82%						
20	Nov 17 - Apr 18	10.6%	$0.0200	5,298,900	$ 105,978	$0.6645	$0.6445	$ 878.70	$ 865 94	$ 12.76	1.47%						
21	Nov 18 - Apr 19					$0.7611	$0.7411	$ 984.83	$ 972.12	$ 12.71	1 31%						
22	Total									$ 734.45						$ 274.09	

Liberty Utilities (EnergyNorth Natural Gas) Corp.
Peak 2018 - 2019 Winter Cost of Gas Filing
Short-Term Debt Limitations

Schedule 24
Page 1 of 1

		For Purposes of Fuel Financing
Total Direct Gas Costs	$	61,003,856
Total Indirect Gas Costs		3,070,244
Total Gas Costs	$	64,074,101
% of Debt to Total Gas Costs		30%
Short Term Debt	$	19,222,230
		For Purposes Other Than Fuel Financing
12/31/2019 Projected Net Plant	**$**	**474,391,309**
% of Debt to Net Plant		20%
Short Term Debt	$	94,878,262

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

Company Allowance Calculation

	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-2017	Dec-2017	Jan-2018	Feb-2018	Mar-2018	Apr-2018	May-2018	Jun-2018	Total
Total Sendout- Therms	5,306,840	5,772,930	5,860,490	7,994,340	17,861,650	28,637,450	30,624,660	21,366,370	21,723,760	15,818,960	6,945,470	5,806,070	173,718,990
Total Throughput- Therms	5,477,505	5,417,274	5,774,031	5,961,899	9,536,108	19,770,779	30,048,336	27,009,800	21,555,424	20,558,307	12,636,576	6,839,328	170,585,367
Variance	(170,665)	355,656	86,459	2,032,441	8,325,542	8,866,671	576,324	(5,643,430)	168,336	(4,739,347)	(5,691,106)	(1,033,258)	3,133,623
Company Allowance													**1.80%**

Lost and Unaccounted For Gas ("LAUF") Calculation

	Jul-2017	Aug-2017	Sep-2017	Oct-2017	Nov-2017	Dec-2017	Jan-2018	Feb-2018	Mar-2018	Apr-2018	May-2018	Jun-2018	Total
Total Sendout- Therms	5,306,840	5,772,930	5,860,490	7,994,340	17,861,650	28,637,450	30,624,660	21,366,370	21,723,760	15,818,960	6,945,470	5,806,070	173,718,990
Total Throughput- Therms	5,477,505	5,417,274	5,774,031	5,961,899	9,536,108	19,770,779	30,048,336	27,009,800	21,555,424	20,558,307	12,636,576	6,839,328	170,585,367
Company Use	5,787	4,233	5,020	7,859	21,786	44,117	97,872	59,687	46,735	37,832	13,658	6,029	350,615
Variance	(176,452)	351,423	81,439	2,024,582	8,303,756	8,822,554	478,452	(5,703,117)	121,601	(4,777,179)	(5,704,764)	(1,039,287)	2,783,008
LAUF													**1.60%**

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

Fuel Inventory Revenue Requirement

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
1		**5 Quarter Avg**	**Q2 2017**	**Q3 2017**	**Q4 2017**	**Q1 2018**	**Q2 2018**
2	Gas Stored Underground	$ 2,620,073	$ 2,624,008	$ 3,950,391	$ 3,348,517	$ 836,781	$ 2,340,667
3	Fuel Stock - Propane	$ 1,069,605	$ 872,312	$ 906,758	$ 954,781	$ 1,318,235	$ 1,295,942
4	UG Storage - LNG	$ 66,153	$ 79,815	$ 87,853	$ 43,445	$ 54,602	$ 65,051
5		$ 3,755,832					
6	ROR	6.8%	Pre-Tax Rate of 6.29% & Statutory Tax Rate of 27.24%				
		$ 255,397					
7	Income Tax Gross-up	1.3744					
8	Revenue Requirement	$ 351,017					

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DG 18-137

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

2018/2019 Winter/Summer Cost of Gas Filing

Order Approving Cost of Gas Rates and Other Charges

O R D E R N O. 26,188

November 1, 2018

APPEARANCES: Michael J. Sheehan, Esq., for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities; the Office of the Consumer Advocate by D. Maurice Kreis, Esq., on behalf of residential ratepayers; Lynn Fabrizio, Esq., for the Staff of the Public Utilities Commission.

In this order, the Commission approves Liberty's proposed 2018/2019 winter and summer cost of gas rates. For residential customers, the initial rate for the winter period (November 1, 2018, through April 30, 2019) will be $0.7411 per therm and the fixed-price option rate will be $0.7611 per therm. The local delivery adjustment charge rate for residential customers will be $0.0660 per therm from November 1, 2018, through October 31, 2019. The initial cost of gas rate for residential customers during the summer period (May 1through October 31, 2019) will be $0.4445 per therm. For the six months beginning November 1, a typical residential customer will see an average monthly bill of about $159 compared to $151 for last winter, and for the six months beginning May 1, 2019, an average monthly bill of $40 compared to $39 in summer 2018.

I. PROCEDURAL HISTORY

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (Liberty or the Company) is a public utility that distributes natural gas to approximately 90,000 customers in southern and central New Hampshire and in the City of Berlin. On September 4, 2018, Liberty submitted a tariff filing for the 2018/2019 winter and summer periods that proposed adjustments to its cost of gas (COG) rates. The filing, which included direct testimony and supporting schedules, proposed changes to COG rates for firm sales customers, fixed winter COG rates under the fixed-price option (FPO), firm transportation COG rates, and local delivery adjustment charge (LDAC) rates.

On September 11, 2018, the Office of the Consumer Advocate (the OCA) notified the Commission of its participation on behalf of residential ratepayers pursuant to RSA 363:28. The Commission issued an Order of Notice on September 12, 2018. Commission Staff and the OCA conducted discovery and held a technical session with Liberty on October 8. There were no intervenors.

The Company filed a technical statement on October 5, 2018, followed by an amended technical statement on October 9, informing the Commission that "the low income portion of the energy efficiency budget was included in the residential program budget and was also included as an allocation between both residential and commercial & industrial (C&I) LDAC rates." Hearing Exhibit (Exh.) 3 at 1. The Company further stated that although the company has "followed the same process since the winter of 2014/2015, residential customers were only impacted during the winter of 2014/2015 due to the running balance of the over/under collection. Post winter 2014/2015 the additional low income costs included in the residential EE rate were substantially offset by the prior year over-collection." *Id.* Liberty noted the over-collected balance totaled $1,310,342, which was ultimately reflected within the overall LDAC rates rather than the COG rates. In its amended technical statement, Liberty proposed to use this overcollection to reduce the residential LDAC rate by $0.0163 per therm to a new proposed rate of $0.0673 per therm.

On October 30, the Company moved to reopen the record in order to update Exhibits 4, 6, 8, and 9. The Commission admitted the updated exhibits by Secretarial Letter on October 31. The updated exhibits correct an error in the RLIAP rate calculation. The correction reduced the proposed residential LDAC rate further to $0.0660 per therm, and lowered the C&I LDAC rate from $0.0772 per therm to $0.0757 per therm.

Liberty's filing and subsequent docket entries, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at http://www.puc.nh.gov/Regulatory/Docketbk/2018/18-137.html.

II. COST OF GAS ADJUSTMENT MECHANISM

The COG adjustment mechanism was implemented in 1974 during a time of rapidly changing prices as a way to pass on to consumers increases and decreases in energy supply costs quickly, without having to go through extended proceedings to change delivery rates. Supply costs make up approximately half of a residential heating customer's annual bill and include commodity prices (the cost of gas), the cost to transport the gas over the pipelines, and storage costs. Liberty has little control over the price of natural gas, which is an unregulated commodity. Similarly, it has little price control over pipeline transportation rates, which are set by the Federal Energy Regulatory Commission. The COG adjustment mechanism allows the Company to pass fuel supply costs on to its customers directly and efficiently without mark-up or profit. COG rates are initially set using projected costs and sales for the upcoming winter and summer periods. Through the COG adjustment mechanism, the Company may adjust its COG rates monthly to take into account changes in the natural gas market based on actual costs to date and projected costs for the remainder of the period.

In COG proceedings, the Commission also sets the LDAC rates that allow for recovery of expenses the Commission has approved in prior dockets through a per therm surcharge to be determined and implemented in the COG proceeding. In this proceeding, those expenses include costs associated with Liberty's low-income and energy efficiency programs, an environmental surcharge for manufactured gas plant remediation, and the energy efficiency resource standard lost revenue adjustment mechanism (LRAM). The LRAM is included in the LDAC in accordance with *Energy Efficiency Resource Standard,* Order No. 25,932 (August 2, 2016), which approved the implementation of a mechanism to recover lost revenue due to the installation of energy efficiency measures.

III. POSITIONS OF THE PARTIES AND STAFF

A. Liberty

In its initial filing of September 4, Liberty proposed several rates for approval, including: winter and summer COG rates for various rate classes; annual LDAC rates for various rate classes; a fixed price option (FPO) COG rate for residential customers; and a firm transportation COG rate. Exh. 1 at 47-49, 52.

At the October 22 hearing, Liberty entered several updated exhibits primarily affecting the LDAC. The first was an updated calculation of the Rate Case Expense & Recoupment Rate (Recoupment Rate) portion of the LDAC. Exh. 5. The updated calculation indicated that the Company believes the new Recoupment Rate should decrease from the filed rate of $0.0105 per therm (Exh. 1 at 54) to the new rate of $0.0079 per therm. Liberty also entered, as Exhibit 6, an updated calculation for the Residential Low Income Assistance Program (RLIAP). The calculation added a "test year adjustment to Base Rates" of $1,820,418 to the recovery amount but did not reduce the "First Block" or "Last Block" R-3 Delivery Charge which decreased from the filed amount of $0.5631 to the updated amount of $0.5502. Exh. 7 and Updated Exh. 8.[1] The Company included an updated Energy Efficiency Charge (EEC) of $0.0287 (Updated Exh. 4) down from the filed EEC of $0.0450 for residential customers,[2] but included no further information concerning the decrease. On October 30, 2018, Liberty filed an Updated Exh. 6, which corrected the RLIAP rate calculation, along with revised schedules affected by the correction. (Updated Exh. 4, 8, and 9).

As revised, Liberty's proposed winter COG per therm rates for the various rate classes are: $0.7411 for residential, with $0.7611 for the fixed price option; $0.7403 for commercial and industrial (C&I) high winter use; and $0.7456 for C&I low winter use. Updated Exh. 8. Liberty proposed initial summer COG per therm rates of $0.4445 for residential, $0.4417 for C&I high winter use, and $0.4506 for C&I low winter use customers. *Id*. The Company also proposed an LDAC rate of $0.0660 per therm for residential customers from November 1, 2018, through October 31, 2019, and $0.0757 per therm for C&I customers for the same period. *Id*.

The following tables include the expected total bill impact based on the prior winter's and summer's average use of each customer class. Updated Exh. 9.

---

[1] The updated RLIAP rate calculation for the R-3 first block base rate (Exhibit 6, lines 2 and 10) is $0.5631 per therm, whereas the R-3 first block base rate approved in DG 17-048 and in Updated Exhibit 8 (Residential Heating – R-3) is $0.5502 per therm. Correcting the error reduces the $2.4 million program costs by $50,000; that correction will be included in the RLIAP reconciliation and reflected in next year's RLIAP rate.

[2] By approving the reduced EE component of the LDAC, the Commission is making no judgment on issues raised in the 2018-2020 New Hampshire Statewide Energy Efficiency Plan Update, filed September 14, 2018, in Docket No. DE 17-136.

Winter 2018-2019 Projected Bill Impacts

Class	2017/2018 (Actual)	2018/2019 (Projected)	Percent Change
R-3 Residential Heating	$ 905	$ 953	5%
G-42 C&I High Winter Use	$17,859	$18,438	3%
G-52 C&I Low Winter Use	$12,250	$12,594	3%

Summer 2019 Projected Bill Impacts

Class	2018 (Actual)	2019 (Projected)	Percent Change
R-3 Residential Heating	$ 232	$ 241	4%
G-42 C&I High Winter Use	$3,324	$3,642	10%
G-52 C&I Low Winter Use	$5,119	$5,605	10%

A typical residential heating customer will see an average monthly bill of about $159 per month in winter 2018/2019 compared to $151 for winter 2017/2018, and an average monthly bill of $40 in the 2019 summer period compared to $39 in the 2018 summer period. *Id.*

The Company also proposed: (1) a supplier balancing charge of $0.19 per MMBtu of daily imbalances; (2) a transportation peaking service demand charge of $20.41 per MMBtu of peak maximum daily quantity; (3) a gas allowance factor of 1.8 percent; (4) a transportation capacity allocator; (5) short-term debt limits of $19,222,230 for fuel financing, and $94,878,262 for non-fuel financing for the November 1, 2018, through October 31, 2019 period.

B. Staff

At the hearing, Staff expressed support for approval of the 2018/2019 COG and LDAC rates as amended by the technical statement filed on October 9 and as revised by the exhibits presented at the October 22 hearing.

C. OCA

The OCA stated that the proposed rate changes reflected in the Company's filing and technical statement are just and reasonable, and recommended that those changes be approved. The OCA also noted that any effort on the Company's part to make its tariffs clearer and more comprehensible would be helpful.

IV. COMMISSION ANALYSIS

The Commission has broad statutory authority to set rates in addition to "powers inherent within its broad grant" of express authority. *See Appeal of Verizon New England, Inc.*, 153 N.H. 50, 64-65 (2005) (citations omitted). The Commission applies the "just and reasonable" ratemaking standard of RSA 374:2 and RSA 378:7 when setting COG rates. Based on our review of the record in this docket, we approve the proposed, revised 2018/2019 winter and 2019 summer COG rates presented in Updated Exhibits 4 and 9 as just and reasonable. We also approve Liberty's LDAC rates as presented in Updated Exhibit 4. Since actual costs and revenues are reconciled every year, any adjustments needed as a result of further inquiry into the matters addressed in this order, including the correction to the RLIAP calculation, can be made in Liberty's COG filing for 2019/2020.

Pursuant to *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH*, Order No. 24,963 (April 30, 2009), the approved non-FPO rates may be adjusted downward so far as needed and upward by no more than 25 percent, without further Commission action. *See also Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities,* Order No. 25,958 (October 26, 2016). By approving the corrected rates in Updated Exhibit 9 at the beginning of the period, the 25 percent upward limit has an appropriate starting point.

Based upon the foregoing, it is hereby

ORDERED, that Liberty's 2018/2019 winter period COG per therm rates effective for service rendered on or after November 1, 2018, and Liberty's 2019 summer season per therm rates effective May 1, 2019, are approved as set forth in this Order, as follows:

Customer Class	2018-2019 Winter COG	2018-2019 Winter Maximum COG	2018-2019 Winter FPO	2019 Summer COG	2019 Summer Maximum COG
Residential	$0.7411	$0.9264	$0.7611	$0.4445	$0.5556
C&I High Winter Use	$0.7403	$0.9254		$0.4417	$0.5521
C&I Low Winter Use	$0.7456	$0.9320		$0.4506	$0.5633

and it is

FURTHER ORDERED, that Liberty may, without further Commission action, adjust the COG rates based on the projected over- or under-collection for the period, the adjusted rate to be effective the first day of the month and not to exceed, cumulatively, a maximum rate of 25 percent above the approved rate with no limitation on reductions to the COG rates; and it is

FURTHER ORDERED, that Liberty shall provide the Commission with its monthly calculation of the projected over- or under-collection, along with the resulting revised COG rates for the subsequent month, not less than five business days prior to the first day of the subsequent month. Liberty shall include revised Calculation of the Firm Sales Cost of Gas Rate tariff pages and revised rate schedules under separate cover letter if Liberty elects to adjust COG rates, with revised tariff pages to be filed as required by N.H. Code Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that the over- or under-collection shall accrue interest at the prime rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates, the rate to be adjusted monthly; and it is

FURTHER ORDERED, that Liberty's proposed LDAC per therm rates for the period November 1, 2018, through October 31, 2019, effective for service rendered on or after November 1, 2018, are $0.0660 and $0.0757 for residential and C&I customers, respectively; and it is

FURTHER ORDERED, that Liberty's proposed firm transportation winter COG rate of $0.0005 per therm for the period November 1, 2018, through April 30, 2019, is approved; and it is

FURTHER ORDERED, that Liberty's proposed supplier balancing charge of $0.19 per MMBtu of daily imbalance volumes is approved; and it is

FURTHER ORDERED, that Liberty's proposed transportation peaking service demand charge of $20.41 per MMBtu of peak maximum daily quantity is approved; and it is

FURTHER ORDERED, that Liberty's company gas allowance factor of 1.8 percent is approved; and it is

FURTHER ORDERED, that Liberty's proposed transportation capacity allocators as filed in proposed First Revised Page 148, Superseding Original Page 148 are approved; and it is

FURTHER ORDERED, that Liberty's proposed short-term debt limits of $19,222,230 for fuel financing and $94,878,262 for non-fuel financing for the period November 1, 2018, through October 31, 2019, are approved; and it is

FURTHER ORDERED, that Liberty shall promptly file properly annotated tariff pages in compliance with this order no later than 15 days from the issuance date of this order, as required by N.H. Code Admin. Rules Puc 1603; and it is

FURTHER ORDERED, that Liberty shall file its proposed notice of rate change to customers with the Director of the Consumer Services and External Affairs Division, prior to delivery to its customers.

By order of the Public Utilities Commission of New Hampshire this first day of November, 2018.

Martin P. Honigberg Chairman	Kathryn M. Bailey Commissioner	Michael S. Giaimo Commissioner

Attested by:

Debra A. Howland
Executive Director

Docket No. DG 22-___
Attachment ELM-1

SERVICE LIST - EMAIL ADDRESSES - DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

Executive.Director@puc.nh.gov
al-azad.iqbal@puc.nh.gov
amanda.noonan@puc.nh.gov
anthony.leone@puc.nh.gov
catherine.mcnamara@libertyutilities.com
david.simek@libertyutilities.com
deborah.gilbertson@libertyutilities.com
donald.kreis@oca.nh.gov
jayson.laflamme@puc.nh.gov
karen.sinville@libertyutilities.com
lynn.fabrizio@puc.nh.gov
mary.casey@libertyutilities.com
maureen.karpf@libertyutilities.com
michael.sheehan@libertyutilities.com
ocalitigation@oca.nh.gov
paul.dexter@puc.nh.gov
pradip.chattopadhyay@oca.nh.gov
steve.frink@puc.nh.gov
steven.mullen@libertyutilities.com

Docket #: 18-137-1 Printed: November 01, 2018

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:**

DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

Liberty Utilities

EXHIBIT
#12
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

DIRECT TESTIMONY

OF

DAVID B. SIMEK

April 28, 2017

THIS PAGE INTENTIONALLY LEFT BLANK

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name and business address.

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

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

A. I am a Lead Utility Analyst for Liberty Utilities Service Corp. ("Liberty") which provides service to Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth" or the "Company"). I am responsible for providing rate-related services for the Company.

Q. Please describe your educational background and training.

A. My educational background and qualifications are set forth in the prefiled joint testimony filed with Daniel S. Dane in support of EnergyNorth's request for a permanent increase on distribution rates.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to explain the Company's changes to its tariff as a result of this distribution rate case filing.

Q. Please describe the changes that were made.

A. Attachment DBS-TARIFF-1 contains a clean version of the proposed tariff while Attachment DBS-TARIFF-2 contains a redlined version. The following substantive changes were made to the tariff:

- the distribution rates were modified to incorporate the proposed rates contained in Attachment RATES-7 of the Simek-Therrien rate design testimony;
- the Towns of Pelham and Windham and the City of Keene were added to the Service Area of the tariff;
- a Revenue Decoupling Mechanism was added; and
- the Lost Revenue Adjustment Mechanism (LRAM) was deleted.

The last change is being made because upon implementation of the Revenue Decoupling Mechanism, there will no longer be a need for a LRAM, since the decoupling mechanism will account for changes in sales volume due to energy efficiency measures.

The Company has also made housekeeping changes to the tariff which include correcting spelling and grammatical errors, page re-numbering and formatting, header and footer formatting, and margin corrections.

Q. Have all changes made to the EnergyNorth tariff been redlined in Attachment DBS-TARIFF-2?

A. No, only substantive changes were redlined. In order to facilitate review, the housekeeping changes mentioned above were not redlined, because redlining such changes would produce a document that would have so many changes on each page, it would be unwieldy.

Q. Has the Company added the Keene Division to the EnergyNorth tariff?

A. Yes, the Keene Division has been added to the EnergyNorth tariff. All EnergyNorth distribution rates and charges including those contained in the local distribution adjustment clause (LDAC) will now be applicable to Keene customers. The Company is proposing that a separately calculated cost of gas rate continue to apply to Keene customers. Therefore, we have included a cost of gas provision for Keene customers in the tariff.

Q. Will Keene commercial customers still have the Fixed Priced Option to choose as their Winter Cost of Gas rate?

A. Yes. The Company is not proposing to change any part of Keene's current cost of gas procedures.

Q. What will happen to the existing Keene tariff?

A. The existing Keene tariff will no longer be valid once permanent rates become effective following a Commission order in this docket.

Q. Under the Delivery Terms and Conditions section of the EnergyNorth tariff is a section for a Supplier Service Agreement. Is a copy of the Agreement provided in the tariff?

A. Yes. A copy of the Supplier Service Agreement is included with this filing to rectify the current condition that although the current tariff includes references to the Supplier Service Agreement, a copy of that agreement was not previously included.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DE 15-137

GAS AND ELECTRIC UTILITIES

Energy Efficiency Resource Standard

Order Approving Settlement Agreement

O R D E R N O. 25,932

August 2, 2016

APPEARANCES: Matthew J. Fossum, Esq., for Public Service Company of New Hampshire d/b/a Eversource Energy; Susan S. Geiger, Esq., of Orr & Reno, P.A., for Northern Utilities, Inc., and Unitil Energy Systems, Inc.; Michael J. Sheehan, Esq., for Liberty Utilities Corp. (Granite State Electric) d/b/a Liberty Utilities, Inc., and for Liberty Utilities Corp. (EnergyNorth Natural Gas) d/b/a Liberty Utilities; Mark W. Dean, Esq., for New Hampshire Electric Cooperative; Dennis Labbe, Esq., of the New Hampshire Legal Assistance, for The Way Home; Ryan Clouthier for the New Hampshire Community Action Agencies' Southern New Hampshire Services, Inc., and the Belknap-Merrimack Counties, Inc.; Melissa Birchard, Esq., for Conservation Law Foundation NH; Laura Richardson for The Jordan Institute; Kate Epsen for the NH Sustainable Energy Association; Joseph Harrison for the Community Development Finance Association; Ellen Hawes for the Acadia Center; Tom Rooney for TRC Energy Services; Rep. Robert Backus, *pro se*; Meredith A. Hatfield, Esq., for the New Hampshire Office of Energy and Planning; Rebecca Ohler for the New Hampshire Department of Environmental Services; Donald M. Kreis, Esq., of the Office of the Consumer Advocate, on behalf of residential ratepayers; and Rorie E. Patterson, Esq., for Staff of the New Hampshire Public Utilities Commission.

In this order, the Commission approves a Settlement Agreement supported by all parties, extending the 2014-2016 Core program an additional year (through 2017) and establishing an Energy Efficiency Resource Standard (EERS). The EERS is a framework within which the Commission's energy efficiency programs shall be implemented, and the effective date for implementation is January 1, 2018. The framework consists of three-year planning periods and savings goals as well as a long-term goal of achieving all cost-effective energy efficiency. The electric and gas utilities will be administrators of the EERS programs to achieve specific statewide savings goals for the 2017 Core program and for the first three-year period of the EERS. Specific programs will be subject to Commission approval and such approval will require a demonstration that they are cost effective in subsequent proceedings before the Commission. This order also establishes a recovery mechanism to compensate the utilities for lost-revenue related to the EERS programs, and approves the performance incentives and the processes described in the Settlement Agreement for stakeholder involvement, evaluation, measurement and verification, and our oversight of the EERS programs.

I. BACKGROUND

On May 8, 2015, the Commission opened this proceeding to establish an Energy Efficiency Resource Standard. An EERS is a policy that sets specific targets or goals for energy savings, which utility companies serving New Hampshire ratepayers must meet. The Commission indicated that the EERS would include long- and short-term, energy-type-specific savings goals based on sales volumes for 2014. In addition, the Commission defined the scope of the proceeding to include consideration of funding requirements, program-cost recovery, lost-revenue recovery, performance-based incentives, program administration, evaluation, measurement, and verification (EM&V), and ways to transition from the existing energy efficiency paradigm to the EERS. The Order of Notice and subsequent docket filings, other than any information for which confidential treatment is requested of or granted by the Commission, are posted on the Commission's website at: http://puc.nh.gov/Regulatory/Docketbk/2015/15-137.html.

Until now, the Commission has implemented energy efficiency primarily through the Core programs, which has evolved in the last 15 years into a statewide system used by electric and natural gas utilities to deliver energy efficiency products and services to their customers or members.[1] Since 2001, the Systems Benefits Charge funding for Commission-regulated energy efficiency has remained at $0.0018 per kWh level. The programs have been designed to deliver as much energy efficiency savings as possible within the bounds of that funding, plus additional funding in recent years from the Regional Greenhouse Gas Initiative (RGGI) and the Independent System Operator-New England's (ISO-NE) Forward Capacity Market (FCM). Establishing an EERS presents an opportunity to set savings goals based on savings potential in addition to consideration of the funding level.

Several New Hampshire specific studies of energy efficiency potential have been conducted in the last decade, and all suggested that additional opportunities for cost-effective energy efficiency exist beyond those attained through the Core program.[2] In September 2014, the Governor's Office of Energy and Planning released a 10-year State Energy Strategy, which recognized the need for an EERS:

> In order to reduce energy costs by implementing more cost-effective efficiency programs, the State must set specific efficiency goals and metrics to measure progress. The Public Utilities Commission should open a proceeding that directs the utilities, in collaboration with other interested parties, to develop efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost effective efficiency over a reasonable time frame.

2014 New Hampshire State Energy Strategy, Executive Summary at ii.

On February 3, 2015, Commission Staff filed a report entitled "Energy Efficiency Resource Standard: A Straw Proposal for New Hampshire." Staff's report concluded a

---

[1] All of the New Hampshire electric and gas utilities except the New Hampshire Electric Cooperative (NHEC) have customers. NHEC supplies electricity to its members. Subsequent references herein to customers shall include NHEC members unless otherwise stated.

[2] *Additional Opportunities for Energy Efficiency in New Hampshire, Final Report* (January 2009), prepared for the Commission by GDS Associates Inc. (GDS), RLW Analytics, and Research Into Action; *Independent Study of Energy Policy Issues* (2011), prepared for the Commission by Vermont Energy Investment Corporation (VEIC); and *Increasing Energy Efficiency in New Hampshire: Realizing Our Potential* (November 2013), prepared by VEIC, GDS, and Jeffrey H. Taylor & Associates.

months-long endeavor to solicit and capture feedback on establishing an EERS. Staff's report included information about other jurisdictions, input from New Hampshire efficiency stakeholders, questions for additional consideration, and a series of preliminary recommendations.

On March 13, 2015, the Commission opened an investigative docket, IR 15-072, to receive written comments on several threshold recommendations within Staff's report. Written comments were submitted by numerous stakeholders including all of the electric and gas utilities (Joint Utilities),[3] the Office of the Consumer Advocate (OCA), the Governor's Office of Energy and Planning (OEP), and the Department of Environmental Services (DES). The comments reflected unanimous support for the Commission's establishment of an EERS at that time, under existing statutory authority, to advance a policy of energy efficiency as a least-cost supply resource for customers of the Joint Utilities. Some support for an EERS, however, was qualified by requests to consider the universe of EERS issues, and to engage expert assistance at the time of its development. Based on those comments and the recommendations contained in Staff's Straw Proposal report, the Commission opened this proceeding to establish an EERS and to examine the issues related to a successful launch of this important and timely policy.

II. PROCEDURAL HISTORY

The Commission named the Joint Utilities as mandatory parties, and received appearances from each. In addition, the OCA notified the Commission of its participation by statutory right on behalf of residential ratepayers. RSA 363:28, II.

[3] Liberty Utilities Corp. (Granite State Electric) d/b/a Liberty Utilities (Liberty) and Liberty Utilities Corp. (EnergyNorth Natural Gas) d/b/a Liberty Utilities (jointly, Liberty); Unitil Energy Systems, Inc., and Northern Utilities, Inc. (jointly, UES); Public Service Company of New Hampshire d/b/a Eversource Energy (Eversource); and NHEC. Although the order refers to NHEC as one of the Joint Utilities, we recognize that our jurisdiction over NHEC is limited by law. RSA 362:2.

Petitions to intervene were filed by DES; OEP; Conservation Law Foundation (CLF); New Hampshire Community Action Agencies' Southern New Hampshire Services, Inc., and Belknap-Merrimack Counties, Inc.(CAA); The Jordan Institute (Jordan); The Way Home (TWH); New Hampshire Sustainable Energy Association (NHSEA); the New Hampshire Community Development Finance Authority (CDFA); the New England Clean Energy Council (NECEC); TRC Energy Services (TRC); the Acadia Center (Acadia); Representative Robert A. Backus, *pro se*; Henry Herndon, *pro se*; and MCR Performance Solutions, LLC (MCR). The Commission denied Mr. Herndon's and MCR's intervention since neither party has any "rights, duties, privileges, immunities or other substantial interests that may be affected by the proceeding," and both could participate without being made a party since they have access to docketed materials on the Commission's website and may make comments at hearing or in writing pursuant to N.H. Code of Admin. Rules Puc 202.06.

The Commission held a prehearing conference on June 3, 2015, and, afterwards, the parties met in a technical session to develop a proposed procedural schedule and determine other procedural requirements for managing the docket. On June 10, 2015, Staff filed a report of the technical session and a request, on behalf of the parties, for additional time to develop the procedural schedule, which the Commission approved. The Parties and Staff met again on June 29, 2015, to develop a procedural schedule, which included multiple technical sessions each focused on a specific topic or issue identified by the Commission in its Order. The well-attended technical sessions featured presentations from the Joint Utilities as well as New England regional experts. The presentations included information about how other New England states have structured and administered their EERS programs and the Joint Utilities' experience with those programs.

Following the technical sessions, NHSEA along with CLF, Jordan, and NECEC (collectively, the Sustainable Energy Group)[4], Staff, and the Joint Utilities filed EERS proposals supported by testimony. Also, TRC and Acadia filed comments at that time. After those filings, a period of discovery occurred, and responsive testimony was filed by the OCA, the Sustainable Energy Group, and the Joint Utilities. Also, the Acadia Center and TWH filed reply comments.

Settlement negotiations followed, and, on April 27, 2016, a Settlement Agreement was filed by Staff on behalf of all parties except Rep. Backus. A hearing on the Settlement Agreement took place on May 2, 2016. At that hearing, the Settling Parties spoke strongly in favor of approving the agreement, and Rep. Backus supported those positions.

III. ORIGINAL AND SETTLEMENT POSITIONS OF THE PARTIES

The full EERS proposals and comments covered topics studied by the parties in the technical sessions as well as others, including: program administration; savings targets; funding; cost recovery; recovery of lost revenue; performance incentives; stakeholder involvement; evaluation, measurement and verification (EM&V); regulatory process; and implementation date. The parties included energy efficiency stakeholders who have participated for years in the Commission's programs and represented a broad spectrum of interests. The filings unanimously supported the creation of an EERS and featured many commonalities. Differences between the parties' original positions related primarily to the recommended savings targets, lost-revenue recovery, and the implementation date. The Settlement Agreement resolved all issues as described below.

[4] The Nature Conservancy join in this filing but was not a party to this proceeding.

A. Guiding Principles

1. Staff

Staff described several principles that should guide the EERS development. According to Staff, the EERS should build on the Commission's existing energy efficiency policy and experience with the Core programs. The EERS should respond to the recommendations in the 10-year State Energy Strategy and should be consistent with State law and industry best practices. Also, the EERS should include challenging but achievable statewide savings targets that are consistent with targets in other jurisdictions and the targets suggested in New Hampshire specific studies.

2. Joint Utilities

The guiding principles recommended by the Joint Utilities included establishing savings targets with a long-term goal of all achievable cost-effective energy efficiency within the context of available, sustainable funding; using at least a three-year, short-term planning period; considering rate impacts on customers in setting short-term goals; focusing primarily on comprehensive electric and gas programs with secondary focus on fuel neutral programs; continuing joint coordination of programs by the electric and gas utilities; driving innovation in technology, outreach, and regulation to accelerate energy efficiency gains; leveraging the private financing market; and increasing public awareness of the benefits of energy efficiency. According to the Joint Utilities, those guiding principles are consistent with the Commission's existing energy efficiency policy, which supports the award-winning, innovative, Core programs that have had a significant, positive impact on utility customers across the state. The Joint Utilities' support the creation of an EERS, because they believe an EERS will also provide significant benefits for New Hampshire utility customers.

3. The Way Home

TWH supported the guiding principle espoused by the Joint Utilities that energy efficiency programs be available to all customers, including low-income residential customers. TWH defined low income as at or below 200 percent of the federal poverty guidelines.[5] According to TWH, approximately 20 percent of New Hampshire residents are considered low income by this standard.

B. Program Administration

1. Staff

Staff discussed the use of independent third-party administrators in other jurisdictions and noted the benefits of such a structure. Staff observed, however, that the Joint Utilities have effectively administered the Core programs. Consequently, Staff recommended that the Joint Utilities administer the EERS programs at this time.

2. Joint Utilities

The Joint Utilities recommend that they administer the EERS programs based on their years of successful experience as administrator of the Core programs and their commitment to energy efficiency's success. According to the Joint Utilities, they have the knowledge, infrastructure, and relationships in place to scale up and transition the Core programs quickly to EERS programs. In support, the Joint Utilities noted their deep understanding of customer usage, their established and widespread vendor networks, their access to expertise from other jurisdictions, and the findings of several studies that customers consider utilities as trusted advisors on energy efficiency. The Joint Utilities also provided recent examples of their ability to scale up Core programs quickly and effectively beyond planned program budgets.

---

[5] For a household of one, 200 percent of the federal poverty guidelines is $23,450 in annual income. For a household of two, low-income eligibility is capped at a total household annual income of $31,860.

3. Sustainable Energy Group

The Sustainable Energy Group opined that the Joint Utilities are capable of serving as administrator of the EERS programs. Nonetheless, the Sustainable Energy Group recommended that the Commission consider the benefits of transitioning over time some or all of program delivery to a non-utility statewide program administrator. Competitively bidding out the entire portfolio or individual pieces of the EERS may maximize private funding and deliver savings in a manner that allows for all potential administrators, utilities, and third parties alike, to offer comprehensive, least-cost savings. According to the Sustainable Energy Group, important conditions for successful administration include the right incentives, oversight, underlying procurement and resource acquisition policies, clarity of the purpose for pursuing efficiency, consistency of policy over time, and consensus among stakeholders.

4. TRC

TRC recommended programs that leverage consumer engagement efforts from multiple sources including the Joint Utilities and third-party administrators.

5. The Way Home

TWH supported the Joint Utilities' administration of EERS programs, at least in the short term. According to TWH, with appropriate performance incentives, rate structures, and program oversight in place, the Joint Utilities should have the incentive and initiative to continue implementing robust energy efficiency programs effectively, to the mutual benefit of ratepayers, shareholders, and the natural environment of the state.

6. Settlement Agreement

The Settlement Agreement provides for the Joint Utilities' administration of the EERS programs, at least for the first three years. In addition, the Settling Parties recommend that no changes to the Joint Utilities' administrative role may be proposed prior to January 1, 2020, or be effective prior to January 1, 2021.

C. Savings Targets and Planning Periods

1. Staff

Staff proposed two sets of statewide, three-year, short-term savings targets and ten-year, "notional" long-term targets, referred to as Plan A and Plan B. Staff's targets, as well as all other parties' target recommendations, were expressed as a percent of actual 2014 kilowatt-hour (kWh) or one million British thermal units (MMBtu) sales. Staff noted that its annual year-over-year targets for gas savings were lower than its annual year-over-year electric savings targets, because the gas utilities have reached a higher level of savings historically relative to 2014 actual MMBtu usage.

Staff's Plan A sets the initial short-term cumulative targets at 1.82 percent for electric savings and 2.14 percent for gas savings over a three-year period. Both of the Plan A short-term targets are higher than current Core savings targets but lower than Plan B levels. Plan B's initial three-year cumulative targets are 2.04 percent for electric and 2.39 percent for gas. Staff estimated that using Plan B's short-term savings targets would result in cumulative kWh savings of approximately 220 million kWh by the end of the first three-year period, and lifetime kWh savings of approximately 3.1 billion kWh.[6] Staff's ten-year long-term targets for Plan A were 9.74 percent for electric and 10.20 percent for gas. Staff's long-term targets for Plan B were 14.48 percent for electric and 13.96 percent for gas. Staff referred to its long-term target as a "guidepost" and recommended that it be refined during the first three-year period of the EERS.

[6] Based on average life of 14.3 years – *i.e.*, cumulative kWh savings of 220 million kWh x 14.3 years average life = lifetime kWh savings of 3.146 billion kWh.

Staff asserted that both Plan A and Plan B targets are consistent with the Commission's energy efficiency policies; the State's 10-Year Energy Strategy; RSA 378:37, as well as a recent change in the Least Cost Integrated Resource Planning (IRP) law; and RSA 378:38, which requires utilities to maximize the use of cost-effective energy efficiency. Staff also stated that it developed its proposed savings targets to meet the criteria for an EERS as established by the American Council for an Energy-Efficient Economy (ACEEE), including creating a framework that promotes market stability. Further, according to Staff, its savings target recommendations are comparable to savings targets in other New England states and numerous Midwestern states, as well as to the potential savings identified in New Hampshire specific studies conducted during the last decade. Describing them as reasonable and achievable, Staff recommended the Commission's adoption of Plan B savings targets.

2. Joint Utilities

Similar to Staff, the Joint Utilities recommended a framework that includes short-term planning periods of at least three years. According to the Joint Utilities, transitioning from the Core's two-year planning period to a three-year planning period will provide more stability and continuity in program delivery, which will assist customers and other stakeholders in planning and investment decisions. The Joint Utilities contended that three-year periods would allow flexibility to adjust specific savings targets in response to changes in market conditions and to New Hampshire specific information such as results from evaluation and technical potential studies. A three-year planning period is also consistent with the EERS planning periods used in neighboring states and with the ACEEE's definition of an EERS.

Under the Joint Utilities' framework, the Commission would set annual kWh and MMBtu sales reduction targets, customized for each utility to account for different market conditions and opportunities in different service territories and for different classes of customers. The Joint Utilities cautioned against setting targets based solely on aligning New Hampshire with neighboring jurisdictions. According to the Joint Utilities, savings targets should come from demonstrated savings potential in New Hampshire, although little weight should be given to prior studies, which are outdated at this point. The Joint Utilities recommended that savings goals should only apply to regulated fuels, but savings related to unregulated fuels should be identified and tracked so that associated benefits are captured and reported. The costs to achieve the savings targets should be fully funded and, in setting the targets, the Commission should be mindful of the impacts of such funding on customers. Citing the ACEEE, the Joint Utilities argued that the EERS long-term goal should be all achievable cost-effective energy efficiency.

3. Sustainable Energy Group

The Sustainable Energy Group recommended setting explicit quantitative short-term goals, preferably expressed as a cumulative goal over a three-year term as well as measured reductions in peak demand. Short-term targets, stated the Sustainable Energy Group, allow for greater flexibility and consideration of emerging and changing technology. Specifically, the Sustainable Energy Group recommended as reasonable and achievable, cumulative short-term goals of 3.1 percent for electric savings and 2.25 percent for gas energy savings for the 2017-2019 period.[7] The Sustainable Energy Group also recommended nominal interim annual targets of 0.8 percent, 1.0 percent, and 1.3 percent for electric savings and 0.7 percent, 0.75 percent, and

[7] The Sustainable Energy Group noted that their recommended targets are based on net savings (*i.e.*, not including "free rider" participants and including "spill over" participants) and do not include savings from updated codes and standards, self-direct customers, and before-the-meter projects. A "free rider" participant is one whose savings is counted in the program but who would have made the efficiency investment even in the absence of the program. A "spill over" participant is one who made efficiency investments but who did not participate in the program and was therefore not counted. Should gross or other savings be counted, the Group recommended that the Commission set even higher savings targets.

0.8 percent for gas savings. The Sustainable Energy Group described their recommended targets as well below actual achievement and near-term goals in most New England states.

According to the Sustainable Energy Group, longer-term goals may also be appropriate and are valuable, both as aspirational metrics and to express a commitment to efficiency in the future. The changing landscape of energy and efficiency, however, suggests that these may be best expressed in qualitative terms, such as all cost-effective energy efficiency. The Sustainable Energy Group opined that such a qualitative long-term goal can be quantified based on periodic revising of what is cost-effective given conditions at the time. A goal of all cost-effective energy efficiency, the Sustainable Energy Group stated, is consistent with New Hampshire's 10-year State Energy Strategy, RSA 378:37, and the Commission's objective of ensuring just and reasonable rates. In addition, to provide the confidence that businesses need to enter the efficiency market and invest for future growth, the Sustainable Energy Group recommended that long-term goals should not be used as a ceiling or an arbitrary maximum if and when greater investments in efficiency are justified. To achieve all cost-effective energy efficiency over the long term, the Sustainable Energy Group recommended mid-term annual goals of 2 percent and 1 percent, for electric and gas, respectively, by 2021.

For electric utilities, the Sustainable Energy Group also recommended a peak demand reduction target, because peak demand growth drives electricity prices by creating the need for additional generation, transmission, and distribution capacity requirements, and by driving up wholesale energy prices. According to the Sustainable Energy Group, that target should be set at a minimum of the expected peak demand reduction from a comprehensive efficiency portfolio designed to reach the electric savings target.

The Sustainable Energy Group opined that increasing energy efficiency targets can mean lower customer bills, improved customer choice, enhanced system reliability, and increased economic activity statewide. According to the Sustainable Energy Group, those objectives are consistent with New Hampshire's Electric Utility Restructuring law, RSA 374-F:3, X, prioritizing the reduction of market barriers to investments in energy efficiency, not reducing cost-effective customer conservation, and targeting cost-effective efficiency opportunities that may otherwise be lost due to market barriers. Energy efficiency resources are particularly critical, the Sustainable Energy Group argued, given the current regional landscape of retiring generation, decreased supply diversity, and the need to meet significant environmental goals. To meet increased savings goals, the Sustainable Energy Group recommended statewide delivery of some efficiency services, which can provide consistency in program offerings and brand recognition as well as economies of scale in terms of marketing, vendor management, and other administrative needs.

4. Acadia

Acadia provided information and recommendations concerning savings targets. All New England states, according to Acadia, far exceed existing New Hampshire savings goals. For example, compared to the Core electric savings goals for 2016 of 0.68 percent, Rhode Island's electric savings goal is 2.55 percent, and compared to the Core gas savings goal for 2016 of 0.62 percent, Rhode Island's gas savings goal is 1.05 percent.

Acadia recommended that savings targets be approved on three-year cycles. Specifically, Acadia recommended ramping up New Hampshire's savings goals during the first three years of the EERS to 2.5 percent cumulative electric savings and 1.25 percent cumulative gas savings.

5. TRC

TRC recommended aggressive energy savings mandates to drive increased investments in energy efficiency. TRC suggested long-term savings targets that will lead to all cost-effective energy efficiency as well as energy savings that are on par with other New England states. TRC also provided information about the energy efficiency markets in California, New York, and New Jersey, which it described as robust and mature. TRC suggested that the Commission look to those jurisdictions for best practices to launch an EERS effectively and efficiently.

6. The Way Home

TWH agreed with the Joint Utilities' recommendation to establish specific, short-term savings goals with an ultimate savings target of all achievable cost-effective energy efficiency. TWH similarly noted that such a long-term target is consistent with New Hampshire's energy policy, which recognizes efficiency as a first-priority, least-cost resource. TWH strongly recommended that energy efficiency services to low-income residential customers, such as the Core Home Energy Assistance (HEA) program, continue. According to TWH, without such services, efficiency is not available to all customers, and the goal of achieving all cost-effective energy efficiency is undermined.

TWH supported a three-year planning cycle and cumulative targets, along with annual implementation plans and annual interim nominal targets. TWH suggested that shorter-term targets should be quantified as electric kWh and gas MMBtu annual sales reductions based on demonstrated savings potential and should apply only to regulated fuels. Energy savings from unregulated fuels, according to TWH, should be counted towards quantifying the benefits of energy efficiency measures in the cost-benefit tests by which all programs are screened.

7. Settlement Agreement

The Settlement Agreement provides deadlines for the Joint Utilities' filing of a 2017 Core plan as well as the Settling Parties' expectations for that plan, including statewide savings goals of 0.60 percent for electric savings and 0.66 percent for gas savings, using 2014 delivered sales as the baseline figure. The Settlement Agreement also defines the savings targets for the first three-year period of the EERS, 2018-2020, and describes the collaborative process by which the plan for that period shall be developed within the proposed framework. The cumulative electric savings goal is 3.1 percent of delivered 2014 kWh sales, with interim annual savings goals of 0.80 percent, 1.0 percent, and 1.3 percent. The cumulative gas savings goal is 2.25 percent of delivered MMBtu 2014 sales, with interim annual savings goals of 0.70 percent, 0.75 percent, and 0.80 percent. The Settling parties agree that future goals will be determined in the planning processes related to the second and any subsequent three-year EERS periods, with the intent of attaining the goal of achieving all cost-effective energy efficiency.

D. Costs and Funding

1. Staff

Staff recommended that the utilities recover the just, reasonable, and prudent costs incurred in developing, promoting, and delivering the EERS programs. To the extent possible, Staff also recommended allocating program spending based on class-specific sales volumes, which is consistent with long-standing Commission policy.

For the first triennium, Staff recommended funding most of the utilities' cost recovery with increases to the System Benefits Charge (SBC) and the Local Distribution Adjustment Charge (LDAC). The remaining costs, according to Staff, would be covered by existing funding from RGGI and the ISO-NE FCM. Staff observed that, recently, federal funding has been available and used to support on-bill and third-party financing options for certain Core programs, but that funding is only available for a limited period of time and its future is uncertain.

To supplement public funding, Staff recommended exploring and developing private funding options, which could include loan portfolio sales and asset-backed securitization. According to Staff, private funding supplementation is necessary to achieve all cost-effective energy efficiency, but requires market growth, as well as stability and benefits from standardization of products, processes, and the availability of accurate risk and performance data.

Staff estimated the costs of Plan B for the first triennium, including the costs of lost revenues, performance incentives, several resources for an EERS advisory board, and inflation, as approximately $108 million for electric and $32 million for gas. To recover those amounts, the SBC would need to be increased from $0.0018 per kWh to rates within the range of $0.0022 to $0.0036 per kWh, and the energy efficiency portion of the LDAC would need to be increased from $0.0291 per therm to rates within the range of $0.0340 to $0.0450 per therm. Staff estimated the monthly bill impact of the SBC increase under Plan B for the first triennium on an average residential electric customer, with monthly usage of 700 kWh per month, as an increase of $0.25 to $1.27 per month. Staff estimated the monthly bill impact of Plan B on a General Service customer using 7,000 kWh per month as an increase of $2.53 to $ 12.70 per month. Staff's calculation of SBC bill impacts alone, did not attempt to estimate any of the additional customer savings resulting from the increased energy efficiency measures. Staff did not calculate monthly bill impacts of the LDAC increases associated with Plan B, because the LDAC is utility- and customer-class specific.

2. Joint Utilities

Like Staff, the Joint Utilities recommend funding the EERS with the SBC and LDAC. According to the Joint Utilities, customers are the most reliable and practical sources for funding energy efficiency programs. As the primary beneficiaries of the energy efficiency measures installed, utility customers are more likely to participate by partially funding the programs. Because the SBC and LDAC are variable rates (*i.e.*, applied on a per kWh and per therm basis) and are set according to consumption, using them to fund the EERS will impact customers according to their usage and send an enhanced price signal for using energy more efficiently, which is consistent with the goal of an EERS.

The Joint Utilities observed that the Commission has the authority to raise the SBC or the LDAC to levels it deems just and reasonable, and, because they are already the primary methods of funding the Core programs, changes to those rates can be readily accomplished. Also, funding the EERS primarily through the SBC and LDAC is consistent with how other jurisdictions have funded their EERS programs. In addition, the Joint Utilities opined that third-party financing alone is not as stable or reliable a source of funding as the SBC and LDAC, and will not support the goal of an EERS to significantly increase energy efficiency activity.

The Joint Utilities provided examples of bill impacts to a typical residential electric customer at the current rate and rates based on two increased funding levels. With no change to the SBC, there would be no change to customer bills. Estimated savings, based on 2014 delivery sales at current SBC rate, would be between 0.36 percent and 0.48 percent. With a 50 percent increase to the SBC, from $0.0018 per kWh to $0.0027 per kWh, estimated savings would be between 0.52 percent and 0.68 percent of 2014 delivery sales, and funding would increase by nearly $10 million, increasing a typical residential customer’s bill by $0.56 per month. If the

SBC were doubled to $0.0036 per kWh, estimated savings would be between 0.67 percent and 0.87 percent of 2014 delivery sales, and the increase would provide nearly $20 million of additional funding, increasing a typical residential customer's bill by $1.13 per month. The Joint Utilities did not recommend approval of any specific savings level but stated that, regardless of the level set by the Commission, a uniform rate per kWh should apply to all electric utilities. The Joint Utilities also did not estimate the costs or bill impact of changes to the LDAC.

3. Sustainable Energy Group

According to the Sustainable Energy Group, the existing level of funding for efficiency in New Hampshire is below the amount that is economically efficient, and current funding is insufficient to achieve the Group's recommended targets. In setting funding levels, the Sustainable Energy Group recommended that the Commission address three areas of cost: the recovery of program costs; a mechanism to recover efficiency-related lost revenues; and performance incentives.

The Sustainable Energy Group argued that the utilities or program administrators should be able to collect 100 percent of actual efficiency program costs prudently expended, with any associated carrying costs, in addition to its efficiency-related lost revenues and performance incentives. To the extent practicable, the Sustainable Energy Group recommended that, to eliminate cross-subsidization across customer classes, each customer class (*i.e.*, residential, commercial, and industrial) should contribute to program costs in proportion to spending on programs for the customer class. The Sustainable Energy Group noted that the one exception to linking cost recovery to program expenditures is the low-income program budgets, which should be allocated first, with the remaining budgets allocated proportionally to remaining customer classes.

The Sustainable Energy Group recommended that all ratepayers contribute to efficiency programs, because all customers benefit from them. In terms of how funding is collected, the Sustainable Energy Group recommended that, in order to protect customers and ensure that efficiency spending is generating benefits, efficiency costs should not be included in base rates. Amortizing program implementation costs over a short period of time, however, may be an option if the utilities are allowed to recover carrying costs. The Sustainable Energy Group estimated that by saving 3.1 percent of retail energy sales, New Hampshire ratepayers will save $45 million and thousands of jobs will be created.

The Sustainable Energy Group acknowledged that rate impacts will result from the implementation of efficiency programs regardless of the source of funding, because the utility's fixed costs will be collected over lower billing units. Nonetheless, cost-effective efficiency programs result in lower total bills for ratepayers even if per unit energy rates increase. According to the Sustainable Energy Group, bill impacts do not represent increased societal or ratepayer costs, but rather a shift in the allocation and recovery of sunk fixed costs among ratepayers. Despite those shifts, the Sustainable Energy Group contends that using public funds to invest in energy efficiency results in a more rational and efficient allocation of resources and increases total net economic benefits for the state. To the extent that the Commission considers rate impacts of efficiency funding, it should do so in the larger context of comparative costs for all resource acquisition and their impacts on ratepayers, including the risk of stranded costs and other large fixed capital costs that must be amortized through rates over multiple years, if not decades.

The Sustainable Energy Group recommended that the Commission view "buying" energy efficiency as akin to paying for any prudent acquisition of an energy resource. According to the

Sustainable Energy Group, energy efficiency is widely considered the lowest cost energy resource, meaning that a unit of energy saved through efficiency is less expensive than the total lifetime cost of a unit of energy from other resources such as traditional fossil fuel generation and renewable energy sources, when compared on a consistent and fair basis. This is true, the Sustainable Energy Group argued, even when no economic value is placed on the environmental, health, and economic impacts that are not currently monetized in our economy. In addition, not increasing energy efficiency at this time could disadvantage New Hampshire utility customers in terms of mandatory, socialized regional costs of transmission and distribution expansion due to peak demand. Because other states are investing more in efficiency and distributed generation, their share of the ISO-NE peak load is decreasing and, without more efficiency in New Hampshire, its ratepayers' share of load, and the associated costs, will be proportionately higher.

The Sustainable Energy Group opined that private funding is not a replacement for public funding, in part because numerous barriers exist, including uncertainty and lack of knowledge on the part of investors, the up-front investment required from the customer, and a relatively immature market for efficiency services. According to the Sustainable Energy Group, the barriers to increased private funding may be best addressed by focusing initially on ratepayer-funded energy efficiency to build the knowledge, understanding, trust, and infrastructure that can later support private funding.

4. Acadia

Acadia recommended that the Commission fund the EERS through increases to the SBC and the LDAC. According to Acadia, private financing should not be considered a standalone funding option, because it generally will not have substantial uptake in the absence of ratepayer-funded programs, and it will not capture all cost-effective energy efficiency.

Acadia provided information about the many benefits of increased energy efficiency investment that should be considered against the impacts of associated rate increases. For example, to illustrate that energy efficiency is cheaper than other supply resources, Acadia stated that New Hampshire spent $4.5 billion on fossil fuel imports, at an average cost of $0.14 per kWh, when the average cost of energy efficiency was $0.0226 per kWh. Citing a 2009 study to demonstrate benefits enjoyed by all ratepayers regardless of participation in efficiency programs, Acadia stated that increasing efficiency investments to a level needed to capture all cost-effective electric efficiency over 15 years, or $1.4 billion, would increase economic activity by $14 billion (in 2008 dollars). Likewise, increasing gas efficiency by $219 million over 15 years would increase state economic activity by $4.1 billion. In addition, according to Acadia, all ratepayers benefit from decreases in the cost of generation, because less demand means lower prices in the regional forward capacity market and lower wholesale electricity prices.

5. TRC

TRC described the SBC, LDAC, and other existing mechanisms used to fund energy efficiency in New Hampshire as a solid foundation for structuring an EERS market. TRC's recommendations for funding, however, focused on the proceeds from RGGI auctions, most of which are not available for efficiency by statute.

6. The Way Home

TWH urged the Commission to increase public funding to the extent needed to meet the EERS targets it sets and to maintain the existing percentage allocations of program resources among customer sectors pursuant to the Core plan. According to TWH, without a commensurate increase in funding to accompany more aggressive savings goals, existing programs are put at risk.

TWH described an increase in the SBC and LDAC as the easiest and most equitable means of increasing funding to support an EERS. TWH recommended that the Commission continue its Core practice of first allocating low-income program budgets and then allocating program budgets for remaining customers. In addition, TWH recommended that the Commission consider increasing the low-income allocation above the existing 15.5 percent if private funding of efficiency is expanded under an EERS. According to TWH, allocating more public funding to low-income efficiency measures is consistent with the statutory requirement to "target cost-effective opportunities that may otherwise be lost due to market barriers." RSA 374-F:3, X.

7. Settlement Agreement

To achieve the recommended targets for the 2017 Core extension and the first three-year period of the EERS, the Settling Parties recommend that the Commission increase the SBC and LDAC. Illustrations of the estimated costs of funding the recommended savings goals associated with those periods of time are shown in attachments to the Settlement Agreement. The Settling Parties agree that the costs to fund the EERS include the costs associated with, (1) an independent expert to assist in refining the framework, planning and implementation of the EERS; (2) an independent expert to assist with the oversight and execution of EM&V activities; and, (3) independent experts to conduct the EM&V activities of the individual programs.

In addition, the Settlement Agreement provides for an increase in the minimum low-income share of the overall energy efficiency budget from 15.5 percent to 17 percent. As proposed, the increase would take effect on January 1, 2017, and remain in effect through the first three-year period of the EERS. During that time, the Settling Parties will explore additional funding sources to augment ratepayer funding.

E. Recovery of Lost Revenues

1. Staff

According to Staff, a targeted lost revenue adjustment mechanism (LRAM) or decoupling may be used to compensate utilities for lost revenues associated with energy efficiency. LRAMs limit the recovery to sales revenue lost on account of energy efficiency activity, while decoupling permits the utility to recover the difference between its actual revenues and its authorized revenue requirement no matter the reason. With an LRAM, under certain conditions, a utility may actually earn more than its authorized revenue requirement. With decoupling, the utility would refund to customers any amount that exceeds its authorized revenue requirement. Decoupling also addresses the throughput incentive that traditional ratemaking creates (*i.e.*, higher sales equals higher revenues). Because of Commission policy requiring the consideration of decoupling only within the context of a rate case, Staff recommended the adoption of an LRAM for the initial three-year period, to be replaced thereafter by a decoupling mechanism.

Staff's LRAM included several adjustments: (1) an adjustment that would allow for the recovery of lost revenues through the LRAM only above a specific threshold level to reflect historical Core energy efficiency investment; (2) an adjustment that would reduce the lost revenues recovered through the LRAM by savings associated with the retirement of measures installed in the past; and, (3) for gas utilities only, a fuel-switching adjustment that would reduce the recovery of lost revenues through the LRAM by the amount of new gas revenues associated with program participants who convert from other fuels to high-efficiency natural gas for heating. Staff also recommended that the annual recovery of lost revenues through the LRAM be capped at 0.50 percent of sales revenue and that the costs associated with the LRAM be included in the benefit/cost test used to screen energy efficiency programs. For the first three-year period of the EERS, Staff estimated that its LRAM would increase the costs of energy efficiency by approximately $2 million for the electric utilities and $0 for the gas utilities. Staff recommended recovery of lost revenues determined by the LRAM through the SBC and LDAC.

2. Joint Utilities

The Joint Utilities[8] recommended that the EERS allow for recovery of lost distribution revenues associated with energy efficiency savings, because revenue for all components of service is reduced by implementing energy efficiency measures. That reduced revenue is a consequence of the way utility distribution rates are set, based on an approved revenue requirement, designed using assumptions of a set level of customers, demand, and consumption for each rate class, and collected, in part, through a volumetric charge. Also, between rate cases, there is no reconciliation of actual revenues to the approved revenue requirement. The Joint Utilities contended that the recovery of lost revenues would restore the assumed relationship between sales levels and revenue requirements used in setting rates through historic test year ratemaking. According to the Joint Utilities, costs increase between rate cases, and the loss of sales does not necessarily equate to a similar decrease in the fixed costs used to set rates. Therefore, without recovery of energy efficiency related lost revenues, the utility collects less than its approved revenue requirement.

The Joint Utilities proposed that each recover lost distribution revenues through a Lost Base Revenue Adjustment (LBR Adjustment). The Joint Utilities proposed a formula to calculate the LBR Adjustment for future periods:

[8] For the purpose of this section, references to the Joint Utilities do not include the NHEC. NHEC does not seek recovery of lost revenues, because lost revenue mechanisms primarily address revenue recovery issues associated with distribution rate regulatory processes that apply to investor-owned utilities. Because NHEC is a deregulated, member-owned rural electric cooperative, it is not subject to the same regulation as the other electric utilities.

Total Lost Revenues = Projected Cumulative Electric Savings x Utility's Distribution Rate

Lost Revenue Rate = Total Lost Revenues / Projected Kilowatt Hours

Under their proposal, the LBR Adjustment would be a factor in setting the SBC and LDAC, and lost base revenues would be reconciled annually, when the LBR Adjustment factor is set for the upcoming period. Because each utility's lost revenues may be different, each utility's SBC or LDAC may be different. The Joint Utilities opposed, and described as confiscatory, Staff's recommendations to cap or adjust lost revenues. The Joint Utilities also opposed Staff's recommendation to include lost revenues as a cost within the cost/benefit test for the purpose of screening efficiency programs.

The Joint Utilities contended that the SBC and LDAC are transparent, efficient mechanisms that can be readily implemented to recover lost revenues (as well as to fund the costs of the EERS programs). According to the Joint Utilities, the LBR Adjustment can be established without the need for a distribution rate case and would implement lost revenue recovery coincident with implementation of savings measures. In contrast, a mechanism such as decoupling would require a distribution rate case entailing a lengthy process that requires extensive resources from each utility, Commission Staff, and interested parties. Such a case, the Joint Utilities argued, would consider more than the revenue impacts of energy efficiency in determining the revenue requirement and appropriate rate mechanisms; all aspects of the revenue requirement would come into play, including issues associated with distribution capital investments, operating and maintenance costs, and rate of return. The Joint Utilities opposed implementing decoupling, contending that an LBR Adjustment leaves a utility in the financial position contemplated by its last rate case (*i.e.*, equal to where it would have been absent efficiency activities), no better or worse, and only a lost revenue recovery mechanism isolates the effect on utility revenue of efficiency.

3. Sustainable Energy Group

The Sustainable Energy Group recommended a mechanism to permit recovery of lost revenue resulting from lower energy sales due to efficiency. According to the Sustainable Energy Group, and contrary to the Staff, lost revenue is not a cost of efficiency programs, because lost revenues would have been collected from customers even in the absence of efficiency programs. Instead, recovery of lost revenue from efficiency is simply a shift in how those authorized revenues are recovered from ratepayers.

The Sustainable Energy Group described lost revenue recovery mechanisms as designed to quantify the lost net revenue that can be recovered by the utility. To develop accurate estimates of lost revenue, the Sustainable Energy Group argued that precise evaluation, measurement, and verification are required. Best practices include independent third-party review, frequent rate cases to avoid the "pancake effect" of lost revenue recovery costs accumulating over time, and combining lost revenue recovery with performance incentives sufficient to promote increased utility investment in energy efficiency. The Sustainable Energy Group also suggested that, with an LRAM, performance incentives can be focused solely on exemplary performance. In addition, the Sustainable Energy Group noted that an LRAM allows a utility's earnings to increase with increased sales and, consequently, it is possible for a utility with an LRAM to have sales in excess of the test year used to set rates (even with reductions from efficiency programs) and earn excess profit as well as collect lost revenues.

The Sustainable Energy Group contrasted an LRAM with decoupling, which seeks to remove the direct connection between sales and revenue, such that the utility's fixed costs are covered regardless of total energy sales. According to the Sustainable Energy Group, decoupling generally includes a price adjustment to "true up" revenues when sales are different than those forecasted in the rate setting process. The correction of variances should take place at least annually, the Sustainable Energy Group argued, and should accrue to the utility, or credit back to the ratepayers. With decoupling, throughput is fully decoupled from revenue, meaning it accounts for all sales fluctuations not just those related to energy efficiency. The Sustainable Energy Group noted that this could translate into benefits for customers in cases where sales increase.

In the Sustainable Energy Group's opinion, the symmetrical treatment of revenue requirement recovery using decoupling results in, along with other benefits, the potential for both customer surcharges and refunds, rather than just surcharges, and makes full decoupling preferable to an efficiency specific LRAM. Other benefits include simplifying future rate cases and reducing the volatility of utility revenues. Consequently, the Sustainable Energy Group recommended that the Commission consider moving towards full decoupling, even if LRAM is used as an interim step. Should an LRAM be implemented first, the Sustainable Energy Group opposed incorporating the cap and adjustments that Staff recommended, and the Sustainable Energy Group recommended that the LRAM be reconciled annually.

4. Acadia

Acadia recommended that the Commission establish decoupling for the Joint Utilities in their next rate cases. Under decoupling, customers would pay two charges: one for the energy they use; and the other for the costs of the distribution system used to deliver the energy. Distribution charges would be adjusted annually so that the utility does not collect more or less than it is allowed by the Commission. According to Acadia, decoupling complements performance incentives.

Acadia discussed Staff's recommendation of an LRAM for the initial three-year period, to be transitioned into decoupling. Acadia agreed with that approach but opposed Staff's retirement and fuel-switching adjustments. In addition, Acadia urged Staff to support decoupling in the next rate case for each utility.

5. The Way Home

TWH supported the Joint Utilities' general parameters for recovery of lost distribution revenue associated with higher levels of energy efficiency savings, and it supported the implementation of a lost revenue adjustment mechanism in the short term. TWH indicated it would take a position on Staff's recommendation to transition such a mechanism to decoupling, when a more comprehensive decoupling rate structure is proposed.

TWH agreed with the Sustainable Energy Group's (and the Joint Utilities') recommendation that lost net revenue recovery not be treated as a cost in the cost/benefit test used for efficiency programs. Doing so, TWH stated, might make it difficult to achieve energy efficiency savings comparable to neighboring states and could result in the low-income Home Energy Assistance program, and perhaps other efficiency programs, being mistakenly labeled as cost ineffective in the future.

TWH also agreed with the Sustainable Energy Group that the most equitable way of recovering lost revenue is through increases to the volumetric charges, not the fixed charges, on customer bills. According to TWH, increasing the fixed charges disproportionately harms low-income ratepayers least able to absorb them, and acts as a disincentive to customer conservation efforts and energy efficiency program participation.

6. Settlement Agreement

The Settling Parties recommend that the Commission implement an LRAM for effect January 1, 2017 and that the LRAM continue after implementation of the EERS. The LRAM will be designed and implemented consistent with the Joint Utilities' proposal, the details of which are summarized above. In addition, the Settlement Agreement requires total recovery through the LRAM to be capped at 110 percent of planned annual savings; savings to be adjusted to account for the actual month the measures are installed within the year of installation and for the results of EM&V studies.[9] The Settlement defines the rate used to calculate LRAM recovery (*i.e.*, the "Utility Distribution Rate" in the Joint Utilities' proposed formula) to be an average distribution rate excluding customer charges.

The Settling Parties recommend, for each utility's rate cases following the implementation of the LRAM, that the savings used to calculate the utility's lost revenue be reset to zero. They also recommend that in each utility's first rate case following the first three-year period of the EERS, the utility seek approval of a new decoupling mechanism as an alternative to the LRAM, and that the LRAM cease when the new mechanism is implemented.

F. Performance Incentives

1. Staff

Staff recommended including performance incentives (PI) in the EERS framework to incent the Joint Utilities' investment in energy efficiency. According to Staff, performance incentives place energy efficiency and supply-side investments on a relatively equal financial footing and enables utility shareholders to earn a comparable return on either investment. Staff also noted the vital role of PI in the success of the Core programs.

---

[9] The Settlement Agreement does not incorporate Staff's proposed threshold, retirement, and fuel-switching adjustments to the LRAM, or Staff's recommendation to include lost revenues as a cost for the purpose of determining the cost/benefit ratio of the 2017 Core and EERS programs.

Staff recommended 10 percent of annual budgets as an appropriate PI cap for both the electric and gas utilities. The 10 percent cap is the same as the existing Core PI cap for electric utilities, and it is 2 percent less than the existing 12 percent Core PI cap for gas utilities. Staff asserted that the PI cap for electric and gas utilities should be the same, because the Commission's energy efficiency programs are statewide. Staff further supported the reduction to the gas PI cap by considering it in relation to the PI caps in other New England states, which are all lower than 10 percent. To calculate PI, Staff recommended continuation of the existing (*i.e.*, Core program) cap on actual spending at 5 percent of budgeted spending. In addition, Staff recommended that the Commission review the PI level after the first triennium of the EERS, when it has data on the impact of the LRAM on the Joint Utilities' energy efficiency activities.

2. Joint Utilities

The Joint Utilities proposed that the Commission maintain the current Core PI mechanism and levels. Under their proposal, the Joint Utilities' performance would continue to be evaluated against both the achievement of the defined savings and the cost-effectiveness targets. The methodology would be based on actual program expenditures with threshold and maximum performance payout levels. The Joint Utilities contend that the existing mechanism is easy for stakeholders to understand, effectively tracks performance, and appropriately focuses on the primary factors that are most pertinent to rewarding performance. In response to the Order of Notice, the Joint Utilities opposed incorporating penalties into the EERS framework, contending that the failure to earn PI constitutes sufficient financial detriment.

3. Sustainable Energy Group

The Sustainable Energy Group recommended that the EERS provide performance incentives to allow the Joint Utilities a reasonable incentive to pursue exemplary performance and to make efficiency investments attractive relative to other available investment opportunities. The design of the incentive mechanism, the Sustainable Energy Group stated, should ensure that ratepayers are protected from providing excessive earnings levels beyond those necessary to create that incentive and equal footing. PI should be commensurate with the lower risk of investing in efficiency as compared to supply-side investments, and to the extent existing PI levels include compensation for lost revenues, they should be reduced.

The Sustainable Energy Group discussed several PI models used in other jurisdictions and noted that New Hampshire already uses one model for the Core programs, a performance target incentive. Regardless of the model used in the EERS, it should include clearly articulated earnings and/or penalties, based on tangible, measurable performance that is under some control of the utility or program administrator. Also, the Sustainable Energy Group recommended that the performance incentive metrics be defined in a way that achieves efficiency policy objectives and guards against perverse incentives that could lead to undesirable policy outcomes. The Sustainable Energy Group noted that incentive designs where multiple parameters can be rewarded or penalized, are one way to protect against perverse effects.

4. Acadia

Acadia described PI as essential to maximizing investment in efficiency and demand-side resources. Acadia linked decoupling with PI, suggesting that decoupling enhances the effect of PI. Acadia opposed the PI levels recommended by Staff, contending that if a lost revenue recovery mechanism is approved for the EERS, PI should be more in line with neighboring states, or between 2 percent and 8 percent.

5. The Way Home

TWH supported providing the opportunity to the Joint Utilities (or other program administrator) to earn performance incentives when the Core programs transition to an EERS, because the incorporation of a reasonable PI is consistent with the policy of treating energy efficiency as a supply resource. TWH suggested, however, that if a lost revenue recovery mechanism is implemented, the Commission may want to consider reducing the current Core levels of PI, because such a mechanism shifts risk away from the utility to the ratepayer by guaranteeing the recovery of certain revenues.

6. Settlement Agreement

The Settlement Agreement recommends PI for the Joint Utilities at a target level of 5.5 percent and a maximum level of 6.875 percent of spending. Those PI levels should be effective when the LRAM is implemented, or January 1, 2017, and should remain unchanged at least through the first three-year period of the EERS. In addition, prior to the filing of the first EERS plan, the Settling Parties would review the existing PI formula and consider the way it values achievements of low-income programs. The Settling Parties agree that any recommendations for modifications to the PI formula may be included in that filing or proposed during the Commission's review of that filing.

G. Stakeholder Involvement

1. Staff

Staff recommended the creation of a permanent EERS Advisory Council made up of a broad group of stakeholders representing a variety of interests. Staff asserted that other jurisdictions use stakeholder groups to develop consensus and energy efficiency policy recommendations. According to Staff, the Advisory Council should include representatives from the utilities, the Commission and DES, the OCA, environmental groups, customers, energy efficiency program providers, and consultants. Staff recommended that the Commission designate the existing Energy Efficiency and Sustainable Energy (EESE) Board as the Advisory Council and authorize the recovery of funds through the SBC and LDAC for its administrative and technical support. Specifically, Staff recommended the use of an independent consultant to facilitate the Advisory Council's work and expert consultants as necessary. Staff envisioned the Advisory Council's work as including annual reports on energy efficiency achievements, coordination of studies, and development of a Technical Resource Manual (TRM). The TRM, according to Staff, would include New Hampshire specific EM&V protocols and reporting forms.

2. Joint Utilities

The Joint Utilities recognized the wide range of stakeholders who work with them to plan, deliver, and evaluate the Core programs. Stakeholders include retailers, manufacturers, equipment distributors, contractors, builders, architects, engineers, trade associations, non-profit organizations, policy makers, program evaluation vendors, and customers. According to the Joint Utilities, the stakeholders' contributions are essential to the success of the programs. Under an EERS, the Joint Utilities, like Staff, recommended that the EESE Board function as an energy efficiency stakeholder board. The Joint Utilities view the roles, responsibilities, and membership of the EESE Board as very similar to the EERS stakeholder boards in other states. EESE Board membership includes energy efficiency and sustainable energy stakeholders, state policy makers, representatives of the business community, and utility program administrators.

Similar to Staff, the Joint Utilities recommended additional resources for the EESE Board in its new role as EERS advisor. Specifically, the Joint Utilities suggested the dedication and funding of an administrative employee and the engagement of specialized organizations such as Northeast Energy Efficiency Partnerships (NEEP) and Regulatory Assistance Project (RAP).

3. Sustainable Energy Group

To oversee and guide efforts to implement the requirements of an EERS, the Sustainable Energy Group also recommended an advisory body with sufficient resources and authority to ensure robust stakeholder involvement and to assist the Commission. According to the Sustainable Energy Group, Commission proceedings are too cumbersome to provide a forum where inclusive, informed discussions and decisions necessary to implement best practice energy efficiency programs can be conducted.

The Sustainable Energy Group recommended that the advisory body's membership include a wide range of stakeholders to ensure a balance of interests in efficiency oversight. Stakeholders should include all customer classes (individually represented), state environmental policy staff, Commission staff, consumer protection agencies, advocacy groups in the energy and environmental fields, and the energy efficiency industry. According to the Sustainable Energy Group, the Joint Utilities should be active participants in the advisory body but should not have voting privileges.

The Sustainable Energy Group noted that the EESE Board includes some features important to a robust advisory body (*e.g.*, diverse membership), but it currently has little authority and no staff or funding. To be effective, the EESE Board will need guidance from experts in energy efficiency planning, evaluation, program design, and implementation. In addition, because the members will likely have full-time jobs and will only serve in a voluntary capacity, administrative and technical support is needed to manage and conduct the basic operations and analysis of the group. According to the Sustainable Energy Group, some jurisdictions contract for administrative support and expert resources.

4. Acadia

Consistent with the positions of others, Acadia also recommended that the Commission supplement the adjudicative process it uses for energy efficiency with a stakeholder council or board to oversee planning and administration of statewide programs through a collaborative process. Doing so ensures that the programs enjoy a broad base of support and reduces the duration and complexity of the approval process at the Commission. Acadia stated that in other states in the Northeast, stakeholder boards may spend six months or more in a collaborative plan development process with the utilities before filing plans for approval. According to Acadia, using a stakeholder body to guide efficiency investment will also reinforce high standards for programs, because the stakeholders are end users. Acadia also recommended that the advisory body have access to expert resources to balance the utilities' access to information and expertise. The EESE Board, Acadia stated, could be transitioned into an advisory body role if adequate funding is made available for such resources.

5. The Way Home

TWH echoed the recommendation of others that the EESE Board be used as an advisor to the Commission in its implementation of an EERS. TWH also observed the EESE Board's limited statutory authority and need for resources, but suggested that those limitations may be overcome by the Commission specifically designating the EESE Board's role in its order approving the EERS.

6. Settlement Agreement

The Settlement Agreement specifically provides opportunities for the EESE Board to actively participate in the development of the EERS programs within the proposed EERS framework, and in the Commission-supervised EM&V activities under the EERS. The Settlement Agreement also recommends EESE Board access to the independent planning and EM&V oversight experts.

H. Evaluation, Measurement and Verification

1. Staff

Staff considers EM&V a vital part of a successful EERS program, for program transparency and credibility. Staff described evaluation as the performance of studies and activities aimed at determining the effects of an energy efficiency program or portfolio. Measurement and verification, according to Staff, constitutes data collection, monitoring, and analysis associated with the calculation of savings from individual projects. EM&V according to Staff, ensures that the Joint Utilities are actually meeting the savings targets and spending ratepayer funds in a just and reasonable manner, and that energy efficiency programs are cost effective. Currently, the Joint Utilities administer EM&V to monitor and manage the Core programs.

To enhance EM&V under an EERS framework, Staff recommended that funding be set aside for independent consultants and for the development of a New Hampshire technical resource manual. Staff noted recent efforts in New England to develop consistent protocols and reporting for EM&V, which could be adopted where feasible. In addition, Staff recommended that the EESE Board in its role as an EERS Advisory Council guide EM&V, and that the results of EM&V impact studies be used to update savings assumptions and program design.

2. Joint Utilities

The Joint Utilities described EM&V practices for the Core programs, which include stringent and transparent reporting regarding their achievement of planned savings, participation, and cost-effectiveness goals, verification of results, onsite inspections, independent third-party market assessments, program process and impact evaluations, and annual financial audits. According to the Joint Utilities, the existing practices hold them to high standards of accountability and verification, which includes several layers of quality control.

For an EERS with increased savings goals, the Joint Utilities, like Staff, recommended that the Commission hire an independent consultant to help guide energy efficiency evaluation activities. Accordingly, the consultant would create an implementation plan and review and adjust evaluation priorities. The Joint Utilities suggested that the consultant's review could include consideration of the Environmental Protection Agency's Clean Power Plan as well as the standardization of EM&V reporting forms.

The Joint Utilities proposed that they manage the evaluation activities under the Commission's oversight. In support of their proposal, the Joint Utilities cited their procurement and contract management capabilities, which allow them to act efficiently and cost effectively. Citing a recent example, the Joint Utilities contended that their existing relationships with EM&V consultants and colleague counterparts from among their affiliates in other states will help them coordinate evaluation activities and identify best practices, current challenges, and opportunities.

3. Sustainable Energy Group

The Sustainable Energy Group opined that the success of an EERS can only be measured by assessing the extent to which energy reduction targets are actually realized. The key concepts and requirements of EM&V, according to the Sustainable Energy Group, include rigor, transparency, and independent third-party verification, to ensure consistent and fair assessment of program performance. The Sustainable Energy Group recommended that the achievement of savings targets and earning of performance incentives be evaluated on the same basis for the sake of efficiency and fairness. In addition, the Commission and its advisory body should oversee EM&V services.

4. The Way Home

TWH generally concurred with the EM&V recommendations of other parties. In addition, TWH noted the one measurement consideration specific to low-income residential ratepayers, which is that low-income programs may fall below a benefit cost ratio of 1.0 under the Total Resource Cost test and still be approved by the Commission.

5. Settlement Agreement

The Settlement Agreement requires EM&V studies to be conducted by independent third parties retained and supervised by the Commission with the advice and participation of the Settling Parties and the EESE Board. If requested, an independent expert, separate from the independent planning expert required by the Settlement Agreement, would facilitate the Settling Parties' and the EESE Board's participation in, and provide oversight of, the EM&V study activities. One specific deliverable of the EM&V expert will be assisting with the development of a New Hampshire-specific technical resource manual by the end of the first EERS triennium.

I. Regulatory Process

1. Staff

Staff recommended leveraging the exiting Core mechanisms to transition to an EERS framework. According to Staff, the Joint Utilities, as administrators, would prepare the triennial

EERS plans in collaboration with stakeholders and the EESE Board as Advisory Council, for review and approval by the Commission. Staff also recommended annual reviews during the three-year EERS periods. Those reviews, according to Staff, should include updating savings assumptions based on the results of EM&V studies. In addition, Staff recommended continuing practices developed for the Core program, including the processes for budget transfers and carrying forward unspent funds.

2. Joint Utilities

The Joint Utilities proposed developing savings targets for the EERS through a comprehensive process that validates savings targets feasibility and provides a detailed plan for specific programs. Savings target development, however, would follow an annual determination by the Commission of the funding levels. According to the Joint Utilities, the Commission uses such a process currently to set the LDAC rate for gas utilities.

The Joint Utilities proposed that, each year of the EERS, they prepare and submit to the EESE Board a draft energy efficiency plan for its review before a final plan is filed with the Commission for approval. That process would allow collaboration between the EESE Board and the Joint Utilities in a non-adjudicative setting, which the Joint Utilities believe could result in a more efficient Commission proceeding. According to the Joint Utilities, the Commission's regulatory role of overseeing the state's energy efficiency programs would continue in its current form. The Commission would determine if the final plans submitted by the Joint Utilities are in the public interest, including the program budgets and program cost effectiveness. In addition, the Commission would continue to oversee ongoing reporting and implementation and results of the programs.

The Joint Utilities propose that each utility, except NHEC, file its own request for recovery of EERS-related lost revenues, which will vary by utility each year and that the Commission adjudicate the requests individually. According to the Joint Utilities, the LBR Adjustment process would be separate from the three-year planning process used to set savings targets and to establish specific programs to meet those goals.

3. The Way Home

TWH recommended regular review of the efficiency programs during the three-year EERS planning periods, perhaps quarterly as is currently done for the Core programs. TWH also recommended an annual planning process.

4. Settlement Agreement

The Settling Parties recommend that they work collaboratively to refine a draft plan for the first triennium of the EERS, which will be filed for Commission review and approval by September 1, 2017. An independent consultant would be hired by the Commission, with a budget not to exceed $95,000 annually, to assist in the development of the initial and subsequent EERS plans. The consultant would serve as a resource to the EESE Board and other stakeholders as requested and deemed appropriate by the Commission.

The Settlement Agreement requires the filing of annual updates during the three-year EERS plan periods, for Commission review and approval. The review process would be akin to the process currently used to review mid-period submissions in the Core dockets. Such annual update filings will serve as an opportunity to adjust programs and targets and address any other issues that may arise from changes or advancements, including evaluation results, state energy code changes, and federal standard improvements.

The Settlement Agreement and the Joint Utilities' proposal provide specific detail about the processes to be followed with regard to lost revenue recovery, including the annual setting of a rate for the next year and the reconciliation of the prior year's rate and revenue recovery. The Settlement Agreement also requires actual savings and costs to be audited by an independent third party.

J. Implementation Date

1. Staff

Staff recommended an EERS implementation date of January 1, 2017.

2. Joint Utilities

The Joint Utilities recommended that the EERS be implemented beginning January 1, 2018. According to the Joint Utilities, adequate time is needed for thorough program development and a more comprehensive stakeholder review process than is typically used for the Core programs. Under their proposal, the Joint Utilities would present a draft three-year plan to the EESE Board on April 1, 2017, and allow two months for EESE Board's review. Then, the Joint Utilities would file the final plan with the Commission by September 30, 2017, for approval by December 31, 2017. Also before implementation of the EERS, the Commission would determine the SBC and LDAC funding rates.

In the meantime, the Joint Utilities proposed to file, on or before September 30, 2016, an interim, one-year Core plan for 2017. Also by that date, the Joint Utilities would file testimony regarding the implementation of their LBR Adjustment.

3. Sustainable Energy Group

The Sustainable Energy Group did not specifically recommend an implementation date. In discussing savings targets, however, the Group referred to the first three-year period of the EERS as 2017-2019.

4. Settlement Agreement

The Settlement Agreement proposes the implementation of an EERS beginning January 1, 2018. During 2017, the Core programs will continue, and the Settling Parties, in collaboration with the EESE Board, will prepare for EERS implementation.

K. Beyond Implementation

1. Staff

Staff described energy efficiency programs and products that are available in other jurisdictions, but not New Hampshire. Staff suggested that some or all of those offerings could be used to enhance an EERS. According to Staff, the Joint Utilities could use the integrated resource planning process to identify new opportunities for energy efficiency. In addition, demand-side management and grid modernization tie well with energy efficiency programs.

2. Joint Utilities

The Joint Utilities described their vision for the future of the EERS and provided examples of expanded program services, new initiatives, and innovative implementation strategies. The examples included piloting emerging technologies, offering incentives for combined heat and power projects, and incorporating the use of midstream and upstream program delivery models, which allow for energy efficiency equipment incentives at the retailer and manufacturer level.

The Joint Utilities also discussed potential sources of funding for the EERS other than the SBC and LDAC, including the Commercial Property Assessed Clean Energy (C-PACE) program. According to the Utilities, C-PACE falls under third-party financing, specifically for commercial buildings, and allows building owners to finance cash-positive energy efficiency and renewable energy projects, tying the financing to the property through a voluntary, municipal special assessment/lien. The Joint Utilities argued that C-PACE could work in combination with the programs under an EERS.

3. Sustainable Energy Group

To ensure that the benefits of peak demand reduction are realized for all ratepayers, the Sustainable Energy Group recommended that the Commission consider establishing cost-effective peak shaving demand reduction programs.

4. TRC

TRC recommended that the EERS broaden the customer base that is reached by the existing efficiency programs and provide the opportunity for all contributors to program funding to receive program benefits. TRC recommended that the EERS include hybrid programs that effectively address both electricity and fuel savings, because they introduce building owners to deeper energy savings projects.

5. OCA

The OCA recommended that all residential ratepayers participate in a single, statewide customer engagement technology platform (CETP) akin to the platform being developed by Eversource and partially funded through the Core budget. According to the OCA, a CETP is a web-based, data-diagnostic tool that utilities can use in many ways including to educate customers about energy efficiency, target marketing efforts, institute customer behavioral programs, and offer customers online self-service options. The OCA contended that the outcome of using a CETP statewide would be uniform delivery and reduced costs of efficiency services; broader customer participation in efficiency; and greater energy savings for all customers. In addition, a CETP will be needed in the future should the Commission implement programs such as net metering and time-of-use pricing.

6. The Way Home

TWH recommended that the Commission consider quantifying, for the purpose of the cost/benefit test used for efficiency programs, additional non-energy benefits or societal benefits derived from low-income efficiency programs, which are not currently accounted for under that test. According to TWH, a 2008 New Zealand study confirmed benefits such as reduced hospitalizations, and lost days of work and school, and the states of Vermont and Ohio use adders in their cost-benefit tests to quantify non-energy benefits including greater comfort, improved health, enhanced productivity, and other societal benefits.

IV. COMMISSION ANALYSIS

A. Legal Authority

RSA 4-E:1 became effective on July 24, 2013, and spurred the opening of this docket. That statute required the Governor's Office of Energy and Planning (OEP) to prepare a 10-year energy strategy for the State. RSA 4-E:1. The Legislature required the state energy strategy to include "consideration of the extent to which demand-side measures including efficiency … can cost-effectively meet the state's energy needs, and proposals to increase the use of such demand resources to reduce energy costs and increase economic benefits to the state." RSA 4-E:1, II. As detailed in Section I above, OEP prepared the 2014 New Hampshire State Energy Strategy in response to that legislative mandate. The Energy Strategy final report recommended that the

Commission open a proceeding to establish "energy efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost-effective efficiency over a reasonable time frame." 2014 New Hampshire State Energy Strategy, Executive Summary at ii.

Although RSA 4-E:1 and the 2014 New Hampshire State Energy Strategy served as catalysts for this docket, the Commission has a long history of regulating the demand-side measures of the State's electric and gas utilities. The Commission has historically regulated demand-side measures, including energy efficiency programs, pursuant to its general authority under RSA 374:3 (general supervision of all public utilities) and RSA Chapter 378 (rates and charges). In 1988, pursuant to both its general authority and its authority under the New Hampshire Limited Electric Energy Producers Act, RSA Chapter 362-A, the Commission required that electric utilities engage in least cost integrated resource planning (LCIRP). In *Public Service Company of New Hampshire, et al.,* 73 NH PUC 117 (1988), the Commission required electric utilities to "file an integrated least cost resource plan in conjunction with an updated forecast of avoided costs in order that the commission may reasonably review each utility's planning process, resultant plans, and avoided cost forecast." *Id.* at 126.

Shortly thereafter in 1990, the Legislature enacted the LCIRP statute, RSA 378:37-39, and declared least cost integrated resource planning for electric utilities to be the energy policy of the state. As originally enacted, RSA 378:37 provided that:

> The general court declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; the protection of the safety and health of the citizens, the physical environment of the state, and the future supplies of nonrenewable resources; and consideration of the financial stability of the state's utilities.

RSA 378:37 (West 2009).

Although the LCIRP statute has always required our review of utility demand-side programs, including energy efficiency, the Legislature amended the LCIRP statute in 2014 to place a greater emphasis on evaluation of energy efficiency programs. *See* Laws of 2014 ch. 129; *compare* RSA 378:38, II (West 2009) *with* :38, II (West Supp. 2015). In the 2014 amendment, the Legislature declared it the energy policy of the state "to maximize the use of cost effective energy efficiency and other demand side resources." RSA 378:37 (West Supp. 2015). The 2014 amendment increased the emphasis on energy efficiency programs by providing that the Commission's evaluation of utility plans should be guided by certain energy policy priorities, energy efficiency being first and foremost among them. RSA 378:39 (West Supp. 2015).

In addition, the electric restructuring policy principles, enacted in 1996, guide the Commission in the exercise of its general authority over electric utilities. *See* RSA 374-F:3, X (restructured electric market required to "reduce market barriers to investments in energy efficiency and provide incentives for appropriate demand-side management and not reduce cost-effective customer conservation" and "utility sponsored energy efficiency programs should target cost-effective opportunities that may otherwise be lost due to market barriers"); RSA 374-F:4, VIII(e) (Commission authorized to approve a utility's inclusion in its distribution charge of the costs of energy efficiency "that are part of a strategy to minimize distribution costs"). Specifically, RSA 374-F:3, VI authorized the creation of a "nonbypassable and competitively neutral system benefits charge applied to the use of the distribution system" for the support of, among other things, energy efficiency programs.

The Commission has reviewed gas utility demand-side measures pursuant to its general authority since at least 1992. *See, e.g., EnergyNorth Natural Gas, Inc.*, 77 NH PUC 802 (1992);

Northern Utilities, Inc., 77 NH PUC 803 (1992); *see also Northern Utilities, Inc*., 78 NH PUC 310 (1993) (approving pilot DSM program); *EnergyNorth Natural Gas, Inc.,* 79 NH PUC 605 (1994) (same); *EnergyNorth Natural Gas, Inc. et al.,* Order No. 24,109 at 1 (December 31, 2002) (approving gas utility energy efficiency programs following gas industry restructuring). The 2014 amendment to the LCIRP statute has since made that statute's energy efficiency requirements applicable to gas utilities. *See* RSA 378:38.

While nothing prohibits electric utilities from funding energy efficiency programs through their distribution rates as approved by the Commission under its general rate making authority, *see* RSA 374-F:4, VIII(e), electric utilities fund energy efficiency measures primarily through the SBC, pursuant to the Commission's authority under RSA 374-F:3, VI. Gas utilities continue to fund energy efficiency programs primarily through the LDAC as approved by the Commission pursuant to the Commission's general supervisory and rate making authority. *See EnergyNorth Natural Gas, Inc., and Northern Utilities, Inc*., Order No. 24,109, at 9 (December 31, 2002). In addition, limited proceeds from the RGGI, pursuant to RSA 125-O:23, and the ISO-NE Forward Capacity Market, are used to fund energy efficiency. In recent years, the Commission has approved the use of third-party private financing options to fund energy efficiency measures. *See* Order No. 25,747 at 9 (describing third-party financing proposals approved by the order).

Electric and gas utility programs are currently reviewed jointly as part of the Core Energy Efficiency Program. *See Electric and Gas Utilities*, Order No. 25,747 (December 31, 2014) (approving 2015-2016 Core programs); *Electric and Gas Utilities,* Order No. 25,462 (February 1, 2013) (approving 2013-2014 Core programs); *Electric and Gas Utilities*, Order No. 25,189 (December 30, 2010) (approving the 2011-2012 Core programs and listing, at page 21, the Commission's energy efficiency orders from 2001 through 2009). As detailed in Section I, above, however, several studies have concluded that additional opportunities for cost-effective energy efficiency exist beyond those attained through the Core program. Accordingly, we opened this docket to consider ways to transition from the Core program to an EERS. The Commission's general supervisory and ratemaking authority, historic energy efficiency program management, and legislative policy pronouncements, provide an adequate legal framework for the creation and financing of the next generation of energy efficiency measures.

B. Settlement Agreement

Pursuant to RSA 541-A:31, V(a), informal disposition may be made of a contested case at any time prior to the entry of a final decision or order, by stipulation, agreed settlement, consent order, or default. We encourage parties to settle issues through negotiation and compromise because it is an opportunity for creative problem solving, allows the parties to reach a result in line with their expectations, and is often a better alternative to litigation. *Granite State Electric Co.*, Order No. 23,966 at 10 (May 8, 2002); *see* RSA 541-A:31, V(a) ("informal disposition may be made of any contested case … by stipulation [or] agreed settlement"). Even when all parties join a settlement, however, we must independently determine that the result comports with "applicable standards." *EnergyNorth Natural Gas, Inc. d/b/a National Grid NH,* Order No. 24,972 at 48 (May 29, 2009). We analyze settlements to ensure that a just and reasonable result has been reached. *Id.*; *see* N.H. Code Admin. Rules Puc 203.20(b) ("The commission shall approve a disposition of any contested case by stipulation [or] settlement … if it determines that the result is just and reasonable and serves the public interest.").

Based on the record, the terms of the Settlement Agreement appear to be consistent with applicable law, because they will reduce market barriers to investment in cost-effective energy efficiency investment, provide incentives for appropriate demand-side management, and not reduce cost-effective consumer conservation. *See Electric Utility Restructuring,* Order No. 23,574 (Nov. 1, 2000) at 10 (citing the requirements of RSA 374-F:3, X).

The record supports a finding that cost-effective energy efficiency is a lower cost resource than other energy supply.[10] In addition, over the past 14 years the Commission has used a cost effectiveness, or cost benefit, test for energy efficiency measures in the Core energy efficiency programs. The cost benefit test calculates the cost of acquiring and installing an energy efficiency measure, spread over the expected useful life of the measure, and compares that cost to the cost of the energy saved, or the energy supply avoided, over the expected useful life of the measure. Using the cost benefit test in the Core programs, the Commission has approved numerous Core energy efficiency measures where the cost of the measure is less than the cost of the avoided energy supply.

For avoided costs of supply, we rely on the *Avoided Energy Supply Costs in New England: 2015 Study* (March 27, 2015, revised April 3, 2015) prepared by TCR Group for the Avoided Energy Supply Component (AESC) Study Group (AESC 2015 study) and used in the Core programs to evaluate cost effectiveness.[11] The AESC 2015 study indicates that direct avoided retail electric costs are approximately \$0.11 per kWh on a 15-year levelized basis. *See* *2016 New Hampshire Statewide Core Energy Efficiency Plan,* Docket No. DE 14-216, Hearing Exhibit 5 at 20 (December 15, 2015). For the costs of energy efficiency, we use both the utilities' and the customers' costs. The Joint Utilities calculated the utilities' costs of energy efficiency to be \$0.030 per kWh saved over the life of the measure. *See* Exh. 3 Joint Utilities at

---

[10] *See* Exh. 2 Sustainable Energy Group at 5 and Attachment 1; Exh. 3 Joint Utilities at 32; and Exh. 5 Acadia Center at 1.
[11] The Commission takes administrative notice of this analytical tool used in the Core Docket, DE 14-216 pursuant to Puc 203.27 (a)(2) (notice of relevant portion of the record in other proceedings).

32. The customer costs are currently estimated in the Core programs as $0.02 per kWh saved over the life of the measure.[12] Based on the experience with the Core programs, even with the customer costs added to the utilities' costs of energy efficiency, the total costs of energy efficiency are less than the costs of supply. *See id.* at 22, 30, 35 and 40.

As discussed above, the Commission has consistently imposed a cost-effectiveness test before including energy efficiency measures in the Core Programs. Cost effectiveness is a statutory requirement for least cost planning. We will continue to require that all measures used to achieve an EERS meet cost-effectiveness tests. By ensuring that EERS measures are cost effective, we remain consistent with the Legislature's mandate that the Commission prioritize energy efficiency and demand-side supply resources in order to provide the lowest reasonable cost energy supply to customers, RSA 378:37 and :39, and with New Hampshire's Energy Policy, as well as the requirement to set just and reasonable rates, RSA 378:7.

The parties asserted that energy efficiency has a multitude of customer benefits, including lower utility bills now and in the future, improvements in comfort, health, and safety, more customer control and understanding of energy use, increased reliability of the grid and avoidance of new generation capacity, and job creation and reduced pollution. *See* Exh. 5 Acadia Center at 1; Exh. 2 Sustainable Energy Group, Attachment at 1; Exh. 3 Joint Utilities at 38 and 46; Exh. 4 Staff at 14; Exh. 8 Sustainable Energy Group at 8; and Exh. 11 The Way Home at 9. While those benefits have not yet been quantified by the Commission for New Hampshire, we will monitor the cost effectiveness of the energy efficiency measures installed under the EERS and will review the results of the EERS over time to determine its effect on customers.

---

[12] The estimated customer costs include kilowatt-hour savings for electric programs, and MMBtu savings – converted to kilowatt-hour-equivalent savings – for gas programs.

In addition to the cost effectiveness of the EERS measures, we must consider the impact on customers of funding the EERS through the SBC and LDAC. The Settlement quantifies the increases to the SBC for each electric utility. It also estimates the corresponding bill impacts for average users. The bill impact calculations do not take into account customer savings due to energy efficiency programs. The SBC and bill impact estimates are as follows.

- The SBC for Eversource will increase from the current rate per kWh of $0.00330 to $0.00383 in 2017, $0.00488 in 2018, $0.00631 in 2019, and $0.00850 in 2020. Exh. 1 at 22. The impact of those increases on an average residential customer using 625 kWh per month[13] will be $0.33 in 2017, $0.65 in 2018, $0.90 in 2019, and $1.37 in 2020. *Id*. The impact of those increases on an average General Service customer using 10,000 kWh per month will be $5.34 in 2017, $10.41 in 2018, $14.34 in 2019, and $21.88 in 2020. *Id*.
- The SBC for Liberty electric customers will increase from $0.00330 to $0.00381 in 2017, $0.00480 in 2018, $0.00615 in 2019, and $0.00825 in 2020. Exh. 1 at 23. The impact of those increases on an average residential customer using 625 kWh per month will be $0.32 in 2017, $0.61 in 2018, $0.85 in 2019, and $1.31 in 2020.[14] *Id*. The impact of those increases on an average Liberty General Service customer using 10,000 kWh per month will be $5.13 in 2017, $9.83 in 2018, $13.58 in 2019, and $20.94 in 2020. *Id*.
- The SBC for UES will increase from $0.00330 to $0.00384 in 2017, $0.00486 in 2018, $0.00626 in 2019, and $0.00841 in 2020. Exh. 1 at 24. The impact of those increases on an average residential customer using 625 kWh per month will be $0.34 in 2017, $0.64 in

---

[13] We recognize that the Settlement calculates bill impacts using 625 kWh per month for Residential customer usage and 10,000 kWh per month for General Service customer usage, and the Staff used different average usage to calculate the bill impacts in their proposal. Staff used 700 kWh per month for residential usage and 7,000 for commercial/industrial usage. *See* Exh. 4 Staff at 45-46. We note that the Joint Utilities used the same usage that we use in this order to calculate bill impacts. *See* Exh. 3 Joint Utilities Attachment 1, at 70.

[14] Settlement Electric Attachment A, revised page 7 of 10 (Bates page 23), *also* Liberty's response to Record Request 1 (July 27, 2016).

2018, $0.88 in 2019, and $1.34 in 2020. *Id*. The impact of those increases on an average UES General Service customer using 10,000 kWh per month will be $5.41 in 2017, $10.17 in 2018, $14.01 in 2019, and $21.51 in 2020. *Id*.

- The SBC for NHEC will increase slightly less than the SBC increases for the other electric utilities, because NHEC will not recover lost revenues. Specifically, NHEC's SBC will increase from $0.00330 to $0.00376 in 2017, $0.00459 in 2018, $0.00575 in 2019, and $0.00759 in 2020. Exh. 1 at 25. The impact of those increases on an average residential customer using 625 kWh per month will be $0.29 in 2017, $0.52 in 2018, $0.72 in 2019, and $1.15 in 2020. *Id*. The impact of those increases on an average NHEC General Service customer using 10,000 kWh per month will be $4.60 in 2017, $8.30 in 2018, $11.60 in 2019, and $18.40 in 2020. *Id*.

The Settlement also quantifies the increases to the LDAC by utility as follows.

- The LDAC for Liberty gas will increase from $0.0585 to $0.0643 in 2017, $0.0724 in 2018, $0.0817 in 2019, and $0.0907 in 2020. Exh. 1 at 27. The monthly impact of those increases on an average residential customer using 783 therms per month will be $0.38 for 2017, $0.53 for 2018, $0.60 for 2019, and $0.59 for 2020. *Id*. For an average Commercial and Industrial customer using 8,773 therms, the monthly impact will be $2.22 for 2017, $2.98 for 2018, $3.42 for 2019, and $3.30 for 2020. *Id*.
- The LDAC for Northern will increase from $0.0297 to $0.0347 in 2017, $0.0405 in 2018, $0.0466 in 2019, and $0.0576 in 2020. *Id*. The monthly impact of those increases on an average residential customer using 783 therms per month will be $0.33 for 2017, $0.38 for 2018, $0.40 for 2019, and $0.72 for 2020. *Id*. For an average Commercial and

Industrial customer using 8,773 therms, the monthly impact will be $0.96 for 2017, $1.13 for 2018, $1.18 for 2019, and $2.12 for 2020. *Id*.

In approving the EERS as proposed, we are mindful of and do not take lightly the short-term increases in customer rates. When considered in the context of the benefits of increased energy efficiency, participating electric and gas customers will spend less on energy usage and, in the long run, all customers will spend less on energy supply. As suggested by the parties, other benefits could result from increased energy efficiency, but our decision does not rest on that possibility. Instead, our approval of the Settlement Agreement's rate increases is based on a record developed over the course of a year following a year-long investigation by the Staff of EERS potential, both of which were contributed to by numerous experienced and knowledgeable stakeholders and experts. Also, we note in making our decision, the support of the Settlement Agreement by the diverse parties, including the Consumer Advocate, The Way Home, and others. The record and support by parties with diverse interests, along with the customer-protection measures built into the EERS framework, as described below, give us confidence that any short-term rate impacts will be outweighed by the benefits to customers, the grid, and the New Hampshire economy. In addition, we note that our approval of the Settlement Agreement is only the beginning of the EERS; the Commission will oversee the development of the specific EERS programs and their subsequent implementation to ensure that the energy efficiency programs funded by customers are indeed the least-cost resource available to the Joint Utilities' customers.

1. Program Administration

The Joint Utilities have direct relationships with their customers, who may need help and support in making efficiency investment decisions, and the Joint Utilities have direct access to customer consumption data and technical resources in New Hampshire and neighboring jurisdictions. In addition, the Joint Utilities have demonstrated a commitment to energy efficiency and have a history of award-winning management and delivery of the Core programs. They also have infrastructure and market-participant relationships in place to quickly scale up programs to meet increased savings goals. Consequently, at least for the first triennium, the Joint Utilities are a logical choice for the role of administrator within an EERS framework.

2. Savings Targets and Planning Periods

In the last decade, several New Hampshire specific studies have identified energy efficiency savings potential. Although those studies are somewhat dated,[15] based on the record, we find that they provide a reasonable sense of the achievable, cost-effective efficiency savings potential in New Hampshire, for the purpose of approving the EERS framework. *See* Exh. 4 Staff at 15; and Exh. 8 Sustainable Energy Group at 15-16. The short-term savings goals recommended by the Settlement Agreement are reasonably consistent with those studies and also fall within the range of savings recommended by the various parties in this proceeding, who represented diverse interests. In addition, setting a long-term qualitative goal of ultimately achieving all cost-effective efficiency savings as recommended by the Settlement Agreement follows the recommendations of the New Hampshire specific studies and allows flexibility to set that goal in the context of the market conditions that develop over time within the EERS structure.

Consequently, we approve the proposed EERS savings goals for the first triennium of the EERS as a percentage of 2014 statewide delivered sales: 0.80% for electric and 0.70% for gas in 2018; an additional 1.0% for electric and 0.75% for gas in 2019; and an additional 1.3% for electric and 0.80% for gas in 2020. Those statewide savings goals are cumulative and are

[15] GDS Report (January 2009) and the VEIC Report (November 2013)

intended to reach overall savings of 3.1% of electric sales and 2.25% of gas sales, relative to the baseline year of 2014, by the end of 2020. We also approve the recommendation to continue the Core programs in 2017, with adjustments to funding and savings goals as provided in the Settlement Agreement, in order to allow adequate time for careful and thoughtful planning for implementation of the first EERS triennium. Specifically, the 2017 Core-extension savings goals shall be 0.60% of 2014 statewide delivered sales for electric and 0.66% of 2014 statewide delivered sales for gas.

We agree with and approve the Settling Parties' recommendation to use three-year planning periods instead of the two-year periods used in Core. Three years is long enough to afford more stability and continuity in program delivery, which will help customers and other stakeholders plan their efficiency investments, but not so long as to limit the Commission's flexibility to adjust savings targets in response to changes in market conditions or other developments during that time Also, using three-year periods aligns the EERS with industry practice and is consistent with the planning periods used previously for the gas efficiency programs. *See*, *e.g.*, *Northern Utilities, Inc.*, Order No. 24,630 at 7 (June 8, 2006) (order approving a three-year plan refers to the prior three year program cycle).

3. Costs and Funding

The proposed costs of achieving the short-term goals recommended by the Settlement Agreement appear to be just and reasonable as well as consistent with the recent legislative mandate to consider energy efficiency a first-priority supply resource. We take note of the Settling Parties' proposal to increase the low-income program budget. At a time of uncertainty about the future of energy supply in the New England region and consistent with legislative directive in RSA 374-F:3, V (Commission shall "enable residential customers with low incomes to manage and afford essential electricity requirements"), we find this proposal to be appropriate. Moreover, increasing low-income efficiency funding and activities should free up some of the low-income financial assistance also collected through the SBC and LDAC, because those customers' energy consumption will decrease.

While rates may increase slightly for all customers in the short-term in order to recover the costs of an EERS, customer bills will decrease when their energy consumption decreases as well as when the impact of consumption decreases are reflected in reduced grid and power procurement costs. *See*, *e.g*., Exh. 2, Sustainable Energy Group Attachment at 2 and at 3-4. While the cost benefit tests ensure benefits to all customers, it is true that those who participate in efficiency programs are likely to benefit most. They will receive immediate benefits from bill reductions, improved comfort, and higher home or business value. Those advantages are in addition to the utility system benefits enjoyed by all customers. In return, however, customer participants must invest time and take full advantage of financial incentives or technical assistance, and they often must pay additional out-of-pocket expenses. Non-participating customers enjoy the benefits from load and system improvements. *See Granite State Electric Company*, Order No. 20,362, 76 NH PUC 820, 823 (1991). In addition, the efficiency programs will reduce emissions and may reduce utility revenue requirements through reduced operation and maintenance (O&M) expenses. Further, the availability of the direct benefits from participation, coupled with broad-based programs, should send a signal to all customers and encourage broad participation in the programs.

The record supports our finding that the EERS, and the energy efficiency market needed to support it, requires stable funding to grow and function optimally. *See* Exh. 3 Joint Utilities Petition at 48; and Exh. 2, Sustainable Energy Group Attachment at 2. The SBC and the LDAC are stable sources of revenue, and using ratepayer funds to achieve the public benefits of cost-effective energy efficiency is just and reasonable. Although the total funding collected under the RGGI program could cover a good portion of the incremental costs associated with EERS' increased savings goals, at this time, access to those funds for energy efficiency is limited by statute. *See* RSA 125-O:23.

Also at this time, private funding is limited and not as stable and reliable as the SBC and LDAC, and private funding alternatives have not been adequately investigated. *See* Exh. 3 Joint Utilities Petition at 6, 48, and 51-52; and Sustainable Energy Group Exh. 2, Attachment at 11-12; Exh. 5 Acadia Center at 7; and Transcript at 83-84 *see also* 2015-2016 Core Plan (DE 14-216) (includes a few new and relatively-new private financing programs). As seen in other jurisdictions, private funding increases following increased public funding of an EERS.[16] We note the Settling Parties' commitment to continue the work started in the Core programs to nurture and expand private funding options. Private funding should continue to be used to the greatest extent possible to fund the EERS programs. We will look to the plan for the first EERS triennium to describe those efforts and any new private funding proposed or under consideration for the future.

The SBC was established by the Legislature as part of electric restructuring. *See* RSA 374-F:4, VIII. The Commission has not increased the SBC since the inception of the Core programs in 2001. *Id*. Failing to increase the funding to support higher savings goals at this time not only fails to provide the Joint Utilities' customers with viable and proven options for energy

[16] Exh. 2 Sustainable Energy Group at 11 "Studies of financing programs have concluded that combining financing with traditional rebates and incentives leverages deeper savings and broader participation" (citations omitted), Exh. 4 Staff at 86. "In some markets program administrators have begun to tap secondary markets and a number of transactions have taken place representing a total volume of $400 million" and at 89 "Observers believe that when these conditions are met, lower cost capital may become available which will result in lower interest rates for customers.")

at least cost, but also fails to capture other benefits for customers. The Commission's oversight, and the requirement that all programs meet a cost-effectiveness test that projects greater benefits than costs over the life of the measures, ensures that the programs and spending of ratepayer funds are just, reasonable, and least cost. Therefore, we approve the proposal to fund the EERS through increases to the SBC and LDAC as proposed in the Settlement Agreement. We note that, when the three-year EERS plans are filed, we will review in advance and approve that spending only to the extent that it is just, reasonable, and least cost.

4. Recovery of Lost Revenues

With increased energy savings comes decreased utility revenues due to standard rate design, which recovers costs through a variable, or consumption-based, rate. The lost revenue adjustment mechanism (LRAM) recommended by the Settlement Agreement enables the Joint Utilities (except NHEC) to recover the portion of their authorized revenue requirement lost due to energy efficiency activities. The LRAM is not designed to increase the revenues recovered by the utilities, and lost revenues are not considered a cost for the purpose of the cost/benefit test used to assess efficiency programs in the Core or within the EERS. Specifically, without the LRAM, or a change in the way rates are designed today, the utilities may lose revenue that the Commission has already determined in the utility's rate case is just and reasonable for them to recover. Consequently, we approve the LRAM as proposed.

Nonetheless, we are mindful that, with an LRAM, the utilities' revenues can increase above their authorized revenue requirements from increased sales, and, for that reason and others, some parties prefer decoupling. This is because decoupling provides a reconciliation to the last-approved revenue requirement (*i.e.*, in the case of a utility collecting more revenue than its last-approved revenue requirement, the utility would be required to prospectively credit customers for any such over-collection). We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism as an alternate to the LRAM in their first distribution rate cases after the first EERS triennium, if not before.

5. Performance Incentives

The Commission has used performance incentives successfully in the Core programs to encourage utility investment in energy efficiency. In light of the addition of an LRAM, we agree with the Settling Parties' recommendation to reduce the level of performance incentives available to the Joint Utilities under an EERS. The recommended levels are sufficient to provide a reasonable incentive to pursue exemplary performance in program administration and delivery and to put efficiency investment on an equal footing with other earnings opportunities available to the Joint Utilities.

In addition, the recommended performance incentive level is less likely to provide excessive earnings and is more commensurate with the lower risk of investing in efficiency.

6. Stakeholder Involvement

Involving energy service stakeholders in the development and implementation of the EERS is important, because they are directly connected to the provision of energy and efficiency services. The active participation in the EERS of Settling Parties, who include representatives of the Joint Utilities, Commission Staff, DES, consumer advocates like the OCA and NHLA, efficiency experts and service providers, brings different knowledge, experience, and perspectives. New Hampshire is fortunate to have so many stakeholders who are invested in the success of energy efficiency and the EERS; their contributions and collaboration in this proceeding produced a more robust result. As economy wide involvement in energy efficiency measures will yield the best results, we encourage fuller participation of the New Hampshire business community going forward.

We appreciate the Joint Utilities' access to counterparts and expertise in other jurisdictions that lead the nation in the provision of energy efficiency services and encourage further interactions. To enable the well-informed contribution of the non-utility stakeholders in work required in the future to assure success of the framework we establish today, we approve the Settling Parties recommendations related to the retaining and funding of a planning consultant, an EM&V oversight consultant, and the EM&V studies consultants.

The EESE Board is a collection of diverse energy stakeholders, and its involvement in the EERS planning and implementation, as recommended by the Settling Parties, is appropriate. To fulfill that advisory role, the EESE Board requires technical resources consistent with the Settlement.

7. Evaluation, Measurement and Verification

We approve the EM&V proposals contained within the Settlement Agreement. Rigorous and transparent EM&V is essential to a successful EERS, to ensure that the efficiency programs actually achieve planned savings in a cost-effective manner. The addition of the EESE Board and additional expert resources to the EM&V proposed for the EERS will protect customers through consistent and fair assessment of program performance and cost effectiveness. Moreover, a Technical Resource Manual that meets New Hampshire needs, as proposed by the Settlement, will enable EM&V transparency, consistency, and accuracy.

8. Regulatory Process

We approve the Settling Parties' recommendations for an EERS process, including the pre-filing collaborative preparation of a plan for the first triennium with the assistance of a planning expert. We agree that such a process will likely result in a more efficient and less adversarial adjudicative proceeding following the plan's filing for Commission review and approval. An abbreviated annual plan update process during the trienniums, like the process we currently use for the Core dockets, is appropriate and will enable the stakeholders some flexibility to respond to developments in the energy efficiency market during that time.

In addition, we approve the annual process proposed for setting and reconciling the LRAM as described in the Settlement Agreement and the Joint Utilities EERS proposal. In calculating lost revenue, savings shall be adjusted to account for retirements, the actual timing of efficiency-measure installation, and the results of EM&V studies. Total lost revenues shall be capped at 110 percent of planned annual savings, audited by an independent third party, and recovered through an adjustment to the SBC or LDAC, depending on the utility.

9. Implementation Date

We approve the Settling Parties' recommendation to begin implementation of the EERS on January 1, 2018.[17] We recognize the Settling Parties' significant investment of time and resources during the last two years to reach this point in the development of an EERS framework, and we appreciate their willingness to continue their work to carefully and thoughtfully prepare a specific and detailed plan within that structure.

---

[17] An implementation date of January 1, 2018 for an EERS complies with the Legislative directive in HB 2 that, "[f]or the biennium ending June 30, 2017, the public utilities commission shall not expend any funding on the implementation of an energy efficiency resource standard without prior approval of the fiscal committee of the general court." N.H. Laws of 2015 ch. 276:223..

10. Beyond Implementation

We appreciate the foresight of the various parties who offered recommendations for the future of the EERS. Nonetheless, we defer any judgment on the merits until such time as specific proposals are presented for our review and approval.

Although not covered in the Settlement Agreement, Integrated Resource Plans are a critical component to the success of an EERS. IRPs are planning studies produced by electric and gas utilities to determine resource needs over a given planning period. The planning period is generally between 10 and 20 years. Methodologies used in the studies vary, but are intended to produce the least-cost, least-risk resource balance. Typically, the utility performs a number of studies as part of an IRP including a customer energy and peak demand forecast. To plan for achieving the EERS savings goals and confirm that its efficiency programs are least cost, the IRP should also include an energy efficiency market potential study and should model the inclusion of energy efficiency on a similar basis to supply-side resources or market purchases. Within six months of this order, Staff and the utilities shall meet to discuss and refine the IRP requirements.

V. CONCLUSION

Our establishment today of Energy Efficiency Resource Standards for electricity and gas is both routine and remarkable. It is routine, as we have long required our utilities to help their customers save money by using less electricity and gas. The State’s 10-year energy strategy, developed under RSA 4-E:1 and crafted with the input of consumer groups, environmental advocacy organizations, utilities, and others, also calls for increased energy efficiency throughout all sectors of the economy. The Core energy efficiency programs have given the utilities 14 years of experience with developing and implementing cost-effective programs and the EERS will build on that foundation.

At the same time, the establishment of an EERS is remarkable as it is based on the setting of savings targets, not dollars spent. It is the product of extensive investigation by Staff and collaboration between and among diverse groups of stakeholders. The framework that they developed together and that we approve in this Order will move the State forward, toward specific annual savings goals to achieve objectives set out in the 10-year State Energy Strategy consistent with Legislative directives.

Energy prices have been the subject of public discussion and debate for many years. The EERS is a significant step toward addressing the business community's concerns about remaining competitive in today's economy. The development of specific, cost-effective programs to implement this framework will require the robust participation of stakeholders, including those in the commercial and industrial sectors. Those who choose to participate in the energy efficiency programs that will be developed to meet the EERS targets will see reduced gas and electric bills, and all utility customers should see reduced costs for electric and gas supply in the long run.

We recognize that low income customers face greater hurdles to investment in energy efficiency than other customer. We have therefore approved increased funding for low income energy efficiency programs as recommended by the settling parties. We agree that these changes are appropriate in order to comply with legislative directives and to reduce energy consumption for those customers who need it most.

Based upon the foregoing, it is hereby

ORDERED, that the Settlement Agreement is approved; and it is

FURTHER ORDERED, that the Joint Utilities, except NHEC, shall include in their future IRPs an energy efficiency market potential study and shall model the inclusion of energy efficiency on a similar basis to supply-side resources or market purchases.

By order of the Public Utilities Commission of New Hampshire this second day of August, 2016.

Martin P. Honigberg Chairman	Robert R. Scott Commissioner	Kathryn M. Bailey Commissioner

Attested by:

Lori A. Davis
Lori A. Davis
Assistant Secretary

Docket No. DG 22-___
Attachment ELM-1

SERVICE LIST - EMAIL ADDRESSES- DOCKET RELATED

Pursuant to N.H. Admin Rule Puc 203.11 (a) (1): Serve an electronic copy on each person identified on the service list.

Executive.Director@puc.nh.gov
al-azad.iqbal@puc.nh.gov
alexander.speidel@puc.nh.gov
allen.desbiens@nu.com
amanda.noonan@puc.nh.gov
bob.reals@libertyutilities.com
carroll@unitil.com
christopher.goulding@eversource.com
craig.wright@des.nh.gov
cynthia.trottier@psnh.com
deandra.perruccio@nh.gov
dlabbe@nhla.org
donald.kreis@oca.nh.gov
downesm@unitil.com
edward.davis@eversource.com
ehawes@acadiacenter.org
epler@unitil.com
eric.stanley@libertyutilities.com
f.anne.ross@puc.nh.gov
frank.melanson@nu.com
heather.tebbetts@libertyutilities.com
issa.ansara@psnh.com
james.brennan@oca.nh.gov
jarvis@unitil.com
jay.dudley@puc.nh.gov
jbesser@necec.org
jharrison@nhcdfa.org
jim.cunningham@puc.nh.gov
joseph.fontaine@des.nh.gov
karen.cramton@puc.nh.gov
kate@nhsea.org
kbahny@trcsolutions.com
kerry.holmes@nh.gov
kristi.davie@eversource.com
leszek.stachow@puc.nh.gov
lois.jones@eversource.com
lrichardson@jordaninstitute.org
marc.lemenager@eversource.com
mark.naylor@puc.nh.gov
matthew.fossum@eversource.com
maureen.karpf@libertyutilities.com
mbirchard@clf.org
mdean@mdeanlaw.net
michael.sheehan@libertyutilities.com
nicholas.cicale@oca.nh.gov
ocalitigation@oca.nh.gov
palma@unitil.com

Docket #: 15-137-1 Printed: August 01, 2016

FILING INSTRUCTIONS:

a) **Pursuant to N.H. Admin Rule Puc 203.02 (a), with the exception of Discovery, file 7 copies, as well as an electronic copy, of all documents including cover letter with:** DEBRA A HOWLAND
EXEC DIRECTOR
NHPUC
21 S. FRUIT ST, SUITE 10
CONCORD NH 03301-2429

b) **Serve an electronic copy with each person identified on the Commission's service list and with the Office of Consumer Advocate.**

c) **Serve a written copy on each person on the service list not able to receive electronic mail.**

paul.dexter@puc.nh.gov
pradip.chattopadhyay@oca.nh.gov
rclouthier@snhs.org
rebecca.ohler@des.nh.gov
rhonda.bisson@psnh.com
richard.minardjr@nh.gov
robert.bersak@nu.com
robertbackus05@comcast.net
sanderbois@necec.org
sarah.knowlton@libertyutilities.com
sgeiger@orr-reno.com
snowc@nhec.com
Stephen.Eckberg@puc.nh.gov
Stephen.Hall@libertyutilities.com
steve.frink@puc.nh.gov
steven.elliott@nu.com
steven.mullen@libertyutilities.com
suzanne.amidon@puc.nh.gov
thomas.belair@psnh.com
tirwin@clf.org
tom.frantz@puc.nh.gov
trooney@trcsolutions.com
woodsca@nhec.com

EXHIBIT
#27A
DG 17-048

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-048

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Distribution Service Rate Case

REBUTTAL TESTIMONY

OF

GREGG H. THERRIEN

January 25, 2018

THIS PAGE INTENTIONALLY LEFT BLANK

TABLE OF CONTENTS

I. INTRODUCTION 1

II. SCOPE OF REBUTTAL TESTIMONY 2

III. DECOUPLING 5

A. Summary of Staff's Recommendations 5

B. Staff's Proposal to Exclude Weather Variation from the RDM 7

1. Scope of the Company's RDM proposal 7
2. Business Risks 10
3. Weather Normalization and RDMs 10
4. Past Commission Orders 12

C. Staff's remaining five recommended changes to the Company's proposed RDM 16

1. Staff Recommendations 2, 3, and 4. 16
2. Staff Recommendations 5 and 6. 17

D. Energy Efficiency ("EE") Performance Goals 18

E. The Company's response to the OCA's proposed RDM modifications 19

1. Introduction 19
2. OCA's recommended RDM changes 20
3. CIS Upgrade for Real-Time RDM 28

IV. RATE DESIGN 28

A. Response to Staff's Recommendations 28

B. Response to the OCA's Recommendations 31

V. CHANGES TO THE LOW-INCOME PROGRAM 35

VI. SUMMARY 37

THIS PAGE INTENTIONALLY LEFT BLANK

I. INTRODUCTION

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

A. My name is Gregg H. Therrien. I am an Assistant Vice President with Concentric Energy Advisors, 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01752. My professional qualifications and experience have been provided in Attachment GHT/DECPL-11 to my Direct Testimony filed April 28, 2017.

Q. Have you testified previously before the New Hampshire Public Utilities Commission ("PUC" or the "Commission")?

A. No, I have not.

Q. Did you participate in the PUC technical sessions in the instant case?

A. Yes. I participated in both the August 24, 2017, and November 1, 2017, technical sessions at the Commission's office.

Q. What is your responsibility in this proceeding?

A. In this proceeding, I am responsible for: (1) designing the Revenue Decoupling Mechanism (direct Decoupling Testimony of Gregg H. Therrien) and (2) together with Company Witness David Simek, developing the rate design (direct Joint Rate Design Testimony of David B. Simek and Gregg H. Therrien) for Liberty Utilities (EnergyNorth Natural Gas Corp.) d/b/a Liberty Utilities ("EnergyNorth" or the "Company").

II. SCOPE OF REBUTTAL TESTIMONY

Q. Please summarize the scope of this rebuttal testimony.

A. In this testimony, I:

1) Reaffirm why full revenue decoupling, inclusive of weather and economic adjustment, is superior to Commission Staff ("Staff") witness Mr. Iqbal's proposed weather-normalized limited Revenue Decoupling Mechanism ("RDM");
2) Respond to Mr. Iqbal's five other proposed changes to the Company's decoupling proposal;
3) Respond to the Office of Consumer Advocate's ("OCA") proposed modifications to the Company's decoupling proposal, including the proposed "real-time" adjustment;
4) Rebut the OCA's position that the RDM should be calculated on a total revenue basis rather than on a per-customer basis;
5) Rebut the OCA witness Dr. Johnson's assertions that decoupling improves earnings;
6) Rebut both Staff and OCA witnesses' recommendation for inclining block rate design and lower customer charges; and
7) Respond to Staff witness Mr. Frink's recommended changes to the Low-Income Discount Program.

Q. Please summarize your conclusions and recommendations.

A. My conclusions and recommendations are as follows:

As stated in my Direct Testimony, the decoupling rate design measures that the Company is proposing:

- Will allow the Company to remain an effective champion of energy efficiency initiatives without the financial disincentives that currently exist;
- Will comport with the State of New Hampshire's vision in its 2014 State Energy Strategy, which recognized that "[r]ealigning utility incentives to reward utilities for investing in efficiency is a necessary part of any effort to increase efficiency in New Hampshire"; [1]
- Will realize the vision crafted by the Settling Parties in the Energy Efficiency Resource Standards ("EERS") docket[2] by producing equitable ratemaking beyond the interim Lost Revenue Adjustment Mechanism ("LRAM") that fully supports the goals, and enable full acceptance of the energy savings initiatives envisioned in the Settlement Agreement; and
- Will fix a flaw in the traditional ratemaking methodology that does not allow utilities a reasonable opportunity to earn a reasonable return when customer usage is declining.

---

1 New Hampshire 10-Year State Energy Strategy, published by the New Hampshire Office of Energy & Planning September 2014. Executive Summary, page ii.

2 The "Settling Parties" as defined in the Settlement Agreement approved in Docket No. DG 15-137, dated August 2, 2016, include: Commission Staff; Liberty Utilities (Granite State Electric) Corp.; Unitil Energy Systems, Inc.; Public Service Company of New Hampshire d/b/a Eversource Energy; the New Hampshire Electric Cooperative, Inc. Liberty Utilities (EnergyNorth Natural Gas) Corp.; Northern Utilities, Inc.; the Office of the Consumer Advocate; the Department of Environmental Services; the Office of Energy and Planning (OEP); New Hampshire Community Action Association; The Way Home; the Conservation Law Foundation; The Jordan Institute; Acadia Center; the New Hampshire Sustainable Energy Association; the New England Clean Energy Council; the NH Community Development Finance Authority; and TRC Energy Services.

Further, as discussed in detail in this Rebuttal Testimony, I conclude and recommend that:

- Staff's proposed limited decoupling mechanism is not in the best interests of customers as it does not sever the relationship between sales volumes and revenues, thus limiting the effectiveness of decoupling. As a result, Staff's proposal does not maximize the benefits of decoupling envisioned in the EERS Settlement.
- 67 U.S. gas distribution companies have implemented RDMs in 29 different states; decoupling has become the mainstream regulatory framework in support of energy efficiency goals. The majority of these RDMs are constructed the same as the Company's proposal.
- The Company agrees with the OCA that a real-time RDM is better for customers in matching the impact of weather on bills, and is mutually beneficial to customers and the Company's cash flows. The Company does not, however, agree with OCA that a "Total Revenue" RDM is appropriate for EnergyNorth, because the Company has experienced dramatic growth in customers in recent years, which is forecasted to continue. Ignoring the revenue requirement associated with new customer additions is contrary to the Commission's approved natural gas expansion policy, evidenced through the approved Managed Expansion Program "MEP" and associated expansion rates.
- Inclining block delivery rates alone do not send a significant price signal to encourage conservation. This change would undermine long-standing rate design

principles such as cost causation. Further, the Commission should approve the Company's proposal to align Residential Non-Heating and Residential Heating fixed customer charges considering the significant shortfall in these rates compared to the results of the Marginal Cost Study ("MCS")[3].

- The Staff's proposal to modify the Low-Income Discount Program should be deferred. The Company respectfully requests that the Commission reject this change in the instant proceeding and open a separate generic docket to fully evaluate any change (if necessary) to this important program.

Q. How is the remainder of your testimony organized?

A. Section III of this testimony addresses decoupling issues raised by Staff and the OCA, and where appropriate, rebuts assertions made by these Parties. Section IV specifically addresses rate design issues. Section V will address Staff's recommended changes to the Low-Income Program. Finally, Section VI summarizes this rebuttal testimony.

III. DECOUPLING

A. Summary of Staff's Recommendations

Q. Please describe the six modifications to the Company's RDM proposed by Staff.

A. Staff proposed the following six modifications to the Company's RDM proposal:

1) The adjustment should be based on weather normalized revenues.

---

[3] In the case of Residential rates, the MCS results are approximately three times higher than current monthly customer charges.

2) The adjustment should be performed at the rate class level (instead of at the company level).

3) Expected revenue should be calculated at individual rate class level, not at combined rate class level.

4) Expansion rate customers should be included in the RDM calculation.

5) Annual RDM adjustments should be capped at +/- 2 percent.

6) No mid-period adjustment should be made; if needed, an adjustment could be made at the time of Company's next rate case.4

Q. Please summarize the Company's response to Staff's recommendations.

A. As explained in detail below, the Company strongly disagrees with Staff's recommendation that the RDM adjustments should be based on weather normalized revenues. The Company accepts Staff's recommendation Nos. 2 and 3 related to the method of calculating the RDM accrual and the RDM billing rate. The Company does not oppose Staff's recommendation No. 4 to include expansion rate customers in the RDM, with certain exceptions. EnergyNorth disagrees with Staff's proposals Nos. 5 and 6 to cap the annual RDM adjustment at +/- 2 percent and eliminate the mid-period adjustment.

---

4 Direct Testimony of Al-Azad Iqbal ("Iqbal Testimony") dated November 30, 2017, Bates 000010.

B. <u>Staff's Proposal to Exclude Weather Variation from the RDM</u>

Q. Please explain why you disagree with Staff's recommendation to use weather-normalized revenues in the RDM.

A. There are four main areas of disagreement with Staff's direct testimony. First, I disagree that decoupling should be limited solely to company-funded conservation programs. Second, I will rebut the assertion that that the Company's proposal "also eliminates all risk except the risk of management efficiency." Third, I will clarify and explain that the clear majority of RDMs across the country include weather variation in the RDM true-up calculation, either by using actual revenues per customer or a separately billed Weather Normalization Adjustment ("WNA"). Fourth, I add additional context to Staff's interpretations of past Commission guidance regarding decoupling.

1. Scope of the Company's RDM proposal

Q. Do you agree with Staff's assertion that the Company's proposal "is well beyond the efficiency and conservation related sales reductions"?

A. No, I do not. Staff stated, "The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather etc.) which is well beyond the efficiency and conservation related sales reductions."[5] Staff's proposal limits reconciling changes in sales related to utility-funded conservation programs only, and ignores other energy efficiency and conservation actions customers and other stakeholders take to reduce gas

---

[5] Id., Bates 000011, lines 16 through 16.

consumption. In my direct testimony I cite five contributors to declining use per customer:

1) Utility-sponsored Energy Efficiency ("EE")/Demand-Side Management programs;
2) Customer self-funded conservation measures;
3) Improvements in appliance efficiencies and building code requirements;
4) Consumer responsiveness to increases in natural gas prices and/other economic and demographic factors; and
5) A warmer normal weather trend.[6]

Referring to the above list, items 1), 2), and 3) are unambiguously directly related to energy efficiency, and 4) customer price responsiveness, is (short term reversible) conservation-related when customers are responding to price increases. Item 5) is a clear trend that reduces customer usage. Staff's recommendations focus entirely on contributor 1).

Q. Does the OCA support a decoupling mechanism that encompasses all contributors to the variation in sales?

A. Yes. Although the testimony of Dr. Johnson recommended two modifications to the Company's proposal that I will address later in this testimony, he did not propose to eliminate the impact of weather, or any other variable that contributes to the consumption of gas volumes. In his testimony Dr. Johnson wrote:

[6] Direct Testimony of Gregg H. Therrien ("Therrien Testimony"), Bates 305.

> **Q. Is the proposed decoupling mechanism an improvement over the existing LRAM?**
> A. Yes. It does a better job of removing the disincentive for EnergyNorth to encourage energy conservation, while eliminating the bias in favor of programs and initiatives included in the LRAM.[7]

Dr. Johnson also asserted that:

> Decoupling achieves a broader, more fundamental shift in incentives, because revenues become largely impervious to improvements in energy efficiency – including improvements resulting from tightened building codes, increased appliance standards, technology improvements, heightened awareness of greenhouse gas emissions, and other factors. This broader scope is significant, because EnergyNorth can potentially influence the decisions by customers and the companies that construct new buildings concerning what insulation they install, what appliances they purchase, and what type of energy they use. Currently, EnergyNorth has an incentive to steer customers into the programs and initiatives included in the LRAM, rather than finding other ways to reduce their energy usage that are not tied to those specific programs.[8]

Dr. Johnson's assertions are instructive as to how the Company, together with supportive Commission policy, can enhance energy efficiency. In this regard, full decoupling is the means to this broader scope without penalizing the Company.

---

[7] Direct Testimony of Ben Johnson, PH.D. ("Johnson Testimony"), dated November 30, 2017, Bates 9, line 20 through Bates 10, line 1.

[8] Id., Bates 000007, lines 7-17.

2. Business Risks

Q. Please describe Staff's assertions concerning the effect that an RDM would have on EnergyNorth's business risks.

A. Staff stated, "The Commission was also concerned with the potential for risk shifting via decoupling. The Company's proposal adjusts for all impacts on revenue (e.g., the economy, energy efficiency, weather, etc.) which is well beyond the efficiency and conservation related sales reductions. It also eliminates *all risk* except the risk of management efficiency."[9] *(Emphasis added)*.

Q. Does decoupling eliminate all risks except "management efficiency"?

A. No, it does not. Decoupling does not eliminate other, very real risks that gas utilities face, such as increased competition, regulatory risks, economic risks that affect the cost to serve (e.g., inflation), etc. These other exogenous risks, which are beyond the reasonable definition of "management efficiency," are not addressed through decoupling.

3. Weather Normalization and RDMs

Q. Is it common for RDMs to exclude weather from the calculation?

A. No. In fact, only three of the sixty-seven utilities with an RDM in the United States exclude the impact of weather in their RDM calculation. These include utilities in Colorado, Washington State, and Wyoming. Twenty utilities have separate WNA rate

9 Iqbal Testimony, Bates 000011 lines 13-17.

adjustments that complement their RDM, an alternative to including the impact of weather explicitly in the RDM. This is shown here:

Table 1: RDM Calculation Methodologies in the U.S.

Calculation:	Revenue Per Customer (RPC)			Total Revenue			PBR	
State	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	RDM using Actual Weather	RDM using normal weather and a separate WNA	RDM using normal weather and no WNA	PBR (Includes Weather)	Total
AR	1				2			3
AZ		1						1
CA				1			3	4
CO			1					1
CT				1				1
GA							1	1
ID				1				1
IL	2			1				3
IN				2	1			3
LA					1			1
MA	6							6
MD	4			1				5
MI	1							1
MN	1			1				2
MS					1			1
NC	1			1				2
NJ		2						2
NV	1							1
NY	2	7		1	1			11
OR	1	1		1				3
RI	1							1
SC							1	1
TN		1						1
UT		1						1
VA	3							3
VT							1	1
WA	2					1		3
WI	1							1
WY		1	1					2
Grand Total	27	14	2	11	6	1	6	67

As this table shows, almost all LDCs with an RDM also have a mechanism to reconcile for weather. Including a weather reconciliation in the RDM is the norm, not the exception.

4. Past Commission Orders

Q. What is Staff's interpretation of Commission policy regarding decoupling?

A. Staff's interpretation of Commission policy is that a limited decoupling mechanism is the Commission's preferred approach. Staff relied primarily on Docket No. DE 07-064, which pre-dates the EERS Settlement by nearly a decade, and was opened specifically to investigate energy efficiency rate mechanisms.[10] Although Docket No. DE 07-064 did discuss decoupling in the context of overall rate design, and contains high-level guidance regarding cost causation and the impact of rate design changes on certain rate classes,[11] the Order Resolving the Investigation is not a prescriptive document for implementing decoupling. Rather, the investigation set out to answer the following four questions:

1) whether existing rate treatment poses an obstacle to investment in energy efficiency;
2) whether a different rate treatment would promote such investment;
3) whether these issues should be pursued further in this docket, through utility-specific rate cases, as part of a rulemaking, or through some other procedure; and
4) whether decoupling constitutes an alternative form of regulation under RSA 374:3-a. Order No. 24,934 at 4 (January 16, 2009) ("the 2009 Order").

In the 2009 Order, the Commission concluded, "We find, therefore, that the best approach to implementing such rate mechanisms is on a company-by-company basis in the context

[10] "On May 14, 2007, an order of notice was issued commencing this investigation into the merits of instituting, for electric utilities, appropriate rate mechanisms that would have the effect of removing obstacles to, and encouraging investment in, energy efficiency." Order No. 24,934 (January 16, 2009).
[11] Iqbal Testimony, at Bates 000008.

of an examination of company specific costs and revenues inasmuch as each utility has a unique service territory and customer mix as well as company specific operating costs and rate base investment." 2009 Order at 19. Nowhere in that Order does the Commission state its preferred decoupling model. On pages 20 through 22 of the 2009 Order, the Commission did discuss "Rate Mechanism Options" including "Reconciling Rate Adjustments" (decoupling), but did not prescribe, or even suggest, that one option is superior to another. Rather, the Order states "*Regardless of the model used*, it would be appropriate to propose revenue decoupling in the context of a rate case in order to avoid single-issue ratemaking." (Emphasis added.)

Q. Did the EERS Settlement address decoupling?

A. Yes, in part. My Direct Testimony regarding decoupling described the key agreements regarding energy efficiency programs and related rate mechanisms for utilities in New Hampshire:

1) Extends the Core programs;

2) Requires implementation of a LRAM, commencing January 1, 2017 (capped at 110% of planned annual savings);

3) Contemplates the subsequent implementation of a decoupling mechanism to replace the LRAM;

4) Will implement the EERS commencing January 1, 2018;

5) Retains the Performance Incentive, with modifications;

6) Increases the low-income share of the overall energy efficiency budget; and

7) Includes other legal provisions.

The Commission approved the Settlement Agreement in Order No. 25,932 (August 2, 2016).[12]

Q. Please summarize the sections of the EERS Settlement that pertain to LRAM and decoupling.

A. Section II B. of the EERS Settlement, "Lost Revenue Adjustment Mechanism and Decoupling" codified the agreement among the Settling Parties as to when the LRAM must be implemented and when utilities may, in the context of a general rate case, propose a decoupling mechanism. The calculation of the LRAM is very explicit in the EERS Settlement – covering approximately two pages of the document. In contrast, decoupling is discussed in more general terms and consumes only one-half page in the EERS Settlement.

The EERS Settlement states:

> The Settling Parties agree that the LRAM for each utility will cease when a new decoupling mechanism, or another mechanism as an alternative to the LRAM, is implemented. The Settling Parties further agree that each of the Utilities shall seek approval of a new decoupling mechanism, or another mechanism as an alternative to the LRAM, in its next distribution rate case following the first triennium of the EERS, 2018-2020. This provision does not, and is not intended to, prevent or preclude any of the Utilities from

[12] Therrien Testimony, Bates 299.

> seeking approval of such mechanism prior to the end of the first triennium, but the Settling Parties acknowledge and agree that any utility seeking such approval shall do so in the context of a distribution rate case, consistent with the Commission's guidance in Order No. 24,934 (January 16, 2009). The Settling Parties agree that the Commission's approval of the Settlement Agreement does not in any way restrict the Commission from investigating or implementing decoupling, or another mechanism as an alternative to the LRAM, at any time.[13]

Q. Does the EERS Settlement address weather normalization or any aspect of how an RDM should be constructed?

A. No. The above excerpt is the entire content regarding decoupling in the EERS Settlement.

Q. Did the Commission approve the EERS Settlement?

A. Yes. The Commission approved the EERS Settlement in Order 25,932 (August 2, 2016) (the "2016 Order"). In the 2016 Order, the Commission first required utilities to implement an LRAM effective January 1, 2017, and recognized that some of the Settling Parties preferred decoupling. The 2016 Order states:

> We note that our approval of the LRAM does not limit our subsequent consideration and approval at any time of a different lost revenue recovery mechanism, and that the Joint Utilities (except NHEC) are required to seek approval of a decoupling or other lost-revenue recovery mechanism *as an alternate to the LRAM* in their first distribution rate cases after the first EERS triennium, if not before (*emphasis added*).[14]

[13] EERS Settlement Agreement, page 5-6.
[14] Order No. 25,932 (August 2, 2016), at 60.

Q. What can be concluded from the Commission's 2009 Order and 2016 Order regarding decoupling?

A. The 2016 Order clearly articulated the Commission's requirement for utilities to seek approval of something other than an LRAM. As with the 2009 Order, the Commission did not prescribe, endorse, or articulate any specific decoupling methodology, only that utilities should propose an RDM in the context of a general rate case.

C. <u>Staff's remaining five recommended changes to the Company's proposed RDM</u>

1. Staff Recommendations 2, 3, and 4.

Q. Please describe the second and third Staff recommendations to perform the RDM calculation at the rate class level, and the Company's response to Staff recommendations.

A. Staff's second recommendation is that the RDM adjustment should be performed at the rate class level (instead of the proposed RDM Rate Groups).[15] Staff's third recommendation is that expected RDM revenues should be calculated at the individual rate class level, not at combined rate class level.

The Company does not object to calculating the RDM adjustment (accrual) at the rate class level. Further, our understanding of Staff's testimony is that the resulting variances, at the rate class level, will be summed for the Commercial and Industrial ("C&I") classes for purposes of determining the RDM rate adjustment to be applied to customers' bills. Staff did not provide a recommendation as to whether Residential Non-Heating customers

[15] Therrien Testimony, Table 8: RDM Customer Groups, Bates 320.

should receive a separate billing rate from Residential Heating customers under his proposed modification. Staff did, however, tie its recommendation to energy efficiency program "sectors," which combines Residential Non-Heating and Heating together. Using that definition, the Company assumes Staff is suggesting only two separate RDM billing adjustments – one for Residential and one for C&I. Assuming my understanding is correct, the Company does not object to these two recommended changes.

Q. Please explain Staff's fourth recommended change to the Company's RDM Proposal.

A. Staff recommended that customers receiving service under the MEP tariffs also be subject to decoupling. Staff believes RPC for MEP customers should be included in the rate class revenue calculation after the MEP premium is separated.[16]

Q. Does the Company object to this recommendation?

A. No, it does not provided that the RDM rate for MEP customer is the same as the corresponding rate for all other customers in the class.

2. Staff Recommendations 5 and 6.

Q. Does the Company agree with Staff's fifth recommendation to change the +/- 5% cap to a +/- 2% cap?

A. No, the Company's proposed +/- 5% cap should not be changed. The Company's proposal to include weather in the RDM requires a larger cap bandwidth than +/- 2%.

---

16 Iqbal Testimony, Bates 000001, lines 18-19.

Otherwise, large deferrals may occur resulting in a larger collection or refund in a subsequent period.

Q. Does the Company agree with the elimination of the mid-term adjustment?

A. No, because the Company's proposal includes the effects of weather. Staff's rationale for proposing elimination of the bi-annual adjustments in favor of a singular annual adjustment is tied to its recommendation to exclude weather from the RDM calculation. The Company continues to advocate for weather-related variances be included in the RDM. Therefore, we continue to advocate for mid-term adjustments.

D. <u>Energy Efficiency ("EE") Performance Goals</u>

Q. Please summarize Staff's recommendation regarding EE goals and decoupling.

A. Staff introduced another proposed decoupling restriction tied to obtaining EE goals. Staff proposed that, "If the Company does not meet its EE goals, there should be some restriction in decoupling adjustment because the logical conclusion is that the decoupling adjustment was attributed to something other than EE."[17] To summarize, Staff recommended that if the RDM calculation yields a charge in excess of the cap (presumably their 2% recommended cap) and EnergyNorth does not meet its EE goals, then "the Company would be required to demonstrate that its EE efforts were the primary factor in reducing its energy sales in order for any amount above the decoupling cap to be

---

[17] Iqbal Testimony, Bates 000013, lines 10-12.

carried forward for recovery in a subsequent year."[18] A credit calculation would not be subject to such a review.

Q. Do you agree with Staff's recommended asymmetrical cap restriction?

A. No, I do not. Limiting the decoupling calculation to exclude any sales variation "other than EE" will penalize the Company for expanding its EE efforts beyond company-funded programs. I have presented in my Direct Testimony, and in this rebuttal testimony (Section III. B. above), that decoupling is intended to completely sever the link between utility revenues and sales units. Otherwise, the signal to the Company is something less than desired – because sales volumes will still matter.

E. The Company's response to the OCA's proposed RDM modifications

1. Introduction

Q. Please summarize the major points of OCA Witness Dr. Johnson regarding decoupling.

A. Dr. Johnson, on behalf of the OCA, proposes two modifications to the Company's RDM proposal. First, he proposes a "real time" decoupling adjustment for the weather-related portion only, and 2) recommends that the RDM be calculated on a "Total Revenues" basis as opposed to RPC.

[18] Ibid, lines 14-17.

Q. Did the OCA make other assertions regarding decoupling?

A. Yes, he did. I will address, and rebut where appropriate, assertions made by the OCA regarding decoupling's association with Company earnings, rate base, and capital investments and depreciation. I will also address the OCA recommendation to disallow potential Computer Information System ("CIS") modification costs from rates.

2. OCA's recommended RDM changes

a. "real-time" adjustments

Q. Please summarize OCA's first recommendation regarding a "real-time" decoupling adjustment.

A. The OCA recommended that the Company separate the weather-related portion of the RDM from the remainder of the calculation. Specifically, the OCA called for a customer-by-customer calculation of the impact of weather, and bill that amount (based on the customer's actual volumetric delivery charge unit rate) in the month in which the weather variance occurred. In doing so, the OCA submitted that "it will help smooth out bill fluctuations, making cash flows smoother and more predictable for both the Company and its customers."[19] The OCA also provided examples of how this real-time adjustment would work, under both colder-than-normal and warmer-than-normal weather conditions, making the point that the real-time adjustment will match the variation in weather and provide synchronized, real-time revenue stabilization to customers and the Company.[20]

[19] Johnson Testimony, Bates 16, lines 9-11.
[20] Id., Bates 16-18.

Q. How would the portion of the decoupling adjustment that is not weather-related be treated?

A. The calculation of the RDM would be calculated essentially the same as proposed by the Company (I will address the OCA's "Total Revenue" recommendation later in this testimony). The total difference between Actual and Target revenues will be refunded or collected in a subsequent period. The OCA noted that this adjustment would likely be considerably smaller than an RDM that does not adjust for the weather component real-time.[21]

Q. What reservations does the Company have regarding separating the weather component of the RDM on a real-time basis?

A. "Real time" weather adjustment, referred to as a Weather Normalization Adjustment or "WNA," requires that the dollar impact of the difference between actual and normal usage be calculated for each customer bill, at the time the bill is rendered. This requires extensive programming in the billing system, and significant additional training of call center personnel charged with explaining the WNA to customers.

The OCA stated that "customers are more likely to understand and accept the mechanism if the portion that deals with weather-related fluctuations is separated from the portion that deals with energy conservation and other factors influencing usage."[22] Although I agree that matching the weather-related portion of the mechanism with the customer's bill is a

---

[21] Id., Bates 15.
[22] Id., Bates 19, lines 2-4.

reasonable concept, I am not convinced that it is easier to explain than an annual true-up. For example, the Company's proposed RDM results in a single billing rate adjustment to be applied each month of the applicable season. It is easy to explain that a charge occurs because last winter's weather was warmer than normal. The issue I have with real-time application is that the formula is complex and difficult to explain, and contrary to the OCA's assertions, I have experienced first-hand the difficulty in explaining this adjustment on a customer's bill. This difficulty stems from the following factors:

1) EnergyNorth has twenty billing cycles in a billing month, and they span approximately sixty days (i.e., cycle 1 customers are billed from the beginning of the prior month to the beginning of the current month, while the last billing cycle closely matches the calendar month in which it is billed). Call Center employees will need to consult the actual and normal degree days for the applicable billing cycle to explain the variances.
2) Call Center representatives will also need to understand a complex formula used to derive the actual charge that is on each customer's bill. This includes understanding base usage, heat usage, degree days, and the blended volumetric rate applied to the usage adjustment.
3) If there was a reason for the customer's bill to be adjusted (e.g., cancelled then rebilled), the complexity of the bill makes auditing of the WNA charge extremely difficult.

4) From a rate administration perspective, rate changes result in a month of pro-rated bills. The WNA adds complexity to the necessary audit of distribution rate changes.

5) Reporting requirements (both to internal utility management and to state commissions) is likely to increase and add complexity.

In contrast, the Company's proposed RDM is easy to understand, calculate, and audit, and should have minimal reporting requirements.

Q. Please describe the Company's concerns with the OCA's proposed RDM.

A. The concern with the OCA's proposal is that it is unnecessarily complex. Forty-four of the sixty-seven U.S. companies with an RDM use the more straightforward approach to including weather variances that the Company has proposed. Although twenty utilities do employ the combination of a WNA and decoupling, it is likely the result of already having a WNA in place prior to introducing decoupling. Despite its complexity, it is still superior compared to an RDM that excludes the impact of weather.

Q. Do the above concerns imply that the Company is unwilling to employ RDM with a real-time adjustment?

A. No. The OCA's proposed real-time RDM component does have benefits for both customers and the Company, and, most importantly, recognizes that all contributors to sales variation impact the efficacy of energy conservation. A real-time RDM is superior to Staff's proposal that does not include weather variation in the calculation. The OCA's proposal is a true decoupling mechanism, and the Company appreciates the OCA's understanding of, and dedication to, an RDM that truly breaks the link between utility revenues and gas usage.

Q. If a real-time RDM were implemented, how would the Company address the difficulties that you describe above?

A. If a real-time RDM were implemented, the Company would work with both the OCA and Staff to develop communications materials for customers, and to address the administrative and reporting requirements associated with a real-time RDM.

b. "Total Revenue" RDM

Q. Please describe the OCA's proposal to utilize a "Total Revenue" approach to RDM.

A. A Total Revenue approach is exactly that – total revenues are "locked in" as a result of the Commission's final determination in the rate case and these revenues then become the "Target" revenues utilized in subsequent RDM filings, comparing Actual total revenues to this Target. The primary advantage of a Total Revenue approach lies in its simplicity and predictability. Simply put, revenues do not change year-over-year. The primary disadvantage, which the OCA recognized, is that it can be a deterrent to growth. That is why more U.S. LDCs employ an RPC decoupling mechanism rather than a Total Revenue approach. LDCs are in the business of adding new customers to the distribution system, either through conversion from an alternative fuel within its existing system footprint, or from expanding the system to reach new customers. Total Revenue RDMs do not encourage growth (and, in fact, discourage growth) because revenues received from new customer additions are in effect "refunded" to existing customers through the RDM, leaving the utility to fund growth investments without incremental revenue to support those investments.

Q. Please explain why utility retention of revenues from new customers is important.

A. Most U.S. commissions, like New Hampshire, encourage their LDCs to expand, providing greater fuel choice to the residents of their respective states. Further, regulators want to protect against existing customers subsidizing uneconomical growth. New customer revenues help cover the cost of new investments without adding pressure to seek rate relief that results from a growing rate base. If these new customer revenues are not retained, but returned to existing customers through a Total Revenue RDM, then, all else being equal, the utility will seek rate relief sooner than if those revenues were retained.

Q. Does the New Hampshire Commission encourage growth?

A. Yes, it does. The Commission has approved the Managed Expansion Program ("MEP"), which also includes separate rate schedules with premium distribution rates. These premium rates help fund more aggressive system expansion than that which could otherwise be supported through standard delivery rates. The Commission recognizes that increased sales reduces the fixed costs borne by all other customers by spreading those costs over a greater volume of sales.

Q. Are there other related comments made by the OCA regarding funding of growth investment?

A. Yes. The OCA suggests depreciation between rate cases can fund growth. He wrote:

> There is no assurance that the increase in total revenues that occur under the per-customer approach is fully needed, or that the resulting revenue growth will match any corresponding increase in the revenue requirement. It is also important to keep in mind that EnergyNorth has cash flows provided by depreciation and retained earnings that can be used to support new customer additions. If its capital additions exceed depreciation, and as a result its rate base increases (rather than decreases as depreciation accumulates), it will have the opportunity to recover the associated costs after they are reviewed and approved in a rate case.[23]

Dr. Johnson's argument that depreciation is sufficient to fund growth investments is unfounded. His argument relied on system-wide depreciation and retained earnings to fund new customer investments. I agree these are sources of funds, but only depreciation, to the extent it reduces rate base, helps alleviate revenue requirement growth. Depreciation is often used to fund *non-revenue generating capital investment*, such as reliability investments (e.g., improvements to LNG facilities, gate stations, etc.), as well as ongoing capital needs (e.g., fleet vehicles, equipment, information technology, metering, etc.).

Q. Do new customer additions require incremental investment?

A. Yes, any new customer addition to the system will require at least a service line and meter. In many cases, such as MEP projects, new main is also required to serve new customers. If the OCA's recommendation to include new customer revenues in its proposed Total Revenue RDM is implemented, then the Company will incur a shortfall in revenue

[23] Id., Bates 13, lines 4-11.

requirements associated with this new investment, which may have a dampening effect on growth.

Q. Does the OCA offer a solution to this problem?

A. Yes, in part. The OCA proposed an alternative: exclude expansion customers from the RDM.[24] This is the same solution the Company proposed in its Direct Testimony.[25] If the Commission wishes to include expansion customers in the RDM, it should consider Staff's fourth RDM recommendation, which would exclude the 30% distribution rate premium revenues from the RDM calculations, but include the remaining (base level) revenues from MED customers in the RDM calculations. However, the expansion rate is only applicable to those areas where customers could not be served under standard rates (absent a high CIAC by those customers). The OCA's proposal did not address the majority of the Company's growth, which is under standard rates. Additional revenue from that growth would still be refunded to customers through the OCA's proposed RDM.

Q. Please summarize the Company's position regarding the OCA's Total Revenue RDM approach.

A. The Total Revenue approach is flawed insofar as conflicts with Commission policy to encourage natural gas expansion. For gas utilities, retaining growth-related revenues to fund the incremental investment is critical, particularly during a concerted effort to expand the system. Additionally, RPC RDMs are more common than Total Revenue RDMs (*see*

---

24 Id, Bates 14, lines 9-19.
25 Therrien Testimony, Bates 323, line 3 through Bates 324, line 2.

Table 1). For these reasons, the Company reiterates its preference for a revenue-per-customer RDM.

3. CIS Upgrade for Real-Time RDM

Q. Please comment on the OCA's recommendation to disallow any incremental costs associated with CIS investments necessary to implement their proposed real-time decoupling proposal.

A. It is inconsistent for the OCA to advocate for disallowance of a cost that supports the OCA's real-time RDM proposal, a cost that is not necessary to implement the Company's proposal. If the OCA's real-time RDM proposal were to be approved, the related costs should be considered legitimate business expenses and allowed for recovery. The Commission Staff audits expenses and investments made by the Company as part of rate reviews. There is no need to predetermine that the CIS changes necessary to implement a real-time RDM should be disallowed prior to the project commencing.

IV. <u>RATE DESIGN</u>

A. <u>Response to Staff's Recommendations</u>

Q. Please summarize Staff's recommended head and tail block delivery rate changes.

A. Staff recommended two changes:

1) Set the rates for both head and tail block at the same level; and

2) Allocate any decoupling adjustment to the head or tail blocks based on whether it is a surcharge or refund. Refunds would be allocated to head block and surcharges

would be collected from the tail block for the residential sector and high winter use C&I customers.[26]

Q. Please explain the Company's response to Staff's first recommendation, that head and tail blocks should be equalized.

A. Staff's proposed change does not significantly impact customers' bills to warrant objection considering the Company's decoupling and fixed customer charge rate proposals.

Q. Does the Company object to Staff's second recommendation?

A. Yes. Staff proposed an asymmetrical application of the decoupling adjustment between the head and tail block volumetric delivery rates. Justification for this proposal is two-fold. First, Staff claimed that, "It will provide a proper price signal to the customers to encourage energy conservation."[27] Second, "This approach would also benefit lower consumption households that could tend to include be lower income households with smaller homes and less energy use compared to higher income households. Low use households, on average, have relatively little or no consumption in the tail block and thus would see little or no rate increase from decoupling."[28]

Staff's proposal is unfair to higher use customers that have much of their monthly usage in the tail block. Their proposal unfairly allocates RDM under recoveries to higher use

[26] Iqbal Testimony, Bates 000016, lines 19-22.
[27] Id., Bates 000017, lines 14-15.
[28] Id., Bates 000017, lines 15-19.

customers and unfairly allocates RDM over recoveries to lower use customers. Staff's assertion that their proposal further encourages conservation through a price signal that charges a higher rate on higher consumption is unsupported.

Q. Does Staff's proposal have the potential for under-recovery?

A. Yes. Under Staff's proposal, many low use customers would presumably not pay a decoupling charge because their usage would be low enough as to not fall into the tail block. This creates the potential for a shortfall in recovery that must be deferred until the next winter season.

Q. Does Staff's proposal alleviate concerns regarding undue rate impacts to small rate classes?

A. No. Staff argued that "This addresses the stated concern of the Commission that any decoupling proposal to change the rate design needs to consider the impact on small rate classes to ensure that such classes are not unduly impacted by such changes", and "It also reduces the volatility of gas bills for low use customers."[29] Using data from my direct testimony, the highest winter period decoupling adjustment over the past five years would have been $0.0180 per therm.[30] To put this in perspective, a Low Income Residential Heating customer on the R-4 rate using 105 therms in January has a total bill of $105.46 at current rates.[31] If decoupling were in place in January 2017, this customer would have

[29] Id., Bates 000017, line 19 through Bates 000018, line 2.
[30] Therrien Testimony, Bates 328, Table 10, Winter 2016-2017 rate per therm.
[31] Direct Testimony of David B. Simek and Gregg H.Therrien ("Simek/Therrien Testimony"), April 28, 2017, , Attachment RATES-8, page 3 of 16 (Bates 257), line 203.

been charged an additional $1.89, which would have represented a 1.8% increase to their bill. I do not believe that a $1.89 charge would "unduly impact" low use customers or create "volatility" in their gas bills. If Staff's recommendation to eliminate the difference between head and tail block unit rates is implemented, low use customers rates would go down because current rates have a higher head block rate than the tail block. Using Staff's premise that low use customers are less likely to experience usage in the tail block, their overall bill will likely go down more than any increase from a decoupling charge.

B. Response to the OCA's Recommendations

Q. Please summarize your understanding of the OCA's proposed rate design.

A. The OCA seeks to reduce fixed customer charges and increase volumetric charges, particularly in the tail block.

Q. What justifications does the OCA use to rationalize reducing customer charges?

A. The OCA began its argument for lowering fixed charges not by introducing evidence to support such an action, but rather through criticizing the Company's logic for requesting increases. These criticisms include how the flow of the rate design Exhibit-5 works, which is a mathematical schedule that logically reconciles allocated class revenue requirements by first subtracting out fixed cost recovery then volumetric recovery. The OCA also makes the following criticisms and recommendations related to the Company's proposed customer charges: (1) the Company's estimate of marginal customer-related costs is flawed and therefore, the Company's proposed customer charges, which are informed by the estimated customer-related costs is also flawed; (2) greater consideration should be given to increasing volumetric rates, to advance state conservation goals, which necessarily requires lowering fixed charges; and (3) lastly, the OCA attempted to dismiss long-standing cost causation principles used in utility rate design.

Q. Are the Company's rate design workpapers biased towards increasing fixed customer charges?

A. No, the rate design workpapers are mathematical, and follow a logical sequence to prove proposed rates produce proposed revenues (i.e. "revenue proof"). The OCA asserted that "The Company made a priority to increase its customer charges (the fixed monthly rate that applies regardless of how much or how little gas the customer uses). This priority is apparent from the workpapers it used to develop the proposed rate design, and is alluded to on pages 16-17 of the joint testimony of Simek and Therrien."[32] His claim that the construct of the Company's workpapers prioritize increased customer charges is unsupported and no alternative calculation is presented.

Q. Is the Company's rate design approach consistent with past precedent?

A. Yes, the Company's recommended fixed cost rates are in line with prior proposals, which have also relied on the results of the MCS to guide its rate design recommendations. Further, as stated in the Simek/Therrien Testimony, "The proposed rates represent a balancing of the principles of appropriate rate design which include efficiency, simplicity, continuity of rates, fairness between rate classes, and corporate earning stability."[33] These

---

32 Johnson Testimony, Bates 24, lines 19 – 22.
33 Simek/Therrien Testimony, Bates 205.

are long-standing principles that have guided utility ratemaking for decades.[34] The OCA suggested that employing these principles undermines the Company's proposal to increase fixed charges, citing our direct testimony at page 17as follows:

> To determine the appropriate level of customer charges for each class, we considered: (1) the marginal customer costs resulting from the marginal cost study; (2) rate continuity; and (3) customer impacts.

In response to this stated approach the OCA stated, "The second and third items just mentioned did not support increasing the customer charges; rather, they ameliorated the extremely large increases that would be needed to move these rates all the way to the Company's estimate of marginal cost."[35] Interpreting this passage, it appears that Dr. Johnson believes that employing rate continuity and customer bill impacts undermines the Company's proposal. This is contrary to the rate design principles discussed above.

Q. Does the Company have any other comments regarding the efficacy of raising the tail block distribution rates?

A. Yes. First, the Company notes that the tail block currently represents approximately 3.3% of the total bill.[36] The commodity portion is 54.7%.[37] Raising the tail block rate will have only a minimal price signal compared to the price of the commodity, which is subject to change every month, and can change significantly. Second, using OCA's proposed rates,

---

[34] *See* "Principles of Public Utility Rates", Second Edition, by James C. Bonbright, Albert L. Danielsen and David R. Kamerschen. Public Utility Reports, Inc. 1988.

[35] Johnson Testimony, Bates 25, lines 7-9.

[36] Using January 2016 Residential Heating (R-3) as a proxy. See Simek/Therrien Testimony Attachment RATES-8 page 2 of 16 (Bates 256), line 112/132.

[37] Ibid, line 124/132.

[38] bill impacts for larger users are considerably higher compared to the Company's proposal.

Q. Has the Commission considered cost causation when designing utility rates?

A. Yes. The Commission has not only recognized, but has been progressive in recognizing cost causation and has designed rates with this important principle in mind. The OCA referred to an American Gas Association (AGA) survey that indicates that the Company's fixed customer charges are high compared to other gas utilities. This comparison should not deter the Commission from designing rates based on cost causation principles. The costs of providing utility service are largely fixed, and having a customer charge that sends the price signal that utility service is available regardless of how much gas is consumed is appropriate. The Company's Marginal Cost Study indicates Residential class customer costs in excess of $60 per month, well above the Company's proposed monthly customer charge for rates R-1 and R-3.

Q. Should public policy considerations play a role in rate design?

A. Yes. However, the rate design principles cited above should not be ignored. If the Commission wishes to move toward more volumetrically-weighted rates, it should do so only after assessing the impact on the full range of customers' bills, and respecting the other long-standing rate design principles of rate gradualism and simplicity.

[38] Johnson Testimony, Bates 107.

V. CHANGES TO THE LOW-INCOME PROGRAM

Q. Please summarize your understanding of Staff's proposed modifications to the Residential Low-Income Assistance Program ("RLIAP").

A. Staff has proposed to modify the existing RLIAP in two phases. First, the RLIAP is proposed to be reduced from a 60% reduction in delivery-only charges to 25% of total projected gas costs. Second, in year 2 the rate would decline to 20% of projected gas costs. As is currently done, the proposed RLIAP rate should be included in the LDAC rate contained in EnergyNorth's winter COG filing, and the approved LDAC rate would be effective for November 1 through October 31, with savings to be calculated on the projected total bill for an average residential heating customer for the 12 months commencing November 1 of that year.[39] Although not specifically addressed, the Company assumes that base delivery rates in the instant case would continue to include an adjustment to the firm delivery rate classes for the projected rate year RLIAP projected dollar amount, and any differences reconciled through the COG annual filing and billed through the LDAC.

Q. Does the Company agree with this proposal?

A. The Company does not take a position with this proposal. However, the Company questions the timing of this proposal and use of the instant proceeding to review it.

[39] Direct Testimony of Stephen P. Frink, November 30, 2017 Bates 27.

Q. Please explain.

A. The Company believes that this topic is best adjudicated through a generic proceeding, which would continue past precedent established in the original pilot program in Docket No. 05-076, see Order No. 24,508 (September 1, 2005), and subsequent program revisions in Docket No. DG 06-120, see Order No. 24,669 (September 22, 2006). In addition, Staff's proposal implicates other rate components that are not part of this rate case. Further, this issue was not included in the Commission's Order of Notice in this proceeding[40] which may have precluded other interested entities from intervening in this case. For these reasons, the Company respectfully recommends that the Commission open a separate generic proceeding if this proposal is going to be considered.

Q. How would rejecting this proposal change the instant case?

A. The Company's filing in the instant case would not be changed. Further, any changes that may arise from a generic RLIAP proceeding could be implemented through the annual COG filing, and rates adjusted through the LDAC. It is not necessary to implement a change in the RLIAP in the context of a general rate case.

[40] Order No. 26,015 (May 8, 2017) "Order Suspending Proposed Tariff and Scheduling Prehearing Conference and Temporary Rate Hearing".

VI. SUMMARY

Q. Please summarize this rebuttal testimony.

A. EnergyNorth appreciates the inputs received from Staff's witness Mr. Iqbal and OCA witness Dr. Johnson regarding decoupling and rate design. However, some aspects of their respective proposals should be rejected. Specifically:

1) **Staff's recommendation to weather normalize sales prior to performing the RDM adjustment should be rejected.** Staff's decoupling proposal is nothing more than a continuation of the LRAM and does not sever the link between Company sales volumes and revenues, which undermines the potential for greater energy efficiency savings present in the Company's and in the OCA's decoupling proposals.

2) **The Company agrees with the OCA's proposal for a "real-time" RDM, but disagrees with calculating decoupling on a Total Revenue basis.** EnergyNorth is a natural gas utility in growth mode, and the incremental revenues from new customer additions should be retained between rate cases to fund growth investments. Any incremental computer enhancement costs to implement this proposal should not be rejected, as recommended by the OCA..

3) **Staff and the OCA's inclining block rate proposals should be rejected.** The Commission's long-standing practice of designing customer rates based on cost causation should not be discarded as a result of implementing the RDM. As detailed above, gas commodity charges represent the largest component of the bill

and send the most impactful price signal. Further, the Company's proposed fixed customer charges should be approved, as supported through the MCS.

4) Staff's proposal to change the RLIAP should be addressed in a properly noticed generic proceeding.

Q. Does this complete your testimony?

A. Yes, it does.

NHPUC NO. 9 - GAS

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.
D/B/A

LIBERTY UTILITIES

SUPERSEDING NHPUC No. 8

TARIFF

FOR

GAS SERVICE

Applicable

in

Thirty three towns in New Hampshire
served in whole or in part.

(For detailed description, see Service Area)

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day, Year, in Docket No. DG 17-048

Table of Contents

CHECK SHEET 1

I. GENERAL TERMS AND CONDITIONS 7

1	SERVICE AREA	7
2	GENERAL TERMS AND CONDITIONS	7
3	CHARACTER OF SERVICE	7
4	CUSTOMER’S INSTALLATION	8
5	APPLICATION FOR SERVICE	8
6	CREDIT	9
7	SERVICE AND MAIN EXTENSIONS	9
8	INTRODUCTION OF SERVICE	13
9	COMPANY EQUIPMENT ON CUSTOMER'S PREMISES	13
10	SERVICE CONTINUITY	14
11	CUSTOMER'S USE OF SERVICE	14
12	INSPECTIONS	14
13	MEASUREMENT	15
14	METER TESTS	15
15	DISCONNECTION BY THE COMPANY	15
16.1	COST OF GAS CLAUSE	16
16.2	COST OF GAS CLAUSE – KEENE DIVISION	32
17	LOCAL DISTRIBUTION ADJUSTMENT CLAUSE	33
18	SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY	45

II. RATE SCHEDULES 49

1	RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1	49
2	RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-3	51
3	LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4	53
4	MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5	55
5	MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6	57
6	MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7	59
7	COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE	

Table of Contents

RATE CLASSIFCATION NO. G-41 61

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-42 63

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43 65

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44 67

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45.... 69

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46 71

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51 73

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52 75

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFICATION NO. G-53 77

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-54 79

17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55 81

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56..... 83

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-5785

20 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58 87

21 OUTDOOR GAS LIGHTING 89

22 FIRM RATE SCHEDULES 90

23 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM 91

24 FIRM RATE SCHEDULES - OUTDOOR GAS LIGHTING 92

25 ANITCIPATED COST OF GAS 93

26 CALCULATION OF FIRM SALES COST OF GAS RATE 94

27 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE 95

28 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE – KEENE DIVISION 96

29 CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE 97

30 ENVIRONMENTAL SURCHARGE – MANUFACTURED GAS PLANTS 98

31 RATE CASE EXPENSE FACTOR CALCULATION 99

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Table of Contents

32 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION 100

III. DELIVERY TERMS AND CONDITIONS 101

1 RATES AND CHARGES 101
2 DEFINITIONS 101
3 CHARACTER OF SERVICE 105
4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS 105
5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY 106
6 QUALITY AND CONDITION OF GAS 106
7 POSSESSION OF GAS 107
8 COMPANY GAS ALLOWANCE 107
9 DAILY METERED DELIVERY SERVICE 107
10 NON-DAILY METERED DELIVERY SERVICE 112
11 CAPACITY ASSIGNMENT 116
12 BILLING AND SECURITY DEPOSITS 123
13 SALES SERVICE 124
14 PEAKING SERVICE 125
15 DISCONTINUANCE OF SERVICE 127
16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS 127
17 FORCE MAJEURE AND LIMITATION OF LIABILITY 128
18 CURTAILMENT 129
19 TAXES 129
20 SUPPLIER TERMS AND CONDITIONS 130
21 CUSTOMER DESIGNATED REPRESENTATIVE 136

IV. ATTACHMENTS 137

1 ATTACHMENT A Supplier Service Agreement 137
2 ATTACHMENT B Schedule of Administrative Fees and Charges 151
3 ATTACHMENT C Capacity Allocators 152

CHECK SHEET

The title page and pages 1-94 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

Page	Revision
Title	Original
TOC i	Original
TOC ii	Original
TOC iii	Original
1	Original
2	Original
3	Original
4	Original
5	Original
6	Original
7	Original
8	Original
9	Original
10	Original
11	Original
12	Original
13	Original
14	Original
15	Original
16	Original
17	Original
18	Original
19	Original
20	Original
21	Original
22	Original
23	Original
24	Original

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Check Sheet

Page	Revision
25	Original
26	Original
27	Original
28	Original
29	Original
30	Original
31	Original
32	Original
33	Original
34	Original
35	Original
36	Original
37	Original
38	Original
39	Original
40	Original
41	Original
42	Original
43	Original
44	Original
45	Original
46	Original
47	Original
48	Original
49	Original
50	Original
51	Original
52	Original
53	Original
54	Original
55	Original

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 3

Check Sheet

Page	**Revision**
56	Original
57	Original
58	Original
59	Original
60	Original
61	Original
62	Original
63	Original
64	Original
65	Original
66	Original
67	Original
68	Original
69	Original
70	Original
71	Original
72	Original
73	Original
74	Original
75	Original
76	Original
77	Original
78	Original
79	Original
80	Original
81	Original
82	Original
83	Original
84	Original
85	Original
86	Original

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Check Sheet

Page	Revision
87	Original
88	Original
89	Original
90	Original
91	Original
92	Original
93	Original
94	Original
95	Original
96	Original
97	Original
98	Original
99	Original
100	Original
101	Original
102	Original
103	Original
104	Original
105	Original
106	Original
107	Original
108	Original
109	Original
110	Original
111	Original
112	Original
113	Original
114	Original
115	Original
116	Original
117	Original

Check Sheet

Page	Revision
118	Original
119	Original
120	Original
121	Original
122	Original
123	Original
124	Original
125	Original
126	Original
127	Original
128	Original
129	Original
130	Original
131	Original
132	Original
133	Original
134	Original
135	Original
136	Original
137	Original
138	Original
139	Original
140	Original
141	Original
142	Original
143	Original
144	Original
145	Original
146	Original
147	Original
148	Original

Check Sheet

Page	**Revision**
149	Original
150	Original
151	Original
152	Original

I. GENERAL TERMS AND CONDITIONS

1 SERVICE AREA

A. Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Keene, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham,and part of Canterbury and Winnisquam.

2 GENERAL TERMS AND CONDITIONS

A. Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission") and is open to inspection at the offices of the Company.

B. Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the Commission and such changes, when effective, shall have the same force as the original tariff.

C. Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

D. Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

E. No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

F. Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

G. Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

H. Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

3 CHARACTER OF SERVICE

A. Gas Supply. This Tariff applies only to the supply of gas, having a thermal content of nominally 1,000 British thermal units per cubic foot at supply pressures available in the locality in which the premises to be served are situated.

B. Determination of Therms. The gas for any billing period, expressed in hundreds of cubic feet (ccf), shall be multiplied by the average Btu of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period. For billing purposes, gas therms shall be determined on a "dry" basis.

The Btu therm factor of the gas sendout shall be calculated for each billing cycle from the daily weighted average Btu of the natural gas delivered to the Company by its suppliers and the gas produced at the Company's peak-shaving plants. The daily average Btu content shall be determined by appropriate gas measurement devices operated by the Company or its supplier.

C. Delivery of Gas Supply. The rates specified in this tariff are based upon the supply of service to a single customer through one delivery and metering point.

D. Use of Service at Separate Properties. The use of service at two or more separate properties will not be combined for billing purposes.

4 CUSTOMER'S INSTALLATION

A. Point of Delivery. Upon request, the Company will designate a point at which the customer shall terminate his piping for connection to the meter of the Company, but such information does not constitute an agreement or obligation on the part of the Company to furnish service.

B. Space for Meter. The customer shall provide, free of expense to the Company, a dry, warm and otherwise suitable place for the regulator or regulators, meter or meters, or other equipment of the Company which may be necessary for the fulfillment of such contracts as may be entered into with the Company.

C. Location of Meter. The space provided for the Company's meters and equipment shall be convenient access to the Company's employees and, as near as possible, to the point where the service supply pipe enters the customer's building. Its location shall be such that the meter connections are not concealed by plaster or sheathing and shall be otherwise acceptable to the Company.

D. Reverse Flow. The customer may be required to install check valves or other devices to prevent compressed air or other gases from entering the Company's mains.

5 APPLICATION FOR SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of the applicant's use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Right to Reject. The Company may reject any application for service which would involve excessive cost to supply, or which might affect the supply of service to other customers, or for other good and sufficient reasons.

C. Special Contracts. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, contracts of longer terms as specified in the rate, or with a special guarantee of revenue, or both, may be required to safeguard such investment.

D. Unauthorized Use. Unauthorized connection to the Company's gas service supply facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company without notice. The use of service without notifying the Company and without enabling the Company to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last meter reading of the Company's meter immediately preceding the user's occupancy as shown by the Company's books.

E. Managed Expansion Program. The Managed Expansion Program targets gas expansion in specific areas that have high potential for demand. Each Managed Expansion Program project includes a Main Extension. Customers under this program avoid a portion or all of a contribution in aid of construction which would otherwise be required absent the Managed Expansion Program.

6 CREDIT

A. Prior Debts. Service will not be furnished to former customers until any indebtedness to the Company for previous service has been satisfied.

B. Deposits. Before rendering or restoring service, the Company may require a deposit subject to the Commission's Rules and Regulations. (See Puc 1200 rules).

7 SERVICE AND MAIN EXTENSIONS

A. Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in the main and service extensions provisions.

1. Service and Main Extensions. Extensions that require the construction of a new gas main and a service from that new main in order to provide requested gas service to a customer.

2. Service Extensions. Extensions from an Existing Gas Main to the point of delivery on the customer's premises.

3. Main Extension. An extension of the new gas main portion of a Service and Main Extension.

4. Existing Gas Main. A main that is installed in the street and through which gas is flowing.

5. Abnormal Costs. Abnormal Costs are service and/or main construction costs that are attributable to frost or ledge (including ditching or backfilling necessitated as a result of the presence of frost or ledge),and/or other conditions not typically encountered in service and/or main construction that are peculiar to the particular service and/or main construction concerned. Abnormal Costs are to be paid by the customer.

6. Extra Footage. The charge (contribution in aid of construction) for Extra Footage is $31.54 per foot. The charge will be updated annually by calculating the historical average cost per foot for Service Extensions, excluding overheads, for the most recent calendar year and the updated charge shall be effective April 1.

7. Estimated Annual Margin. The Estimated Annual Margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the Service and Main Extension or Service Extension during the first twelve

(12) months after completion of the extension. The Estimated Annual Margin does not include revenue received by the Company for the cost of gas and local distribution adjustment factor.

8. Estimated Cost of Construction. For the purpose of determining the cost of Service and Main Extensions, Estimated Cost of Construction of mains and/or services includes the cost of labor and materials for such construction, and incidental or associated miscellaneous costs, but excluding overheads. Miscellaneous costs include, but are not limited to, meter(s), traffic control and city and town road permits and degradation fees. The customer may perform on-site trenching and backfilling in accordance with the Company's specifications, in which case the Estimated Cost of Construction will be reduced to reflect the costs avoided by the Company as a result of the customer's performance of the work.

B. Costs of Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:

1. Residential Service Extensions. Residential Service Extensions up to 100 feet in length will be installed at no charge to customers served under either a (i) residential heating rate; or (ii) a residential non-heating rate provided that such extension is installed during the installation of a Main Extension or during the performance of work on cast iron/bare steel main replacements; unless there are Abnormal Costs associated with such extensions, in which case the customer shall be charged for the Abnormal Costs. For residential Service Extensions in excess of 100 feet, the customer will be charged for the Extra Footage, plus any Abnormal Costs. This Section 7(B)(1) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

2. Commercial and Industrial Service Extensions. Commercial and industrial Service Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service Extension, excluding any Abnormal Costs. If the Estimated Annual Margin is less than one-sixth of the Estimated Cost of Construction, the customer will be required to pay to the Company, in advance, any amount by which the Estimated Cost of Construction of the Service Extension exceeds six times the Estimated Annual Margin. Abnormal Costs are charged separately and are not included in the Estimated Cost of Construction for the purpose of this calculation. This Section 7(B)(2) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

3. Service and Main Extensions of Less Than $1,000,000. The Company shall not commence construction on a Service and Main Extension for which the Estimated Cost of Construction is less than $1,000,000 until the sum of (i) six times the Estimated Annual Margin for all commercial and industrial customers who have committed to take service, plus (ii) eight times the Estimated Annual Margin for all residential customers who have committed to take service equals or exceeds 25% of the Estimated Cost of Construction.

   a. Residential. Residential Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-eighth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-eighth of the Estimated Cost of Construction, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and eight times the Estimated Annual Margin, plus any Abnormal Costs.

If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated equally among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main. Abnormal Costs associated with Main Extensions will be allocated equally among all customers, unless such costs can be attributed to specific customers.

b. Commercial and Industrial. Commercial and industrial Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-sixth of the cost of construction of the Service and Main Extensions, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and six times the Estimated Annual Margin, plus any Abnormal Costs.

c. If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include in such calculations the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

d. Extensions Serving Customers in More Than One Rate Class. If the Main Extension will serve both residential and commercial or industrial customers, the Company will determine whether a contribution will be required by the customers by calculating the difference between the Estimated Cost of Construction of the Main and Service Extensions and (i) six times the Estimated Annual Margin for all commercial and industrial customers to be served, plus (ii) eight times the Estimated Annual Margin for all residential customers to be served. The Company will also include in the above calculations the Estimated Annual Margin and the Estimated Cost of Construction of Service Extensions for all existing premises for which the Company reasonably anticipates will take service. If the difference described above is positive, the customers will be required to pay to the Company such difference. The amount of payment will be allocated among all metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer's proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer's proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

4. Service and Main Extensions Greater Than or Equal to $1,000,000. If the cost of the Main Extension equals or exceeds $1,000,000, then in addition to the requirements specified in Section 7(B)(3), the Company will not commence construction unless a discounted cash flow analysis demonstrates a positive net present value over a 10-year period of the difference between the Estimated Annual Margin and the revenue requirement associated with the Estimated Cost of Construction.

C. Failure to Use Installed Gas Service. If a customer fails, within nine months after the date a service is installed under this Section 7, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by the customer for the service, which will be forfeited.

D. Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.

E. Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer pays for the extra expense in advance of installation.

F. Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.

G. Timing and Refunding of Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contribution in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, if substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; or (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application, ten percent (10%) of the contribution will be forfeited to the Company and will not be returned to the customer. The balance of the contribution will be refunded if and when the application is withdrawn, or will be applied toward the new contribution if the customer submits a new application for service or subsequently commences construction of the building or buildings. A new application may be submitted at any time.

H. Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.

I. Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.

J. Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied

1. That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;

2. That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;

3. That the customer is proceeding or plans promptly to proceed with such construction; and

4. That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.

8 INTRODUCTION OF SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of his use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Defective Installation. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

C. Unsatisfactory Installation. The Company may refuse to connect if, in its judgment, the customer's equipment or use thereof might injuriously affect the equipment of the Company or the Company's service to other customers.

9 COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

A. Meters and Regulators. The Company shall furnish and install, maintain and own, any meter or meters, regulator or regulators required in the supply of service. For certain large customers, the Company shall furnish, install and maintain, at the customer’s expense, any remote meter reading equipment to record usage for daily balancing. Such equipment shall remain the property of the Company at all times.

B. Customer's Responsibility. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property, the customer shall pay the costs of repairs and replacements.

C. Relocation and/or Replacement of Company Equipment. The original service connection, including piping, meters and all other necessary or incidental equipment, which remains the property of the Company, shall be installed by the Company at its expense unless otherwise expressly provided in this tariff. Subsequent relocation and/or replacement of any such equipment on private property, whether it be for one or more service connections, shall be performed by the Company at the customer's expense unless such work is done at the request of the Company and for its convenience, in which case the Company shall bear the expense.

D. Protection by Customer. The customer shall protect the equipment of the Company on his premises and shall not permit any persons, except a Company employee having a Company photo identification card or other Company identification, to break any seals upon or do any work on any meter, service supply pipe, or other equipment of the Company located on the customer's premises.

E. Tampering. In the event the Company's meter or other property is being tampered with or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter and for any repairs or replacements required as well as for costs of inspections, investigations, and protective installation.

F. Right of Access. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to the Company.

G. Ownership and Removal. All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service for whatever cause.

10 SERVICE CONTINUITY

A. Regularity of Supply. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted or fail by reason of accident, strike, legal process, state or municipal interference, or any cause whatsoever beyond its control, the Company shall not be liable for damages, direct or inconsequential, resulting from such interruption or failure.

B. Notice of Trouble. The customer shall notify the office of the Company immediately should the service be unsatisfactory for any reason or should there be any defects, leaks, trouble, or accident affecting the supply of gas.

11 CUSTOMER'S USE OF SERVICE

A. Resale Forbidden. The customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of to others, gas purchased from the Company, or any part thereof, without the consent of the Company. This rule does not apply to a public utility Company purchasing gas in bulk expressly for the purpose of delivering it to others.

B. Fluctuations. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system. In the case of violation of this rule, the Company may discontinue service or require the customer to modify its installation and/or equip it with approved controlling devices.

C. Additional Load. The service supply pipe, regulators, meters, and equipment supplied by the Company for each customer have definite capacities. The customer shall notify the Company of substantial changes in service requirements or location of appliances.

12 INSPECTIONS

A. Company's Right to Inspect. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any time later and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements. However, such inspection, failure to inspect, or failure to reject shall not render the Company liable or responsible for any losses or damage resulting from defects in the installation, piping or appliances, from violation of Company rules, or from accidents which may occur upon the premises of the customer.

13 MEASUREMENT

A. Supply of Meters. The measurement of gas service shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment and may, from time to time, change or alter the equipment. The Company's sole obligation is to supply meters that will accurately and adequately furnish records for billing purposes.

B. Special Measurements. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments on the premises of any customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the customer's load.

14 METER TESTS

A. Meter Tests. Meters are tested according to NHPUC Rules and Regulations. (See Puc 500 rules).

B. Request Tests. The fee for a special request test is $20.00 when scheduled at the mutual convenience of the Company and the customer; otherwise the amount is $30.00. (See Puc 500 rules).

C. Customer's Bill Adjustment. Should any meter fail to register correctly, the quantity of gas consumed will be determined by the Company based on information supplied by the customer and known by the Company subject to NHPUC Rules and Regulations. (See Puc 500 rules).

15 DISCONNECTION BY THE COMPANY

A. Disconnection by the Company. The Company may disconnect its service to a customer for violation of its rules subject to NHPUC Rules and Regulations. (See Puc 1200 rules).

B. Non-Payment Shut-Off. The Company may disconnect its service on reasonable notice and remove its equipment in case of non-payment of amounts billed for gas usage.

C. Shut-Off for Cause. The Company may disconnect its service on reasonable notice if entry or access to its meter or meters is refused, obstructed, or hazardous, or for other violation of the Company's standard requirements.

D. Safety Shut-Off. The Company may disconnect without notice if the customer's installation has become dangerous or defective.

E. Defective Equipment. The Company may disconnect without notice if the customer's equipment, or use thereof, might injuriously affect the equipment of the Company or the Company's service to other customers.

F. Shut-Off for Fraud. The Company may disconnect without notice for abuse, fraud or tampering with the connections, meters or other equipment of the Company.

G. Reconnection Charge. A reconnection charge is made for reconnection of service discontinued by the Company and is payable in advance in addition to all other amounts due. The reconnection charge is made instead of the meter account charge. The amount of the reconnection charge is the same as the comparable meter account charge except when it has been necessary to dig up the service pipe or connection to effect discontinuance of service. In such cases, the reconnection charge is the price of removal and restoration of service pipe or connection.

16.1 COST OF GAS CLAUSE

A. Purpose. The purpose of this Cost of Gas Clause is to establish procedures that allowthe Company, subject to the jurisdiction of the Commission, to adjust, on a semiannual basis, its rates for firm gas sales in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchased gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit to customers receiving firm service from the Company all supplier refunds and capacity release sales.

B. Applicability. This Cost of Gas Clause (“COGC”) shall be applicable to the Company and all firm gas sales made by the Company, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the NHPUC. See Section 16(N), "Other Rules."

C. Cost of Firm Gas Allowable for COGC. All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, hedging related costs, other gas supply expense incurred to procure and transport supplies and commodity related bad debt expense, the gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the COGC. Any costs recovered through application of the COGC shall be identified and explained fully in the semiannual filings outlined in Section 16(M).

D. Effective Date of Cost of Gas Factor. The seasonal Cost of Gas Factor (“COG”) shall become effective upon NHPUC approval on the first day of each season as designated by the Company. Unless otherwise notified by the NHPUC, the Company shall submit COG filings as outlined in Section 16(M) of this clause on or before the first business day in September...

E. Definitions. The following terms shall be defined in this section, unless the context requires otherwise.

1. Bad Debt Expense: The uncollectible expense attributed to the portion of the Company's revenue associated with the recovery of gas costs under this clause.

2. Capacity Release Revenues: The economic benefit derived from the sale or release of transportation and storage capacity that the Company has under contract.

3. Carrying Charges: Interest expense calculated on the average monthly balance using the *monthly* prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end of month balance.

4. Correction Factor: Seasonal Adjustment necessary to align the peak day volumes used to calculate the Commercial and Industrial load factor ratios with the seasonal Commercial and Industrial High Winter and Low Winter throughput volumes applied to the cost of gas calculations.

5. Direct Gas Costs: All purchased gas costs including supplier, storage and pipeline demand and commodity costs, as well as the commodity costs for local manufactured gas (Liquid Propane Gas (“LPG”) and Liquefied Natural Gas (“LNG”)).

6. Economic Benefit: The difference between the revenues received and the marginal cost determined to serve non-core customers.

7. Inventory Finance Charges: As billed in each Winter Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing or anticipated financing rate through a trust or other financing vehicle.

8. Local Production and Storage Capacity Costs: The costs of providing storage service from the Company's storage facilities (*i.e.*, LNG and LPG) as determined in the Company's most recent rate proceeding.

9. Market Based Allocator (“MBA”): The method used to allocate gas costs among Commercial and Industrial Customer Classifications. These ratios are presented in Section 16(F).

10. Non-Core Commodity Costs: The commodity cost of gas assigned to non-core sales to which the COG is not applied.

11. Non-Core Sales: Sales made under non-traditional off-system sales.

12. Non-Core Sales Margins: The economic benefit derived from non-core transactions to which the COG is not applied, including non-core sales generated from the use of the Company's Gas Supply Resource portfolio.

13. Summer Commodity: The gas supplies procured by the Company to serve firm load in the Summer Season.

14. Summer Demand: The gas supply demand and transmission capacity procured by the Company to serve firm load in the Summer Season.

15. Summer Season: The calendar months May 1 through October 31.

16. Off-System Sales Margin: The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

17. Winter Commodity: The gas supplies procured by the Company to serve firm load in the Winter Season.

18. Winter Demand: Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.

19. Winter Season: The calendar months November 1 through April 30.

20. PR Allocator: The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.

21. Purchased Gas Working Capital: The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

F. Approved Cost. The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

Variable	Description	Approved Figure
MISC	Miscellaneous Overhead	$13,170
PS	Production and Storage Capacity	$1,980,428
WCA%	Working Capital Allowance Percentage	3.91%

Bad Debt % Measurement and Reconciliation Period	COG Recovery Period	Actual Bad Debt Rate	Bad Debt allowed Recovery Rate
May 2010 – April 2011	November 2011 – October 2012	Actual	Actual
May 2011 – April 2012	November 2012 – October 2013	Greater than 2.9%	Actual less 0.4
		2.5% to 2.9%	2.5%
		Less than 2.5%	Actual
May 2012 - April 2013 and each subsequent May – April period thereafter	November 2013 - October 2014 and each subsequent November – October period thereafter	Greater than 3.3%	Actual less 0.8
		2.5% to 3.3%	2.5%
		Less than 2.5%	Actual

If the Company's actual bad debt percentage is reduced to 2.5% or less during any 12 month period, which need not be the same 12 months as the measurement periods defined above, then beginning with the reconciliation filing for the period during which this bad debt percentage was achieved the Company shall thereafter recover its actual gas supply related bad debt on a fully reconcilable basis and the percentages in the table above shall no longer apply. The actual bad debt percentage shall be calculated by dividing the Company's actual net write-offs for the relevant measurement period by its revenue for the same period.

G. Cost of Gas (COG) Calculations by Customer Class. The COG Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment C of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

GROUP	CUSTOMER CLASSES
Residential	Residential Heating and Non-Heating
Commercial and Industrial: Low Winter Use	G-51 through G-58
Commercial and Industrial: High Winter Use	G-41 through G-46

Winter Season Cost of Gas Formula (CGw)

The Winter Season COG shall be comprised of Winter Demand costs, Winter commodity costs, Winter reconciliation costs, Winter working capital reconciliation, Winter bad debt expenses, local production and storage capacity costs, and miscellaneous and A&G costs calculated at the beginning of the Winter Season according to the following formula:

$$CGw = Dw + Cw + Rw + WCRw + BDw + PS + ((MISC + Rbd) \times \frac{W:Sales)}{A:Sales}$$

Winter Demand Cost (Dw) Formula

$$Dw = DEMw – NCSMw + WCwd – R1d – R2d$$

and:

$$NCSMw = CRRw + OSSMw + SBdw$$

and:

$$WCwd = (DEMw – NCSMw) \times WCA\% \times CC$$

where:

CGw = The total cost of gas for the Winter Season for the Company’s firm sales customers previously defined.

BDw = Bad Debt expense for the Winter Season.

Cw = Commodity-related direct gas cost for the Winter Season.

Dw = The total Winter Demand costs.

DEMw = Demand Charges allocated to the Winter Season defined in Section 16(E).

NCSMw = The Non-Core Sales Margins equal to the sum of the Winter Season returnable Capacity Release Revenues, and Off-System Sales Margins.

WCwd = Working Capital allowable associated with demand charges allocated to the Winter Season as defined in Section 16(K).

R1d, R2d = Supplier demand-related refunds - The Supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

CRRw = The returnable Capacity Release Revenues allocated to the Winter Season. See Section 16(E).

OSSMw = The returnable Off-System Sales Margins allocated to the Winter Season. See Section 16(E).

SBdw = Demand revenues received from Firm Stand-By Sales Service customers in the Winter Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rw = Reconciliation Costs – Winter Season deferred gas costs, Account 1920-1740 balance, inclusive of the associated Account 1920-1740 interest, as outlined in Section 16(J).

WCRw = Working Capital reconciliation adjustment associated with Winter Gas Costs - Account 1163-1422 balance as outlined in Section 16(K).

PS = The total dollar amount of costs associated with the local production and storage capacity gas less any production and storage capacity assignment revenues. Refer to Section 16(F) for this dollar amount.

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 16(F) for this dollar amount.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance

W:Sales = Forecasted firm sales volumes associated with the Winter Season.

A:Sales = Forecasted annual firm sales volumes.

Winter Season Commodity (Cw) Formula

Cw = COMw + FC + WCwc – R1c – R2c
and:

COMw = WSC – NCCCw - SBcw
and:

WCwc = (COMw + FC) × WCA% × CC
where:

COMw = Commodity Charges allocated to the Winter Season as defined in Section 16(E).

FC = Inventory finance charges as defined in Section 16(E).

WCwc = Working Capital Allowable Associated with commodity charges allocated to the Winter Season as defined in Section 16(K).

R1c, R2c = Supplier commodity-related refunds - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds". See Section 16(I).

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

WSC = Commodity charges associated with gas supply sent out in Winter Season as defined in Section 16(E).

NCCCw = Non-Core Commodity Costs incurred in the Winter Season as defined in Section 16(E).

SBcw = Winter Season commodity revenues received from Firm Stand-By Gas Supply Service sales customers.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Winter Bad Debt (BDw) Formula

BDw = BD% x (Dw + Cw + Rw + WCRw)
where:

BDw = Forecasted gas supply cost related Bad Debt Expense calculated for Winter Season.

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

Dw = Demand related costs in the Winter Season as previously defined.

Cw = Commodity related costs in the Winter Season as previously defined.

Rw = Reconciliation Costs – Winter Season deferred gas costs as previously defined.

WCRw = Winter Season Working Capital Reconciliation adjustment as previously defined.

Residential Winter Season Cost of Gas (COGwr)

All residential firm sales customers will pay the same Cost of Gas for the Winter Season. The factor represents the total forecasted Winter Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGwr = \frac{CGw}{W{:}Sales}$$

where:

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers previously defined.

W:Sales = Forecasted sales volumes associated with the Winter Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Summer Season Cost of Gas (COG) Formula (CGs)

The Summer Season COG shall be comprised of Summer demand costs and Summer commodity costs, Summer reconciliation costs, Summer working capital reconciliation, plus a Summer bad debt charge, and a miscellaneous and A&G charge calculated at the beginning of the Summer Season according to the following formula:

$$CGs = Ds + Cs + Rs + WCRs + BDs + \left((MISC + Rbd) \times \frac{S{:}Sales}{A{:}Sales}\right)$$

Summer Demand Cost (Ds) Formula

Ds = DEMs + WCsd – Rld – R2d
and:

WCsd = DEMs × WCA% × CC
where:

A:Sales =	Forecasted annual sales volumes.
BDs =	Bad Debt Expense for Summer Season.
Cs =	Commodity-related direct gas costs for the Summer Season.
CGs =	The total cost of gas for the Summer Season for the Company's firm sales customer previously defined.
DEMs =	Demand charges allocated to the Summer Season defined in Section 16(E).
MISC =	The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. Refer to Section 16(F) for this dollar amount.
R1d, R2d =	Supplier refunds from pipeline demand charges - The per unit supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).
Rs =	Summer Season Reconciliation Costs - Account 1920-1741 balance, inclusive of the associated Account 1920-1741 interest, as outlined in Section 16(J).
S:Sales =	Forecasted sales volumes associated with the Summer Season.
WCA % =	Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.
CC =	Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.
Rbd =	Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance.
WCRs =	Working Capital reconciliation adjustment associated with Summer gas costs – Account 1163-1424 as outlined in Section 16(K).
WCsd =	Working Capital allowable costs associated with demand costs allocated to the Summer Season as defined in Section 16(K).

Summer Season Commodity Cost (Cs) Formula

Cs = COMs – NCCCs + WCsc – R1c – R2c
and:

WCsc = (COMs – NCCCs) × WCA% × CC
where:

COMs =	Commodity charges associated with gas supply sent out in the Summer Season as defined in Section 16(E).
WCsc =	Working Capital allowable costs associated with commodity charges allocated to the Summer Season as defined in Section 16(K).
R1c, R2c =	Supplier refunds from pipeline commodity charges - The supplier refunds associated with refund program credits derived from Account 5541-8048, “Undistributed Gas Suppliers' Refunds.”
NCCCs =	Non-core commodity costs incurred in the Summer Season as defined in Section 16(E).
WCA % =	Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.
CC =	Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Summer Bad Debt (BDs) Formula

BDs = BD% x (Ds + Cs + Rs + WCRs)
where:

BD% =	Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.
BDs =	Forecasted gas supply related Bad Debt Expense calculated for Summer Season defined in Section 16(E).
Ds =	Demand related costs in the Summer Season as previously defined.
Cs =	Commodity related costs in the Summer Season as previously defined.
Rs =	Reconciliation Costs – Summer deferred gas costs as previously defined.
WCRs =	Summer Season Working Capital Reconciliation adjustment as previously defined.

Residential Summer Season Cost of Gas (COGsr)

All residential firm sales customers will pay the same cost of gas for the Summer Season. The factor represents the total forecasted Summer Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGsr = \frac{CGs}{S:Sales}$$

where:

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

S:Sales = Forecasted sales volumes associated with the Summer Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Commercial and Industrial Winter and Summer Season Cost of Gas

The Commercial and Industrial customer classes Winter Season Cost of Gas will be based on the Winter Season average cost of gas components used for the Residential Winter Season Cost of Gas. A separate Winter Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58 and a separate Winter Season Cost of Gas Factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

The Commercial and Industrial customer classes Summer Season Cost of Gas will be based on the Summer Season average cost of gas components used for the Residential Summer Season Cost of Gas. A separate Summer Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53,G-54, G-55, G-56, G-57, and G-58 and a separate Summer Season Cost of Gas factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

These Cost of Gas Factors will be computed by applying ratios to the average demand portion of the Winter and Summer Season's cost of gas unit rate times the correction factor and then adding the remaining Residential average cost of gas unit rate.

These factors are calculated according to the following formulas:

Low Winter Use (COGwl) Formula Winter Season

COGwl = RATIOl x CFw x CGwd + CGwo

Low Winter Use (COGsl) Formula Summer Season

COGsl = RATIOl x CFs x CGsd + CGso

and:

$$RATIOl = \frac{DDcl}{DDc} \div \frac{DCc}{}$$

RATIOl = DCcl ÷ DCc
DDcl = DDc

and:

High Winter Use (COGwh) Formula Winter Season

COGwh = RATIOh x CFw xCGwd + CGwo

High Winter Use (COGsh) Formula Summer Season

COGsh = RATIOh x CFs x CGsd + CGso
and

RATIOh = $\frac{\text{DCch}}{\text{DDch}} \div \frac{\text{DCc}}{\text{DDc}}$

and:

CFw = $\frac{\text{(WL:Sales + WH Sales)}}{\text{(RATIOl x WL:Sales) + (RATIOh x WH:Sales)}}$

CFs = $\frac{\text{(SL:Sales + SH:Sales)}}{\text{(RATIOl x SL:Sales) + (RATIOh x SH:Sales)}}$

CGwd = $\frac{\text{Dw}}{\text{W:Sales}}$

CGwo = $\frac{\text{CGw - Dw}}{\text{W:Sales}}$

CGsd = $\frac{\text{Ds}}{\text{S:Sales}}$

CGso = $\frac{\text{CGs - Ds}}{\text{S:Sales}}$

DCcl = Bcl * PLrate + (DDcl – Bcl) * REMrate

DCch = Bch * PLrate + (DDch- Bch) * REMrate

PLrate = PL/ PLmdcq

REMrate = $\frac{\text{(DCc – (Bc*PLrate))}}{\text{DDc - Bc}}$

DCc = $\frac{\text{(DC x DDc)}}{\text{DD}}$

where:

Bc = The daily base load for all the Commercial and Industrial rate classes

Bch = The daily base load for the Commercial and Industrial rate classes G-41, G-42, G-43, G-44, G-45 and G-46.

Bcl = The daily base load for the Commercial and Industrial rate classes G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.

CFs = Summer Season Commercial and Industrial gas cost correction factor.

CFw = Winter Season Commercial and Industrial gas cost correction factor.

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

CGw = The total cost of gas for the Winter Season for the Company's firm sales customers as previously defined.

DC =	The annual forecasted pipeline, storage and peaking demand charges plus the total production and storage capacity costs, as stated in Section 16(F).
DCc =	The Commercial and Industrial rate classes pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs.
DCch =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to Commercial and Industrial High Winter Use rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DCcl =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to the Commercial and Industrial Low Winter Use rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
DD =	Total peak design day determinants.
DDc =	The peak design day determinants allocated for all the Commercial and Industrial rate classes.
DDch =	The peak design day determinants for the Commercial and Industrial rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DDcl =	The peak design day determinants for the Commercial and Industrial rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
Ds =	The total Summer Demand charges as defined below.
Dw =	The total Winter Demand charges as previously defined.
PL =	The annual forecasted pipeline only demand charges
PLmdcq =	The maximum daily contract pipeline volume available to the Company.
PLrate =	The pipeline demand rate.
RATIOh =	Ratio of the average high Winter Use class Cost of Gas low load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
RATIOl =	Ratio of the average low Winter Use class Cost of Gas high load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
REMrate =	The weighted average demand rate for storage and peaking supplies.
S: Sales =	Forecasted sales volumes associated with the Summer Season.
SH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
SL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.
W:Sales =	Forecasted sales volumes associated with the Winter Season.
WH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
WL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.

H. Non-Core Sales Margins (“NCSM”). One hundred percent (100%) of margins from Off-System Sales and all revenues from Capacity Release will be credited to firm sales customers during the winter season through operation of the COG.

I. Gas Suppliers' Refunds. Account 5541-8048: Refunds from suppliers of gas, from upstream capacity suppliers and suppliers of product demand are credited to Account 5541-8048, "Commodity and Demand Refunds." Transfers from these accounts will reflect as a credit in the semiannual calculation of the COG to be calculated as follows:

Refund programs shall be initiated with each semiannual COG filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. Refunds shall be segregated by demand and commodity charges and distributed volumetrically, producing per unit refund that will return the principal amount with interest as calculated using the Company's average short-term cost of borrowing for the month to the average of the beginning and end of month balances of refunds. The Company shall track and report on all Account 5541-8048 activities as specified in Section 16(K).

J. Reconciliation Adjustments – Various Accounts.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Capacity Costs Allowable per Winter Season Formula shall be:

(1) Charges associated with upstream storage transmission capacity and product demand procured by the Company to serve firm load in the Winter Season, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Charges associated with peaking, downstream production and storage capacity to serve firm load dispatching costs, and other administrative and general expenses in connection with purchasing gas supplies in the Winter Season from the Company's most recent test year and allocated to firm sales service.

(3) Non-Core Sales Margins or economic benefits associated with returnable capacity release and off-system sales.

(4) Credits associated with firm Stand-by Gas Supply Service Monthly Reservation Charges, daily imbalance charges and fixed component of penalty charges billed transportation customers in the Winter peak Season.

(5) Winter Season Demand Cost carrying charges.

b. Gas Costs Allowable Per Winter Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter Season.

(2) Credit non-core commodity costs assigned to non-core customers to which the COGC does not apply, as defined in Section 16(H) (NCCCw).

(3) Inventory finance charges (FC).

(4) Winter Season commodity cost carrying charges.

c. Capacity Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with transmission capacity and product demand procured by the Company to serve firm load in the Summer Season

(2) Credits associated with daily imbalance charges and fixed component of penalty charges billed transportation customers in the Summer Season.

(3) Summer Season demand cost carrying charges.

d. Gas Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Summer Season commodity cost carrying charges.

e. Costs Allowable Per Bad Debt Formula shall be:

(1) Costs associated with uncollected gas costs, incurred by the Company to serve sales load. Such costs represent the bad debt expense related to the gas supply related write-off of sales customers and will be computed by multiplying actual gas costs by the Bad Debt Allowed Recovery Rate specified in Section 16(F). The reconciliation adjustment each season will be computed as the difference between the actual supply related bad debt revenues and the actual gas costs multiplied by the actual Bad Debt Allowed Recovery Rate as specified in Section 16(F).

(2) Account 1920-1743 – Annual Bad Debt, carrying charges.

2. Calculation of the Reconciliation Adjustments: These accounts contain the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Winter Season Gas Costs (Account 1920-1740) and Summer Season Gas Costs (Account 1920-1741), Account 1920-1740 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Winter Season Gas Cost for each Customer Classification, (COGwr, COGwl and COGwh) times monthly firm sales volumes for each Customer Classification, and the total costs allowable per the Winter Season gas cost formula. Account 1920-1741 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Summer Season Gas Cost for each Customer Classification, (COGsr, COGsl and COGsh) times monthly firm sales volumes for each Customer Classification, and the total gas costs allowable per the Summer Season demand formula.

Carrying Charges shall be calculated on the average monthly balance of each subaccount. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

The annual bad debt reconciliation adjustments Rbd shall be determined for use, incorporating the bad debt balances in Account 1920-1743.

The bad debt account balance contains the accumulated difference between the Bad Debt Allowed Recovery Rate for the applicable period multiplied by the actual gas costs and the actual supply related bad debt revenues for the Winter and Summer COG filings.

The Winter Season reconciliation shall be filed with the NHPUC no later than July 29 of each year.

The Summer Season reconciliation shall be filed with the NHPUC no later than January 31 of each year.

K. <u>Working Capital Reconciliation Adjustments - Accounts 1163-1422 and 1163-1424</u>.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Working Capital Demand Gas Costs Allowable per Winter Season Gas Formula shall be:

(1) Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the Winter period, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Carrying charges.

b. Working Capital

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Carrying charges.

c. Working Capital Demand Gas Costs Allowable per Summer Season Gas Formula shall be:

(1) Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Summer Season.

(2) Carrying charges.

d. Working Capital Commodity Gas Costs Allowable per Summer Season Gas Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales.

(3) Carrying charges.

e. The Winter and Summer Cost of Gas working capital allowances shall be calculated by applying the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F).

2. Calculation of the Reconciliation Adjustments

a. Accounts 1163-1422 and 1163-1424 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance cost. The actual monthly working capital allowance shall be calculated by multiplying the actual gas costs times the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F), to the actual Direct Gas Costs allowable.

b. The Winter Season working capital reconciliation adjustment (WCRw) shall be determined for use in the Winter Season Gas Cost calculations incorporating the Winter Season working capital account 1163-1422. A Summer Season working capital reconciliation adjustment (WCRs) shall be determined for use in the Summer Season Gas Cost calculations incorporating the Summer Season working capital account 1163-1424 balance.

L. Application of COG to Bills: The Company will employ the COGs as follows: The COGs ($/therm) for each customer group for each season shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volume within the corresponding customer classification. The Cost of Gas will be applied to gas consumed on or after the first day of the month in which the cost of gas becomes effective.

M. Information Required to be Filed with the NHPUC.

1. Reconciliation Adjustments: The Company shall file with the NHPUC a seasonal reconciliation of gas costs and gas cost collections containing information in support of the reconciliation calculation set out in Sections 16(J) (2) and 16(K) (2). Such information shall include the complete list of gas costs recoverable through the COGC over the previous season. This seasonal reconciliation shall be filed with the respective seasonal COG reconciliation filing, along with complete documentation of the reconciliation adjustment calculations.

   Additionally, information pertaining to the Cost of Gas shall be filed with the NHPUC in accordance with the format established by the NHPUC. Reporting requirements include filing the Company’s monthly calculation of the projected over or under-collection with the NHPUC, along with notification by the Company to the NHPUC of any revised COG for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month.

   The Company shall file with the NHPUC an annual reconciliation of bad debt expense and bad debt collections containing information in support of the reconciliation calculation set out in Sections 16(J) (1) and 16(J) (2). Such information shall detail the revenues collected as an allowance for bad debt, as well as the actual bad debt expense associated with gas cost recoverable through the COGC over the 12-month period ending April 30th. This annual reconciliation of bad debt expenses shall be filed with the Winter COG reconciliation filing, along with documentation.

2. Commercial and Industrial COG Ratio: The following factors will be filed annually by the Company for informational purposes. Significant changes in these factors signal the need to evaluate the COG ratios. These variables will assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

   a. The percentage of load migration from sales to transportation service in the Commercial and Industrial High and Low Winter Use classes.

   b. The ratio of delivered costs of winter supplies to pipeline delivered supplies.

   c. The July and August consumption for the Commercial and Industrial High and Low Winter classes as a percentage of their annual consumption.

N. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of this tariff, upon such terms that it may determine to be in the public interest.

2. The Company may, without further NHPUC action, adjust the approved COG upward or downward monthly based on the Company's calculation of the projected over or under-collection for the period, but the cumulative adjustments upward shall not exceed twenty-five percent (25%) of the approved COG.

3. The Company may, at any time, file with the NHPUC an amended COG.

4. The operation of the Cost of Gas Clause is subject to all powers of suspension and investigation vested in the NHPUC.

5. The Company shall file both seasonal COG filings on or before the first business day in September. The summer portion of the filing will include COG rates effective May 1 of the following year.

O. Reconciliation Adjustment Accounts.

1163-1422

Winter Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas working capital allowance revenues and Winter Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1163-1424

Summer Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas working capital allowance revenues and Summer Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1740

Winter Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas revenues and Winter Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1741

Summer Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas revenues and Summer Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1743

Annual Bad Debt Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Annual bad debt revenues and annual bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

5541-8048

Commodity and Demand Refunds: This account shall be used to record the refunds from upstream commodity supplies and suppliers of product commodity and transfers of credits in the semiannual calculation of the COG as well as to record the refunds from upstream capacity supplies and suppliers of product demand and transfer of credits in the semiannual calculation of the COG. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

P. Firm Transportation Cost of Gas Charge. To permit the Company to charge its firm transportation customers with a portion of the cost of gas produced by the Company between November 1 and April 30 of each year, there is a Firm Transportation Cost of Gas Charge ("FTCG") which applies to all firm transportation billed under this tariff. This volumetric charge is to compensate firm sales customers for the increase in gas costs, through the use of supplemental liquid fuels, attributable to firm transportation customers during the Winter Period.

1. Application. The FTCG will be calculated for the Winter Period, defined as the period from November 1 through April 30. The FTCG will be applied to billings commencing with the first November revenue billing cycle

2. Purpose. The amount of the FTCG is the estimated liquid costs used for pressure support purposes multiplied by the transportation throughput as a percentage of the total system throughput for the Winter Period. The resulting amount shall be adjusted by the prior period over or under collection, if any, and shall be recovered over the estimated total transportation throughput subject to the FTCG to yield a per therm volumetric charge. The FTCG shall be computed to the nearest one hundredth cent per therm and shown separately on customers' bills. At the conclusion of the Winter Period, the Company will calculate the extent that the FTCG revenues are greater or lesser than actual unit cost. The revenue and liquid costs will be reconciled so that all liquids costs shall be collected from either firm sales or firm transportation customers.

3. Changes. The amount of the FTCG may be changed within the period whenever the unit cost materially deviates from the anticipated unit cost

4. Reporting. The Company shall submit to the New Hampshire Public Utilities Commission, on or before the first business day in September, a copy of the FTCG computation. A reconciliation of the prior period under/over collection will be submitted to the New Hampshire Public Utilities Commission no later than July 29.

Q. Fixed Price Option Program. Fixed Price Option Program. An alternative to the traditional Winter Period cost of gas pricing mechanism may be elected by a residential customer (rates R-1, R-3, R-4, R-5 or R-6) pursuant to the Company's Fixed Price Option Program (the "Program"). The Company may offer up to 50% of its weather normalized firm sales for the prior Winter Period under the Program. The cost of gas rate offered under the Program will remain fixed for all Winter Period deliveries commencing November 1 and ending April 30. The Company shall submit to the New Hampshire Public Utilities Commission on or before September 1 of each year a copy of the fixed price option computation. Once elected, customers must remain on the Program for the duration of the Winter Period, unless service is terminated. There are no maximum or minimum usage levels. No sign up fees apply.

16.2 COST OF GAS CLAUSE – KEENE DIVISION

A. Purpose. To permit the Company to charge its customers in the Keene Division with the cost of gas purchased or produced. A cost of gas rate will be applied to all firm gas billed under this tariff as calculated on the appropriate pages.

B. Application. A cost of gas rate will be calculated for the winter heating period, defined as the period from November 1 through April 30, and a cost of gas rate will be calculated for the summer period, defined as the period from May 1 through October 31.

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

A. Purpose. The purpose of the Local Distribution Adjustment Clause (“LDAC” or this “Clause”) is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges (“CC”), Revenue Decoupling Adjustment Clause (“RDAC”), Winter Period Surcharges (“WPS”), Environmental Surcharges (“ES”) including the Relief Holder Surcharge (“RHS”) and the Manufactured Gas Program Surcharge (“MGP”), recover gas restructuring expenses (“GRE”), rate case expenses (“RCE”), Residential Low Income Assistance Program costs (“RLIAP”) and any other expenses the NHPUC may approve from time to time.

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	CC 17(C)	RDAC 17(C.1)	ES 17(D)	GRE 17(E)	RCE 17(F)	RLIAP 17(G)
Residential Non-Space Heating – R-1, R-5	2	2	X	N/A	2	X
Residential Space Heating – R-3, R-4, R-6, R-7	2	2	X	N/A	2	X
Small C&I – G-41, G-51, G-44, G-55	2	2	X	X	2	X
Medium C&I – G-42, G-52, G-45, G-56	2	2	X	X	2	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	2	2	X	X	2	X

Notes:
N/A Not applicable
X Applicable to all
1 Applicable to Non-Managed Expansion Program Customers
2 As ordered by the NHPUC

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the Commission as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under

collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

C.1 Revenue Decoupling Adjustment Clause

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on a semi-annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

2. Effective Date: The Winter Season Revenue Decoupling Adjustment Factor ("RDAF") for the Winter Season shall be effective on the first day of each Winter Season as defined herein. The Summer Season RDAF shall become effective on the first day of each Summer Season as defined herein.

3. Applicability: The Revenue Decoupling Adjustment Factor shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC.

4. Definitions: The following definitions shall apply throughout the RDAC:

   a. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the Actual Number of Customers for a given season for a Customer Class Group.

   b. Actual Number of Customers is the actual number of customers for the applicable Customer Class Group for the most recently completed Winter Season or Summer Season. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for a given season for a Customer Class Group and dividing by the number of months in each Season.

   c. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

   d. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment amounts. The three Customer Class Groups are as follows:

(1) The Residential Non-Heating Customer Class Group (CG1) shall consist of all customers taking service pursuant to the Company's residential non-heating rate schedule R-1.

(2) The Residential Heating Customer Class Group (CG2) shall consist of all customers taking service pursuant to the Company's residential heating rate schedules R-3, and R-4.

(3) The Commercial and Industrial Customer Class Group (CG3) shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-51, G-52, G-53 and G-54.

e. Summer Season is the continuous period from May 1 through October 31.

f. Winter Season is the continuous period from November 1 through April 30.

g. Benchmark Base Revenue per Customer is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

	Benchmark Base Revenue per Customer	
Customer Class Group	**Winter Season**	**Summer Season**
Residential Non-Heating (CG1)	$165.77	$145.53
Residential Heating (CG2)	$433.98	$210.90
Commercial and Industrial (CG3)	$2,200.52	$894.95

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Winter Season and Summer Season, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the Actual Base Revenue per Customer and the Benchmark Base Revenue per Customer, and multiplying that difference by the Actual Number of Customers for the applicable Customer Class Group. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for each of the three Customer Class Groups and shall include a reconciliation component.

The total Revenue Decoupling Adjustment determined in accordance with Section 5.0 may not exceed plus or minus five percent (±5%) of total base revenues from firm Rate Classes for the most recent corresponding Winter or Summer Season. To the extent that the application of the Revenue Cap results in a Revenue Decoupling Adjustment that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the Revenue

Decoupling Reconciliation for recovery in the subsequent year during the corresponding Winter or Summer Season. Carrying charges shall be calculated on the average deferred balance using the prime lending rate and then added to the end-of-month balance.

b. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CG=1}^{CG=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CG} \right) x\ ACUSTS_{T-1}^{CG} \right]$$

If
$RD < (5\%\ x\ DIST\ REV_T)$
And
$RD > (-5\%\ x\ DIST\ REV_T)$

Then
$DEF_{incm} = 0$
And:
$DEF_{rec} = Lower\ of\ (DEF_{balp)}\ or\ \left((5\%\ x\ DIST\ REV_T) - RD\right)$
And:
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} - DEF_{rec}$
And:

$$RDAF = \frac{RD + RF_{rd} + DEF_{rec}}{P:Thru_T}$$

Else:
$DEF_{incm} = RD - (5\%\ x\ DIST\ REV_T)$
And:
$DEF_{rec} = 0$
And
$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} + DEF_{incm}$
And

$$RDAF = \frac{(5\%\ x\ DIST\ REV_T) + RF_{rd}}{P:Thru_T}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CG}$: The Actual Number of Customers for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1). Actual number of customers for each Winter or Summer Season shall be the average number monthly customers in that season, calculated by summing the number of equivalent bills in each month of the most recently completed Winter or Summer Season, and dividing by the number of months in the Season.

$ARPC_{T-1}^{CG}$:	The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1), as defined in Section 4.0. For purposes of calculating the Actual Base Revenue per Customer, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.
$BRPC_{T-1}^{CG}$:	The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section 4.0(A) for the most recently completed Winter or Summer Season (T-1).
cg	Customer Class Groups as defined in Section 4.0(D).
DEF_{bal}	The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.
DEF_{incm}	The amount of Revenue Decoupling that must be deferred in the current year based on the difference between plus or minus five percent (+/-5%) of total distribution revenues as determined in accordance with the definition of DIST REV_T in Section 5.0(B).
DEF_{rec}	The amount of deferrals the Company may recover in the current Winter or Summer Season.
P: $Thru:_T$	Forecast Throughput Volumes inclusive of all firm tariff throughput for the Winter or Summer Season.
RD	The Revenue Decoupling adjustment to revenues.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor for the Winter or Summer Season.
RF_{rd}:	Revenue Decoupling Reconciliation Adjustment as described in Section 6.0.
DIST REV_T	The Distribution revenues from all firm rate classes during the most recent Winter or Summer Season.

6. Calculation of the Reconciliation Adjustments

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Winter Season, as calculated by multiplying the Winter Season RDAF times the Winter Season firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues for the Winter Season, plus carrying charges on the average monthly balance using the prime lending rate.

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Summer Season, as calculated by multiplying the Summer Season Revenue Decoupling Adjustment Clause times the Summer Season firm throughput, and the

Revenue Decoupling Adjustment allowed revenues for the Summer Season, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

   The RDAF ($ per therm) shall be truncated at the nearest one one-hundredth of a cent per therm. The RDAF for the Winter Season will be applied usage in the next Winter Season and the RDAF for the Summer Season will be applied to usage in the next Summer Season. The RDAF will be applied to the monthly firm tariff throughput for each customer.

8. Information to be Filed with the Commission

   Information pertaining to the RDAC will be filed with the Commission ninety (90) days prior to the effective dates of the November 1 Winter Season and May 1 Summer Season RDAF. Such information shall include:

   a. the calculation of the applicable revenue decoupling revenue adjustment

   b. the calculation of the revenue decoupling reconciliation adjustment.;

   c. the calculation of annually updated Benchmark Base Revenue per Customer to be utilized in the upcoming Summer and Winter Seasons.

D. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

E. Expenses Related to Gas Restructuring.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates on an annual basis for the recovery of NHPUC-approved costs associated with the Gas Restructuring Collaborative (Docket DE 98-124).

2. Applicability: The Gas Restructuring Expenses ("GRE") shall be applied to all firm tariffed customers eligible to receive delivery service from the Company as determined in accordance with the provisions of Section 17(F) of this clause. The GRE shall be determined annually by the Company as defined below, subject to review and approved by the NHPUC as provided for in this clause.

3. GRE Allowable for LDAC: Costs associated with the Gas Restructuring Collaborative (DE 98-124), including, but not limited to, any legal, consulting, customer focus group(s) and survey(s),

customer education campaign(s), materials and advertising, subject to review and approval by the NHPUC.

4. Effective Date of GRE Charge: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the GRE applicable to all consumption of tariffed customers eligible to receive delivery service for the subsequent twelve month period commencing with the calendar month of November.

5. Definition: Gas Restructuring Initiatives are activities facilitating the development, design and implementation of unbundled services for all customers.

6. GRE Factor Formula:

$$GREF = \frac{GRE + RAGRE}{A: TPev}$$

where:

A:Tpev Forecast Annual Throughput Volumes of all tariffed customers eligible to receive firm delivery-only service from the Company.

GRE Gas Restructuring Expenses as defined in Section 17(F).05.

RA_{GRE} Gas Restructuring Expense Reconciliation Adjustment - Account 1920-1744, inclusive of the associated Account 1920-1744 interest, as outlined in Section 17(E)(7).

7. Reconciliation Adjustments: Account 1920-1744 shall contain the accumulated difference between revenues toward Gas Restructuring Expenses as calculated by multiplying the Gas Restructuring Expense Factor (“GREF”) times monthly volumes of customers eligible to receive firm delivery service and Gas Restructuring expenses allowed, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end-of-month balance.

8. Application of GREF to Bills: The GREF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the Gas Restructuring Expenses shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GREF filing shall be required on or before the first business day in September of each year. The GREF filing shall contain the calculation of the new annual GREF to become effective November 1 and shall include the updated annual Gas Restructuring Expense reconciliation balance.

F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A: TPev}$$

where:

A: Tpev — Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP — RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} — RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP

account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{X} = CC^{X} + RDAC^{X} + ES + GREF^{x} + RCE + RLIAP$$

and:

$$ES^{X} = RHS + MGP$$

where:

$LDAC^{X}$ = Annualized class specific LDAC.

CC^{X} = Annualized class specific CC or EE Charge.

$RDAC^{X}$ = Annualized class specific RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^{X}$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

K. Other Rules.

1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

L. Amendments to Uniform System of Accounts.

1920-1744 **Gas Restructuring Expense Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(E).

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(D).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(G).

1163-1756 **Lost Revenue Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C.1).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

2. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

3. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

4. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

5. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

6. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

7. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

8. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

9. Feedstock Gas: Is defined as natural gas used as a raw material for its chemical properties in creating an end product

10. Process Gas: Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels

11. Boiler Fuel: Is considered to be natural gas used as a fuel for the generation of steam or electricity including the utilization of gas turbines for the generation of electricity

12. Alternate Fuel Capabilities: Is defined as a situation where an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed, provided however, where the use of natural gas is for plant protection, feedstock or process uses and the only alternate fuel is propane or other gaseous fuel, then the consumer will be treated as if he had no alternate fuel capability.

B. POLICY

In the event that, due to gas supply restrictions or capacity constraints, the Company is unable to deliver the total requirements of its firm, sales or transportation rate customers, the available volumes of gas will be allocated to the Company's firm rate customers in accordance with the provisions of this policy.

In the event that the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of the customer, customer shall be compensated for such emergency gas at the customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.

As curtailment becomes necessary through each succeeding category, the Company will implement full or partial curtailment of a customer, or by groups of customers, taking into consideration customer load characteristics, the Company's delivery system design and Company load characteristics in a manner which is believed to be in the best interests of customers in general.

C. PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories:

1. Company use for fuel and lost and unaccounted for

2. Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3. Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4. Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5. Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (6), or (7)

6. Firm sales or transportation service including the transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7. Firm sales or transportation service including transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

D. STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

E. PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

II. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability

This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.7176 per day or $21.50 per 30 day month
Winter Period:	All therms per 30 day month at $0.2446 per therm
Summer Period:	All therms per 30 day month at $0.2446 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

2 RESIDENTIAL HEATING RATE:
CLASSIFCATION NO. R-3

Availability
This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.8500 per day or $25.50 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5201 per therm
	All over 100 therms per 30 day month at $0.4176 per therm
Summer Period:	First 20* therms per 30 day month at $0.5201 per therm
	All over 20 therms per 30 day month at $0.4176 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability

This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.3400 per day or $10.20 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2080 per therm
	All over 100 therms per 30 day month at $0.1670 per therm
Summer Period:	First 20* therms per 30 day month at $0.2080 per therm
	All over 20 therms per 30 day month at $0.1670 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.9317 per day or $27.95 per 30 day month
Winter Period:	All therms per 30 day month at $0.3180 per therm
Summer Period:	All therms per 30 day month at $0.3180 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.1050 per day or $33.15 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.6761 per therm
	All over 100 therms per 30 day month at $0.5429 per therm
Summer Period:	First 20* therms per 30 day month at $0.6761 per therm
	All over 20 therms per 30 day month at $0.5429 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Low Income Residential Heating Rate R-4.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.4420 per day or $13.26 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.2704 per therm
	All over 100 therms per 30 day month at $0.2171 per therm
Summer Period:	First 20* therms per 30 day month at $0.2704 per therm
	All over 20 therms per 30 day month at $0.2171 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The

delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Low Income Residential Heating Rate R-4.

For those customers qualifying for the program this rate R-7 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-7 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-6. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFCATION NO. G-41

Availability
This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537 per day or $55.61 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5689 per therm
	All over 100 therms per 30 day month at $0.3130 per therm
Summer Period:	First 20* therms per 30 day month at $0.5689 per therm
	All over 20 therms per 30 day month at $0.3130 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE
CLASSIFICATION NO. G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$5.3197 per day or $159.59 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.4458 per therm
	All over 1000 therms per 30 day month at $0.2952 per therm
Summer Period:	First 400* therms per 30 day month at $0.4458 per therm
	All over 400 therms per 30 day month at $0.2952 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$22.8290 per day or $684.87 per 30 day month
Winter Period:	All therms per 30 day month at $0.2684 per therm
Summer Period:	All therms per 30 day month at $0.1227 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the N Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability
This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097 per day or $72.29 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.7396 per therm
	All over 100 therms per 30 day month at $0.4069 per therm
Summer Period:	First 20* therms per 30 day month at $0.7396 per therm
	All over 20 therms per 30 day month at $0.4069 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-41.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$6.9157 per day or $207.47 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.5795 per therm
	All over 1000 therms per 30 day month at $0.3838 per therm
Summer Period:	First 400* therms per 30 day month at $0.5795 per therm
	All over 400 therms per 30 day month at $0.3838 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-42.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$29.6777 per day or $890.33 per 30 day month
Winter Period:	All therms per 30 day month at $0.2684 per therm
Summer Period:	All therms per 30 day month at $0.1595 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to the Firm Rate Scheduleswhich present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-43.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537 per day or $55.61 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.3460 per therm
	All over 100 therms per 30 day month at $0.2060 per therm
Summer Period:	First 100* therms per 30 day month at $0.3460 per therm
	All over 100 therms per 30 day month at $0.2060 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this

tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$5.3197 per day or $159.59 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.2739 per therm
	All over 1000 therms per 30 day month at $0.1897 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2155 per therm
	All over 1000 therms per 30 day month at $0.1192 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE
CLASSIFICATION NO. G-53

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage less than 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:	$23.4937 per day or $704.81 per 30 day month
Winter Period:	All therms per 30 day month at $0.1741 per therm
Summer Period:	All therms per 30 day month at $0.0835 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE
CLASSIFICATION NO. G-54

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms, a Winter Period usage less than 67% of annual usage, and a 12 month average usage greater than or equal to 90% of the average usage of December, January and February as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$23.4937 per day or $704.81 per 30 day month
Winter Period:	All therms per 30 day month at $0.0667 per therm
Summer Period:	All therms per 30 day month at $0.0362 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-51.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097 per day or $72.29 per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.4498 per therm
	All over 100 therms per 30 day month at $0.2678 per therm
Summer Period:	First 100* therms per 30 day month at $0.4498 per therm
	All over 100 therms per 30 day month at $0.2678 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions
Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-51.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-52.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter:	$6.9157 per day or $207.47 per 30 day month
Winter Period:	First 1000* therms per 30 day month at $0.3561 per therm
	All over 1000 therms per 30 day month at $0.2466 per therm
Summer Period:	First 1000* therms per 30 day month at $0.2802 per therm
	All over 1000 therms per 30 day month at $0.1550 per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this

schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-52.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-57

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-53.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge ;

Customer Charge Per Meter:	$30.5417 per day or $916.25 per 30 day month
Winter Period:	All therms per 30 day month at $0.2263 per therm
Summer Period:	All therms per 30 day month at $0.1086 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-53.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

**20 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE
CLASSIFICATION NO. G-58**

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-54.

Character of Service
Natural gas or equivalent will be supplied at a heat content value of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$30.5417 per day or $916.25 per 30 day month
Winter Period:	All therms per 30 day month at $0.0867 per therm
Summer Period:	All therms per 30 day month at $0.0471 per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause, as in effect from time to time and on file with the Commission. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-54.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

21 OUTDOOR GAS LIGHTING

Availability

This rate is available for residential outdoor gas lighting where such service is provided from the Company's existing delivery system to a standard gas light fixture or fixtures, located on the customer's premises, and when it is not feasible to meter such service along with other gas used on the premises and bill the same under the rate in effect for all other services. Service under this rate is available at those locations which were receiving service hereunder as of July 1, 2015, and which have continuously received service hereunder since that date.

Rate Per Light Per Month	$11.34

The above rates shall be adjusted to reflect the recovery of all applicable taxes.

Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a location, an account charge is incurred in addition to all other charges. The account charge is $20.00 when the visit to the location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the Commission.

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 90

Rate Schedules

22 FIRM RATE SCHEDULES

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-1								
Customer Charge per Month per Meter	$21.50			$ 21.50	$ 21.50			$ 21.50
All therms	$ 0.2446	$ 0.4002	$ 0.0640	$ 0.7088	$ 0.2446	$ 0.4368	$ 0.0640	$ 0.7454
Residential Heating - R-3								
Customer Charge per Month per Meter	$25.50			$ 25.50	$ 25.50			$ 25.50
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5201	$ 0.4002	$ 0.0640	$ 0.9843	$ 0.5201	$ 0.4368	$ 0.0640	$ 1.0209
All therms over the first block per month at	$ 0.4176	$ 0.4002	$ 0.0640	$ 0.8818	$ 0.4176	$ 0.4368	$ 0.0640	$ 0.9184
Residential Heating - R-4								
Customer Charge per Month per Meter	$10.20			$ 10.20	$ 10.20			$ 10.20
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2080	$ 0.4002	$ 0.0640	$ 0.6722	$ 0.2080	$ 0.4368	$ 0.0640	$ 0.7088
All therms over the first block per month at	$ 0.1670	$ 0.4002	$ 0.0640	$ 0.6312	$ 0.1670	$ 0.4368	$ 0.0640	$ 0.6678
Commercial/Industrial - G-41								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.5689	$ 0.3961	$ 0.0450	$ 1.0100	$ 0.5689	$ 0.4206	$ 0.0450	$ 1.0345
All therms over the first block per month at	$ 0.3130	$ 0.3961	$ 0.0450	$ 0.7541	$ 0.3130	$ 0.4206	$ 0.0450	$ 0.7786
Commercial/Industrial - G-42								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.4458	$ 0.3961	$ 0.0450	$ 0.8869	$ 0.4458	$ 0.4206	$ 0.0450	$ 0.9114
All therms over the first block per month at	$ 0.2952	$ 0.3961	$ 0.0450	$ 0.7363	$ 0.2952	$ 0.4206	$ 0.0450	$ 0.7608
Commercial/Industrial - G-43								
Customer Charge per Month per Meter	$684.87			$ 684.87	$ 684.87			$ 684.87
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1227	$ 0.4206	$ 0.0450	$ 0.5883
Commercial/Industrial - G-51								
Customer Charge per Month per Meter	$55.61			$ 55.61	$ 55.61			$ 55.61
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.3460	$ 0.4145	$ 0.0450	$ 0.8055	$ 0.3460	$ 0.4574	$ 0.0450	$ 0.8484
All therms over the first block per month at	$ 0.2060	$ 0.4145	$ 0.0450	$ 0.6655	$ 0.2060	$ 0.4574	$ 0.0450	$ 0.7084
Commercial/Industrial - G-52								
Customer Charge per Month per Meter	$159.59			$ 159.59	$ 159.59			$ 159.59
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.2739	$ 0.4145	$ 0.0450	$ 0.7334	$ 0.2155	$ 0.4574	$ 0.0450	$ 0.7179
All therms over the first block per month at	$ 0.1897	$ 0.4145	$ 0.0450	$ 0.6492	$ 0.1192	$ 0.4574	$ 0.0450	$ 0.6216
Commercial/Industrial - G-53								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.1741	$ 0.4145	$ 0.0450	$ 0.6336	$ 0.0835	$ 0.4574	$ 0.0450	$ 0.5859
Commercial/Industrial - G-54								
Customer Charge per Month per Meter	$704.81			$ 704.81	$ 704.81			$ 704.81
All therms over the first block per month at	$ 0.0667	$ 0.4145	$ 0.0450	$ 0.5262	$ 0.0362	$ 0.4574	$ 0.0450	$ 0.5386

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

23 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM

II RATE SCHEDULES
FIRM RATE SCHEDULES

	Winter Period				Summer Period			
	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate	Delivery Charge	Cost of Gas Rate Page 77	LDAC Page 82	Total Rate
Residential Non Heating - R-5								
Customer Charge per Month per Meter	$27.95			$ 27.95	$ 27.95			$ 27.95
All therms	$ 0.3180	$ 0.4002	$ 0.0640	$ 0.7822	$ 0.3180	$ 0.4368	$ 0.0640	$ 0.8188
Residential Heating - R-6								
Customer Charge per Month per Meter	$33.15			$ 33.15	$ 33.15			$ 33.15
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.6761	$ 0.4002	$ 0.0640	$ 1.1403	$ 0.6761	$ 0.4368	$ 0.0640	$ 1.1769
All therms over the first block per month at	$ 0.5429	$ 0.4002	$ 0.0640	$ 1.0071	$ 0.5429	$ 0.4368	$ 0.0640	$ 1.0437
Residential Heating - R-7								
Customer Charge per Month per Meter	$13.26			$ 13.26	$ 13.26			$ 13.26
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.2704	$ 0.4002	$ 0.0640	$ 0.7346	$ 0.2704	$ 0.4368	$ 0.0640	$ 0.7712
All therms over the first block per month at	$ 0.2171	$ 0.4002	$ 0.0640	$ 0.6813	$ 0.2171	$ 0.4368	$ 0.0640	$ 0.7179
Commercial/Industrial - G-44								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				20 therms			
Therms in the first block per month at	$ 0.7396	$ 0.3961	$ 0.0450	$ 1.1807	$ 0.7396	$ 0.4206	$ 0.0450	$ 1.2052
All therms over the first block per month at	$ 0.4069	$ 0.3961	$ 0.0450	$ 0.8480	$ 0.4069	$ 0.4206	$ 0.0450	$ 0.8725
Commercial/Industrial - G-45								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				400 therms			
Therms in the first block per month at	$ 0.5795	$ 0.3961	$ 0.0450	$ 1.0206	$ 0.5795	$ 0.4206	$ 0.0450	$ 1.0451
All therms over the first block per month at	$ 0.3838	$ 0.3961	$ 0.0450	$ 0.8249	$ 0.3838	$ 0.4206	$ 0.0450	$ 0.8494
Commercial/Industrial - G-46								
Customer Charge per Month per Meter	$890.33			$ 890.33	$ 890.33			$ 890.33
All therms over the first block per month at	$ 0.2684	$ 0.3961	$ 0.0450	$ 0.7095	$ 0.1595	$ 0.4206	$ 0.0450	$ 0.6251
Commercial/Industrial - G-55								
Customer Charge per Month per Meter	$72.29			$ 72.29	$ 72.29			$ 72.29
Size of the first block	100 therms				100 therms			
Therms in the first block per month at	$ 0.4498	$ 0.4145	$ 0.0450	$ 0.9093	$ 0.4498	$ 0.4574	$ 0.0450	$ 0.9522
All therms over the first block per month at	$ 0.2678	$ 0.4145	$ 0.0450	$ 0.7273	$ 0.2678	$ 0.4574	$ 0.0450	$ 0.7702
Commercial/Industrial - G-56								
Customer Charge per Month per Meter	$207.47			$ 207.47	$ 207.47			$ 207.47
Size of the first block	1000 therms				1000 therms			
Therms in the first block per month at	$ 0.3561	$ 0.4145	$ 0.0450	$ 0.8156	$ 0.2802	$ 0.4574	$ 0.0450	$ 0.7826
All therms over the first block per month at	$ 0.2466	$ 0.4145	$ 0.0450	$ 0.7061	$ 0.1550	$ 0.4574	$ 0.0450	$ 0.6574
Commercial/Industrial - G-57								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.2263	$ 0.4145	$ 0.0450	$ 0.6858	$ 0.1086	$ 0.4574	$ 0.0450	$ 0.6110
Commercial/Industrial - G-58								
Customer Charge per Month per Meter	$916.25			$ 916.25	$ 916.25			$ 916.25
All therms over the first block per month at	$ 0.0867	$ 0.4145	$ 0.0450	$ 0.5462	$ 0.0471	$ 0.4574	$ 0.0450	$ 0.5495

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

24 FIRM RATE SCHEDULES - OUTDOOR GAS LIGHTING

Outdoor Gas Lighting	
Per Light Per Month	$11.34

DATED: April 28, 2017
ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017
TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

NHPUC No.8 GAS
LIBERTY UTILITIES

25 ANITCIPATED COST OF GAS

Anticipated Cost of Gas

PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(REFER TO TEXT ON IN SECTION 16 COST OF GAS CLAUSE)

(Col 1)	(Col 2)	(Col 3)
ANTICIPATED DIRECT COST OF GAS		
Purchased Gas:		
Demand Costs:	$ 7,527,898	
Supply Costs:	49,523,042	
Storage Gas:		
Demand, Capacity:	$ 941,660	
Commodity Costs:	4,026,000	
Produced Gas:	1,797,499	
Hedged Contract (Saving)/Loss	-	
Hedge Underground Storage Contract (Saving)/Loss	-	
Unadjusted Anticipated Cost of Gas		$ 63,816,099
Adjustments:		
Prior Period (Over)/Under Recovery (as of 05/01/15)	$ 2,690,610	
Interest	14,641	
Prior Period Adjustments	-	
Broker Revenues	(1,374,947)	
Refunds from Suppliers	-	
Fuel Financing	-	
Transportation CGA Revenues	(29,471)	
Interruptible Sales Margin	-	
Capacity Release and Off System Sales Margins	(5,448,856)	
Hedging Costs	-	
Fixed Price Option Administrative Costs	41,972	
Total Adjustments		(4,106,050)
Total Anticipated Direct Cost of Gas		$ 59,710,049
Anticipated Indirect Cost of Gas		
Working Capital:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Working Capital Rate: Lead Lag Days / 365	0.0391	
Prime Rate	3.50%	
Working Capital Percentage	0.137%	
Working Capital	$ 87,342	
Plus: Working Capital Reconciliation (Acct 142.20)	(33,597)	
Total Working Capital Allowance		53,745
Bad Debt:		
Total Unadjusted Anticipated Cost of Gas 11/01/15 - 04/30/16	$ 63,816,099	
Less: Refunds	-	
Plus: Total Working Capital	53,745	
Plus: Prior Period (Over)/Under Recovery	2,690,610	
Subtotal	$ 66,560,454	
Bad Debt Percentage	4.04%	
Bad Debt Allowance	$ 2,689,042	
Plus: Bad Debt Reconciliation (Acct 175.52)	(37,241)	
Total Bad Debt Allowance		$ 2,651,801
Production and Storage Capacity		$ 1,980,428
Miscellaneous Overhead (11/01/15 - 04/30/16)	$ 13,170	
Times Winter Sales	90,536	
Divided by Total Sales	112,609	
Miscellaneous Overhead		10,589
Total Anticipated Indirect Cost of Gas		$ 4,696,563
Total Cost of Gas		$ 64,406,611

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

26 CALCULATION OF FIRM SALES COST OF GAS RATE

CALCULATION OF FIRM SALES COST OF GAS RATE
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to Text in Section 16 Cost of Gas Clause)

(Col 1)		(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas		$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Direct Cost of Gas Rate			$ 0.6640	per therm
Demand Cost of Gas Rate		$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate		55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate		(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate		$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas		$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)		89,920,078		
Indirect Cost of Gas			$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE 11/01/16			**$ 0.7162**	**per therm**
RESIDENTIAL COST OF GAS RATE - 11/01/16		**COGwr**	**$ 0.7162**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
RESIDENTIAL COST OF GAS RATE - 12/01/2016		**COGsr**	**$ 0.6439**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
RESIDENTIAL COST OF GAS RATE - 01/01/2017		**COGwr**	**$ 0.7276**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
RESIDENTIAL COST OF GAS RATE - 2/1/2017		**COGwr**	**$ 0.6012**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
RESIDENTIAL COST OF GAS RATE - 3/1/2017		**COGwr**	**$ 0.4841**	**/therm**
	Maximum	(COG + 25%)	$ 0.8953	
C&I LOW WINTER USE COST OF GAS RATE - 11/01/16		**COGwl**	**$ 0.7305**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
C&I LOW WINTER USE COST OF GAS RATE - 12/01/2016		**COGsl**	**$ 0.6582**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
C&I LOW WINTER USE COST OF GAS RATE - 01/01/2017		**COGsl**	**$ 0.7419**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
C&I LOW WINTER USE COST OF GAS RATE - 2/01/2017		**COGsl**	**$ 0.6155**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
C&I LOW WINTER USE COST OF GAS RATE - 3/01/2017		**COGsl**	**$ 0.4984**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942			
Times: Low Winter Use Ratio (Winter)	1.1637	Maximum (COG + 25%)	$ 0.9131	
Times: Correction Factor	0.9898			
Adjusted Demand Cost of Gas Rate	$ 0.1085			
Commodity Cost of Gas Rate	$ 0.6155			
Adjustment Cost of Gas Rate	$ (0.0457)			
Indirect Cost of Gas Rate	$ 0.0522			
Adjusted C&I Low Winter Use Cost of Gas Rate	$ 0.7305			
C&I HIGH WINTER USE COST OF GAS RATE - 11/01/16		**COGwh**	**$ 0.7121**	**/therm**
Change in rate due to change in under/over recovery			**$ (0.0723)**	
C&I HIGH WINTER USE COST OF GAS RATE - 12/01/2016		**COGsh**	**$ 0.6398**	**/therm**
Change in Rate due to change in under/over recovery			**$ 0.0837**	
C&I HIGH WINTER USE COST OF GAS RATE - 01/01/2017		**COGwh**	**$ 0.7235**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1264)**	
C&I HIGH WINTER USE COST OF GAS RATE - 2/01/2017		**COGwh**	**$ 0.5971**	**/therm**
Change in Rate due to change in under/over recovery			**$ (0.1171)**	
C&I HIGH WINTER USE COST OF GAS RATE - 3/01/2017		**COGwh**	**$ 0.4800**	**/therm**
Average Demand Cost of Gas Rate Effective 11/01/16	$ 0.0942			
Times: High Winter Use Ratio (Winter)	0.9667	Maximum (COG + 25%)	$ 0.8901	
Times: Correction Factor	0.9898			
Adjusted Demand Cost of Gas Rate	$ 0.0901			
Commodity Cost of Gas Rate	$ 0.6155			
Adjustment Cost of Gas Rate	$ (0.0457)			
Indirect Cost of Gas Rate	$ 0.0522			
Adjusted C&I High Winter Use Cost of Gas Rate	$ 0.7121			

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

27 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE

II. RATE SCHEDULES			
CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE			
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017			
(Refer to Text in Section 17(A) Fixed Price Option Program)			
(Col 1)	(Col 2)	(Col 3)	
Total Anticipated Direct Cost of Gas	$ 59,710,049		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Direct Cost of Gas Rate		$ 0.6640	per therm
Demand Cost of Gas Rate	$ 8,469,558	$ 0.0942	per therm
Commodity Cost of Gas Rate	55,346,541	$ 0.6155	per therm
Adjustment Cost of Gas Rate	(4,106,050)	$ (0.0457)	per therm
Total Direct Cost of Gas Rate	$ 59,710,049	$ 0.6640	per therm
Total Anticipated Indirect Cost of Gas	$ 4,696,563		
Projected Prorated Sales (11/01/16 - 04/30/17)	89,920,078		
Indirect Cost of Gas		$ 0.0522	per therm
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as updated, see page 77		**$ 0.7162**	
Calculation of FPO - Consistent with Order No. 24,515 in DG 05-127			
TOTAL PERIOD AVERAGE COST OF GAS EFFECTIVE (11/01/16) as originally filed 9-1-16		**$ 0.7068**	
FPO Risk Premium		$ 0.0200	
TOTAL PERIOD FIXED PRICE OPTION COST OF GAS RATE EFFECTIVE (11/01/16)		**$ 0.7268**	
RESIDENTIAL COST OF GAS RATE - 11/01/16	**COGwr**	**$ 0.7268**	**/therm**

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 96

Rate Schedules

28 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE – KEENE DIVISION

Period Covered:	Winter Period November 1, 2014, through April 30, 2015		
Projected Gas Sales - therms			1,076,725
Total Anticipated Cost of Propane Sendout			$1,826,090
Add:	Prior Period Deficiency Uncollected	$9,404	
	Interest	$2,382	
Deduct:	Prior Period Excess Collected	$0	
	Interest	$0	
	Prior Period Adjustments and Interest		$11,786
Total Anticipated Cost			$1,837,876
Cost of Gas Rate			
Non-Fixed Price Option Cost of Gas Rate (per therm)			$1.7069
Fixed Price Option Premium			$0.0200
Fixed Price Option Cost of Gas Rate (per therm)			$1.7269
Non-Fixed Price Option Cost of Gas Rate - Beginning Period (per therm)			$1.7069
Mid Period Adjustment - December 1, 2014			($0.2427)
Mid Period Adjustment - January 1, 2015			($0.0718)
Revised Non-Fixed Price Option Cost of Gas Rate - Effective January 1, 2015 (per therm)			$1.3924
Pursuant to tariff section 17(d), the Company may adjust the approved cost of gas rate upward on a monthly basis to the following rate:			
Maximum Cost of Gas Rate - Non-Fixed Price Option (per therm)			$2.1336

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

29 CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE

II. RATE SCHEDULES
Calculation of Firm Transportation Cost of Gas Rate
PERIOD COVERED: WINTER PERIOD, NOVEMBER 1, 2016 THROUGH APRIL 30, 2017
(Refer to text in Section 16(Q) Firm Transportation Cost of Gas Clause)

(Col 1)	(Col 2)		(Col 3)		(Col 4)
ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES:					
PROPANE	$ 283,609				
LNG	1,513,890				
TOTAL ANTICIPATED COST OF SUPPLEMENTAL GAS SUPPLIES	1,797,499				
ESTIMATED PERCENTAGE USED FOR PRESSURE SUPPORT PURPOSES	9.9%				
ESTIMATED COST OF LIQUIDS USED FOR PRESSURE SUPPORT PURPOSES	$ 177,952				
PROJECTED FIRM THROUGHPUT (THERMS):					
FIRM SALES	90,536,024		64.4%		
FIRM TRANSPORTATION SUBJECT TO FTCG	50,086,696		35.6%		
TOTAL FIRM THROUGHPUT SUBJECT TO COST OF GAS CHARGE	140,622,721		100.0%		
TRANSPORTATION SHARE OF SUPPLEMENTAL GAS SUPPLIES	35.6%	x	$ 177,952	=	$ 63,383
PRIOR (OVER) OR UNDER COLLECTION					(33,912)
NET AMOUNT TO COLLECT FROM (RETURNED TO) TRANSPORTATION CUSTOMERS					$ 29,471
PROJECTED FIRM TRANSPORTATION THROUGHPUT					50,086,696
FIRM TRANSPORTATION COST OF GAS					$0.0006

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

30 ENVIRONMENTAL SURCHARGE – MANUFACTURED GAS PLANTS

Environmental Surcharge - Manufactured Gas Plants		
Manufactured Gas Plants		
Required annual Environmental increase	$2,893,504	
DG 10-17 Base Rate Revision Collections	$0	
Environmental Subtotal	$2,893,504	
Overall Annual Net Increase to Rates	$2,893,504	
Estimated weather normalized firm therms billed for the twelve months ended 10/31/17 - sales and transportation	186,909,214	therms
Surcharge per therm	$0.0155	per therm
Total Environmental Surcharge	$0.0155	

DATED: April 28, 2017

EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney

TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

31 RATE CASE EXPENSE FACTOR CALCULATION

Liberty Utilities (Energy North Natural Gas) Corp. d/b/a Liberty Utilities		
Local Distribution Adjustment Charge (LDAC) decrease due to Rate Case Expense and Recoupment		
For LDAC effective November 1, 2016 - December 31, 2016		
Docket No. DG 14-180		
1	August 1, 2016 Balance of Acct. 8840-2-0000-10-1930-1745	$46,132
2	Estimated August 2016 - October 2016 Recovery	($292,028)
3	Estimated August 2016 - October 2016 Interest	($761)
4		
5	Estimated Balance November 1, 2016	($246,658)
6	Estimated November 2016 - December 2016 Interest	($791)
7		
8	Estimated Remaining Recovery	($247,449)
9		
10	Estimated November 2016 - December 2016 Sales (therms)	34,894,997
11		
12	RCE rate per therm November 2016 - December 2016	($0.0071)

DATED: April 28, 2017

EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney
TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

32 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION

Local Delivery Adjustment Clause Calculation

		Sales Customers	Transportation Customers	
Residential Non Heating Rates - R-1, R-5				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Interruptible Transportation Margin Credit (ITMC)		0.0000		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Residential Heating Rates - R-3, R-4, R-6, R-7				
Energy Efficiency Charge	$0.0402			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0402		
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155		
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0016		
Rate Case Expense Factor (RCEF)		0.0000		
Residential Low Income Assistance Program (RLIAP)		0.0067		
LDAC		**$0.0640**		**per therm**
Commercial/Industrial Low Annual Use Rates - G-41, G-51, G-44, G-55				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**
Commercial/Industrial Medium Annual Use Rates - G-42, G-52, G-45, G-56				
Energy Efficiency Charge	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**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	$0.0219			
Demand Side Management Charge	0.0000			
Conservation Charge (CCx)		$0.0219	$0.0219	
Relief Holder and pond at Gas Street, Concord, NH	0.0000			
Manufactured Gas Plants	0.0155			
Environmental Surcharge (ES)		0.0155	0.0155	
Energy Efficiency Resource Standard Lost Revenue Mechanism		0.0009	0.0009	
Gas Restructuring Expense Factor (GREF)		0.0000	0.0000	
Rate Case Expense Factor (RCEF)		0.0000	0.0000	
Residential Low Income Assistance Program (RLIAP)		0.0067	0.0067	
LDAC		**$0.0450**	**$0.0450**	**per therm**

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

III. DELIVERY TERMS AND CONDITIONS

1 RATES AND CHARGES

1.1 The Company shall apply this tariff on a non-discriminatory and non-preferential basis to all Customers who obtain service from the Company, except as this tariff is explicitly modified by order of the NHPUC. The provisions of Part III Section 20 of this tariff will specifically apply to all entities designated by the Customer as set forth in Section 20.5 to supply Gas to a Designated Receipt Point for the Customer's account.

1.2 The Company reserves the right to impose reasonable fees and charges pursuant to the various provisions of this tariff.

1.3 In the event that the Company incurs minimum bill, inventory, transition, take or pay, imbalance, or any other charges associated with the provision of Delivery Service to Customers, the Company may impose an additional charge on the Suppliers serving said Customers as approved by the NHPUC.

2 DEFINITIONS

Adjusted Target Volume ("ATV)	The volume of Gas determined by the Company using a Consumption Algorithm and required to be nominated and delivered each Gas Day by the Supplier on behalf of Customers taking non-daily metered Delivery Service.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 20.6 of this tariff for operational purposes, including but not limited to nominating, scheduling, and balancing Gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 11.6 of this tariff.
Assignment Date	Five (5) Business Days prior to the first Gas Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 11.4 of this tariff.
Authorization Number	A number unique to the Customer generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 20.4, and to initiate or terminate Supplier Service as set forth in Section 20.5 of this tariff.
Btu	One British thermal unit; i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60°) Fahrenheit.
Business Day	Monday through Friday excluding holidays recognized by the Company. Where relevant, a Business Day shall consist of the hours during which the Company is open for business with the public. ***<u>If any performance date referenced in this Tariff is not a Business Day, such performance shall be the next succeeding Business Day</u>***.
Capacity	Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity as defined in this tariff.

Capacity Allocators	The estimated proportions of the Customer's Total Capacity Quantity that comprise Pipeline Capacity, Storage Withdrawal Capacity and Peaking Capacity.
Capacity Mitigation Service	The service available to Suppliers in accordance with Section 11.10.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Commodity	See Gas.
Company	Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system (including Gas produced by the Company) and the sum of all amounts of Gas delivered from the Company's distribution system divided by said amount of Gas received. Such difference shall include but not be limited to Gas consumed by the Company for its own purposes, line losses, and Gas vented and lost as a result of force majeure, excluding Gas otherwise accounted for.
Company-Managed Supplies	Capacity and Supply contracts held and managed by the Company and made available to the Supplier pursuant to Section 11.9 of this tariff including Supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 16 of this tariff, a day declared at any time by the Company in its reasonable discretion when unusual operating conditions may jeopardize operation of the Company's distribution system.
Customer	The recipient of Delivery Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a customer of record of the Company.
Daily Baseload	The Customer's average usage per Gas Day that is assumed to be unrelated to weather.
Daily Index	The mid-point of the range of prices as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)". In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of Gas as the basis for this calculation until such time that the NHPUC approves a suitable replacement.
Dekatherm	Ten Therms.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Delivery Service	The distribution of Gas by the Company on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point and related Customer services.
Design Peak Season	The forecasted Peak Season during which the Company's system experiences the highest aggregate Gas Usage.

Designated Receipt Point	For each Customer, the Company designated interconnection between a Transporting Pipeline and the Company's distribution facilities at which point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account.
Designated Representative	The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Delivery Service in accordance with the provisions of Section 21 of this tariff.
Gas	Natural Gas that is received by the Company from a Transporting Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural Gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural Gas that the Customer is otherwise entitled to have delivered by the Company.
Gas Day	A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Transporting Pipeline.
Gas Service Area	An area within the Company's distribution system as defined in Section 4 of this tariff, for the purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools.
Gas Usage	The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.
Heating Degree Day	A measure used to estimate weather-sensitive Gas consumption calculated by subtracting the average temperature for each day from the number 65. Each degree day that represents a degree below 65 is considered a Heating Degree Day.
Heating Factor	The Customer's estimated weather-sensitive Gas consumption per Heating Degree Day.
MMBtu	One million Btus.
Maximum Daily Peaking	The portion of a Customer's Total Capacity Quantity identified
Quantity ("MDPQ")	and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Supplier's Peaking Service Account pursuant to Section 14 of this tariff shall be equal to the sum of the MDPQs for all Customers in that Supplier's Aggregation Pool.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Index numbers for all Gas Days in a Month.
NHPUC	The New Hampshire Public Utilities Commission.
Nomination	The notice given by the Supplier to the Company that specifies, in accordance with the Standard Nomination Form attached as Attachment A, an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of one or more Customers, including the volume to be received, the Designated

	Receipt Point(s), the Transporting Pipeline, the delivering contract(s), the shipper, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months of May to October, inclusive.
Operational Flow Order ("OFO")	The Company's instructions to the Supplier to take such action as conditions require including, but not limited to, diverting Gas to or from the Company's distribution system pursuant to Section 16 of this tariff.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage.
Peak Season	The consecutive months of November to April, inclusive.
Peaking Capacity	Capacity in addition to upstream pipeline and underground storage Capacity normally used by the Company to meet daily requirements during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Service	A Company-managed resource consisting of Peaking Capacity and Peaking Supply.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to this tariff.
Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company's Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers' Peaking Service Accounts in order for the Company to meet system demands under Design Peak Season conditions. The Company will communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Peaking Service Rule Curve as identified in Section 14 of this tariff.
Peaking Supply	The aggregate amount of Supply in excess of upstream pipeline and underground storage Supply required to meet the Company's forecasted Supply needs during a Design Peak Season and acquired specifically for the Peak Season.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer's estimated Gas Usage during the Design Peak Season that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company's city gates, exclusive of Storage Withdrawal Capacity.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the method allocation of discrepancies in confirmed Nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier Service Agreement.
Rate Schedule	The schedule of rates included in this tariff.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

Sales Service	Commodity service provided on a firm basis to a Customer who is not receiving Supplier Service, in accordance with the provisions set forth in this tariff. The provision of Sales Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated Supplier pursuant to law or regulation.
Seasonal Storage Capacity	Contracts for Capacity in off-system storage facilities used to accumulate and maintain Gas inventories for re-delivery to the Company's city gates normally during the Peak Season.
Storage Withdrawal Capacity	Capacity for the withdrawal of Gas inventories maintained in off-system storage facilities, as well as the Pipeline Capacity used to deliver such Gas to the Company's city gates.
Supplier	Any entity that has met the Company's requirements set forth in Section 20 of this tariff and that has been designated by a Customer to supply Gas to a Designated Receipt Point for the Customer's account; provided, however, that a Customer may act as its own Supplier in accordance with Section 5.2 of this tariff.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Supplier Service Agreement	An agreement, substantially in the form set forth in Attachment A, which must be executed by the Company and a Supplier in order for the Supplier to serve Customers on the Company's system.
Supply	See Gas.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier on behalf
("TCQ")	of a Customer.
Transporting Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.

3 CHARACTER OF SERVICE

3.1 All rates within Part II Rate Schedule are predicated upon service to a Customer at a single Delivery Point and metering installation, except as otherwise specifically provided by a given rate. Where service is supplied to a Customer at more than one Delivery Point or metering installation, each single Delivery Point or metering installation shall be considered to be a separate Customer for purposes of applying the Rate Schedule, except when a Customer is served through multiple points of delivery or metering installations for the Company's own convenience.

3.2 The Company may refuse to supply service to loads of unusual characteristics which, in its sole reasonable judgment, might adversely affect the quality of service supplied to other Customers, the public safety or the safety of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS

4.1 There shall be 1 Gas Service Area defined for purposes of administering Capacity assignments, Nominations, balancing, imbalance trading, and Aggregation Pools pursuant to this tariff. Each such Gas Service Area shall be defined to include the municipalities listed within each such Gas Service Area, as follows:

(1) Area 1: Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities.
The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelahm, Pembroke, Sanbornton, Tilton, Windham, and part of Canterbury.

4.2 For each Aggregation Pool as set forth by Section 20.6, the Company will designate at least one specific interconnection between a Transporting Pipeline and the Company's distribution facilities, at which point, or such other point as the Company may designate from time to time, the Supplier will make deliveries for the Aggregation Pool. The interconnections that the Company may assign as the Customer's Designated Receipt Point for the Aggregation Pool are as follows:

(1) *Name Transporting Pipeline: Tennessee Gas Pipeline*
Names of City Gates/Meter Numbers:

Nashua/Milford	#020132
Manchester	#020133
Hooksett	#020254
Concord/Laconia	#020426
Suncook	#020451
Londonderry	#020632

(2) *Name Transporting Pipeline: Portland Natural Gas Transmission System*
Names of City Gates/Meter Number

Berlin	#020260

5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY

5.1 Application for Delivery Service, Sales Service, or any other service offered by the Company to a Customer will be received by any duly authorized representative or agent of the Company.

5.2 Before any service from the Company may commence, the Customer must request such service. A Customer applying for Delivery Service only must also arrange for Supplier Service with a Supplier pursuant to Section 20. A Customer may act as its own Supplier provided it meets all of the Supplier requirements delineated in Section 20.

6 QUALITY AND CONDITION OF GAS

6.1 Gas delivered to the Company by or for the Customer shall conform, in all respects, to the Gas quality standards of the Transporting Pipeline. All Gas tendered by a Supplier at a Designated Receipt Point shall be of merchantable quality and shall be interchangeable with Gas purchased by the Company from its Suppliers. The Company reserves the right to refuse non-conforming Gas.

6.2 In no event shall the Company be obligated to accept and deliver any Gas that does not meet the quality standards of the Transporting Pipeline.

6.3 The Company reserves the right to commingle Gas tendered by a Supplier at a Designated Receipt Point with other Gas, including liquefied natural Gas and propane-air vapor.

6.4 Gas tendered by a Supplier at a Designated Receipt Point will be at a pressure sufficient to enter the Company's distribution system without requiring the Company to adjust its normal operating pressures to receive the Gas. The Company has no obligation to receive Gas at a pressure that exceeds the maximum allowable operating pressure of the Company's distribution system at the Designated Receipt Point.

7 POSSESSION OF GAS

7.1 Gas shall be deemed to be in the control and possession of the Company after such Gas is delivered to the Designated Receipt Point and until the Gas is delivered to the Customer at the Delivery Point. The Company shall not be responsible for the Gas when the Gas is not in the Company's control and possession.

7.2 The Company shall not be liable to the Supplier or the Customer for any loss arising from or out of Delivery Service, including loss of Gas in the possession of the Company or for any other cause, except for the negligence of the Company's own employees or agents.

8 COMPANY GAS ALLOWANCE

8.1 The amount of Gas tendered by the Supplier to the Designated Receipt Point will be reduced, upon delivery to the Customer's Delivery Point, by the Company Gas Allowance. The Company Gas Allowance shall be in effect from November 1 through October 31. Such adjustment shall be recalculated prior to the Company's Peak Season cost of Gas filing with the NHPUC.

9 DAILY METERED DELIVERY SERVICE

9.1 Applicability

Section 9 of this tariff shall be applicable in the following conditions:

9.1.1 All Customers whose service may be interrupted at any time during the year shall be required to take daily metered Delivery Service.

9.1.2 Any Customer, regardless of annual Gas Usage, may elect daily metered Delivery Service.

9.1.3 Customers under Rate Schedules G-43, G-46, G-53, G-54, G-57, and G-58 wishing to take Delivery Service are required to take Daily Metered Delivery Service. In addition, the Company may require a Customer to take daily metered Delivery Service if the Company determines that the daily Gas Usage characteristics of the Customer cannot be accurately modeled using the Company's Consumption Algorithm or if the volumes reasonably anticipated by the Company to be used by the Customer are of a size that may materially affect the integrity of the Company's distribution system.

9.2 Delivery Service Provided

This service provides delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day. For Customers taking Delivery Service under Rate Schedules ***G-43, G-46, G-53, G-54, G-57, and G-58*** this service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point.

9.3 Nominations and Scheduling of Service

9.3.1 The Supplier is responsible for nominating and delivering to the Designated Receipt Point(s) every Gas Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool plus the Company Gas Allowance in accordance with Section 8 of this tariff.

9.3.2 Nominations shall be communicated to the Company by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means.

9.3.3 Nominations for the first Gas Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month Nominations of the Transporting Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of Nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.4 The Supplier may make daily Nominations including, but not limited to, changes to existing Nominations, within a given Month no later than two (2) hours prior to the deadline for daily Nominations of the Transporting Pipeline for the Gas Day on which the Nomination is to be effective, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.5 The Supplier may make intra-Gas Day Nominations, including but not limited to changes to existing Nominations, within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

9.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis.

9.3.7 Nominations may be rejected, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Delivery Service in effect from time to time.

9.4 Determination of Receipts

9.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

9.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

9.5 Metering and Determination of Deliveries

9.5.1 The Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. Telemetering equipment shall remain the property of the Company at all times. The Company shall require each Customer to install and maintain, at the Customer's expense, reliable telephone lines and electrical connections that meet the Company's operating requirements. The Company may require the Customer to furnish a dedicated telephone line. If the Customer fails to maintain such telephone lines and electrical connections for fourteen (14) consecutive days after notification by the Company, the Company may discontinue service to the Customer.

9.5.2 Should a Customer or a Supplier request that additional telemetering equipment or a communication device be attached to the existing telemetering equipment in addition to that provided pursuant to Section 9.5.1, the Company shall install, test, and maintain the requested telemetering equipment or communication device; provided that such telemetering equipment or communication device does not interfere with the operation of the equipment required for the Company's purposes and otherwise meet the Company's requirements. The Customer or Supplier shall provide such telemetering equipment or communication device, unless the Company elects to do so. The Customer or Supplier shall bear the cost of providing and installing the telemetering equipment, communication device, or any other related equipment, and shall have electronic access to the Customer's Gas Usage information. Upon installation, the telemetering equipment or communication device shall become the property of the Company and will be maintained by the Company. The Company shall bill the Customer or Supplier after installation.

9.5.3 The Company shall complete installation of telemetering equipment and communication devices, if reasonably possible, within sixty (60) days of receiving a written request from the Customer or Supplier provided that the Customer completes the installation of any required telephone or electrical connections within ten (10) days of such request.

9.5.4 The Company may, at its sole discretion, bill the Customer on a calendar month or cycle month basis.

9.6 Balancing

9.6.1 The Supplier must maintain a balance between daily receipts and daily Gas Usage within the following tolerances:

Off-Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 15% of said receipts. The Supplier shall be charged 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 10% of said receipts. The Supplier shall be charged 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool exceeds 20% of said receipts [(Receipts - Usage) > (20% x Receipts)].

Critical Day That Will Be Aggravated by Over-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.1 times the Daily Index to the extent that the difference between the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 120% of the Supplier's aggregate actual receipts on the Transporting Pipeline to each Gas Service Area.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 5 times the Daily Index to the extent that the difference between the Supplier's actual receipts on the Transporting Pipeline to each Gas Service Area and the Supplier's aggregated Gas Usage of Customers in the Aggregation Pool exceeds 2% of said receipts [(Receipts - Usage > (2% x Receipts)].

Point Specific Balancing: In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

9.6.2 If the Supplier has an accumulated imbalance within a Month, the Supplier may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

9.6.3 In addition to the charges set forth in Section 9.6.1, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

9.6.4 If, as a result of the Company interrupting or curtailing service pursuant to Section 17 of this tariff, the Supplier incurs a daily imbalance penalty due to over delivery, the Company will waive such penalty for the First Day of the interruption or curtailment period. If the Company has issued notice of an interruption or curtailment in service and the Supplier is unable to change its Nomination, or if the Supplier's Gas has been delivered to the Designated Receipt Point, then the Company will credit such Gas against the Supplier's imbalance.

9.6.5 The Supplier will maintain a balance between receipts at the Designated Receipt Point(s) and the aggregated Gas Usage of Customers in each Aggregation Pool. If the Transporting

Pipeline posts notice on its electronic bulletin board that its customers will be required to adhere to a maximum hourly flow rate, the Supplier will be deemed to have notice that maximum hourly flows will be in effect on the Company's distribution facilities as of the same time and for the same period as maximum hourly flows are in effect on the Transporting Pipeline. The Supplier's maximum hourly flow will be established based on an allocation of even hourly flows of daily receipts of Gas scheduled in the relevant period in accordance with the applicable transportation tariff of the Transporting Pipeline. All Gas Usage in excess of the Supplier's maximum hourly flow rate shall be subject to an additional charge of 5 times the Daily Index for each Dekatherm in excess of the Supplier's maximum hourly flow. The Company will notify the Supplier of the Supplier's maximum hourly flow.

9.6.6 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the aggregated Gas Usage of Customers in the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, and storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

9.7 Cash Out

For each Aggregation Pool, the Supplier must maintain total Monthly receipts within a reasonable tolerance of total Monthly Gas Usage. Any differences between total Monthly receipts for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly receipts, will be cashed out according to the following schedule:

Imbalance Tier	**Over-deliveries**	**Under-deliveries**
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month
> 5% ≤ 10%	0.85 times the above stated rate.	1.15 times the above stated rate.
> 10% ≤ 15%	0.60 times the above stated rate.	1.4 times the above stated rate.
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% under-delivery on a Transporting Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven (7) consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven (7) consecutive Daily Indices.

10 NON-DAILY METERED DELIVERY SERVICE

10.1 Applicability

Section 10 of this tariff applies to Customers taking Delivery Service under Rate Schedules G-41, G-42, G-51, G-52 and their Suppliers.

10.2 Delivery Service Provided

This service provides firm, year-round delivery of Customer purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers, without the requirement of recording Gas Usage at the Delivery Point on a daily basis. Daily Nominations are calculated by the Company on the basis of a Consumption Algorithm and the Supplier is obligated to deliver to the Designated Receipt Point(s) such quantities.

10.3 Nominations and Scheduling of Service

10.3.1 The Supplier is obligated to nominate and deliver the Adjusted Target Volume (“ATV”), as determined in Section 10.3.2, to the Designated Receipt Points on every Gas Day for each Aggregation Pool.

10.3.2 The Company shall determine the ATV for each Aggregation Pool of Customers taking non-daily metered Delivery Service for each Gas Day using a Consumption Algorithm. The ATV shall include the Company Gas Allowance. On each Business Day, the Company will communicate, electronically, by facsimile, or by other agreeable alternative means, the forecasted ATV to the Supplier for at least the subsequent four (4) Gas Days. The ATV in effect for any Gas Day shall be the most recent ATV for that Gas Day communicated to the Supplier by the Company. The ATV for a given Gas Day shall not be effective unless it has been communicated to the Supplier at least two (2) hours prior to the Company’s Supplier Nomination deadline for that Gas Day, which shall be at least two (2) hours prior to the deadline for nominations on the Transporting Pipeline, or such lesser period as determined by the Company.

10.3.3 Nominations will be communicated to the Company electronically, by facsimile, or other agreeable alternative means.

10.3.4 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.5 The Supplier shall provide an intra-Month nomination no later than two (2) hours prior to the deadline of the Delivering Pipeline for the next Gas Day, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized for its own operations.

10.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Transporting Pipeline. The Company will attempt to confirm the nominated volume with the Transporting Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Transporting Pipeline, the lower volume will be deemed confirmed. The Company will allocate such discrepancy based on a predetermined allocation method set forth in the Supplier Service Agreement. If no predetermined allocation method has been established prior to the event of such discrepancy, the Company will allocate the discrepancy on a pro rata basis. The Company will not confirm any volume nominated by the Supplier in excess of the ATV.

10.3.7 In the event that the Supplier is unable to deliver a confirmed ATV Nomination, the Supplier may make intra-Gas Day Nominations relating to changes to existing Nominations within a given Gas Day no later than two (2) hours prior to the intra-Gas Day Nomination deadline for the Transporting Pipeline on which the Nomination is to be effective, or such lesser period as determined by the Company; provided, however, that the Nomination must be in conformance with the requirements of and must be permitted by the Transporting Pipeline. Intra-Gas Day Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a basis consistent with that utilized by the Company for its own operations. The Company shall not adjust the ATV applied for the Gas Day.

10.3.8 Nominations may be rejected if they do not satisfy the conditions for Delivery Service in effect from time to time.

10.3.9 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an Operational Flow Order ("OFO") declared by the Company pursuant to Section 16 will be subject to the Critical Day provisions of Section 10.6.1 of this tariff, and the delivered quantity specified in the OFO will replace the ATV.

10.4 Determination of Receipts

10.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Transporting Pipeline(s).

10.4.2 The Company Gas Allowance will be assessed against receipts pursuant to Section 8 of this tariff.

10.5 Metering and the Determination of Deliveries

The Company shall record the Customer's Gas Usage at the Delivery Point by making actual meter reads on a monthly [or bi-monthly] basis. In the event that the Customer's Gas Usage is metered on a bi-monthly basis, the Company shall make available to the Supplier estimates of the Customer's Gas Usage for each of the two billing months.

10.6 Balancing

10.6.1 Any difference between the Supplier's ATV for an Aggregation Pool and the receipts on the Transporting Pipeline to the appropriate Designated Receipt Point(s) will be cashed out by the Company according to the following:

Off-Peak Season: For receipts less than the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Peak Season: For receipts less than the ATV but greater than or equal to 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the difference. For receipts less than 95% of the ATV, the Supplier shall be charged 1.1 times the Daily Index for the first 5% difference, and the Supplier shall be charged two (2) times the Daily Index for the remaining difference. For receipts greater than the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day(s) The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 16.

Critical Day That Will Be Aggravated by Under-delivery.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by under-delivery shall be charged five (5) times the Daily Index for the difference between the ATV and actual receipts.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by under-delivery shall be charged the following amounts for all receipts in excess of the ATV:

(a) up to 25% in excess of the ATV, the Supplier shall be charged the Daily Index for the difference.

(b) for receipts in excess of 25% above the ATV, the Supplier shall be charged 0.8 times the Daily Index for the difference.

Critical Day That Will Be Aggravated By Over-delivery.

Supplier who over-delivers. A Supplier who over-delivers on a Critical Day that will be aggravated by over-delivery shall be charged 0.4 times the Daily Index for receipts greater than the ATV.

Supplier who under-delivers. A Supplier who under-delivers on a Critical Day that will be aggravated by over-delivery shall be charged the following amounts--for receipts less than the ATV but greater than or equal to 75% of the ATV, the Supplier shall be charged the Daily Index for the first 25% difference, and the Supplier shall be charged 1.1 times the Daily Index for the remaining difference.

10.6.2 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

10.6.3 In addition to the charges set forth in Section 10.6.1, the Company shall use a daily balancing charge calculation to account for balancing costs it incurs in serving each Aggregation Pool due to differences in forecast versus actual Heating Degree Days. The daily balancing charge shall be based on the sum of the absolute values of the daily differences between the Aggregation Pool's ATV and the recalculated ATV value described in Section 10.7.1 below. Such charge shall be billed to the Supplier monthly and shall reflect the cost of resources used by the Company to balance such differences for each Gas Day of the Month. The Company shall calculate such charge annually in its Winter Season Cost of Gas filing according to a formula as set forth in Attachment B.

In the event that the Transporting Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this Section at each Designated Receipt Point.

10.6.4 In addition to the charges set forth in Sections 10.6.1 and 10.6.2, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

10.7 Cash Out

10.7.1 The Company shall use a daily cash out calculation to account for imbalances due to differences in forecast versus actual Heating Degree Days. Using a Consumption Algorithm, the Company will recalculate the ATV for each Aggregation Pool for each Gas Day of the Month, substituting actual Heating Degree Days for forecast Heating Degree Days. Daily recalculations shall be compared to the Aggregation Pool’s daily ATV, and the difference shall be cashed out at 100% of the Daily Index.

10.7.2 During the billing months of both June and December, the Company shall use a six-month cash-out calculation to account for differences in forecast usage versus billed Gas Usage. The Company may cash-out differences in forecast usage versus billed usage at intervals that are less than six months as provided by the Supplier Service Agreement.

(1) In the billing month of June, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of November 1 through April 30 to the sum of billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index weighted by actual Heating Degree Days over the same period. The Winter period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending April 30.

(2) In the billing month of December, using the recalculated ATV values described in Section 10.7.1, the Company will compare the sum of the recalculated ATV values for each Aggregation Pool for the six-month period of May 1 through October 31 to the sum of the billed usage volumes used by each Aggregation Pool for that same period. The differences shall be cashed out at 100% of the average of the Daily Index over the same period. The Off-Peak period cash-out shall be calculated and provided to Suppliers within 60 days of the month ending October 31.

10.7.3 The Company shall allow Suppliers to trade seasonal differences. Prior to the seasonal cash-out, the Company shall make available a list of Suppliers. Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company. All trades must be communicated to the Company within three (3) Business Days following receipt of the list.

10.7.4 If, during any fifteen (15) consecutive Gas Days, the Supplier delivers an amount less than 70% of the sum of the ATVs of the Aggregation Pool in said Gas Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Gas Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Gas Days, the Supplier may be reinstated at the end of the 30 Gas Days, provided it posts security equal to the product of: (1) the Supplier's estimated maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this Section, the Supplier will be disqualified from service under this tariff for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under this tariff, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

11 CAPACITY ASSIGNMENT

11.1 Applicability

Section 11 of this tariff applies to all Suppliers that have enrolled one or more Customers into one or more Aggregation Pools and shall include Customers acting as their own Supplier. The Company shall assign and the Supplier shall accept each Customer's pro-rata share of Capacity, if any, as established in accordance with this Section.

11.2 Identification of Capacity for Assignment

11.2.1 On or before September 15 of each year, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning in October.

11.2.2 The Company shall identify, by Gas Service Area, the specific contracts and resources for assignment to Suppliers based on the Company's Capacity and resource plans. Such identified contracts and resources shall be used to determine the pro-rata shares of Capacity assignable to a Supplier on behalf of the Customers enrolled in its Aggregation Pool.

11.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates, the assignment of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)] and other contracts that are not assignable to third-parties due to governing tariffs.

11.3 Determination of Pro-Rata Shares of Capacity

11.3.1 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Delivery Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.

11.3.2 For a Customer receiving Sales Service on or after March 14, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.

11.3.3 For a Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had an executed contract for firm transportation service (i.e., the equivalent of Delivery Service) on file with the Company on or before March 14, 2000, the TCQ shall be zero.

11.3.4 A Customer that was either receiving Supplier Service (or the equivalent form of service at the time) on March 14, 2000, or had a written request on file with the Company on or before March 14, 2000 may elect for its Supplier to accept assignment of its pro-rata share of Capacity as determined by the Company in accordance with Section 11.2 and, subject to availability, as determined by the Company in its sole reasonable discretion. In order to make such election, the Customer must have submitted to the Company, on or before ten (10) days prior to the first Assignment Date prior to the original effective date of this tariff, a completed application for Capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 11 and 14 of this tariff as if the Customer had been receiving Sales Service on or after March 14, 2000

11.3.5 For a new Customer taking Supplier Service as its initial service after March 14, 2000, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, in which case the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company may reduce said TCQ value for the new Customer, if, in its sole reasonable discretion, the Company determines that the old Customer's TCQ exceeds the new Customer's estimated future consumption on the Peak Day. In the event that Sales Service is provided at a new meter location for Gas Usage associated with new construction, the TCQ shall be zero, provided that the Customer initiates Supplier Service upon the completion of said new construction in accordance with Section 20.5 of this tariff

11.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 11.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Sales Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 11.3.2 if the Customer again elects to take Supplier Service after returning to Sales Service, unless otherwise established herein..

11.3.7 The Company shall determine the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Rate Schedule shall be set forth annually in Attachment C to this tariff.

11.3.8 The Company shall determine the pro-rata share of Seasonal Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Storage Withdrawal Capacity.

11.3.9 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 14 of this tariff.

11.4 Capacity Assignments

11.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 11.2, 11.3 and 11.7.

11.4.2 The total amount of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall be at least equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of Five (5) Business Days prior to the Assignment Date.

11.4.3 Storage Withdrawal Capacity shall be subject to Operational Flow Orders that are issued by the Company pursuant to Section 16 of this tariff, in the event that the Company requires the Supplier to deliver or to store quantities of Gas for the purposes of managing system imbalances and maintaining Delivery Service. Whenever the Company assigns incremental Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Seasonal Storage Capacity pursuant to Section 11.8.

11.4.4 The Peaking Capacity assigned to the Supplier shall establish the Maximum Daily Peaking Quantity ("MDPQ") for the Aggregation Pool in the Supplier's Service Agreement. In the event that the Company increases a Supplier's MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 14.

11.4.5 The Company shall execute Capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial increment of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity assigned to the Supplier pursuant to Section 11.4.1 exceeds 150 MMBtus. The Supplier shall accept additional increments of Capacity on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assigned to the Supplier, as rounded to the nearest 200 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assigned Capacity as established in accordance with Section 11.4.1. Section 11.4.2 shall not apply to a Customer that is acting as its own Supplier.

11.4.6 If a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 11.3.

11.5 Release of Contracts

11.5.1 With the exception of Company-Managed Supplies and Peaking Capacity, Capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged Capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs.

11.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first Gas Day of the Month following the Assignment Date through the expiration date of the respective capacity contract being assigned. and ending on October 31. For example, contracts assigned to a Supplier on April 25 of a given year shall be released for a term beginning on May 1 of that year and ending on October 31 of that year.

11.5.3 The Company reserves the right to adjust releases of Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Storage Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but are not limited to, the reassignment of certain Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over Capacity resources associated with system balancing, and/or the retention of specific Capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

11.6 Annual Reassignment of Capacity

11.6.1 On each Annual Reassignment Date, the Company shall adjust the Capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the Customers enrolled in the Supplier's Aggregation Pools (as of the first Gas Day of the Month following the Annual Reassignment Date).

11.6.2 If the reassignment of Storage Withdrawal Capacity requires adjustments to the Seasonal Storage Capacity previously assigned to a Supplier, the Company shall reassign Seasonal Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 11.8 of this tariff.

11.6.3 If the reassignment of Peaking Capacity requires adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 14 of this tariff.

11.7 Recall of Capacity

11.7.1 If the pro-rata shares of Capacity assignable to a Supplier decline because one or more of the Supplier's Customers has returned to Sales Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its Capacity-recall rights shall be made by the Company in its sole reasonable discretion. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the Assignment Date following the effective date of the Customer's return to Sales Service. Notwithstanding the foregoing, in the following circumstances the Company shall be required to recall Capacity associated with Customers returning to Sales Service:

(a) The Supplier returning the Customers to Sales Service certifies that it is ceasing all business operations in New Hampshire;

(b) The Supplier returning the Customers to Sales Service certifies that it will no longer offer service to a particular market sector (e.g., small commercial and industrial Customers) and, therefore, once such Customers are returned to Sales Service, the Supplier is not eligible to re-enroll Customers of that type; or

(c) The Supplier demonstrates that it has provided Supplier Service to the Customer for a 12-month period, and for a period of no less than any 12-month increment, prior to the Customer's return to Sales Service.

11.7.2 If the Company elects to recall Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 11.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Seasonal Storage Capacity associated with the affected Aggregation Pool in accordance with Section 11.8 of this tariff. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 14 of this tariff.

11.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs and/or the reduction in assigned quantities set forth in the Supplier Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assigned to the Supplier, rounded to the nearest 200 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Storage Withdrawal Capacity, and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) Gas Days pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30 Gas Days, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.

11.7.5 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 9.6.6 or 10.7.4 of this tariff, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 11.4 and 11.5. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro rata shares of Capacity reassignments.

11.7.6 In the event that the Supplier fails to meet the applicable registration and licensing requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 20.3 of this tariff, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.

11.7.7 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this Section. Such forfeiture shall be effected in accordance with applicable laws and regulations and the governing tariffs. In the event of Capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.

11.8 Seasonal Storage Capacity

11.8.1 On each Assignment Date, the Company shall release Seasonal Storage Capacity to a Supplier that accepts the assignment of Storage Withdrawal Capacity pursuant to Section 11.4. The Company shall assign such Seasonal Storage Capacity consistent with the tariffs governing the release of the associated Storage Withdrawal Capacity.

11.8.2 If the Company assigns Seasonal Storage Capacity to a Supplier pursuant to Section 11.8.1 above, the Company shall transfer in-place Gas inventories to the Supplier. The quantity of inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Seasonal Storage Capacity assigned to the Supplier on the Assignment Date times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two Business Days prior to each Assignment Date.

11.8.3 In the event that the Company recalls Storage Withdrawal Capacity from the Supplier pursuant to Section 11.7, the Company shall also recall Seasonal Storage Capacity from the Supplier. The Company shall determine the total Seasonal Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Storage Withdrawal Capacity returned to the Company.

11.8.4 If the Company recalls Seasonal Storage Capacity from a Supplier pursuant to Section 11.8.3, the Supplier shall transfer in-place Gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Seasonal Storage Capacity times the applicable storage inventory percentage described in Section 11.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in off-system storage facilities as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the Company's weighted average cost of inventories, by Gas Service Area, at least two (2) Business Days prior to each Assignment Date.

11.8.5 Seasonal storage inventory percentages shall represent the amount of Seasonal Storage Capacity in each assigned storage resource that is assumed to be filled with inventories as of the first Gas Day of the month following the Assignment Date. Each September, the Company shall communicate, by electronic means as determined by the Company or, in the event of failure of such electronic means, by facsimile or other agreeable alternative means, the storage inventory percentages for each resource that shall be applied to incremental or decremental Seasonal Storage Capacity assignments executed on each of the twelve (12) Assignment Dates beginning in October.

11.9 Company-Managed Supplies

11.9.1 The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain Capacity contracts including Canadian, Federal Energy Regulatory Commission, 15 U.S.C. § 717(c) or Section 7(c) [Part 157 of the FERC regulations (18 C.F.R. part 157)], and other contracts that are not assignable to third-parties.

11.9.2 The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 11.4 and 11.8.

11.9.3 The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies pursuant to the tariffs governing the resources.

11.9.4 The Company shall invoice the Supplier for its pro-rata shares of the demand charges for Capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs, including Supply costs, incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

11.9.5 The Company shall nominate quantities to the Transporting Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned Company-Managed Supplies, provided that the requested Nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired Nomination quantities to the Company subject to the provisions in Sections 9.3 and 10.3 of this tariff.

11.10 Capacity Mitigation Service

11.10.1 Capacity Mitigation Service is available to Suppliers that have been assigned Capacity pursuant to Section 11 of this tariff. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with this tariff.

11.10.2 Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 11.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

11.10.3 The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the Capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

11.10.4 The Company will market Capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month and will be included in the bill sent to the Supplier in the following Month.

12 BILLING AND SECURITY DEPOSITS

12.1 The Customer shall be responsible for all charges for service furnished by the Company under the Company's applicable rates, as filed from time to time with the NHPUC, from the time service is commenced until it is terminated. The Company shall provide a single bill, reflecting unbundled charges, to Customers for Sales Service.

12.2 The Company shall offer two billing service options to Customers taking only Delivery Service: standard complete billing service and standard pass-through billing service. The Supplier shall inform the Company of the selected billing option in accordance with the provisions set forth in Section 20.5

12.2.1 Standard Complete Billing Service

The Customer shall receive a single bill from the Company for both Delivery Service and Supplier Service. The Company shall use the rates supplied by the Supplier to calculate the Supplier's portion of the single bill and integrate this billing within a single mailing to the Customer. The Company may charge a fee to the Supplier for providing this billing service as approved by the NHPUC.

The Supplier shall adhere to the Customer classes and rate structure as specified in the Company's then current Rate Schedule on file with and approved by the NHPUC. The Company shall reasonably accommodate, at the Supplier's expense, different Customer classes or rate structures as agreed to by the Company and the Supplier in the Supplier Service Agreement.

The Company shall provide an electronic file to the Supplier that will, in addition to the usage being billed, contain the calculated Supplier billing amounts for the current billing cycle. Customer revenue due the Supplier shall be transferred to the Supplier in accordance with the Supplier Service Agreement. Upon receipt of Customer payments, the Company shall provide a file for the Supplier summarizing all revenue from Supplier sales which have been received and recorded that day.

If a Customer pays the Company less than the full amount billed, the Company shall apply the payment first to Delivery Service, and if any payment remains, it shall be applied to Supplier Service.

12.2.2 Standard Pass-through Billing Service

The Customer taking Delivery Service shall receive two (2) bills: the Company shall issue one bill for Delivery Service and the Supplier shall issue a second bill for Supplier Service.

The Supplier shall be responsible for the collection of amounts due to the Supplier from the Customer. Customer payment responsibility with Suppliers shall be governed by the particular Customer/Supplier contract.

Within three (3) Business Days following the end of the Customer's billing cycle, the Company shall provide an electronic file for the Supplier that will contain the Customer's usage being billed including the current and previous meter readings.

12.2.3 The Company shall inform a Customer when Supplier Service has been initiated by a Supplier along with information on how the Customer may file a complaint regarding an unauthorized initiation of Service. This information shall be included on the first bill rendered to the Customer after such initiation.

12.2.4 A Customer acting as its own Supplier will be subject to the billing and payment requirements in Section 20.8 of this tariff.

12.2.5 Readings taken by an automated meter reading device will be considered actual readings for billing purposes.

13 SALES SERVICE

13.1 Sales Service is the Commodity service provided by the Company for Customers not electing to subscribe to Supplier Service and shall be provided by the Company, or its designated Supplier, in accordance with this tariff. Each Customer receiving Sales Service shall receive one bill from the Company reflecting delivery and Commodity charges.

13.2 A Customer receiving Sales Service on March 14, 2000 shall continue to receive Sales Service unless the Customer elects to take Supplier Service and until such time that Supplier Service is initiated for the Customer in accordance with Section 20.5 of this tariff. If the Customer terminates Supplier Service, if a Supplier terminates service to the Customer, or if the Customer's designated Supplier becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide Sales Service to the Customer. Pursuant to Section 20.5 of this tariff, the Company will initiate Sales Service for the Customer and will provide Sales Service to the Customer until such time that Supplier Service is initiated for the Customer by a new Supplier.

13.3 Any Customer whose Supplier has been assigned Capacity on behalf of said Customer pursuant to Section 11 of this tariff may elect to return to Sales Service if the Customer is no longer receiving Supplier Service. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to said Customer up to a maximum daily level of Gas Usage not to exceed the Total Capacity Quantity ("TCQ") of recallable Capacity assigned to the Customer's former Supplier.

13.4 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff terminates Supplier Service to the Customer, the Customer may select another Supplier. If necessary, the Company will initiate Sales Service for the Customer pursuant to Section 20.5 of this tariff and will provide the Customer with Sales Service until Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Sales Service to the Customer up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's former Supplier.

13.5 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 11 of this tariff becomes ineligible to serve the Customer pursuant to Sections 9.6.6, 10.7.4, or 20.3 of this tariff, the Company will provide the Customer with Sales Service up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable Capacity assigned to the Customer's Supplier.

13.6 The Company shall be under no obligation to provide Sales Service to a Customer at a maximum daily level in excess of the TCQ of recallable Capacity assigned to a Supplier on behalf of the Customer. The Company may elect to provide Sales Service to the Customer if, and to the extent that, adequate system Capacity and Supplies are available and upon the same terms and subject to the same conditions as any new Customer seeking to take Sales Service.

14 PEAKING SERVICE

14.1 Applicability

Section 14 of this tariff applies to all Suppliers, and to all Customers acting as their own Supplier, that have been assigned, or have elected to be assigned, Capacity on behalf of themselves or Customers in their Aggregation Pools pursuant to Section 11 of this tariff.

14.2 Character of Service

14.2.1 Peaking Service shall be provided by the Company subject to an executed Supplier Service Agreement that sets forth the Maximum Daily Peaking Quantity ("MDPQ") and the assigned Peaking Supply for each of the Supplier's Aggregation Pools.

14.2.2 The Company shall provide quantities of Gas, at the Supplier's request, from the Supplier's Peaking Service Account as established in accordance with Section 14.4. Such quantities shall be deemed delivered by the Company and received by the Company at the Designated Receipt Point(s) for the Aggregation Pool. Peaking Service shall be firm and available to the Supplier each Gas Day in accordance with the balance of the Supplier's Peaking Service Account and the parameters of the Company's Peaking Service Rule Curve.

14.3 Rates and Charges

14.3.1 The applicable rates for Peaking Service shall be established in the Company's tariff. The Supplier shall pay a peaking demand charge based on its MDPQ of assigned Peaking Capacity as billed by the Company for the Peak Season. Such unit demand charge shall be equal to the total Capacity costs and other fixed costs associated with the Company's peaking resources, excluding costs collected through Delivery rates, divided by the estimated peaking resources needed to meet the Company's total system Peak Day requirement.

14.3.2 The Supplier shall pay a Commodity charge equal to the estimated weighted average cost of peaking supplies, including fuel retention and carrying charges. The Company shall communicate electronically, by facsimile or by other agreeable alternative means the Company's estimated weighted average cost of peaking supplies by the 15th of the month preceding the next Assignment Date. The Commodity charge will be multiplied by the volumes of Peaking Service Gas nominated by the Supplier during each Month.

14.4 Peaking Supply

14.4.1 The Customer's portion of the Peaking Supply that shall be assigned to the Supplier on behalf of the Customer shall be equal to the Peaking Supply multiplied by the ratio of the Customer's MDPQ to the aggregate MDPQ of the total system.

14.4.2 On each Assignment Date, the Company shall assign Peaking Supply to a Supplier whose MDPQ has been increased pursuant to Section 11.4. If the Company assigns incremental Peaking Supply to a Supplier, the Company shall credit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the

Peaking Service Rule Curve. The amount credited to the Supplier's Peaking Service Account shall be determined by multiplying the incremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.3 On each Assignment Date, the Company shall recall Peaking Supply from a Supplier whose MDPQ has been decreased pursuant to Section 11.7. The Company shall determine the Supplier's total Peaking Supply for recall to be equal to the difference between the cumulative total Peaking Supply assigned to the Supplier as of the previous Assignment Date and the total Peaking Supply that is assignable to the Supplier in accordance with Section 14.4.1 above.

14.4.4 If the Company recalls Peaking Supply from a Supplier pursuant to Section 14.4.3, the Company shall debit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount debited from the Supplier's Peaking Service Account shall be determined by multiplying the decremental Peaking Supply by the peaking inventory percentage described in Section 14.4.5.

14.4.5 The peaking inventory percentage shall represent the level of Peaking Supply assumed to be available to a Supplier in its Peaking Service Account as of the first Gas Day of the Month following the Assignment Date for incremental and decremental assignments of Peaking Supply. Each September, the Company shall communicate electronically, by facsimile or by other agreeable alternative means the Peaking Inventory Percentages that shall be applied to incremental or decremental Peaking Supply assignments executed on each of the twelve (12) Assignment Dates beginning in October.

14.4.6 On each Annual Reassignment Date, the Company shall reset the balance in the Supplier's Peaking Service Account to equal the total Peaking Supply assignable to the Supplier on behalf of Customers enrolled in its Aggregation Pool (as of the first Gas Day of the Month following the Annual Reassignment Date) as determined in accordance with Section 14.4.1 above.

14.5 Nomination of Peaking Service

14.5.1 The Supplier shall nominate with the Company the quantity of Peaking Supply, not in excess of the amount determined pursuant to Section 14.4.2, that the Supplier desires to be provided from its Peaking Service Account for the applicable Gas Day. For an Aggregation Pool of Customers taking daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 9.3 of this tariff. For an Aggregation Pool of Customers taking non-daily metered Delivery Service, the notice given by the Supplier to the Company for an applicable Gas Day shall be made in accordance with Section 10.3 of this tariff.

14.5.2 In response to a valid Nomination for Peaking Service, the Company shall provide the requested quantity of Gas, which shall be deemed to be delivered by the Company and received by the Company at the Designated Receipt Point(s) of the Supplier's Aggregation Pool, subject to the limitations herein. Nominated quantities shall be included in the determination of receipts at the Designated Receipt Point(s) for the Supplier's Aggregation Pool which factors into the daily balancing provisions set forth in this tariff.

14.5.3 The Company may reject a Supplier's Nomination for Peaking Service if the nominated quantity would cause the balance of the Supplier's Peaking Service Account to fall to a level that is 10% or more below the minimum allowable account balance for the Month in which the Nomination is requested, as computed in accordance with the Peaking Service Rule Curve. Under such circumstances, the Company shall require the Supplier to nominate the pipeline and/or storage resources, within the contract entitlements assigned to the Supplier under Section 11, required to maintain the Supplier's Peaking Service Account above the minimum allowable account balance described above. The balance of the Supplier's Peaking Service Account may not in any event fall below zero (0).

14.5.4 The Company shall provide Peaking Service supplies to the Supplier only when the volumes in the Peaking Service Account for the Aggregation Pool are greater than zero (0).

14.6 Peaking Service Critical Day Provisions

14.6.1 In the event that the volumes in a Supplier's Peaking Service Account for an Aggregation Pool are reduced to a level below the minimum allowable account balance as computed in accordance with the Company's Peaking Service Rule Curve, the Company may issue an OFO to such Supplier pursuant to Section 16 of this tariff.

14.6.2 In the event that the total volumes of all Peaking Service Accounts within one or more of the Company's Gas Service Areas are reduced to levels below the total minimum allowable account balances as computed in accordance with the Company's Peaking Service Rule Curve, the Company may declare a Critical Day and issue a blanket OFO pursuant to Section 16 of this tariff.

14.6.3 If, on a Critical Day, the Company projects, based on the Supplier's Nominations, that the Supplier's scheduled deliveries to the Designated Receipt Point(s) of an Aggregation Pool are less than the maximum feasible volumes for deliveries on the Transporting Pipeline, the Company may issue an OFO to the Supplier in accordance with Section 16 of this tariff.

15 DISCONTINUANCE OF SERVICE

15.1 The Company shall notify a Customer's Supplier of record that it has initiated any applicable billing and termination procedures as prescribed by the NHPUC. In the event that the Company discontinues Delivery Service to a Customer in accordance with the provisions set forth above, the Company shall provide electronic notification to the Customer's Supplier of record upon final billing to the Customer. The Company shall not be liable for any revenue loss to the Supplier as a result of any such disconnection.

16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS

16.1 In the event of a material and significant threat to the operational integrity of the Company's system, the Company may declare a Critical Day.

16.2 Circumstances constituting a threat to the operational integrity of the system that may cause the Company to declare a Critical Day shall include, but not be limited to: (1) a failure of the Company's distribution, storage, or production facilities; (2) near-maximum utilization of the Company's distribution, storage, production, and Supply resources; (3) inability to fulfill firm service obligations; and (4) issuance of an OFO or similar notice by upstream transporters.

16.3 In the event that the Company has declared a Critical Day, the Company will have the right to issue an Operational Flow Order ("OFO") in which the Company may instruct Suppliers to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system, within the contract entitlements, if any, assigned to the Supplier under Section 11 hereof. An OFO may be issued on a pipeline or point-specific basis. An OFO may be issued by the Company as a blanket order to all Suppliers or to an individual Supplier whose actions are determined by the Company to jeopardize system integrity. The Company may issue an OFO to an individual Supplier if the Company faces Gas cost exposure in excess of daily cashout or imbalance penalties as set forth in Sections 9.6, 9.7, 10.6, and 10.7 for any under-deliveries or over-deliveries caused by that Supplier.

16.4 The Company will provide the Supplier with as much notice as is reasonably practicable of the issuance and removal of a Critical Day or an OFO; under most circumstances, the Company intends to provide at least twenty-two (22) hours' notice prior to the start of the Gas Day for the issuance of the Critical Day or OFO. Notification of the issuance and removal of a Critical Day or an OFO will be made by means as established in the Supplier Service Agreement. The Supplier will be responsible for coordinating with its Customers any change to the Customer's quantity of Gas Usage. An OFO or Critical Day will remain in effect until its removal by the Company.

16.5 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO will be subject to the Critical Day provisions of Sections 9.6 and 10.6 of this tariff.

17 FORCE MAJEURE AND LIMITATION OF LIABILITY

17.1 Neither the Company nor the Supplier will be liable to the other for any act, omission, or circumstance occasioned by or in consequence of any event constituting force majeure, and unless it is otherwise expressly provided herein, the obligations of the Company and the Supplier then existing hereunder will be excused during the period thereof to the extent affected by such event of force majeure, provided that reasonable diligence is exercised to overcome such event. As used herein, force majeure will mean the inability of the Company or the Supplier to fulfill its contractual or regulatory obligations: as a result of compliance by either party with an order, regulation, law, code, or operating standard imposed by a governmental authority; by reason of any act of God or public enemy; by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, or breakage or accident to machinery or pipeline (which breakage or accident is not the result of the negligence or misconduct of the party claiming force majeure); by reason of any declaration of force majeure by upstream Transporting Pipelines; or by reason of any other cause, whether the kind enumerated herein or otherwise, not within the control of the party claiming force majeure and which by the exercise of reasonable diligence such party is unable to prevent or overcome. Notwithstanding the foregoing, the Customer's and the Supplier's obligation to make any payments required under this tariff will in no case be excused by an event of force majeure. Nor will a failure to settle or prevent any labor dispute or other controversy with employees or with anyone purporting or seeking to represent employees be considered to be a matter within the control of the party claiming excuse. The party claiming force majeure will, on request, provide the other party with a written explanation thereof and of the remedy being undertaken.

17.2 The Company shall be liable only for direct damages resulting from the Company's conduct of business when the Company, its employees, or agents have acted in a negligent or intentionally wrongful manner. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract, or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under this tariff or in accordance with or required by law, including, without limitation, termination of the Customer's service.

17.3 If the Company is unable to render firm Delivery Service to the Customer taking such service as contemplated by this tariff as a result of force majeure and such inability continues for a period of thirty (30) Gas Days, the Customer may provide written notice to the Company of its desire to terminate Delivery Service at the expiration of thirty (30) Gas Days from the Company's receipt of such notice, but no sooner than sixty (60) Gas Days following the outset of the force majeure. If the Company has not restored Delivery Service to the Customer at the end of such notice period, the Customer's Delivery Service will terminate and both parties will be released from further performance hereunder, except for obligations to pay sums due and owing as of the date of termination.

17.4 The Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "affiliates") harmless from and against any and all damages, costs (including attorney's fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "liabilities"), resulting from claims of third parties arising, or claimed to have arisen, from the acts or omissions of either party in connection with the performance of the indemnifying party's obligations under this tariff. The Company and the Supplier shall waive recourse against the other party and its affiliates for or arising from the non-negligent performance by such other party in connection with the performance of its obligations under this tariff.

18 CURTAILMENT

18.1 Whenever the integrity of the Company's system or the Supply of the Company's Customers taking Sales Service or Delivery Service is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole reasonable judgment, curtail or interrupt Gas service or reduce pressure as set out in Section 18, Supply and Capacity Shortage Allocation Policy of this tariff. Such action shall not be construed to constitute a default nor shall the Company be liable therefor in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

18.2 The Company shall communicate notice of curtailment as soon as practicable to the Suppliers of affected Customers by means as specified in the Supplier Service Agreement.

18.3 The Company shall take reasonable care in providing regular and uninterrupted service to its firm Customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract and shall not render the Company liable for any damages suffered thereby by any person, or excuse the Customer from further fulfillment of the contract.

18.4 In any case where the Company determines in its judgment that a curtailment or interruption of firm services is necessary, the Company will curtail and/or interrupt firm Delivery Service and Sales Service Customers on a nondiscriminatory basis.

19 TAXES

19.1 In the event a tax of any kind is imposed or removed by any governmental authority on the distribution of Gas or on the gross revenues derived from the distribution of Gas at retail (exclusive, however, of taxes based on the Company's net income), the rate for service herein stated will be adjusted to reflect said tax. Similarly, the effective rate for service hereunder will be adjusted to reflect any refund of imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental or regulatory authorities.

19.2 The Customer will be responsible for all taxes or assessments that may now or hereafter be levied with respect to the Gas or the handling or subsequent disposition thereof after its delivery to the

Delivery Point. However, if the Company is required by law to collect and/or remit such taxes, the Customer will reimburse the Company for all amounts so paid. If the Customer claims exemption from any such taxes, the Customer will provide the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

19.3 The Supplier will be responsible for all production, severance, ad valorem, or similar taxes levied on the production or transportation of the Gas before its delivery to the Designated Receipt Point. The Supplier will also be responsible for sales taxes imposed on Gas delivered for the Customer's account. However, if the Company is required by law to remit such taxes to the collecting authority, it will do so and invoice the Supplier for such taxes paid on the Supplier's behalf.

20 SUPPLIER TERMS AND CONDITIONS

20.1 Applicability

The following terms and conditions shall apply to every Supplier providing Supplier Service in the State of New Hampshire, to every Customer doing business with said Suppliers, and to Customers acting as their own Supplier.

20.2 Obligations of Parties

20.2.1 Customer

Unless otherwise agreed to by the Company and the Customer, a Customer shall select one Supplier for each account at any given time. A Customer electing Supplier Service must provide the selected Supplier with its applicable Authorization Number. A Customer may choose only a Supplier who meets the terms described in Sections 20.2.3 and 20.3 below and who meets any applicable registration requirements established by law or regulation.

20.2.2 Company

The Company shall deliver Customer purchased Gas from the Designated Receipt Point to the Delivery Point in accordance with the service selected by the Customer pursuant to this tariff and, among other things, shall:

(a) Provide Customer service and support, including call center functions, for services provided by the Company under this tariff;

(b) Respond to service interruptions, reported Gas leaks, and to other Customer safety calls;

(c) Handle connections, curtailments, and terminations for services provided by the Company under this tariff;

(d) Read meters;

(e) Submit bills to Customers for Delivery Service and if contracted by the Supplier, for Supplier Service in accordance with Section 12.2.1.

(f) Address billing inquiries for Delivery Service;

(g) Answer general questions about Delivery Service;

(h) Provide to Suppliers, on request, the data format and procedures for electronic information transfers and funds transfers;

(i) Arrange for or provide Sales Service to the Customer at the request of the Customer in accordance with the Company's tariff; and

(j) Provide information regarding, at a minimum, rate tariffs, billing cycles, Capacity assignment methods, and Consumption Algorithms.

20.2.3 Supplier

The Supplier shall act on behalf of the Customer to acquire Supplies and to deliver them to the Designated Receipt Point pursuant to the service selected by the Customer and the requirements of this tariff.

The Supplier is responsible for enrolling Customers pursuant to Section 20.5 of this tariff.

The Supplier must request, complete and sign a Supplier Service Agreement to act as a Supplier on the Company's system, satisfy the Supplier requirements and practices as set forth in Section 20.3 of this tariff, be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign Capacity, if any, under Section 11, and be and remain eligible to provide service to Customers in New Hampshire.

The Supplier is responsible for completing all transactions with the Company and for all applicable charges associated with Customer enrollment and changes in the Customer's service as set forth in Section 20.5 and Attachment B.

20.3 Supplier Requirements and Practices

20.3.1 The Company shall have the right to establish reasonable financial and non-discriminatory credit standards for qualifying Suppliers. Accordingly, in order to serve Customers on the Company's system, the Supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three (3) years, as well as two (2) trade and two (2) banking references. To the extent that such annual reports to shareholders are not publicly available, the Supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies, and subsidiaries. The Supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The Supplier shall be subject to a credit investigation by the Company. The Company shall review the Supplier's financial position periodically.

20.3.2 The Supplier shall also confirm in the Supplier Service Agreement that:

(a) The Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) The Supplier is not aware of any change in business conditions which would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) The Supplier has no delinquent balances outstanding for services previously provided by the Company, and the Supplier has paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding which would materially affect the Supplier's ability to remain solvent as a business entity.

(e) The Supplier's New Hampshire business advertising and marketing materials conform to all applicable state and federal laws and regulations.

20.3.3 In the event the Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company shall require the Supplier to provide one of the following at the Maximum Financial Liability as calculated below:

(a) Advance deposit;

(b) Letter of credit;

(c) Surety bond; or

(d) Financial guaranty from a parent company that meets the creditworthiness criteria.

The Company shall base the Supplier's maximum financial liability as two (2) times the highest month's aggregated Gas Usage of all Customers currently served by the Supplier at the highest Monthly Index in the preceding twenty-four (24) Months. This amount may be updated continuously, and at minimum, whenever the aggregated Gas Usage of all Customers served by the Supplier changes by more than 25%. The Supplier agrees that the Company has the right to access and apply the deposit, letter of credit, or bond to any payment of any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other amounts owed to the Company, or to secure additional Gas supplies, including payment of the costs of the Gas supplies themselves, the cost of transportation storage, and other related costs incurred in bringing those Gas supplies into the Company's system. The Supplier shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims with the Company. The Supplier's financial security as established above must be in place no later than five (5) Business Days prior to the first day of each calendar month in order for the Supplier to maintain its eligibility to provide service to Customers.

20.3.4 The Supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of Supplies which it desires the Company to transport to its Customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these Gas supplies to the Designated Receipt Point.

20.3.5 The Supplier shall warrant to the Company that it has good title to or lawful possession of all Gas delivered to the Company at the Designated Receipt Point on behalf of the Supplier or the Supplier's Customers. The Supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damages, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said Gas.

20.3.6 The Supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates, or permits to enable Gas to be delivered to the Company's system.

20.3.7 By agreeing to provide service under this tariff, the Supplier acknowledges that adherence to any applicable law regarding unfair trade practices, truth in advertising law, or law of similar import is required. Any Supplier found by a court of competent jurisdiction to have willfully or repeatedly violated the New Hampshire Consumer Protection Act, N.H.R.S.A. Ch. 358-A; the Federal Trade Commission Telemarketing Sales Rules, 16 C.F.R. Part 310; or the regulations promulgated pursuant to the Federal Trade Commission Act, 15 U.S.C. § 45 (a) (1), may be suspended or disqualified from acting as a Supplier on the Company's system.

20.3.8 If the Supplier fails to comply with or perform any of the obligations on its part established in this tariff or in the Supplier Service Agreement (e.g., failure to deliver Gas or late payment of bills rendered or failure to execute a capacity assignment), the Company maintains the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system. Written notice of such an intent to terminate the Supplier's eligibility shall be given to the Supplier, its Customers, and the NHPUC. Notification to the Supplier shall be via Registered U.S. Mail - Return Receipt Requested or other means of documented delivery. Upon issuance of such written notice, the Company shall have the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system at the expiration of ten (10) Gas Days after the giving of such notice, unless within such ten (10) Gas Day period the Supplier shall remedy to the full satisfaction of the Company such failure. Termination of such Supplier eligibility for any such cause shall be a cumulative remedy as to the Company, and shall not release the Supplier from its obligation to make payment of any amount or amounts due or to become due from the Supplier to the Company under the Company's applicable tariffs. Customers whose Supplier's deliveries have been terminated will be placed on Sales Service pursuant Section 13 of this tariff.

20.4 Access to Usage History and Current Billing Information

The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to requesting the Company to release the Company's historic usage information specific to that Customer to such Supplier.

The Company shall be required to provide the most recent twelve (12) months of a Customer's historic usage data to a Supplier, provided that the Supplier has received the appropriate authorization as set forth above.

20.5 Enrollment, Cancellation, and Termination of Supplier Service

20.5.1 The Supplier shall be responsible for obtaining the necessary Authorization Number from each Customer prior to initiating Supplier Service to the Customer.

20.5.2 The Supplier must provide the Company with the following minimum information in the Company's predetermined format prior to the commencement or termination of service by the Supplier pursuant to Section 20.5 of this tariff:

(a) The Customer's name and current Authorization Number;

(b) The name of the Supplier;

(c) The Customer's billing option (for commencement of service);

(d) The type of change in Supplier Service (e.g., commencement of service, termination of service, or cancellation of service due to the rescission of an agreement with the Supplier by the Customer); and

(e) Any additional information reasonably required by the Company.

The Company shall determine whether each Customer's enrollment request as provided by a Supplier is complete and accurate, and matches the Customer's account record. In the event that the enrollment request is incomplete, inaccurate, or does not match the Customer's account record, then the Company will notify the Supplier so that the Supplier can resolve any discrepancies.

20.5.3 A change in Supplier Service will normally be made on a monthly metering and billing cycle basis, with changes taking effect on the date of the Customer's next scheduled meter read. Enrollment forms must be transmitted no less than ten (10) Business Days prior to the Customer's next scheduled meter read. If more than one Supplier submits a Supplier Service transaction for a given Customer during the monthly billing cycle, the first completed transaction that is received during the cycle shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted after the Customer's next scheduled meter read.

20.5.4 If the Supplier submits information to the Company to terminate Supplier Service to a Customer less than ten (10) Gas Days before the next scheduled meter read, Supplier Service shall be terminated on the date of the Customer's subsequent scheduled meter read. The Company shall confirm the termination date for Supplier Service.

20.5.5 In those instances when a Customer who is receiving Supplier Service from an existing Supplier initiates such service with a new Supplier, the Company shall send the date for the Customer's change in Supplier Service to the existing Supplier. To terminate Supplier Service with a Supplier and to initiate Sales Service, a Customer shall so inform the Company and the Supplier. Supplier Service shall be terminated on the date of the Customer's next scheduled meter read provided that the Company receives notice of such termination no less than ten (10) days in advance of the next scheduled meter read. Where such notice is received by the Company in less than ten (10) days in advance of the next scheduled read, the termination shall be effective as of the date of the following scheduled read. The Company shall send the Customer's termination date for Supplier Service to the Supplier.

20.5.6 A Customer who moves within the Company's service territory shall have the opportunity to notify its existing Supplier that it seeks to continue Supplier Service with said Supplier. Upon such notification, the Supplier may enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer at the new location. The Company shall make the necessary adjustments to the Supplier's affected Aggregation Pools, including but not limited to, changes to Designated Receipt Points, and quantities of Capacity for assignment, if any, pursuant to this tariff and the Supplier's Service Agreement with the Company. In the event that the existing Supplier does not enroll the Customer for Supplier Service at the new location, the Company shall arrange for or provide Sales Service to the Customer.

20.5.7 In those instances when a new Customer moves to the Company's service territory, the Customer's Supplier must enroll the Customer pursuant to the provisions set forth in this Section in order to initiate Supplier Service for the Customer. Otherwise, the Customer shall receive Sales Service in accordance with Section 13.

20.5.8 The Company may charge fees to the Supplier for processing the transactions described in this Section, as approved by the NHPUC. These fees are included in Attachment D.

20.6 Aggregation Pools

20.6.1 The aggregation of Customer accounts into an Aggregation Pool is limited by the Delivery Service of the respective Customers. Non-daily metered Customers subscribing to Delivery Service under Rate Schedules G-41, G-42, G-51 and G-52 must be aggregated in a separate pool from Customers subscribing to daily metered service under Rate Schedules G-43, G-53, and G-54.

20.6.2 Non-daily metered Customers taking Delivery Service pursuant to Section 10 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.3 Daily metered Customers taking Delivery Service pursuant to Section 9 of this tariff shall be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Gas Service Areas.

20.6.4 A separate Supplier account will be established for each Supplier Aggregation Pool.

20.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

20.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Attachment B.

20.7 Imbalance Trading

20.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

20.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.

20.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

20.7.4 Daily imbalance trades must be point-specific on those Gas Days when the Transporting Pipeline required the Company to balance on a point-specific basis.

20.8 Billing and Payment

20.8.1 By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the prior Month. The Company will provide Suppliers with their Customers' consumption data based on estimated or actual meter readings at the appropriate cycle read dates for each Customer in the Aggregation Pool pursuant to Section 12 of this tariff. This data will be provided on a rolling basis as readings or estimates are made.

20.8.2 Calculation of the charges applicable to the Aggregation Pool will be based on aggregated Gas Usage and other such indicators of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, including but not limited to imbalance charges, credits or penalties, shall be billed to the Supplier on a calendar month basis.

20.8.3 The Supplier shall have ten (10) Business Days from the date of such statement to render payment to the Company. The Supplier shall render payment by means of electronic funds transfer to the Company. The late payment rate will apply to all amounts outstanding after ten (10) days.

20.8.4 If the correctness of the Company's bill to the Supplier is questioned or disputed by the Supplier, an explanation should be promptly requested from the Company. If the bill is determined to be incorrect, the Company shall issue a corrected bill. In the event that the Supplier and the Company fail to agree on the amount of the bill, the Supplier may file a complaint with the Commission to resolve such complaint.

21 CUSTOMER DESIGNATED REPRESENTATIVE

21.1 The Customer may appoint a Designated Representative to satisfy or undertake the Customer's duties and obligations; including, but not limited to submitting and/or receiving notices, making nominations, arranging for trades of imbalances, and performing operational and administrative tasks; provided, however, that under no circumstances will the appointment of a Designated Representative relieve the Customer of the responsibility to make full and timely payment to the Company for all Delivery Service provided under this tariff.

21.2 A request by a Designated Representative to the Company that contains the Customer's Authorization Number will be deemed to be confirmation that the Customer has designated such person or entity as a Designated Representative. A Customer may appoint only one (1) Designated Representative per account.

21.3 Under any agency established hereunder, the Company shall rely upon information concerning the applicable Customer's Delivery Service that is provided by the Designated Representative. All such information shall be deemed to have been provided by the Customer. Similarly, any notice or other information provided by the Company to the Designated Representative concerning the provision of Delivery Service to such Customer shall be deemed to have been provided to the Customer. The Customer shall rely upon any information concerning Delivery Service that is provided to the Designated Representative as if that information had been provided directly to the Customer.

21.4 The Customer shall agree to indemnify the Company and hold it harmless from any liability (including reasonable legal fees and expenses) that the Company incurs as a result of the Designated Representative's negligence or willful misconduct in its performance of agency functions on the Customer's behalf.

IV. ATTACHMENTS

1 ATTACHMENT A
Supplier Service Agreement

GAS SUPPLIER SERVICE AGREEMENT

This Agreement made this **[day]** day of **[month]**, 20**[xx]**, between Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, a New Hampshire Corporation with a principal place of business at 15 Buttrick Road, Londonderry, NH 03053 (the "Company") and **[name of supplier]**, a [state] company with a principal place of business at [address] ("Supplier"). The Company and the Supplier is also individually referred to herein as a "Party" or collectively as the "Parties."

BASIC UNDERSTANDINGS

Whereas, the Company operates as a natural gas local distribution company and provides firm transportation of third- party gas on its distribution system; and

Whereas, the Company's Tariff (the "Tariff") on file with, and approved by, the New Hampshire Public Utilities Commission (the "NHPUC") permits delivery service customers to assign their rights of nominating and scheduling delivery of gas for transportation on the Company's system to a third-party natural gas supplier; and

Whereas, Supplier seeks to nominate and schedule delivery of gas for distribution on the Company's system on behalf of one or more customers taking delivery service from the Company; and

Whereas, the Company's Tariff, Part III, Section 20.2.3, requires Supplier to enter into this Supplier Service Agreement (the "Agreement") with the Company prior to the initiation of Supplier Service, as defined therein; and

Now therefore, the Parties hereto, each in consideration of the agreement of the other, do hereby agree as follows:

I. SCOPE AND APPLICATION

1.0 This Agreement shall be subject to the Company's Tariff as on file with the NHPUC and in effect from time to time. The Company's Tariff and applicable Rate Schedules are hereby incorporated by reference as though directly set forth herein. In the event the terms of this Agreement conflict with the Company's Tariff, the Tariff shall control.

1.1 This Agreement is intended for use between the Company and natural gas suppliers providing service to customers on the Company's distribution system, and may not be waived, altered, amended, or modified, except as provided herein.

1.2 Exhibits A and B, attached hereto and incorporated herein by reference, include additional terms that are a part of this Agreement.

II. DEFINITIONS

2.0 Any capitalized terms used in this Agreement and not defined herein shall be as defined in the Tariff or as stated in the NHPUC's regulations.

III. TERM

3.0 This Agreement shall become effective on the date hereof (the "Effective Date") and shall continue in full force and effect from month to month unless terminated by either Party by written notice given no less than thirty (30) days prior to the desired termination date, or unless otherwise agreed by the Parties. Notwithstanding the foregoing, the Parties agree to abide by all terms of this Agreement until any transactions that are outstanding at the time of termination are completed, including, but not limited to, the payment by Supplier to the Company of any and all outstanding balances.

3.1 Notwithstanding anything to the contrary elsewhere in this Agreement or in the Company's Tariff, any Party, by written notice to the other Party (the "Breaching Party") may terminate this Agreement, in whole or in part, with respect to such Breaching Party or suspend further performance without terminating this Agreement upon the occurrence of any of the following:(a) the Breaching Party terminates or suspends doing business; (b) the Breaching Party becomes subject to any bankruptcy or insolvency proceeding under federal or state law (unless removed or dismissed within sixty (60) days from the filing thereof), or becomes insolvent, becomes subject to direct control of a transferee, receiver or similar authority, or makes an assignment for the benefit of creditors; or (c) the Breaching Party commits a material breach of any of its obligations under this Agreement or the Tariff and has not cured such breach within fifteen (15) days after receipt of a written notice from the other Party specifying the nature of such

3.2 Consistent with the provisions of Part III, Section 20.3.8 of the Company's Tariff, the Company also maintains the right to terminate the Supplier's eligibility to act as a Supplier. on the Company's system in the event that Supplier fails to comply with or perform any of the obligations on its part established in the Tariff or in this Agreement, including but not limited to, failure to deliver gas or to make payment of amounts due to the Company.

3.3 Notwithstanding the Effective Date, Supplier acknowledges and agrees that the Company is obligated to provide services pursuant to this Agreement only upon full satisfaction, or the Company's express written waiver, of the Conditions Precedent set forth in Article IV of this Agreement.

3.4 No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights, nor shall a waiver of one default be deemed a waiver of any other or subsequent default.

3.5 The enumeration of the foregoing remedies shall not be deemed a waiver of any other remedies to which either Party is legally entitled.

IV. CONDITIONS PRECEDENT

4.0 The following requirements shall be conditions precedent to the Company's obligations hereunder:

(a) Supplier shall provide the Company with all information requested in Exhibits A and B attached hereto and incorporated herein;

(b) Pursuant to Part Ill, Section 20.3.1 of the Company's Tariff, the Company shall confirm the Supplier's creditworthiness. In the event that Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company will identify such deficiencies to the Supplier, and the Supplier shall provide financial assurances as required by the Company consistent with the provisions of Part III, Section 20.3.3;

(c) Pursuant to Part Ill, Section 20.2.3 of the Company's Tariff, Supplier shall register with the NHPUC and provide evidence of such to the Company on an annual basis;

(d) Pursuant to Part III, Section 20.2.3 of the Company's Tariff, Supplier shall demonstrate to the Company that it is an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity;

(e) Pursuant to Part Ill, Section 12.2.1 of the Company's Tariff, where Supplier elects to utilize the Standard Complete Billing Services from the Company, Supplier shall furnish to the Company a complete schedule of its relevant rates and rate pricing options for Supplier Service in written form or in an electronic format reasonably acceptable to the Company, at Company's option, no less than ten (10) Business Days prior to initial Customer enrollment for any such rate or prior to a change in Supplier's existing rates or five (5) Business Days prior to a change in rate pricing options.

(f) Prior to Customer Enrollment, Supplier shall successfully complete testing of the business-transaction communication protocols established by the Company, which may include communication by fax or telephone, electronic transactions as specified by the Company, or any other applicable communication requirements set forth by the Company.

V. SUPPLIER CERTIFICATION

5.0 In addition to the requirements listed in Section IV of this Agreement, and pursuant to Part III, Section 20.3.2 of the Company's Tariff, the Supplier hereby affirms the following:

(a) Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(b) Supplier is not aware of any change in business conditions that would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(c) Supplier has no delinquent balances outstanding for services previously provided by the Company, and Supplier has paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(d) No significant collection lawsuits or judgments are outstanding that would materially affect Supplier's ability to remain solvent as a business entity.

(e) Supplier's New Hampshire business advertising and marketing materials conform to all applicable New Hampshire state and federal laws and regulations.

5.1 Supplier shall promptly notify Company of any material change in its financial condition as it relates to Supplier's creditworthiness or solvency as a business enterprise.

5.2 In the event that the NHPUC enacts regulations whereby Supplier must register with the NHPUC, Supplier shall notify Company within twenty-four (24) hours in writing in the event that its registration as a Competitive Supplier is acted upon by the NHPUC in such a way that it materially affects Supplier's performance under this Agreement, including but not limited to suspension, revocation, modification, or non-renewal. Consistent with Part III, Section 20.3.8 of the Company's Tariff, revocation or non-renewal of Supplier's registration shall be grounds for immediate termination of this Agreement by Company.

VI. NOMINATIONS AND SCHEDULING

6.0 The Company and Supplier, pursuant to the Company's Tariff on file with the NHPUC and the terms of this Agreement, agree to exchange and act on information regarding the nomination and scheduling of gas for transportation on behalf of Supplier's customers.

6.1 Supplier acknowledges and agrees that its transportation rights under this Agreement are solely those that have been assigned to it by the Customer pursuant to the Company's Tariff. Supplier further agrees that the Company shall have no obligation to honor any nomination or scheduling request from Supplier that, in the Company's sole judgment, exceeds the scope of Supplier's assigned rights or where such nominations or requests could be reasonably refused, directly or indirectly, based on the terms of this Agreement or the Company's Tariff.

6.2 Pursuant to Part III, Sections 9.3.2 and 10.3.3 of the Company's Tariff, nominations will be communicated to the Company in accordance with the terms of this Agreement as set forth in Exhibit A.

6.3 In the event of a discrepancy between the volume nominated to the Company by Supplier and the volume confirmed by the Company, the discrepancy shall be allocated between and among Supplier's Aggregation Pools and/or Customers in accordance with the Pre-Determined Allocation Method set forth in Exhibit B, attached hereto. In the event that the Supplier has not provided the Company with a Pre-Determined Allocation Method, the discrepancy will be allocated consistent with the provisions of the Company's Tariff.

VII. CAPACITY ASSIGNMENTS

7.0 The Supplier's Maximum Daily Peaking Quantity ("MDPQ") may be modified during the calendar year in accordance with the provisions of Part Ill, Sections 11.0 and 14.0 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.1 Pursuant to Part III, Section 11.9.2 of the Company's Tariff, the quantity of each Company Managed Supply assigned to Supplier may be modified during the calendar year in accordance with Part III, Sections 11.4 and 11.8 of the Company's Tariff. Company will notify Supplier prior to the effective date of such changes.

7.2 In accordance with Part Ill, Sections 11.0 and 14.0 of the Company's Tariff, the quantity of Capacity assigned to Supplier may be modified during the calendar year. In addition, the Company shall have the right to adjust a Customer's total capacity quantity C'TCQ") if the Company determines that the TCQ calculation is in error or is otherwise not calculated in accordance with the provisions of Part Ill, Sections 11.3.2.

7.3 Pursuant to Part Ill, Section 11.10.2 of the Company's Tariff, Supplier shall provide notice to the Company of its designation of contracts to be managed by the Company for cost mitigation purposes by the means set forth in Exhibit 8.0.

VIII. LEFT BLANK INTENTIONALLY (RESERVED FOR FUTURE USE)

IX. BILLING AND PAYMENT

9.0 Bills, fees and charges for services provided by the Company, including, but not limited to, monthly cashouts, monthly imbalance charges, daily imbalance charges, and any other applicable charges set forth in the Tariff or in this Agreement, shall be rendered to Supplier on a monthly basis and shall be due upon receipt of said bill, unless otherwise specified in Exhibit A.

In addition to any other right or remedy available to the Company, Supplier's failure to make payment within ten (10) days of the posting date on the bill shall result in the addition of interest on any unpaid balance calculated at the maximum monthly rate allowable by the Company's Tariff. Interest shall accrue commencing from the date said bill was posted. The posting date is the date the bill is transmitted to Supplier. The bill may also be transmitted electronically if agreed to between the Parties in Exhibit A.

9.1 The Company shall have the right to deduct any amounts owed by Supplier to the Company for such services, which are thirty (30) days or more past due, from any amounts collected in the normal course of business by the Company on the Supplier's behalf. Amounts subject to a good faith dispute will not be subject to deduction.

9.2 The Parties agree to cooperate and provide each other with necessary documentation relating to any transactions resulting hereunder, including but not limited to, applicable sales or other tax exemptions. The Parties agree that Supplier's failure to comply with the provisions of this Article IX shall constitute default of payment under the Tariff and expose Supplier to liability thereunder as well as under this Agreement.

9.3 Consistent with the provisions of Part Ill, Sections 20.3.1 and 20.3.3 of the Company's Tariff, Supplier shall satisfy the creditworthiness standards established by the Company. In the event the Supplier has not demonstrated satisfaction of the Company's creditworthiness standards, the Supplier shall provide, upon ten (10) days written notice from the Company, financial assurance in the form of an advance deposit, letter of credit, surety bond or financial guaranty from a parent company, as reasonably determined by the Company. The amount of any such financial assurance required by the Company shall be calculated in accordance with the provisions of Part III, Section 20.3.3 of the Company's Tariff. The Company shall review Supplier's satisfaction of the Company's creditworthiness standards every twelve (12) months during the term of this Agreement giving consideration to Supplier's payment history in the preceding twelve-month period. Upon the request of Supplier, the Company shall exercise its sole reasonable discretion to determine whether a change in the form of financial assurance is warranted. In the event that the Company requires financial assurances in the form of a deposit, such deposits shall accrue interest in accordance with the Company's Tariff. Such deposit shall be returned to Supplier within thirty (30) days of the expiration or termination of this Agreement, provided that Supplier is not in default under this Agreement. The Company may deduct from the deposit any amount payable to the Company by Supplier under this Agreement, which has not been paid by the Supplier when due, unless such non-payment relates to a documented billing dispute between Supplier and the Company. Such deduction may be taken by the Company without notice or demand of any kind and the Company may, in its sole discretion, apply such deposit against any amount then due and payable. In the event that Company applies all or any portion of such deposit, Supplier shall deposit such sums as are necessary to replenish the security deposit to its maximum amount, within ten (10) days' notice of such deduction and application.

X. REPRESENTATIONS

10.0 Each Party represents that it is and shall remain in compliance with all applicable laws, tariffs, and NHPUC regulations during the term of this Agreement.

10.1 Each person executing this Agreement for the respective Parties represents and warrants that he or she has authority to bind that Party.

10.2 Each Party represents that (a) it has the full power and authority to execute, deliver, and perform this Agreement; (b) the execution, delivery, and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party; and (c) this Agreement constitutes that Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.

10.3 Each Party shall exercise all reasonable care, diligence and good faith in the performance of its duties pursuant to this Agreement, and carry out its duties in accordance with applicable recognized professional standards.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

XI. NONDISCLOSURE

11.0 Neither Party may disclose any Confidential Information obtained pursuant to this Agreement to any third Party, including affiliates of such Party, without the express prior written consent of the other Party. As used herein, the term "Confidential Information" shall include, but not be limited to, all business, financial, and commercial information pertaining to the Parties, Customers of either or both Parties, Suppliers for either Party, personnel of either Party; any trade secrets; and other information of a similar nature; whether written or in intangible form that is marked proprietary or confidential with the appropriate owner's name.

11.1 Confidential Information shall not include information known to either Party prior to obtaining the same from the other Party, information in the public domain, or information obtained by a Party from a third party who did not, directly or indirectly, receive the same from the other Party to this Agreement or from a Party who was under an obligation of confidentiality to the other Party to this Agreement, or information developed by either Party independent of any Confidential Information. The receiving Party shall use the higher of the standard of care that the receiving Party uses to preserve its own Confidential Information or a reasonable standard of care to prevent unauthorized use or disclosure of such Confidential Information. Each receiving Party shall, upon termination of this Agreement or at any time upon the request of the disclosing Party, promptly return or destroy all Confidential Information of the disclosing Party then in its possession.

11.2 Notwithstanding the preceding, Confidential Information may be disclosed to any governmental, judicial or regulatory authority requiring such Confidential Information pursuant to any applicable law, regulation, ruling, or order, provided that: (a) such Confidential Information is submitted under any applicable provision, if any, for confidential treatment by such governmental, judicial or regulatory authority; and (b) prior to such disclosure, the other Party is given prompt notice of the disclosure requirement so that it may take whatever action it deems appropriate, including intervention in any proceeding and the seeking of any injunction to prohibit such disclosure.

11.3 No provision of this Agreement shall prohibit the Company from communicating to its Customers and prospective customers, information regarding Supplier's eligibility to conduct business on the Company's distribution system. In addition, obligations under this Article XI shall survive the termination or expiration of this Agreement.

XII. LIABILITY AND INDEMNIFICATION

12.0 The Parties acknowledge and agree that the Force Majeure provisions set forth in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.1 The Parties acknowledge and agree that the liability and indemnification provisions in Part III, Section 17 of the Company's Tariff are incorporated by reference as if set forth herein.

12.2 For purposes of such liability and indemnification, however, the Parties acknowledge and agree that nothing in such Tariff prohibits one Party from impleading the other Party as a third-party defendant, whether or not one or both Parties are named as defendants in the initial claim of a third party. The third-party claim shall be stayed pending resolution of any dispute regarding liability and indemnification under this Agreement. Such resolution shall be final and binding upon the Parties only after agreement between the Parties or after entry of a final judgment, after any further appeals of a court of competent jurisdiction to which any appeal may have been taken from the determination of the arbitrator(s).

12.3 The Parties acknowledge and agree that for purposes of Part III, Section 17 the Company's Tariff, a Party seeking recovery from the other Party in connection with the performance of its obligations of the Tariff shall not be entitled to recovery where its own negligent acts or omissions contribute to or cause such damages, costs, fines, penalties or liabilities.

12.4 The Parties expressly acknowledge and agree that the dispute resolution provision in Article XIII of this Agreement shall apply to any and all disputes arising under this Article, including, without limitation, those disputes that arise as a result of either of the Parties being named as a defendant in the primary action or being named as a third-party defendant by a defendant in the primary action.

12.5 Notwithstanding anything in this Agreement or the Tariff to the contrary, in no event shall any Party hereto be liable to any other Party hereto for indirect, consequential, punitive, special, or exemplary damages under any theory of law that is now or may in the future be in effect, including without limitation: contract, tort, N.H.R.S.A. Ch. 358-A, strict liability, or negligence.

12.6 Notwithstanding the availability of other remedies at law or in equity, either Party hereto shall be entitled to specific performance to remedy a breach of this Agreement by the other Party.

12.7 Supplier further agrees that it shall indemnify, defend and hold harmless the Company with respect to any claim, suit, damages or costs of any kind arising from any action or inaction of the Company in reliance upon the nominations, scheduling instructions or other communications from Supplier. The Parties agree that reliance on such instructions and communications shall be deemed reasonable and shall not constitute negligence.

12.8 The provisions of this Article XII shall survive the termination of this Agreement.

XIII. DISPUTE RESOLUTION

13.0 Disputes hereunder shall be reduced to writing and referred to the Parties' representatives for resolution. The Parties' representatives shall meet and make all reasonable efforts to resolve the dispute. Pending resolution, the Parties shall continue to fulfill their obligations under this Agreement in good faith, unless this Agreement has been suspended or terminated. If the Parties fail to resolve the dispute within thirty (30) days, they may mutually agree to pursue mediation or arbitration to resolve such issues.

13.1 The interpretation and performance of this Agreement shall be in accordance with and controlled by the laws of the State of New Hampshire, without regard to the doctrines governing choice of law. All disputes arising hereunder shall be brought either before the NHPUC or the state courts of the State of New Hampshire.

XIV. COMMUNICATIONS

14.0 Except as otherwise provided herein, any notices given under this Agreement shall be in writing and shall be delivered to the Company as set forth in Exhibit A, by hand or sent by (a) certified mail, return receipt requested, first class postage prepaid, (b) telecopy, or (c) a nationally recognized courier service. Notices and other communications to Supplier shall also be addressed as shown on Exhibit A. Notices given hereunder shall be deemed to have been given upon receipt or any refusal to accept; telecopied notices shall be deemed to have been given upon confirmation of their receipt.

14.1 All communications required by the Company's Tariff shall be made in accordance with the schedule listed in Exhibit A. Information on active Company fax numbers and e-mail addresses shall be posted on the Company's Internet Website at http://www.libertyutilities.com/east/gas/business_partners/index.html

XV. ENFORCEABILITY

15.0 In the event that any portion or part of this Agreement is deemed invalid, against public policy, void or otherwise unenforceable by a court of law, the validity and enforceability of the remaining portions thereof shall otherwise be fully enforceable.

15.1 No waiver by any Party of any one or more defaults by the other Party in the performance of any provision of this Agreement shall operate or be construed as a waiver of any other present or future default, whether of a like or different character. No delay by either Party in enforcing any of its rights hereunder shall be deemed a waiver of such rights.

XVI. ASSIGNMENT AND DELEGATION

16.0 Any entity that shall succeed by purchase, merger or consolidation to the assets and properties, substantially or as an entity, of either Party hereto shall be entitled to the rights and shall be subject to the obligations of its predecessor in interest under this Agreement.

16.1 Either Party may, without relieving itself of its obligations under this Agreement, assign any of its rights or obligations hereunder to an affiliated entity, but otherwise no assignment of this Agreement or any of the rights or obligations hereunder shall be made unless there first shall have been obtained the written consent of the other Party. No assignment by Supplier shall take effect until the assignee has met the requirements of Article IV hereunder. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee.

16.2 The restrictions on assignment contained herein shall not in any way prevent either Party from pledging or mortgaging its rights as security for its indebtedness.

16.3 In addition, either Party may subcontract its duties under this Agreement to a subcontractor provided that the subcontracting Party shall remain fully responsible as a principal and not as a guarantor for performance of any subcontracted duties, and shall serve as the point of contact between its subcontractor and the other Party, and the subcontractor shall meet the requirements of any applicable laws, rules, regulations, and Tariff. The assigning or subcontracting Party shall provide the other Party with thirty (30) calendar days' prior written notice of any such subcontracting or assignment, which notice shall include such information about the subcontractor as the other Party shall reasonably require.

XVII. MISCELLANEOUS

17.0 This Agreement, all Exhibits and attachments hereto and all documents referenced herein, constitute the entire agreement between the Parties and supersedes all other agreements, communications, and representations. Paragraph headings are for convenience only and are not to be construed as part of this Agreement.

17.1 Unless otherwise provided herein, no modification of, or supplement to, the terms and provisions stated in this Agreement shall be or become effective without the written consent of both Parties.

17.2 This Agreement may be executed simultaneously in two or more counterparts, each of which shall be deemed to be an original but all of which shall constitute one and the same document.

In witness whereof, the Parties have caused this Agreement to be executed by their duly authorized representatives as of the date above.

[SUPPLIER NAME]

By ______________________ Title______________________

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

By ______________________ Title______________________

DATED: April 28, 2017

EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney

TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

2 ATTACHMENT B
Schedule of Administrative Fees and Charges

I.	Supplier Balancing Charge:	$0.23 per MMBtu of Daily Imbalance Volumes	
II.	Capacity Mitigation Fee	15% of the Proceeds from the Marketing of Capacity for Mitigation.	
		Capacity for Mitigation.	
III.	Peaking Demand Charge	$ 11.39	MMBTU of Peak MDQ
IV.	Company Allowance Calculation (per Schedule 25)		
		152,544,340	Total Sendout - Therms Aug-2015 - Jul-2016
		148,757,282	Total Throughput - Therms Aug-2015 - Jul-2016
		3,787,058	Variance (Sendout - Throughput)
	Company Allowance Percentage 2016-17	2.5%	Variance / Total Sendout

DATED: April 28, 2017
EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney
TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

3 ATTACHMENT C
Capacity Allocators

Rate Class		Pipeline	Storage	Peaking	Total
G-41	Low Annual /High Winter Use	48.3%	19.3%	32.4%	100.0%
G-51	Low Annual /Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-42	Medium Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-52	High Annual / Low Winter Use	75.4%	9.2%	15.4%	100.0%
G-43	High Annual / High Winter	48.3%	19.3%	32.4%	100.0%
G-53	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%
G-54	High Annual / Load Factor < 90%	75.4%	9.2%	15.4%	100.0%

NHPUC NO. 9 - GAS

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. D/B/A

LIBERTY UTILITIES

SUPERSEDING NHPUC No. 8

TARIFF

FOR

GAS SERVICE

Applicable

in

Thirty three towns in New Hampshire
served in whole or in part.

(For detailed description, see Service Area)

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day, Year, in Docket No. DG 17-048

Table of Contents

CHECK SHEET....1

I. GENERAL TERMS AND CONDITIONS....7

1 SERVICE AREA....7
2 GENERAL TERMS AND CONDITIONS....7
3 CHARACTER OF SERVICE....7
4 CUSTOMER'S INSTALLATION....8
5 APPLICATION FOR SERVICE....8
6 CREDIT....9
7 SERVICE AND MAIN EXTENSIONS....9
8 INTRODUCTION OF SERVICE....13
9 COMPANY EQUIPMENT ON CUSTOMER'S PREMISES....13
10 SERVICE CONTINUITY....14
11 CUSTOMER'S USE OF SERVICE....14
12 INSPECTIONS....14
13 MEASUREMENT....15
14 METER TESTS....15
15 DISCONNECTION BY THE COMPANY....15
16.1 COST OF GAS CLAUSE....16
16.2 COST OF GAS CLAUSE – KEENE DIVISION....32
17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE....33
18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY....46

II. RATE SCHEDULES....49

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1....49
2 RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-3....51
3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4....53
4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5....55
5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6....57
6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7....59
7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE

Table of Contents

RATE CLASSIFCATION NO. G-41 61
8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-42 63
9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43 65
10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44 67
11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45 69
12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46 71
13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51 73
14 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-52 75
15 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFICATION NO. G-53 77
16 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-54 79
17 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-55 81
18 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-56 83
19 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR LESS THAN 90% RATE CLASSIFCATION NO. G-5785
20 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, LOAD FACTOR GREATER THAN 90% RATE CLASSIFICATION NO. G-58 87
21 OUTDOOR GAS LIGHTING 89
22 FIRM RATE SCHEDULES 90
23 FIRM RATE SCHEDULES - MANAGED EXPANSION PROGRAM 91
24 FIRM RATE SCHEDULES - OUTDOOR GAS LIGHTING 92
25 ANITCIPATED COST OF GAS 93
26 CALCULATION OF FIRM SALES COST OF GAS RATE 94
27 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE 95
28 CALCULATION OF FIXED WINTER PERIOD COST OF GAS RATE – KEENE DIVISION 96
29 CALCULATION OF FIRM TRANSPORTATION COST OF GAS RATE 97
30 ENVIRONMENTAL SURCHARGE – MANUFACTURED GAS PLANTS 98
31 RATE CASE EXPENSE FACTOR CALCULATION 99

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Table of Contents

32 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE CALCULATION 100

III. DELIVERY TERMS AND CONDITIONS 101

1 RATES AND CHARGES 101
2 DEFINITIONS 101
3 CHARACTER OF SERVICE 105
4 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS 105
5 CUSTOMER REQUEST FOR SERVICE FROM COMPANY 106
6 QUALITY AND CONDITION OF GAS 106
7 POSSESSION OF GAS 107
8 COMPANY GAS ALLOWANCE 107
9 DAILY METERED DELIVERY SERVICE 107
10 NON-DAILY METERED DELIVERY SERVICE 112
11 CAPACITY ASSIGNMENT 116
12 BILLING AND SECURITY DEPOSITS 123
13 SALES SERVICE 124
14 PEAKING SERVICE 125
15 DISCONTINUANCE OF SERVICE 127
16 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS 127
17 FORCE MAJEURE AND LIMITATION OF LIABILITY 128
18 CURTAILMENT 129
19 TAXES 129
20 SUPPLIER TERMS AND CONDITIONS 130
21 CUSTOMER DESIGNATED REPRESENTATIVE 136

IV. ATTACHMENTS 137

1 ATTACHMENT A Supplier Service Agreement 137
2 ATTACHMENT B Schedule of Administrative Fees and Charges 151
3 ATTACHMENT C Capacity Allocators 152

CHECK SHEET

The title page and pages 1-94 inclusive of this tariff are effective as of the date shown on the individual tariff pages.

Page	Revision
Title	Original
TOC i	Original
TOC ii	Original
TOC iii	Original
1	Original
2	Original
3	Original
4	Original
5	Original
6	Original
7	Original
8	Original
9	Original
10	Original
11	Original
12	Original
13	Original
14	Original
15	Original
16	Original
17	Original
18	Original
19	Original
20	Original
21	Original
22	Original
23	Original
24	Original

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 2

Check Sheet

Page	Revision
25	Original
26	Original
27	Original
28	Original
29	Original
30	Original
31	Original
32	Original
33	Original
34	Original
35	Original
36	Original
37	Original
38	Original
39	Original
40	Original
41	Original
42	Original
43	Original
44	Original
45	Original
46	Original
47	Original
48	Original
49	Original
50	Original
51	Original
52	Original
53	Original
54	Original
55	Original

DATED: April 28, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney

EFFECTIVE: July 1, 2017

TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 3

Check Sheet

Page	Revision
56	Original
57	Original
58	Original
59	Original
60	Original
61	Original
62	Original
63	Original
64	Original
65	Original
66	Original
67	Original
68	Original
69	Original
70	Original
71	Original
72	Original
73	Original
74	Original
75	Original
76	Original
77	Original
78	Original
79	Original
80	Original
81	Original
82	Original
83	Original
84	Original
85	Original
86	Original

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Page	Revision
87	Original
88	Original
89	Original
90	Original
91	Original
92	Original
93	Original
94	Original
95	Original
96	Original
97	Original
98	Original
99	Original
100	Original
101	Original
102	Original
103	Original
104	Original
105	Original
106	Original
107	Original
108	Original
109	Original
110	Original
111	Original
112	Original
113	Original
114	Original
115	Original
116	Original
117	Original

Check Sheet

Page	Revision
118	Original
119	Original
120	Original
121	Original
122	Original
123	Original
124	Original
125	Original
126	Original
127	Original
128	Original
129	Original
130	Original
131	Original
132	Original
133	Original
134	Original
135	Original
136	Original
137	Original
138	Original
139	Original
140	Original
141	Original
142	Original
143	Original
144	Original
145	Original
146	Original
147	Original
148	Original

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 6

Check Sheet

Page	**Revision**
149	Original
150	Original
151	Original
152	Original
153	Original
154	Original

DATED: April 28, 2017

EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney

TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

I. GENERAL TERMS AND CONDITIONS

1 SERVICE AREA

A. Service Area. The area authorized to be served by the Company and to which this tariff applies are the following cities and towns: Allenstown, Amherst, Auburn, Bedford, Belmont, Berlin, Boscawen, Bow, Concord, Derry, Franklin, Gilford, Goffstown, Hollis, Hooksett, Hudson, Keene, Laconia, Litchfield, Londonderry, Loudon, Manchester, Merrimack, Milford, Nashua, Northfield, Pelham, Pembroke, Sanbornton, Tilton, Windham, ~~-~~and part of Canterbury and Winnisquam.

2 GENERAL TERMS AND CONDITIONS

A. Filing. A copy of this tariff is on file with the New Hampshire Public Utilities Commission ("NHPUC" or the "Commission") and is open to inspection at the offices of the Company.

B. Revisions. This tariff may be revised, amended, supplemented, or otherwise changed from time to time in accordance with the rules of the ~~New Hampshire Public Utilities~~ Commission and such changes, when effective, shall have the same force as the original tariff.

C. Application. The tariff provisions apply to everyone lawfully receiving gas supply service and/or delivery-only service from the Company under the rates herein and receipt of gas service shall constitute the receiver a customer of the Company as the term is used herein whether service is based upon contract, agreement, accepted signed application, or otherwise.

D. Statement by Agents. No representative has the authority to modify a tariff rule or provision or to bind the Company by a promise or representation contrary thereto.

E. No Prejudice of Rights. The failure of the Company to enforce any of the terms of this tariff shall not be deemed a waiver of its right to do so.

F. Gratuities to Employees. The Company's employees are strictly forbidden to demand or accept any personal compensation or gifts for service rendered by them while working for the Company on the Company's time.

G. Advance Payments. Payments to the Company for charges provided in these rules and regulations to be borne by the customer shall be made in advance.

H. Assignment. Subject to the rules and regulations, all contracts by the Company shall be binding upon, and oblige, and continue for the benefit of, the successors and assigns, heirs, executors, and administrators of the parties hereto.

3 CHARACTER OF SERVICE

A. Gas Supply. This Tariff applies only to the supply of gas, having a thermal content of nominally 1,000 British thermal units per cubic foot at supply pressures available in the locality in which the premises to be served are situated.

B. Determination of Therms. The gas for any billing period, expressed in hundreds of cubic feet (ccf), shall be multiplied by the average Btu of the gas send out as determined below and divided by 1,000 in order to determine the number of therms consumed in the billing period. For billing purposes, gas therms shall be determined on a "dry" basis.

The Btu therm factor of the gas sendout shall be calculated for each billing cycle from the daily weighted average Btu of the natural gas delivered to the Company by its suppliers and the gas produced at the Company's peak-shaving plants. The daily average Btu content shall be determined by appropriate gas measurement devices operated by the Company or its supplier.

C. Delivery of Gas Supply. The rates specified in this tariff are based upon the supply of service to a single customer through one delivery and metering point.

D. Use of Service at Separate Properties. The use of service at two or more separate properties will not be combined for billing purposes.

4 CUSTOMER'S INSTALLATION

A. Point of Delivery. Upon request, the Company will designate a point at which the customer shall terminate his piping for connection to the meter of the Company, but such information does not constitute an agreement or obligation on the part of the Company to furnish service.

B. Space for Meter. The customer shall provide, free of expense to the Company, a dry, warm and otherwise suitable place for the regulator or regulators, meter or meters, or other equipment of the Company which may be necessary for the fulfillment of such contracts as may be entered into with the Company.

C. Location of Meter. The space provided for the Company's meters and equipment shall be convenient access to the Company's employees and, as near as possible, to the point where the service supply pipe enters the customer's building. Its location shall be such that the meter connections are not concealed by plaster or sheathing and shall be otherwise acceptable to the Company.

D. Reverse Flow. The customer may be required to install check valves or other devices to prevent compressed air or other gases from entering the Company's mains.

5 APPLICATION FOR SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of ~~his~~ the applicant's use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Right to Reject. The Company may reject any application for service which would involve excessive cost to supply, or which might affect the supply of service to other customers, or for other good and sufficient reasons.

C. Special Contracts. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, contracts of longer terms as specified in the rate, or with a special guarantee of revenue, or both, may be required to safeguard such investment.

D. Unauthorized Use. Unauthorized connection to the Company's gas service supply facilities, and/or the use of service obtained from the Company without authority, or by any false pretense, may be terminated by the Company without notice. The use of service without notifying the Company and without enabling ~~it~~ the Company to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last meter reading of the Company's meter immediately preceding ~~his~~ the user's occupancy as shown by the Company's books.

E. Managed Expansion Program. The Managed Expansion Program ~~T~~target~~ed~~s gas expansion in specific areas that have high potential for demand. Each Managed Expansion Program project includes a Main Extension. Customers under this program avoid a portion or all of a contribution in aid of construction which would otherwise be required absent the Managed Expansion Program.

6 CREDIT

A. Prior Debts. Service will not be furnished to former customers until any indebtedness to the Company for previous service has been satisfied.

B. Deposits. Before rendering or restoring service, the Company may require a deposit subject to the ~~New Hampshire Public Utilities~~ Commission's Rules and Regulations. (See Puc 1200 rules).

7 SERVICE AND MAIN EXTENSIONS

A. Definitions. The following are definitions of terms used in these provisions relative to main and service extensions and are applicable only in ~~such~~ the main and service extensions provisions.

1. Service and Main Extensions. Extensions that require the construction of a new gas main and a service from that new main in order to provide requested gas service to a customer.

2. Service Extensions. Extensions from an Existing Gas Main to the point of delivery on the customer's premises.

3. Main Extension. An extension of the new gas main portion of a Service and Main Extension.

4. Existing Gas Main. A main that is installed in the street and through which gas is flowing.

5. Abnormal Costs. Abnormal Costs are service and/or main construction costs that are attributable to frost or ledge (including ditching or backfilling necessitated as a result of the presence of frost or ledge),and/or other conditions not typically encountered in service and/or main construction that are peculiar to the particular service and/or main construction concerned. Abnormal Costs are to be paid by the customer.

6. Extra Footage. The charge (contribution in aid of construction) for Extra Footage is $31.54 per foot. The charge will be updated annually by calculating the historical average cost per foot for Service Extensions, excluding overheads, for the most recent calendar year and the updated charge shall be effective April 1.

7. Estimated Annual Margin. The Estimated Annual Margin is equal to the estimated revenue to be derived from the monthly Customer Charge and delivery charge to be received from the customer for gas service utilizing the Service and Main Extension or Service Extension during the first twelve

(12) months after completion of the extension. The Estimated Annual Margin does not include revenue received by the Company for the cost of gas and local distribution adjustment factor.

8. Estimated Cost of Construction. For the purpose of determining the cost of Service and Main Extensions, Estimated Cost of Construction of mains and/or services includes ~~not only~~ the cost of labor and materials for such construction, ~~but also~~ and incidental or associated miscellaneous costs ~~incidental thereto or associated therewith~~, but excluding overheads. Miscellaneous costs include, but are not limited to, meter(s), traffic control and city and town road permits and degradation fees. The customer may perform on-site trenching and backfilling in accordance with the Company's specifications, in which case the Estimated Cost of Construction will be reduced to reflect the costs avoided by the Company as a result of the customer's performance of the work.

B. Costs of Extensions. In areas where the Company is authorized to operate, subject to the Application for Service provisions of this tariff, service is available as follows:

1. Residential Service Extensions. Residential Service Extensions up to 100 feet in length will be installed at no charge to customers served under either a (i) residential heating rate; or (ii) a residential non-heating rate provided that such extension is installed during the installation of a Main Extension~~,~~ or during the performance of work on cast iron/bare steel main replacements; unless there are Abnormal Costs associated with such extensions, in which case the customer shall be charged for the Abnormal Costs. For residential Service Extensions in excess of 100 feet, the customer will be charged for the Extra Footage, plus any Abnormal Costs. This Section 7(B)(1) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

2. Commercial and Industrial Service Extensions. Commercial and industrial Service Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service Extension, excluding any Abnormal Costs. If the Estimated Annual Margin is less than one-sixth of the Estimated Cost of Construction, the customer will be required to pay to the Company, in advance, any amount by which the Estimated Cost of Construction of the Service Extension exceeds six times the Estimated Annual Margin. Abnormal Costs are charged separately and are not included in the Estimated Cost of Construction for the purpose of this calculation. This Section 7(B)(2) shall apply only to Service Extensions and shall not apply to Service and Main Extensions as described in Section 7(B)(3).

3. Service and Main Extensions of Less Than $1,000,000. The Company shall not commence construction on a Service and Main Extension for which the Estimated Cost of Construction is less than $1,000,000 until the sum of (i) six times the Estimated Annual Margin for all commercial and industrial customers who have committed to take service, plus (ii) eight times the Estimated Annual Margin for all residential customers who have committed to take service equals or exceeds 25% of the Estimated Cost of Construction.

   a. Residential. Residential Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-eighth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-eighth of the Estimated Cost of Construction, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and eight times the Estimated Annual Margin, plus any Abnormal Costs.

If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated equally among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main. Abnormal Costs associated with Main Extensions will be allocated equally among all customers, unless such costs can be attributed to specific customers.

b. Commercial and Industrial. Commercial and industrial Service and Main Extensions will be installed at no charge to the customer provided that the Estimated Annual Margin is at least one-sixth of the Estimated Cost of Construction of the Service and Main Extensions. If the Estimated Annual Margin is less than one-sixth of the cost of construction of the Service and Main Extensions, the customer will be required to pay to the Company the difference between the Estimated Cost of Construction and six times the Estimated Annual Margin, plus any Abnormal Costs.

c. If the Main Extension will serve more than one location, the Company will calculate the sum of the Estimated Annual Margin from all metered services and the sum of the Estimated Cost of Construction for the Main Extension and all Service Extensions to determine whether any payment will be required from the customers to be served. The Company will also include in such calculations the Estimated Annual Margin and the Estimated Cost of Construction for Service Extensions for all existing premises for which the Company reasonably anticipates will take service, using the assumption that 60% of such premises will take service. If any payment is required, it will be allocated among all current metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer’s proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer’s proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

d. Extensions Serving Customers in More Than One Rate Class. If the Main Extension will serve both residential and commercial or industrial customers, the Company will determine whether a contribution will be required by the customers by calculating the difference between the Estimated Cost of Construction of the Main and Service Extensions and (i) six times the Estimated Annual Margin for all commercial and industrial customers to be served, plus (ii) eight times the Estimated Annual Margin for all residential customers to be served. The Company will also include in the above calculations the Estimated Annual Margin and the Estimated Cost of Construction of Service Extensions for all existing premises for which the Company reasonably anticipates will take service. If the difference described above is positive, the customers will be required to pay to the Company such difference. The amount of payment will be allocated among all metered services that exist as of the date that the Main Extension becomes an Existing Gas Main based on each customer’s proportional share of the Estimated Annual Margin. Abnormal Costs associated with Main Extensions will also be allocated based on each customer’s proportional share of the Estimated Annual Margin, unless such costs can be attributed to specific customers, in which case the costs shall be allocated appropriately to specific customers.

4. Service and Main Extensions Greater Than or Equal to $1,000,000. If the cost of the Main Extension equals or exceeds $1,000,000, then in addition to the requirements specified in Section 7(B)(3), the Company will not commence construction unless a discounted cash flow analysis demonstrates a positive net present value over a 10-year period of the difference between the Estimated Annual Margin and the revenue requirement associated with the Estimated Cost of Construction.

C. Failure to Use Installed Gas Service. If a customer fails, within nine months after the date a service is installed under this Section 7, either in whole or in part, to make use of the service, the customer will reimburse the Company for all costs of constructing, removing and retiring the service less any contribution in aid of construction made by the customer for the service, which will be forfeited.

D. Easements, Etc. The Company is not required to construct extensions other than in public ways unless the customer provides, in advance and without expense or cost to the Company, all necessary permits, consents, authorizations and right-of-way easements, satisfactory to the Company, for the construction, maintenance and operation of the pipeline.

E. Shortest Distance. Services are run the shortest practical safe distance to the meter location. However, a customer may have the Company install a longer alternate service provided that the customer pays for the extra expense in advance of installation.

F. Winter Construction. Ordinarily, no new service pipes or main extensions are installed during the winter conditions (when frost is in the ground) unless the customer defrays the extra expenses.

G. Timing and Refunding of Contribution. Except as otherwise agreed by the Company under unusual circumstances, any required contribution in aid of construction will be made prior to installation by the Company of a service. To help cover the Company's expenses, damages and lost business, if substantial construction of the building or buildings for which gas service has been sought is not commenced by the earlier of (1) November 30th next following submission of the application; or (2) the date when the Company commences construction of the main and service concerned prior to withdrawal of the application, ten percent (10%) of the contribution will be forfeited to the Company and will not be returned to the customer. The balance of the contribution will be refunded if and when the application is withdrawn, or will be applied toward the new contribution if the customer submits a new application for service or subsequently commences construction of the building or buildings. A new application may be submitted at any time.

H. Reasonable Duration and Non-Discrimination. Under none of the foregoing provisions will the Company be required to install service pipes or to contract main extensions where the business to be secured may not be of reasonable duration or will tend, in any way, to constitute unreasonable discrimination.

I. Title. Title of all extensions constructed in accordance with the above shall be vested in the Company.

J. Other Requirements. The Company generally will not approve any application or, if it shall have given such approval, will not proceed or continue with main and/or service construction unless the Company is satisfied

1. That the final site plans, sub-division plans and plans and specification for building or buildings to be served by the main and/or service concerned, including plans for waste disposal, water and other associated systems and facilities, have been prepared and approved by owner;

2. That all permits, exceptions, approvals and authorizations of governmental bodies or agencies required for construction of such building or buildings and associated systems and facilities have been obtained;

3. That the customer is proceeding or plans promptly to proceed with such construction; and

4. That nothing has occurred or failed to occur which will or is likely to prevent or interfere with such construction.

8 INTRODUCTION OF SERVICE

A. Service Contract. Every applicant for gas service may be required to sign a contract, agreement, or other form then in use by the Company covering the special circumstances of his use of gas and must agree to abide by the rules and regulations and standard requirements of the Company.

B. Defective Installation. The Company may refuse to connect if, in its judgment, the customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety, or is in violation of the Company's standard requirements.

C. Unsatisfactory Installation. ~~–~~ The Company may refuse to connect if, in its judgment, the customer's equipment or use thereof might injuriously affect the equipment of the Company or the Company's service to other customers.

9 COMPANY EQUIPMENT ON CUSTOMER'S PREMISES

A. Meters and Regulators. The Company shall furnish and install, maintain and own, any meter or meters, regulator or regulators required in the supply of service. For certain large customers, the Company shall furnish, install and maintain, at the customer’s expense, any remote meter reading equipment to record usage for daily balancing. Such equipment shall remain the property of the Company at all times.

B. Customer's Responsibility. The customer shall be responsible for safekeeping of the Company's property while on the customer's premises. In the event of injury or destruction of any such property, the customer shall pay the costs of repairs and replacements.

C. Relocation and/or Replacement of Company Equipment. The original service connection, including piping, meters and all other necessary or incidental equipment, which remains the property of the Company, shall be installed by the Company at its expense unless otherwise expressly provided in this tariff. Subsequent relocation and/or replacement of any such equipment on private property, whether it be for one or more service connections, shall be performed by the Company at the customer's expense unless such work is done at the request of the Company and for its convenience, in which case the Company shall bear the expense ~~thereof~~.

D. Protection by Customer. The customer shall protect the equipment of the Company on his premises and shall not permit any persons, except a Company employee having a Company photo identification card or other Company identification, to break any seals upon or do any work on any meter, service supply pipe, or other equipment of the Company located on the customer's premises.

E. Tampering. In the event the Company's meter or other property is being tampered with or interfered with, the customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter and for any repairs or replacements required as well as for costs of inspections, investigations, and protective installation.

F. Right of Access. The Company's identified employees shall have access to the premises of the customer at all reasonable times for the purpose of reading meters, testing, repairing, removing, or exchanging any or all equipment belonging to the Company.

G. Ownership and Removal. All equipment supplied by the Company shall remain its exclusive property and the Company shall have the right to remove the same from the premises of the customer at any time after the termination of service for whatever cause.

10 SERVICE CONTINUITY

A. Regularity of Supply. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service, but should the supply be interrupted by the Company for the purpose of making repairs, changes, or improvements in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted or fail by reason of accident, strike, legal process, state or municipal interference, or any cause whatsoever beyond its control, the Company shall not be liable for damages, direct or inconsequential, resulting from such interruption or failure.

B. Notice of Trouble. The customer shall notify the office of the Company immediately should the service be unsatisfactory for any reason or should there be any defects, leaks, trouble, or accident affecting the supply of gas.

11 CUSTOMER'S USE OF SERVICE

A. Resale Forbidden. The customer shall not, directly or indirectly, sell, sublet, assign, or otherwise dispose of to others, gas purchased from the Company, or any part thereof, without the consent of the Company. This rule does not apply to a public utility Company purchasing gas in bulk expressly for the purpose of delivering it to others.

B. Fluctuations. Gas service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system. In the case of violation of this rule, the Company may discontinue service or require the customer to modify ~~his~~ its installation~~,~~ and/or equip it with approved controlling devices.

C. Additional Load. The service supply pipe, regulators, meters, and equipment supplied by the Company for each customer have definite capacities. The customer shall notify the Company of substantial changes in service requirements or location of appliances.

12 INSPECTIONS

A. Company's Right to Inspect. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any time later and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements. However, such inspection, ~~or~~ failure to inspect, or failure to reject shall not render the Company liable or responsible for any losses or damage resulting from defects in the installation, piping or appliances, ~~or~~ from violation of Company rules, or from accidents which may occur upon the premises of the customer.

13 MEASUREMENT

A. Supply of Meters. The measurement of gas service shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment and may, from time to time, change or alter the equipment. ~~its~~ The Company's sole obligation ~~being~~ is to supply meters that will accurately and adequately furnish records for billing purposes.

B. Special Measurements. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments on the premises of any customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the customer's load.

14 METER TESTS

A. Meter Tests. Meters are tested according to NHPUC Rules and Regulations. (See Puc 500 rules).

B. Request Tests. The fee for a special request test is $20.00 when scheduled at the mutual convenience of the Company and the customer; otherwise the amount is $30.00. (See Puc 500 rules).

C. Customer's Bill Adjustment. Should any meter fail to register correctly, the quantity of gas consumed will be determined by the Company based on information supplied by the customer and known by the Company subject to NHPUC Rules and Regulations. (See Puc 500 rules).

15 DISCONNECTION BY THE COMPANY

A. Disconnection by the Company. The Company may disconnect its service to a customer for violation of its rules subject to NHPUC Rules and Regulations. (See Puc 1200 rules).

B. Non-Payment Shut-Off. The Company may disconnect its service on reasonable notice and remove its equipment in case of non-payment of amounts billed for gas usage.

C. Shut-Off for Cause. The Company may disconnect its service on reasonable notice if entry or access to its meter or meters is refused, ~~or if access thereto is~~ obstructed, or hazardous, or for other violation of the Company's standard requirements.

D. Safety Shut-Off. The Company may disconnect without notice if the customer's installation has become dangerous or defective.

E. Defective Equipment. The Company may disconnect without notice if the customer's equipment, or use thereof, might injuriously affect the equipment of the Company or the Company's service to other customers.

F. Shut-Off for Fraud. The Company may disconnect without notice for abuse, fraud or tampering with the connections, meters or other equipment of the Company.

G. Reconnection Charge. A reconnection charge is made for reconnection of service discontinued by the Company and is payable in advance in addition to all other amounts due. The reconnection charge is made instead of the meter account charge. The amount of the reconnection charge is the same as the comparable meter account charge except when it has been necessary to dig up the service pipe or connection to effect discontinuance of service. In such cases, the reconnection charge is the price of removal and restoration of service pipe or connection.

16.1 COST OF GAS CLAUSE

A. Purpose. The purpose of this Cost of Gas Clause is to establish procedures that allow ~~Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (the "Company")~~the Company, subject to the jurisdiction of the ~~State of New Hampshire Public Utilities~~ Commission ~~("NHPUC")~~, to adjust, on a semiannual basis, its rates for firm gas sales in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchased gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit to customers receiving firm service from the Company all supplier refunds and capacity release sales.

B. Applicability. This Cost of Gas Clause ("COGC") shall be applicable to the Company and all firm gas sales made by the Company, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the NHPUC. See Section 16(N), "Other Rules."

C. Cost of Firm Gas Allowable for COGC. All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, hedging related costs, other gas supply expense incurred to procure and transport supplies and commodity related bad debt expense, the gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the COGC. Any costs recovered through application of the COGC shall be identified and explained fully in the semiannual filings outlined in Section 16(M).

D. Effective Date of Cost of Gas Factor. The seasonal Cost of Gas Factor ("COG") shall become effective upon NHPUC approval on the first day of each season as designated by the Company. Unless otherwise notified by the NHPUC, the Company shall submit COG filings as outlined in Section 16(M) of this clause on or before the first business day in September...

E. Definitions. The following terms shall be defined in this section, unless the context requires otherwise.

1. Bad Debt Expense: The uncollectible expense attributed to the portion of the Company's revenue associated with the recovery of gas costs under this clause.

2. Capacity Release Revenues: The economic benefit derived from the sale or release of transportation and storage capacity that the Company has under contract.

3. Carrying Charges: Interest expense calculated on the average monthly balance using the *monthly* prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end of month balance.

4. Correction Factor: Seasonal Adjustment necessary to align the peak day volumes used to calculate the Commercial and Industrial load factor ratios with the seasonal Commercial and Industrial High Winter and Low Winter throughput volumes applied to the cost of gas calculations.

5. Direct Gas Costs: All purchased gas costs including supplier, storage and pipeline demand and commodity costs, as well as the commodity costs for local manufactured gas (Liquid Propane Gas ("LPG") and Liquefied Natural Gas ("LNG")).

6. Economic Benefit: The difference between the revenues received and the marginal cost determined to serve non-core customers.

7. Inventory Finance Charges: As billed in each Winter Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing or anticipated financing rate through a trust or other financing vehicle.

8. Local Production and Storage Capacity Costs: The costs of providing storage service from the Company's storage facilities (*i.e.*, LNG and LPG) as determined in the Company's most recent rate proceeding.

9. Market Based Allocator ("MBA"): The method used to allocate gas costs among Commercial and Industrial Customer Classifications. These ratios are presented in Section 16(F).

10. Non-Core Commodity Costs: The commodity cost of gas assigned to non-core sales to which the COG is not applied.

11. Non-Core Sales: Sales made under non-traditional off-system sales.

12. Non-Core Sales Margins: The economic benefit derived from non-core transactions to which the COG is not applied, including non-core sales generated from the use of the Company's Gas Supply Resource portfolio.

13. Summer Commodity: The gas supplies procured by the Company to serve firm load in the Summer Season.

14. Summer Demand: The gas supply demand and transmission capacity procured by the Company to serve firm load in the Summer Season.

15. Summer Season: The calendar months May 1 through October 31.

16. Off-System Sales Margin: The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

17. Winter Commodity: The gas supplies procured by the Company to serve firm load in the Winter Season.

18. Winter Demand: Gas supply demand, peaking demands, storage and transmission capacity procured by the Company to service firm load in the Winter Season.

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 18

General Terms and Conditions

19. Winter Season: The calendar months November 1 through April 30.

20. PR Allocator: The percentage of annual capacity charges assigned to the Winter Season calculated using the Proportional Responsibility Method.

21. Purchased Gas Working Capital: The allowable working capital derived from Winter Season and Summer Season demand and commodity related costs.

F. Approved Cost. The Cost of Gas calculation utilizes information periodically established by the NHPUC. The table below lists the approved costs factors:

Variable	Description	Approved Figure
MISC	Miscellaneous Overhead	$13,170
PS	Production and Storage Capacity	$1,980,428
WCA%	Working Capital Allowance Percentage	3.91%

Bad Debt % Measurement and Reconciliation Period	COG Recovery Period	Actual Bad Debt Rate	Bad Debt allowed Recovery Rate
May 2010 – April 2011	November 2011 – October 2012	Actual	Actual
May 2011 – April 2012	November 2012 – October 2013	Greater than 2.9%	Actual less 0.4
		2.5% to 2.9%	2.5%
		Less than 2.5%	Actual
May 2012 - April 2013 and each subsequent May – April period thereafter	November 2013 - October 2014 and each subsequent November – October period thereafter	Greater than 3.3%	Actual less 0.8
		2.5% to 3.3%	2.5%
		Less than 2.5%	Actual

If the Company's actual bad debt percentage is reduced to 2.5% or less during any 12 month period, which need not be the same 12 months as the measurement periods defined above, then beginning with the reconciliation filing for the period during which this bad debt percentage was achieved the Company shall thereafter recover its actual gas supply related bad debt on a fully reconcilable basis and the percentages in the table above shall no longer apply. The actual bad debt percentage shall be calculated by dividing the Company's actual net write-offs for the relevant measurement period by its revenue for the same period.

G. Cost of Gas (COG) Calculations by Customer Class. The ~~Cost of Gas (~~COG~~)~~ Formula shall be computed on a semiannual basis for three (3) groups of customer classes as shown on the following table. The computation will use forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts shall be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

The COG for the Residential rate classes shall represent the total system average unit cost of gas of meeting firm sales load, projected in each COG filing. The Commercial & Industrial (C&I) Low Winter (LW) and High Winter (HW) rates will be calculated in the following way: first, the demand unit cost of gas, the sum

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

of purchased and stored gas demand costs divided by projected prorated sales, will be multiplied by the applicable load factor ratio and then multiplied by the correction factor. This adjusted demand factor will then be added to the commodity factor, adjustment factor and indirect cost of gas rate to determine the total COG rates for the C&I LW and HW rate classes. The two load factor ratios shall be derived once a year, for effect every November 1 through October 31, using the ratio of the unit capacity cost of each C&I group to the total system unit capacity cost that is determined in the Company's submittal of its Capacity Allocators, for Capacity Assignment purposes, filed with its Winter COG, and as presented in Attachment C of the Delivery Service Terms and Conditions. The Correction Factor aligns the peak day volumes used to calculate the load factor ratios with the seasonal throughput volumes applied to the COG calculations.

GROUP	CUSTOMER CLASSES
Residential	Residential Heating and Non-Heating
Commercial and Industrial: Low Winter Use	G-51 through G-58
Commercial and Industrial: High Winter Use	G-41 through G-46

Winter Season Cost of Gas Formula (CGw)

The Winter Season COG shall be comprised of Winter Demand costs, Winter commodity costs, Winter reconciliation costs, Winter working capital reconciliation, Winter bad debt expenses, local production and storage capacity costs, and miscellaneous and A&G costs calculated at the beginning of the Winter Season according to the following formula:

$$CGw = Dw + Cw + Rw + WCRw + BDw + PS + ((MISC + Rbd) \times \frac{W{:}Sales)}{A{:}Sales}$$

Winter Demand Cost (Dw) Formula

Dw = DEMw – NCSMw + WCwd – R1d – R2d
and:

NCSMw = CRRw + OSSMw + SBdw
and:

WCwd = (DEMw – NCSMw) × WCA% × CC
where:

CGw = The total cost of gas for the Winter Season for the Company’s firm sales customers previously defined.

BDw = Bad Debt expense for the Winter Season.

Cw = Commodity-related direct gas cost for the Winter Season.

Dw = The total Winter Demand costs.

DEMw = Demand Charges allocated to the Winter Season defined in Section 16(E).

NCSMw = The Non-Core Sales Margins equal to the sum of the Winter Season returnable Capacity Release Revenues, and Off-System Sales Margins.

WCwd = Working Capital allowable associated with demand charges allocated to the Winter Season as defined in Section 16(K).

R1d, R2d = Supplier demand-related refunds - The Supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

CRRw = The returnable Capacity Release Revenues allocated to the Winter Season. See Section 16(E).

OSSMw = The returnable Off-System Sales Margins allocated to the Winter Season. See Section 16(E).

SBdw = Demand revenues received from Firm Stand-By Sales Service customers in the Winter Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rw = Reconciliation Costs – Winter Season deferred gas costs, Account 1920-1740 balance, inclusive of the associated Account 1920-1740 interest, as outlined in Section 16(J).

WCRw = Working Capital reconciliation adjustment associated with Winter Gas Costs - Account 1163-1422 balance as outlined in Section 16(K).

PS = The total dollar amount of costs associated with the local production and storage capacity gas less any production and storage capacity assignment revenues. -Refer to Section 16(F) for this dollar amount.

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. -Refer to Section 16(F) for this dollar amount.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance

W:Sales = Forecasted firm sales volumes associated with the Winter Season.

A:Sales = Forecasted annual firm sales volumes.

Winter Season Commodity (Cw) Formula

Cw = COMw + FC + WCwc – R1c – R2c
and:

COMw = WSC – NCCCw - SBcw
and:

WCwc = (COMw + FC) × WCA% × CC
where:

COMw = Commodity Charges allocated to the Winter Season as defined in Section 16(E).

FC = Inventory finance charges as defined in Section 16(E).

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

WCwc = Working Capital Allowable Associated with commodity charges allocated to the Winter Season as defined in Section 16(K).

R1c, R2c = Supplier commodity-related refunds - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds". See Section 16(I).

WSC = Commodity charges associated with gas supply sent out in Winter Season as defined in Section 16(E).

NCCCw = Non-Core Commodity Costs incurred in the Winter Season as defined in Section 16(E).

SBcw = Winter Season commodity revenues received from Firm Stand-By Gas Supply Service sales customers.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Winter Bad Debt (BDw) Formula

BDw = BD% x (Dw + Cw + Rw + WCRw)

where:

BDw = Forecasted gas supply cost related Bad Debt Expense calculated for Winter Season.

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

Dw = Demand related costs in the Winter Season as previously defined.

Cw = Commodity related costs in the Winter Season as previously defined.

Rw = Reconciliation Costs – Winter Season deferred gas costs as previously defined.

WCRw = Winter Season Working Capital Reconciliation adjustment as previously defined.

Residential Winter Season Cost of Gas (COGwr)

All residential firm sales customers will pay the same Cost of Gas for the Winter Season. The factor represents the total forecasted Winter Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGwr = \frac{CGw}{W{:}Sales}$$

where:

CGw = The total cost of gas for the Winter Season for the Company’s firm sales customers previously defined.

W:Sales = Forecasted sales volumes associated with the Winter Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Summer Season Cost of Gas (COG) Formula (CGs)

The Summer Season COG shall be comprised of Summer demand costs and Summer commodity costs, Summer reconciliation costs, Summer working capital reconciliation, plus a Summer bad debt charge, and a miscellaneous and A&G charge calculated at the beginning of the Summer Season according to the following formula:

$$CGs = Ds + Cs + Rs + WCRs + BDs + \left((MISC + Rbd) \times \frac{S{:}Sales}{A{:}Sales}\right)$$

Summer Demand Cost (Ds) Formula

$$Ds = DEMs + WCsd - R1d - R2d$$

and:

$$WCsd = DEMs \times WCA\% \times CC$$

where:

A:Sales = Forecasted annual sales volumes.

BDs = Bad Debt Expense for Summer Season.

Cs = Commodity-related direct gas costs for the Summer Season.

CGs = The total cost of gas for the Summer Season for the Company's firm sales customer previously defined.

DEMs = Demand charges allocated to the Summer Season defined in Section 16(E).

MISC = The total dollar amount of gas costs associated with acquisition, dispatching, Administrative and General expenses and overheads as determined in the Company's most recent rate proceeding. –Refer to Section 16(F) for this dollar amount.

R1d, R2d = Supplier refunds from pipeline demand charges - The per unit supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds." See Section 16(I).

Rs = Summer Season Reconciliation Costs - Account 1920-1741 balance, inclusive of the associated Account 1920-1741 interest, as outlined in Section 16(J).

S:Sales = Forecasted sales volumes associated with the Summer Season.

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Rbd = Annual Bad Debt Expense reconciliation adjustment - Account 1920-1743 balance.

WCRs = Working Capital reconciliation adjustment associated with Summer gas costs – Account 1163-1424 as outlined in Section 16(K).

WCsd = Working Capital allowable costs associated with demand costs allocated to the Summer Season as defined in Section 16(K).

Summer Season Commodity Cost (Cs) Formula

Cs = COMs – NCCCs + WCsc – R1c – R2c
and:

WCsc = (COMs – NCCCs) × WCA% × CC
where:

COMs = Commodity charges associated with gas supply sent out in the Summer Season as defined in Section 16(E).

WCsc = Working Capital allowable costs associated with commodity charges allocated to the Summer Season as defined in Section 16(K).

R1c, R2c = Supplier refunds from pipeline commodity charges - The supplier refunds associated with refund program credits derived from Account 5541-8048, "Undistributed Gas Suppliers' Refunds."

NCCCs = Non-core commodity costs incurred in the Summer Season as defined in Section 16(E).

WCA % = Percentage of gas costs equivalent to Working Capital Allowance associated with gas costs. Refer to Section 16(F) for this percentage.

CC = Monthly interest rate as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

Summer Bad Debt (BDs) Formula

BDs = BD% x (Ds + Cs + Rs + WCRs)
where:

BD% = Bad Debt percentage calculated based on a twelve month basis ending April of each year. Refer to Section 16(F) Bad Debt Allowed Recovery Rate for this percentage.

BDs = Forecasted gas supply related Bad Debt Expense calculated for Summer Season defined in Section 16(E).

Ds = Demand related costs in the Summer Season as previously defined.

Cs = Commodity related costs in the Summer Season as previously defined.

Rs = Reconciliation Costs – Summer deferred gas costs as previously defined.

WCRs = Summer Season Working Capital Reconciliation adjustment as previously defined.

Residential Summer Season Cost of Gas (COGsr)

All residential firm sales customers will pay the same cost of gas for the Summer Season. The factor represents the total forecasted Summer Season average cost of gas rate. This factor is calculated according to the following formula:

$$COGsr = \frac{CGs}{S{:}Sales}$$

where:

CGs = The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.

S:Sales = Forecasted sales volumes associated with the Summer Season.

R = Designates the Residential Heating and Residential Non-Heating customer classes.

Commercial and Industrial Winter and Summer Season Cost of Gas

The Commercial and Industrial customer classes Winter Season Cost of Gas will be based on the Winter Season average cost of gas components used for the Residential Winter Season Cost of Gas. A separate Winter Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58 and a separate Winter Season Cost of Gas Factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

The Commercial and Industrial customer classes Summer Season Cost of Gas will be based on the Summer Season average cost of gas components used for the Residential Summer Season Cost of Gas. A separate Summer Season Cost of Gas factor will be computed for the low winter use class, Rates G-51, G-52, G-53,G-54, G-55, G-56, G-57, and G-58 and a separate Summer Season Cost of Gas factor will be computed for the high winter use class, Rates G-41, G-42, G-43, G-44, G-45, and G-46.

These Cost of Gas Factors will be computed by applying ratios to the average demand portion of the Winter and Summer Season's cost of gas unit rate times the correction factor and then adding the remaining Residential average cost of gas unit rate.

These factors are calculated according to the following formulas:

Low Winter Use (COGwl) Formula Winter Season

$$COGwl = RATIOl \times CFw \times CGwd + CGwo$$

Low Winter Use (COGsl) Formula Summer Season

$$COGsl = RATIOl \times CFs \times CGsd + CGso$$

and:

$$RATIOl = \frac{DCcl}{DDcl} \div \frac{DCc}{DDc}$$

and:

High Winter Use (COGwh) Formula Winter Season

$$COGwh = RATIOh \times CFw \times CGwd + CGwo$$

High Winter Use (COGsh) Formula Summer Season

COGsh = RATIOh x CFs x CGsd + CGso
and

$$\text{RATIOh} = \frac{\text{DCch}}{\text{DDch}} \div \frac{\text{DCc}}{\text{DDc}}$$

and:

$$\text{CFw} = \frac{\text{(WL:Sales + WH Sales)}}{\text{(RATIOl x WL:Sales) + (RATIOh x WH:Sales)}}$$

$$\text{CFs} = \frac{\text{(SL:Sales + SH:Sales)}}{\text{(RATIOl x SL:Sales) + (RATIOh x SH:Sales)}}$$

$$\text{CGwd} = \frac{\text{Dw}}{\text{W:Sales}}$$

$$\text{CGwo} = \frac{\text{CGw - Dw}}{\text{W:Sales}}$$

$$\text{CGsd} = \frac{\text{Ds}}{\text{S:Sales}}$$

$$\text{CGso} = \frac{\text{CGs - Ds}}{\text{S:Sales}}$$

DCcl = Bcl * PLrate + (DDcl – Bcl) * REMrate

DCch = Bch * PLrate + (DDch- Bch) * REMrate

PLrate = PL/ PLmdcq

$$\text{REMrate} = \frac{\text{(DCc – (Bc*PLrate))}}{\text{DDc - Bc}}$$

$$\text{DCc} = \frac{\text{(DC x DDc)}}{\text{DD}}$$

where:

Bc =	The daily base load for all the Commercial and Industrial rate classes
Bch =	The daily base load for the Commercial and Industrial rate classes G-41, G-42, G-43, G-44, G-45 and G-46.
Bcl =	The daily base load for the Commercial and Industrial rate classes G-51, G-52, G-53, G-54, G-55, G-56, G-57 and G-58.
CFs =	Summer Season Commercial and Industrial gas cost correction factor.
CFw =	Winter Season Commercial and Industrial gas cost correction factor.
CGs =	The total cost of gas for the Summer Season for the Company's firm sales customers as previously defined.
CGw =	The total cost of gas for the Winter Season for the Company's firm sales customers as previously defined.

DATED: April 28, 2017
ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017
TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

DC =	The annual forecasted pipeline, storage and peaking demand charges plus the total production and storage capacity costs, as stated in Section 16(F).
DCc =	The Commercial and Industrial rate classes pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs.
DCch =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to Commercial and Industrial High Winter Use rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DCcl =	The Commercial and Industrial pro-rata share of the annual forecasted pipeline, storage, and peaking demand capacity costs allocated to the Commercial and Industrial Low Winter Use rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
DD =	Total peak design day determinants.
DDc =	The peak design day determinants allocated for all the Commercial and Industrial rate classes.
DDch =	The peak design day determinants for the Commercial and Industrial rate classes, G-41, G-42, G-43, G-44, G-45, and G-46.
DDcl =	The peak design day determinants for the Commercial and Industrial rate classes, G-51, G-52, G-53, G-54, G-55, G-56, G-57, and G-58.
Ds =	The total Summer Demand charges as defined below.
Dw =	The total Winter Demand charges as previously defined.
PL =	The annual forecasted pipeline only demand charges
PLmdcq =	The maximum daily contract pipeline volume available to the Company.
PLrate =	The pipeline demand rate.
RATIOh =	Ratio of the average high Winter Use class Cost of Gas low load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
RATIOl =	Ratio of the average low Winter Use class Cost of Gas high load factor demand capacity costs to the total average Commercial and Industrial demand capacity costs.
REMrate =	The weighted average demand rate for storage and peaking supplies.
S: Sales =	Forecasted sales volumes associated with the Summer Season.
SH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
SL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.
W:Sales =	Forecasted sales volumes associated with the Winter Season.
WH:Sales =	Total Winter Season forecasted Commercial and Industrial high winter use sales.
WL: Sales =	Total Winter Season forecasted Commercial and Industrial low winter use sales volumes.

H. Non-Core Sales Margins ("NCSM"). One hundred percent (100%) of margins from Off-System Sales and all revenues from Capacity Release will be credited to firm sales customers during the winter season through operation of the COG.

I. Gas Suppliers' Refunds. Account 5541-8048: Refunds from suppliers of gas, from upstream capacity suppliers and suppliers of product demand are credited to Account 5541-8048, "Commodity and Demand Refunds." Transfers from these accounts will reflect as a credit in the semiannual calculation of the COG to be calculated as follows:

Refund programs shall be initiated with each semiannual COG filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. Refunds shall be segregated by demand and commodity charges and distributed volumetrically, producing per unit refund that will return the principal amount with interest as calculated using the Company's average short-term cost of borrowing for the month to the average of the beginning and end of month balances of refunds. The Company shall track and report on all Account 5541-8048 activities as specified in Section 16(K).

J. Reconciliation Adjustments – Various Accounts.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Capacity Costs Allowable per Winter Season Formula shall be:

(1) Charges associated with upstream storage transmission capacity and product demand procured by the Company to serve firm load in the Winter Season, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Charges associated with peaking, downstream production and storage capacity to serve firm load dispatching costs, and other administrative and general expenses in connection with purchasing gas supplies in the Winter Season from the Company's most recent test year and allocated to firm sales service.

(3) Non-Core Sales Margins or economic benefits associated with returnable capacity release and off-system sales.

(4) Credits associated with firm Stand-by Gas Supply Service Monthly Reservation Charges, daily imbalance charges and fixed component of penalty charges billed transportation customers in the Winter peak Season.

(5) Winter Season Demand Cost carrying charges.

b. Gas Costs Allowable Per Winter Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter Season.

(2) Credit non-core commodity costs assigned to non-core customers to which the COGC does not apply, as defined in Section 16(H) (NCCCw).

(3) Inventory finance charges (FC).

(4) Winter Season commodity cost carrying charges.

c. Capacity Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with transmission capacity and product demand procured by the Company to serve firm load in the Summer Season

(2) Credits associated with daily imbalance charges and fixed component of penalty charges billed transportation customers in the Summer Season.

(3) Summer Season demand cost carrying charges.

d. Gas Costs Allowable Per Summer Season Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Summer Season commodity cost carrying charges.

e. Costs Allowable Per Bad Debt Formula shall be:

(1) Costs associated with uncollected gas costs, incurred by the Company to serve sales load. Such costs represent the bad debt expense related to the gas supply related write-off of sales customers and will be computed by multiplying actual gas costs by the Bad Debt Allowed Recovery Rate specified in Section 16(F). The reconciliation adjustment each season will be computed as the difference between the actual supply related bad debt revenues and the actual gas costs multiplied by the actual Bad Debt Allowed Recovery Rate as specified in Section 16(F).

(2) Account 1920-1743 – Annual Bad Debt, carrying charges.

2. Calculation of the Reconciliation Adjustments: These accounts contain the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Winter Season Gas Costs (Account 1920-1740) and Summer Season Gas Costs (Account 1920-1741), Account 1920-1740 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Winter Season Gas Cost for each Customer Classification, (COGwr, COGwl and COGwh) times monthly firm sales volumes for each Customer Classification, and the total costs allowable per the Winter Season gas cost formula. Account 1920-1741 shall contain the accumulated difference between revenues toward gas costs calculated by multiplying the Summer Season Gas Cost for each Customer Classification, (COGsr, COGsl and COGsh) times monthly firm sales volumes for each Customer Classification, and the total gas costs allowable per the Summer Season demand formula.

Carrying Charges shall be calculated on the average monthly balance of each subaccount. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

The annual bad debt reconciliation adjustments Rbd shall be determined for use, incorporating the bad debt balances in Account 1920-1743.

The bad debt account balance contains the accumulated difference between the Bad Debt Allowed Recovery Rate for the applicable period multiplied by the actual gas costs and the actual supply related bad debt revenues for the Winter and Summer COG filings.

The Winter Season reconciliation shall be filed with the NHPUC no later than July 29 of each year.

The Summer Season reconciliation shall be filed with the NHPUC no later than January 31 of each year.

K. Working Capital Reconciliation Adjustments - Accounts 1163-1422 and 1163-1424.

1. The following definitions pertain to reconciliation adjustment calculations:

a. Working Capital Demand Gas Costs Allowable per Winter Season Gas Formula shall be:

(1) Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the Winter period, plus a reallocation of a portion of such charges incurred in the Summer Season to serve firm load.

(2) Carrying charges.

b. Working Capital

(1) Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Winter season.

(2) Non-core commodity costs associated with non-core sales to which the COG is not applied, as defined in Section 16(E).

(3) Carrying charges.

c. Working Capital Demand Gas Costs Allowable per Summer Season Gas Formula shall be:

(1) Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Summer Season.

(2) Carrying charges.

d. Working Capital Commodity Gas Costs Allowable per Summer Season Gas Formula shall be:

(1) Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Summer Season.

(2) Non-core commodity costs associated with non-core sales.

(3) Carrying charges.

e. The Winter and Summer Cost of Gas working capital allowances shall be calculated by applying the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F).

2. Calculation of the Reconciliation Adjustments

a. Accounts 1163-1422 and 1163-1424 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance cost. The actual monthly working capital allowance shall be calculated by multiplying the actual gas costs times the Working Capital Allowance Percentage (WCA%) set forth in Section 16(F), to the actual Direct Gas Costs allowable.

b. The Winter Season working capital reconciliation adjustment (WCRw) shall be determined for use in the Winter Season Gas Cost calculations incorporating the Winter Season working capital account 1163-1422. A Summer Season working capital reconciliation adjustment (WCRs) shall be determined for use in the Summer Season Gas Cost calculations incorporating the Summer Season working capital account 1163-1424 balance.

L. Application of COG to Bills: The Company will employ the COGs as follows: The COGs ($/therm) for each customer group for each season shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volume within the corresponding customer classification. The Cost of Gas will be applied to gas consumed on or after the first day of the month in which the cost of gas becomes effective.

M. Information Required to be Filed with the NHPUC.

1. Reconciliation Adjustments: The Company shall file with the NHPUC a seasonal reconciliation of gas costs and gas cost collections containing information in support of the reconciliation calculation set out in Sections 16(J) (2) and 16(K) (2). -Such information shall include the complete list of gas costs recoverable through the COGC over the previous season. This seasonal reconciliation shall be filed with the respective seasonal COG reconciliation filing, along with complete documentation of the reconciliation adjustment calculations.

   Additionally, information pertaining to the Cost of Gas shall be filed with the NHPUC in accordance with the format established by the NHPUC. Reporting requirements include filing the Company’s monthly calculation of the projected over or under-collection with the NHPUC, along with notification by the Company to the NHPUC of any revised COG for the subsequent month, not less than five (5) business days prior to the first day of the subsequent month.

   The Company shall file with the NHPUC an annual reconciliation of bad debt expense and bad debt collections containing information in support of the reconciliation calculation set out in Sections 16(J) (1) and 16(J) (2). -Such information shall detail the revenues collected as an allowance for bad debt, as well as the actual bad debt expense associated with gas cost recoverable through the COGC over the 12-month period ending April 30th. This annual reconciliation of bad debt expenses shall be filed with the Winter COG reconciliation filing, along with documentation.

2. Commercial and Industrial COG Ratio: The following factors will be filed annually by the Company for informational purposes. Significant changes in these factors signal the need to evaluate the COG ratios. These variables will assist in predicting significant shifting of the MBA-based escalator of gas costs and resulting changes in the COG ratios:

   a. The percentage of load migration from sales to transportation service in the Commercial and Industrial High and Low Winter Use classes.

   b. The ratio of delivered costs of winter supplies to pipeline delivered supplies.

   c. The July and August consumption for the Commercial and Industrial High and Low Winter classes as a percentage of their annual consumption.

N. Other Rules.

1. The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of this tariff, upon such terms that it may determine to be in the public interest.

2. The Company may, without further NHPUC action, adjust the approved COG upward or downward monthly based on the Company's calculation of the projected over or under-collection for the period, but the cumulative adjustments upward shall not exceed twenty-five percent (25%) of the approved COG.

3. The Company may, at any time, file with the NHPUC an amended COG.

4. The operation of the Cost of Gas Clause is subject to all powers of suspension and investigation vested in the NHPUC.

5. The Company shall file both seasonal COG filings on or before the first business day in September. The summer portion of the filing will include COG rates effective May 1 of the following year.

O. Reconciliation Adjustment Accounts.

1163-1422

Winter Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas working capital allowance revenues and Winter Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1163-1424

Summer Season Gas Working Capital Allowance Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas working capital allowance revenues and Summer Season gas working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1740

Winter Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Winter Season gas revenues and Winter Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1741

Summer Season Gas Cost Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Summer Season gas revenues and Summer Season gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

1920-1743

Annual Bad Debt Reconciliation Adjustment for COGC: This account shall be used to record the cumulative difference between Annual bad debt revenues and annual bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

5541-8048

Commodity and Demand Refunds: This account shall be used to record the refunds from upstream commodity supplies and suppliers of product commodity and transfers of credits in the semiannual calculation of the COG as well as to record the refunds from upstream capacity supplies and suppliers of product demand and transfer of credits in the semiannual calculation of the COG. Entries to this account shall be determined as outlined in the Cost of Gas Clause.

P. Firm Transportation Cost of Gas Charge. To permit the Company to charge its firm transportation customers with a portion of the cost of gas produced by the Company between November 1 and April 30 of each year, there is a Firm Transportation Cost of Gas Charge ("FTCG") which applies to all firm transportation billed under this tariff. This volumetric charge is to compensate firm sales customers for the increase in gas costs, through the use of supplemental liquid fuels, attributable to firm transportation customers during the Winter Period.

1. Application. The FTCG will be calculated for the Winter Period, defined as the period from November 1 through April 30. The FTCG will be applied to billings commencing with the first November revenue billing cycle

2. Purpose. The amount of the FTCG is the estimated liquid costs used for pressure support purposes multiplied by the transportation throughput as a percentage of the total system throughput for the Winter Period. The resulting amount shall be adjusted by the prior period over or under collection, if any, and shall be recovered over the estimated total transportation throughput subject to the FTCG to yield a per therm volumetric charge. The FTCG shall be computed to the nearest one hundredth cent per therm and shown separately on customers' bills. At the conclusion of the Winter Period, the Company will calculate the extent that the FTCG revenues are greater or lesser than actual unit cost. The revenue and liquid costs will be reconciled so that all liquids costs shall be collected from either firm sales or firm transportation customers.

3. Changes. The amount of the FTCG may be changed within the period whenever the unit cost materially deviates from the anticipated unit cost

4. Reporting. The Company shall submit to the New Hampshire Public Utilities Commission, on or before the first business day in September, a copy of the FTCG computation. A reconciliation of the prior period under/over collection will be submitted to the New Hampshire Public Utilities Commission no later than July 29.

Q. Fixed Price Option Program. Fixed Price Option Program. An alternative to the traditional Winter Period cost of gas pricing mechanism may be elected by a residential customer (rates R-1, R-3, R-4, R-5 or R-6) pursuant to the Company's Fixed Price Option Program (the "Program"). The Company may offer up to 50% of its weather normalized firm sales for the prior Winter Period under the Program. The cost of gas rate offered under the Program will remain fixed for all Winter Period deliveries commencing November 1 and ending April 30. The Company shall submit to the New Hampshire Public Utilities Commission on or before September 1 of each year a copy of the fixed price option computation. Once elected, customers must remain on the Program for the duration of the Winter Period, unless service is terminated. There are no maximum or minimum usage levels. No sign up fees apply.

16.2 COST OF GAS CLAUSE – KEENE DIVISION

A. Purpose. To permit the Company to charge its customers in the Keene Division with the cost of gas purchased or produced. A cost of gas rate will be applied to all firm gas billed under this tariff as calculated on the appropriate pages.

B. Application. A cost of gas rate will be calculated for the winter heating period, defined as the period from November 1 through April 30, and a cost of gas rate will be calculated for the summer period, defined as the period from May 1 through October 31.

The winter cost of gas rate will be applied to billings commencing with the first November revenue billing cycle; the summer cost of gas rate will be applied to billings commencing with the first May revenue billing cycle.

C. Calculation. The amount of the cost of gas rate is the anticipated unit cost of gas sold.

At the conclusion of each winter and summer period the Company will calculate the extent that cost of gas revenues are greater or less than actual unit costs of gas compared with the anticipated unit costs. The calculated difference (actual gas sales volumes multiplied by the difference between actual and anticipated unit costs) will be carried forward into the computation of the cost of gas rate for the corresponding winter or summer period.

Any excess revenue collected, as determined above, will earn interest as specified by the Commission.

D. Changes. The cost of gas rate may be adjusted without further Commission action based on the projected over-/under-collection of gas costs, the adjusted rate to be effective the first of the month. Any such rate adjustments may not exceed a maximum rate of 25 percent above the approved rate, but there is no limit on the amount of any rate reductions.

E. Refunds. When refunds are made to the Company by its suppliers that are applicable to increased charges collected under this provision, the Company will make appropriate refunds to its customers and as the Commission may direct.

F. Reporting. The Company shall submit to the Commission, at least 30 days prior to the effective date, the proposed winter and summer period cost of gas rate computation. Any monthly adjustments to the cost of gas rate must be filed five (5) business days prior to the first day of the subsequent month (the effective date of the new rate).

The cost of gas rate shall be computed to the nearest one hundredth cent per therm and shown on customers' bills.

G. Fixed Price Option Program. An alternative to the traditional winter period cost of gas rate mechanism may be elected by the customer pursuant to the Company's Fixed Price Option (FPO) Program. The Company may offer up to 50% of its expected firm sales for the winter period under the FPO Program. The cost of gas charge offered under the FPO Program will remain fixed for all winter period billings commencing November 1 and ending April 30 of the effective winter period. Once elected, customers must remain on the FPO Program for the duration of the winter period unless service is terminated. There are no maximum or minimum usage levels. Customers may enroll in this Program by contacting the Company between the October 1 and October 19 period immediately preceding the effective winter period.

17 LOCAL DISTRIBUTION ADJUSTMENT CLAUSE

A. Purpose. The purpose of the Local Distribution Adjustment Clause ("LDAC" or this "Clause") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, its delivery charges in order to recover Conservation Charges ("CC"), ~~Lost Revenues Adjustment Mechanism~~ Revenue Decoupling Adjustment Clause ~~related to the Energy Efficiency Programs~~ ("~~LRAM~~RDAC"), Winter Period Surcharges ("WPS"), Environmental Surcharges ("ES") including the Relief Holder Surcharge ("RHS") and the Manufactured Gas Program Surcharge ("MGP"), recover gas restructuring expenses ("GRE"), rate case expenses ("RCE"), Residential Low Income Assistance Program costs ("RLIAP") and any other expenses the NHPUC may approve from time to time.

B. Applicability. This Clause shall be applicable in whole or part to all of the Company's firm sales service and firm delivery service customers as shown on the table below. The application of this clause may, for good cause shown, be modified by the NHPUC. See Section 17(K) "Other Rules."

Applicability	**CC 17(C)**	**~~LRAM~~RDAC 17(C.1)**	**ES 17(D)**	**GRE 17(E)**	**RCE 17(F)**	**RLIAP 17(G)**
Residential Non-Space Heating – R-1, R-5	~~1~~2	~~1~~2	X	N/A	~~1~~2	X
Residential Space Heating – R-3, R-4, R-6, R-7	2~~1~~	~~1~~2	X	N/A	~~1~~2	X
Small C&I – G-41, G-51, G-44, G-55	2~~1~~	~~1~~2	X	X	~~1~~2	X
Medium C&I – G-42, G-52, G-45, G-56	2~~1~~	~~1~~2	X	X	~~1~~2	X
Large C&I – G-43, G-53, G-54, G-46, G-57, G-58	2~~1~~	~~1~~2	X	X	~~1~~2	X

Notes:
N/A Not applicable
X Applicable to all
1 ~~As ordered by the NHPUC~~ Applicable to Non-Managed Expansion Program Customers
2 As ordered by the NHPUC

C. Conservation Charges Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Conservation Charge, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers costs and lost margins associated with its energy efficiency management programs.

2. Applicability: A conservation charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the ~~New Hampshire Public Utilities~~ Commission ~~(the "Commission")~~ as determined in accordance with the provision of this rate schedule. Such conservation charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.

3. Calculation of Conservation Charge: The Company will properly assign expenses for forecasted conservation expenditures to the applicable rate categories for a future twelve (12) month period commencing November 1 of each year. The total of such conservation expenditures plus any prior period reconciling adjustments shall be divided by therm sales as forecasted by the Company for the same annual period and rounded to the nearest hundredth of a cent. The resulting conservation charge shall be included in the Company's Local Distribution Adjustment Charge and applied to actual therms sold or transported for the following twelve (12) month period starting November 1, and ending October 31.

4. Reporting: The Company shall submit annual reports to the Commission reconciling any difference between the actual conservation expenditures and actual revenues collected under this rate schedule. The difference whether positive or negative will be carried forward into the conservation charge for the next recovery period. Upon completion of the conservation program(s), any over or under collection may be credited or charged to the deferred Winter Period cost of gas account, subject to Commission approval.

5. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the CC applicable to each Rate Category during the next subsequent twelve-month period commencing with the calendar month of November.

6. Reconciliation Adjustment: Account 1163-1755 shall contain the cumulative difference between the sum of the DSM expenditures incurred by the Company plus the sum of the DSM repayments and the revenues collected from customers. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.

C.1 ~~Lost Revenue Adjustment Mechanism Allowable for LDAC.~~Revenue Decoupling Adjustment Clause

1. Purpose: The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company, subject to the jurisdiction of the NHPUC, to adjust, on a semi-annual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

2. Effective Date: The Winter Season Revenue Decoupling Adjustment Factor ("RDAF") for the Winter Season shall be effective on the first day of each Winter Season as defined herein. The Summer Season RDAF shall become effective on the first day of each Summer Season as defined herein.

3. Applicability: The Revenue Decoupling Adjustment Factor shall apply to all of the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this RDAC.

4. Definitions: The following definitions shall apply throughout the RDAC:

   a. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the Actual N~~n~~umber of C~~c~~ustomers for a given season for a Customer Class Group.

   b. Actual Number of Customers is the actual number of customers for the applicable Customer Class Group for the most recently completed Winter Season or Summer Season. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for ~~bills for~~ a given season for a Customer Class Group and dividing by the number of months in each Season.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

c. -Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

d. Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Adjustment amounts. The three Customer Class Groups are as follows:

(1) The Residential Non-Heating Customer Class Group (CG1) shall consist of all customers taking service pursuant to the Company's residential non-heating rate schedule R-1.

(2) The Residential Heating Customer Class Group (CG2) shall consist of all customers taking service pursuant to the Company's residential heating rate schedules R-3, and R-4.

(3) The Commercial and Industrial Customer Class Group (CG3) shall consist of all customers taking service pursuant to one of the Company's general service rate schedules, G-41, G-42, G-43, G-51, G-52, G-53 and G-54.

e. Summer Season is the continuous period from May 1 through October 31.

f. Winter Season is the continuous period from November 1 through April 30.

g. Benchmark Base Revenue per Customer is the allowed average revenue per Customer for a given season for a Customer Class Group, reflecting the base revenue from the Company's base rate case or other proceeding that results in an adjustment to base rates. The following are the Benchmark Base Revenue per Customer values as approved by the Commission in Docket No. DG 17-048:

Customer Class Group	Benchmark Base Revenue per Customer	
	Winter Season	Summer Season
Residential Non-Heating (CG1)	$165.77	$145.53
Residential Heating (CG2)	$433.98	$210.90
Commercial and Industrial (CG3)	$2,200.52	$894.95

5. Calculation of Revenue Decoupling Adjustment

a. Description of Revenue Decoupling Adjustment

At the conclusion of each Winter Season and Summer Season, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the A~~a~~ctual Base Revenue per Customer and the Benchmark Base Revenue per Customer, and multiplying that difference by the Actual Number of Customers for the applicable Customer Class Group. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for each of the three Customer Class Groups and shall include a reconciliation component.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

The total Revenue Decoupling Adjustment determined in accordance with Section 5.0 may not exceed plus or minus five percent (±~~+/-~~5%) of total base revenues from firm Rate Classes for the most recent corresponding Winter or Summer Season. To the extent that the application of the Revenue Cap results in a Revenue Decoupling Adjustment that is less than that calculated in accordance with Section 5.0, the difference shall be deferred and included in the Revenue Decoupling Reconciliation for recovery in the subsequent year during the corresponding Winter or Summer Season. Carrying charges shall be calculated on the average deferred balance using the prime lending rate and then added to the end-of-month balance.

b. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CG=1}^{CG=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CG} \right) x\ ACUSTS_{T-1}^{CG} \right]$$

If

$RD < (5\%\ x\ DIST\ REV_T)$

And

$RD > (-5\%\ x\ DIST\ REV_T)$

Then

$DEF_{incm} = 0$

And:

$DEF_{rec} = Lower\ of\ (DEF_{balp)}\ or\ \left((5\%\ x\ DIST\ REV_T) - RD \right)$

And:

$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} - DEF_{rec}$

And:

$$RDAF = \frac{RD + RF_{rd} + DEF_{rec}}{P{:}Thru_T}$$

Else:

$DEF_{incm} = RD - (5\%\ x\ DIST\ REV_T)$

And:

$DEF_{rec} = 0$

And

$DEF_{balc} = DEF_{balp} + DEF_{incm} - DEF_{rec} = DEF_{balp} + DEF_{incm}$

And

$$RDAF = \frac{(5\%\ x\ DIST\ REV_T) + RF_{rd}}{P{:}Thru_T}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CG}$: The A~~a~~ctual N~~n~~umber of C~~c~~ustomers for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1). Actual number of customers for each Winter or Summer Season shall be the average number monthly customers in that season, calculated by summing the number of equivalent bills~~billed customers~~ in each month of the most recently completed Winter or Summer Season, and dividing by the number of months in the Season.

$ARPC_{T-1}^{CG}$: The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Winter or Summer Season (T-1), as defined in Section 4.0. For purposes of calculating the Actual Base Revenue per Customer, base revenues for Low Income rate class R-4, shall be determined based on non-discounted rate R-3.

$BRPC_{T-1}^{CG}$: The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section 4.0(A) for the most recently completed Winter or Summer Season (T-1).

cg: Customer Class Groups as defined in Section 4.0(D).

DEF_{bal}: The balance of the unrecovered deferrals inclusive of associated interest using the prime lending rate.

DEF_{incm}: The amount of Revenue Decoupling that must be deferred in the current year based on the difference between plus or minus five percent (+/-5%) of total distribution revenues as determined in accordance with the definition of DIST REV_T in Section 5.0(B).

DEF_{rec}: The amount of deferrals the Company may recover in the current Winter or Summer Season.

P: $Thru:_T$: Forecast Throughput Volumes inclusive of all firm tariff throughput for the Winter or Summer Season.

RD: The Revenue Decoupling adjustment to revenues.

$RDAF_T$: The Revenue Decoupling Adjustment Factor for the Winter or Summer Season.

RF_{rd}: Revenue Decoupling Reconciliation Adjustment as described in Section 6.0.

DIST REV_T: The Distribution revenues from all firm rate classes during the most recent Winter or Summer Season.

6. Calculation of the Reconciliation Adjustments

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Winter Season, as calculated by multiplying the Winter Season RDAF times the Winter Season firm sales and transportation throughput, and the Revenue Decoupling Adjustment allowed revenues for the Winter Season, plus carrying charges on the average monthly balance using the prime lending rate.

Account xxxx-xxxx shall contain the accumulated difference between revenues toward the Revenue Decoupling Adjustment for the Summer Season, as calculated by multiplying the Summer Season Revenue Decoupling Adjustment Clause times the Summer Season firm throughput, and the Revenue Decoupling Adjustment allowed revenues for the Summer Season, plus carrying charges on the average monthly balance using the prime lending rate.

7. Application of the RDAC to Customer Bills

The RDAF ($ per therm) shall be truncated at the nearest one one-hundredth of a cent per therm. The RDAF for the Winter Season will be applied usage in the next Winter Season and the RDAF for the Summer Season will be applied to usage in the next Summer Season. The RDAF will be applied to the monthly firm tariff throughput for each customer.

8. Information to be Filed with the Commission

Information pertaining to the RDAC will be filed with the Commission ninety (90) days prior to the effective dates of the November 1 Winter Season and May 1 Summer Season RDAF. Such information shall include:

a. the calculation of the applicable revenue decoupling revenue adjustment

b. the calculation of the revenue decoupling reconciliation adjustment.;

c. the calculation of annually updated Benchmark Base Revenue per Customer to be utilized in the upcoming Summer and Winter Seasons.

~~D. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to adjust, on an annual basis, the Lost Revenue Adjustment Rate, if and when applicable, to firm sales service and firm delivery service throughput in order to recover from firm customers lost revenue related to Energy Efficiency programs, pursuant to Order No. 25,932 in Docket DE 15-137, Energy Efficiency Resource Standard.~~

~~E. Applicability: A Lost Revenue Adjustment charge shall be applied to therms sold or transported by the Company subject to the jurisdiction of the New Hampshire Public Utilities Commission (the "Commission") as determined in accordance with the provision of this rate schedule. Such Lost Revenue Adjustment charge shall be determined annually by the Company, separately for the Residential Heating, and Commercial/Industrial rate categories, subject to review and approval by the Commission as provided for in this rate schedule.~~

~~F. Calculation of Lost Revenue Adjustment: The Lost Revenue Adjustment for each Rate Category will be derived by dividing the projected annual lost revenue, plus the reconciliation balance, by forecast firm annual throughput. The reconciliation balance shall reflect both actual and projected data, as necessary, through October of the prior rate period.~~

~~G. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the Lost Revenue Adjustment Rate applicable to each Rate Category during the next subsequent twelve month period commencing with the calendar month of November.~~

~~H. Reconciliation Adjustment: Account xxxx-xxxx shall contain the cumulative difference between the Lost Revenue Adjustment Rate revenues collected and actual costs, plus carrying charges. The Company shall file the reconciliation along with the COG filing on or before the first business day in September of each year.~~

~~I.~~D. Environmental Surcharges ("ES") Allowable for LDAC.

1. Purpose: In order to recover expenditures associated with former manufactured gas Programs, there shall be an ES Rate applied to all firm volumes billed under the Company's delivery service charges.

2. Applicability: An annual ES Rate shall be calculated effective every November 1 for the annual period of November 1 through October 31. The annual ES Rate shall be filed with the Company's Winter season Cost of Gas Clause ("COG") filing and be subject to review and approval by the Commission. The annual ES Rate shall be applied to firm sales and to firm delivery throughput as a part of the LDAC. Special contract customers are exempt from the ES.

3. Costs Allowable: All approved environmental response costs associated with manufactured gas Programs may be included in the ES Rate

   The total annual charge to the Company's customers for environmental response costs during any annual ES recovery period shall not exceed five percent (5%) of the Company's total revenues from firm gas sales and delivery throughput during the preceding twelve (12) month period ending June 30. The total annual charge shall represent the ES expenditures reflected in the calculation of the ES Rate to be in effect for the upcoming twelve-month period, November 1 through October 31. If this recovery limitation results in the Company recovering less than the amount that would otherwise be recovered in a particular ES Recovery Year, then the Company would defer this unrecovered amount, with interest, calculated monthly on the average monthly balance, until the next recovery period in which this amount could be recovered without violating the 5% limitation. The interest rate is to be adjusted monthly using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates.

4. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the ES applicable to all firm sales and firm delivery service throughput for the subsequent twelve-month period commencing with the calendar month of November.

5. Definitions:

   Environmental Response Costs shall include all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas Program sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of New Hampshire gas manufacturing facilities. These cost shall include the costs of the closure of the Relief Holder and pond at Gas Street, Concord, NH ~~and pond~~. The ES shall also include the expenses incurred by the Company in pursuing insurance and third-party claims and any recoveries or other benefits received by the Company as a result

6. Reconciliation Adjustments: Prior to the Winter Period COG, the Company shall calculate the difference between (a) the revenues derived by multiplying firm sales and delivery throughput by the ES Rate, and (b) the historical amortized costs approved for recoveries in the prior November's Annual ES Recovery Period. Account 1920-1863 shall contain the cumulative difference and the Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

7. Calculation of the ES: The ES Rate calculated annually consists of one-seventh of actual response costs incurred by the Company in the twelve-month period ending June 30 of each year until fully amortized (over seven years). Any insurance and third-party recoveries or other benefits for the twelve month period ending June 30 shall be applied to reduce the unamortized balance, shortening the amortization period. The sum of these amounts is then divided by the Company's forecast of total firm sales and delivery throughput for the upcoming twelve months of November 1 through October 31.

8. Application of ES to Bills: The annual ES Rate shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

~~J.~~E. Expenses Related to Gas Restructuring.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates on an annual basis for the recovery of NHPUC-approved costs associated with the Gas Restructuring Collaborative (Docket DE 98-124).

2. Applicability: The Gas Restructuring Expenses (“GRE”) shall be applied to all firm tariffed customers eligible to receive delivery service from the Company as determined in accordance with the provisions of Section 17(F) of this clause. The GRE shall be determined annually by the Company as defined below, subject to review and approved by the NHPUC as provided for in this clause.

3. GRE Allowable for LDAC: Costs associated with the Gas Restructuring Collaborative (DE 98-124), including, but not limited to, any legal, consulting, customer focus group(s) and survey(s), customer education campaign(s), materials and advertising, subject to review and approval by the NHPUC.

4. Effective Date of GRE Charge: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the GRE applicable to all consumption of tariffed customers eligible to receive delivery service for the subsequent twelve month period commencing with the calendar month of November.

5. Definition: Gas Restructuring Initiatives are activities facilitating the development, design and implementation of unbundled services for all customers.

6. GRE Factor Formula:

$$GREF = \frac{GRE + RAGRE}{A{:}\ TPev}$$

where:

A:Tpev Forecast Annual Throughput Volumes of all tariffed customers eligible to receive firm delivery-only service from the Company.

GRE Gas Restructuring Expenses as defined in Section 17(F).05.

RA_{GRE} Gas Restructuring Expense Reconciliation Adjustment - Account 1920-1744, inclusive of the associated Account 1920-1744 interest, as outlined in Section 17(E)(7).

7. Reconciliation Adjustments: Account 1920-1744 shall contain the accumulated difference between revenues toward Gas Restructuring Expenses as calculated by multiplying the Gas Restructuring Expense Factor ("GREF") times monthly volumes of customers eligible to receive firm delivery service and Gas Restructuring expenses allowed, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates, and then added to the end-of-month balance.

8. Application of GREF to Bills: The GREF ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the Gas Restructuring Expenses shall be filed with the NHPUC consistent with the filing requirements of all costs and revenue information included in the LDAC. An annual GREF filing shall be required on or before the first business day in September of each year. The GREF filing shall contain the calculation of the new annual GREF to become effective November 1 and shall include the updated annual Gas Restructuring Expense reconciliation balance.

~~K.~~F. Expenses Related to Rate Cases/Temporary Rate Reconciliation Allowable for LDAC.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company to adjust its rates for the recovery of NHPUC-approved rate case expenses and the reconciliation of temporary rates.

2. Applicability: The Rate Case Expenses/Temporary Rate Reconciliation ("RCE") shall be applied to all firm tariffed customers. The RCE will be determined by the Company, as defined below.

3. Rate Case Expenses Allowable for LDAC: The total amount of the RCE will be equal to the amount approved by the Commission.

4. Effective Date of Rate Case Expense Charge: The effective date of the RCE will be determined by the NHPUC in an individual rate proceeding.

5. Definition: The RCE includes all rate case-related expenses approved by the NHPUC. This includes legal expenses, costs for bill inserts, costs for legal notices, consulting fees processing expenses, and other approved expenses. The temporary Rate reconciliation will include the variance between

the delivery revenues obtained from the rates prescribed in the temporary rate order and the delivery revenues obtained from the final rates approved by the NHPUC.

6. Rate Case Expense/Temporary Rate Reconciliation (RCE) Factor Formulas: The RCE will be calculated according to the Commission Order issued in an individual proceeding to establish details including the number of years over which the RCE shall be amortized and the allocation of recovery among rate classes. In general, the RCE Factor will be derived by dividing the annual portion of the total RCE, plus the RCE Reconciliation Adjustment, by forecast firm annual throughput.

7. Reconciliation Adjustments: Account 1930-1745 shall contain the accumulated difference between revenues toward Rate Case Expenses as calculated by multiplying the Rate Case Expense Factor ("RCEF") times the appropriate monthly volumes and Rate Case Expense allowed, plus carrying charges added to the end-of-month balance. The carrying charges shall be calculated beginning on the first month of the recovery period by applying the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates to the average monthly balance.

   At the end of the recovery period, any under or over recovery will be included in an active LDAC component, as approved by the Commission.

8. Application of RCE to Bills: The RCE ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm gas sales and firm delivery service throughput by being included in the determination of the annual LDAC, and also shall be included in the Distribution Adjustment of the Delivery Charges of each firm customer's bill.

9. Information to be Filed with the NHPUC: Information pertaining to the RCE will be filed with the NHPUC consistent with the filing requirements of all cost and revenue information included in the LDAC. The RCE filing will contain the calculation of the new RCE and will include the updated RCE reconciliation balance.

~~L.~~G. Recoverable Residential Low Income Assistance Program Costs.

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with customers participating in the Residential Low Income Assistance Program ("RLIAP"). Such costs, as well as, associated administrative and marketing costs shall be recovered by applying an RLIAP rate to all firm sales and transportation service throughput.

2. Applicability: The RLIAP Rate shall be applied to all firm sales and transportation tariff customers. The RLIAP Rate shall be filed with the Company's Winter season Cost of Gas Clause filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the RLIAP Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. RLIAP Costs Allowable for LDAC: The costs to be recovered through the RLIAP Rate shall comprised of the revenue shortfall calculated by forecasting the number of customers enrolled in

the RLIAP and the associated volumetric billing determinants for the upcoming annual recovery period and applying those billing determinants to the difference between the regular and reduced low income residential base rates, plus administrative, marketing and startup costs. The RLIAP Rate shall be calculated by dividing the resulting costs, plus any prior period reconciling adjustment, by the forecast of annual firm sales and transportation service throughput.

5. RLIAP Factor Formula

$$RLIAPF = \frac{RLIAP + RA_{RLIAP}}{A{:}\ TPev}$$

where:

A: Tpev — Forecast Annual Throughput Volumes of all firm sales and transportation tariffed customers eligible to receive firm delivery-only service from the Company.

RLIAP — RLIAP costs comprising of the revenue shortfall associated with customer participation, plus administrative, marketing, IT and start-up costs.

RA_{RLIAP} — RLIAP Reconciliation Adjustment - Account 1169-1756, inclusive of the associated Account 1169-1756 interest, as outlined in Section 17(G)(6).

6. Reconciliation Adjustments: Prior to the Company's Winter season Cost of Gas filing, the Company will calculate the difference between (a) the revenue derived by multiplying the actual firm sales and delivery service throughput by the RLIAP Rate through October 31st, and (b) the actual costs of the program which consists of (1) the revenue shortfall calculated by applying the actual billing determinants of the RLIAP classes to the difference in the regular and reduced residential base rates in effect for the annual reconciliation period and (2) the start-up, administrative and marketing costs associated with the implementation of the program, plus carrying charges calculated on the average monthly balance using the monthly prime lending rate, as reported by the Federal Reserve Statistical Release of Selected Interest Rates. The combined costs will then be recorded in the deferred RLIAP account 1169-1756. The Company shall file the reconciliation along with its COG filing on or before the first business day in September of each year.

~~M.~~H. Effective Date of Local Distribution Adjustment Clause. The LDAC shall be filed annually and become effective on November 1 of each year pursuant to NHPUC approval. In order to minimize the magnitude of future reconciliation adjustments, the Company may request interim revisions to the LDAC rates, subject to review and approval of the NHPUC.

~~N.~~I. Local Distribution Adjustment Clause Formulas. The LDAC shall be calculated on an annual basis, by customer, by summing up the various factors included in the LDAC, where applicable.

LDAC Formula

$$LDAC^{x} = CC^{x} + \cancel{LRAM^{x}}\ RDAC^{x} + ES + GREF^{x} + RCE + RLIAP$$

and:

$$ES^{x} = RHS + MGP$$

where:

$LDAC^{x}$ = Annualized class specific LDAC.

CC^X = Annualized class specific CC or EE Charge.

~~$LRAM^X$~~ $RDAC^X$ = Annualized class specific ~~LRAM~~RDAC.

ES = Total firm annualized ES.

RHS = Annualized charge to recover the costs of the closure of the Relief Holder at Gas Street, Concord, NH

MGP = Annualized charge to cover the remediation costs related to former manufactured gas plants.

$GREF^X$ = Total firm annualized class specific Gas Restructuring Expense Factor.

RCE = Rate Case Expense Factor.

RLIAP = Residential Low Income Assistance Program Rate

~~O.~~J. Application of LDAC to Bills. The component costs comprising the LDAC ($ per therm) shall be calculated to the nearest one one-hundredth of a cent per therm and shall be applied to the monthly firm sales and firm delivery service throughput in accordance with the table shown in Section 17(B).

~~P.~~K. Other Rules.

1. (1) The NHPUC may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

2. Such amendments may include the addition or deletion of component cost categories, subject to the review and approval of the NHPUC.

3. The Company may implement an amended LDAC with the NHPUC approval at any time.

4. The NHPUC may, at any time, require the Company to file an amended LDAC.

5. The operation of the LDAC is subject to all powers of suspension and investigation vested in the NHPUC.

~~Q.~~L. Amendments to Uniform System of Accounts.

1920-1744 **Gas Restructuring Expense Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third party incremental expenses associated with the Company's Gas Restructuring initiatives. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(E).

1163-1755 **Energy Efficiency Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the sum of DSM and/or EE Expenditures incurred by the Company plus the sum of DSM and/or EE Repayments and the revenues collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C).

1920-1863 **Environmental Response Costs Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the revenues toward environmental response costs as calculated by multiplying the ES times monthly firm sales volumes and delivery service throughput and environmental response costs allowable per formula. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(D).

1930-1745 **Rate Case Expense/Temporary Rates Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the recovery and actual amounts of third-party incremental expenses associated with the Company's Rate Case initiatives and the difference between the final and temporary distribution rates. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(F).

1169-1756 **Residential Low Income Assistance Program Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the actual revenue derived from the actual sales and transportation service throughput multiplied by the RLIAP rate and the actual costs of the program, which consists of the revenue shortfall and all administrative and marketing costs, as outlined in the Local Distribution Adjustment Clause, 18(G).

1163-1756 **Lost Revenue Reconciliation Adjustment:** This account shall be used to record the cumulative difference between the lost revenue of the Company and the revenue collected from customers pursuant to this clause with respect to a given Rate Category. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 18(C.1).

18 SUPPLY & CAPACITY SHORTAGE ALLOCATION POLICY

A. DEFINITIONS

The following are definitions of terms used in this subsection and applicable only to this subsection:

1. Residential: Service to customers which consists of direct natural gas usage in a residential dwelling for space heating, air conditioning, cooking, water heating and other residential uses

2. Commercial: Service to customers engaged primarily in the sale of goods or services including institutions and local, state and federal government agencies for uses other than those involving manufacturing or electric power generation

3. Industrial: Service to customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power

4. Large Volume: Service to large commercial and industrial customers with an annual gas load greater than 200,000 therms

5. Seasonal: Service available from April 1 to October 31 to all customers using gas to replace some other fuel or gas for air conditioning purposes

6. Firm Sales Service: Service from schedules or contracts under which seller is expressly obligated to supply and deliver specific volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened

7. Firm Transportation Service: Service from schedules or contracts under which seller is expressly obligated to deliver specific third-party volumes within a given time period and which anticipates no interruptions, but which may permit unexpected interruption in case the supply to higher priority customers is threatened.

8. Plant Protection Gas: Is defined as minimum volumes required to prevent physical harm to the plant facilities or danger to plant personnel, when such protection cannot be afforded through the use of alternate fuel. This includes the protection of such material in process as would otherwise be destroyed, but shall not include deliveries required to maintain plant production. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels.

9. Feedstock Gas: Is defined as natural gas used as a raw material for its chemical properties in creating an end product

10. Process Gas: Is defined as gas use for which alternate fuels are not technically feasible such as in applications requiring precise temperature controls and precise flame characteristics. For the purpose of this definition, propane and other gaseous fuels shall not be considered alternate fuels

11. Boiler Fuel: Is considered to be natural gas used as a fuel for the generation of steam or electricity including the utilization of gas turbines for the generation of electricity

12. Alternate Fuel Capabilities: Is defined as a situation where an alternate fuel could have been utilized whether or not the facilities for such use have actually been installed, provided however, where the use of natural gas is for plant protection, feedstock or process uses and the only alternate fuel is propane or other gaseous fuel, then the consumer will be treated as if he had no alternate fuel capability.

B. POLICY

In the event that, due to gas supply restrictions or capacity constraints, the Company is unable to deliver the total requirements of its firm, sales or transportation rate customers, the available volumes of gas will be allocated to the Company's firm rate customers in accordance with the provisions of this policy. In the event that the Company, during a curtailment or interruption, requires emergency gas, and takes the gas of the customer, customer shall be compensated for such emergency gas at the customer's alternate cost of fuel as demonstrated to the reasonable satisfaction of the Company.

As curtailment becomes necessary through each succeeding category, the Company will implement full or partial curtailment of a customer, or by groups of customers, taking into consideration customer load characteristics, the Company's delivery system design and Company load characteristics in a manner which is believed to be in the best interests of customers in general.

C. PRIORITIES

Firm rate customers shall be serviced according to the following preference categories with the first and each succeeding category having preference over the succeeding categories:

1. Company use for fuel and lost and unaccounted for

2. Firm sales or transportation service for high priority residential uses including apartment buildings and other multi-unit buildings, small commercial establishments using less than 50 DT on a peak day, schools, hospitals, police protection, fire protection, sanitation facilities and correctional facilities

3. Firm sales or transportation service for essential agricultural uses, as defined by the Secretary of Agriculture, for full food and natural fiber production, process and feedstock use for fertilizer and

agricultural chemicals, process and feedstock for animal feeds and food, food quality maintenance, food packaging, marketing and distribution for food related products and on farm uses

4. Firm sales or transportation service for large commercial requirements (50 DT or more on a peak day), firm industrial requirements for plant protection, feedstock and process needs and firm industrial sales up to 300 DT per day

5. Firm sales or transportation service for all industrial requirements not specified in (2), (3), (4), (6), or (7)

6. Firm sales or transportation service including the transportation for industrial requirements for boiler fuel use at less than 1,500 DT per day, but more than 300 DT per day, where alternate fuel capabilities can meet such requirements

7. Firm sales or transportation service including transportation for industrial requirements for large volume (1,500 DT or more per day) boiler fuel use where alternate fuel capabilities can meet such requirements

D. STORAGE INJECTION

Within each category, storage injection required to meet the needs of higher priorities may be given preference over all other uses within that category.

E. PENALTY

For all unauthorized volumes of gas taken by a customer, the customer shall pay the Company a penalty of five times the daily index for each therm taken. Such penalty shall be added to the regular rates in effect. The Company shall have the right, without obligation, to waive any penalty for unauthorized use of gas, if on the day when the penalty was incurred deliveries to other of the Company's customers were not adversely affected. Continued unauthorized use, at the sole discretion of the Company, may result in termination of service.

II. RATE SCHEDULES

1 RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-1

Availability

This rate is available to all residential customers who do not have gas space heating equipment, who consume less than 80% of their normal usage in the six winter months of November through April and whose usage does not exceed 100 therms in any winter month. Available for use which is separately metered and billed for each dwelling unit. Availability is limited to use in locations served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.7176~~5090~~ per day or $21.50~~15.27~~ per 30 day month
Winter Period:	All therms per 30 day month at $0.2446~~018~~ per therm
Summer Period:	All therms per 30 day month at $0.2446~~018~~ per therm

~~*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.~~

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with ~~The~~ the ~~New Hampshire Public Utilities~~ Commission~~ (NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time,~~;~~ with the ~~New Hampshire Public Utilities~~ Commission.

2 RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-3

Availability

This rate is for all residential use for those domestic customers who use gas as the principal household heating fuel. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company's facilities are adequate.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.8500~~7367~~ per day or $25.50~~22.10~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5201~~3495~~ per therm
	All over 100 therms per 30 day month at $0.4176~~2892~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.5201~~3495~~ per therm
	All over 20 therms per 30 day month at $0.4176~~2892~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time,~~;~~ with the ~~New Hampshire Public Utilities~~ Commission.

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 53

Rate Schedules

3 LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-4

Availability
This rate is for residential use for those domestic customers who use gas as the principal household heating fuel if any member of the household qualifies for a benefit through one of the programs listed below, subject to the qualification period described under the "Terms and Conditions" of this rate. Availability is limited to use in domestic locations which are separately metered and billed and which are served by the Company's mains and for which the Company facilities are adequate.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $0.3400~~2947~~ per day or $10.20~~8.84~~ per 30 day month

Winter Period: First 100* therms per 30 day month at $0.2080~~1398~~ per therm

All over 100 therms per 30 day month at $0.1670~~1156~~ per therm

Summer Period: First 20* therms per 30 day month at $0.2080~~1398~~ per therm

All over 20 therms per 30 day month at $0.1670~~1156~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

DATED: April 28, 2017

EFFECTIVE: July 1, 2017

ISSUED BY: /s/James M. Sweeney
James M. Sweeney

TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
For those customers qualifying for the program this rate R-4 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-4 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-3. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time.~~,~~ with the ~~New Hampshire Public Utilities~~ Commission.

4 MANAGED EXPANSION PROGRAM RESIDENTIAL NON-HEATING RATE: CLASSIFICATION NO. R-5

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Residential Non Heating Rate R-1.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$0.9317~~6617~~ per day or $27.95~~19.85~~ per 30 day month
Winter Period:	All therms per 30 day month at $0.3180~~2623~~ per therm
Summer Period:	All therms per 30 day month at $0.3180~~2623~~ per therm

~~*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.~~

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge

All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with ~~The New Hampshire Public Utilities~~ the Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time~~.~~, with the ~~New Hampshire Public Utilities~~ Commission.

NHPUC No.8 GAS
LIBERTY UTILITIES

Original Page 57

Rate Schedules

5 MANAGED EXPANSION PROGRAM RESIDENTIAL HEATING RATE: CLASSIFICATION NO. R-6

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program projects area who otherwise would have qualified for Residential Heating Rate R-3.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $1.1050~~0.9577~~ per day or $33.15~~28.73~~ per 30 day month

Winter Period: First 100* therms per 30 day month at $0.6761~~4544~~ per therm

All over 100 therms per 30 day month at $0.5429~~3760~~ per therm

Summer Period: First 20* therms per 30 day month at $0.6761~~4544~~ per therm

All over 20 therms per 30 day month at $0.5429~~3760~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Residential Non Heating Rate R-3.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

6 MANAGED EXPANSION PROGRAM LOW INCOME RESIDENTIAL HEATING RATE: CLASSIFCATION NO. R-7

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Low Income Residential Heating Rate R-4.

Qualified Programs:

a. Low Income Home Energy Assistance Program (LIHEAP)
b. Electric Assistance Program (EAP)
c. Supplemental Security Income Program
d. Women, Infants and Children Program
e. Commodity Surplus Foods Program (for women, infants and children)
f. Elderly Commodity Surplus Foods Program
g. Temporary Aid to Needy Families Program
h. Housing Choice Voucher Program (also known as Section 8)
i. Head Start Program
j. Aid to the Permanently and Totally Disabled Program
k. Aid to the Needy Blind Program
l. Old Age Assistance Program
m. Food Stamps Program
n. Any successor program of a-m

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $0.4420~~3831~~ per day or $13.26~~11.49~~ per 30 day month

Winter Period: First 100* therms per 30 day month at $0.2704~~1817~~ per therm

All over 100 therms per 30 day month at $0.2171~~1503~~ per therm

Summer Period: First 20* therms per 30 day month at $0.2704~~1817~~ per therm

All over 20 therms per 30 day month at $0.2171~~1503~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Cost of Gas Charge
All gas delivered under this rate is subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of

these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Low Income Residential Heating Rate R-4.

For those customers qualifying for the program this rate R-7 shall apply for a one year period. On the date that the one-year period expires, eligibility for this rate shall expire unless the customer provides the Company with evidence that the customer continues to be eligible for one or more qualifying programs. When the Rate R-7 expires, the rate on each account shall revert back to the non-low income Residential Heating Rate, R-6. Customers whose eligibility for the program is based on their having qualified for LIHEAP shall be eligible for this rate retroactive to November 1 of the heating season in which they qualified. Eligibility for such customers shall expire the following October 31, subject to their re-qualifying through receipt of LIHEAP or other benefits as set forth above.

Eligibility shall be determined based on the reasonable discretion of the Company subject to verification of heating usage.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

7 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFCATION NO. G-41

Availability
This rate is available for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537~~1.6120~~ per day or $55.61~~48.36~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.5689~~3965~~ per therm
	All over 100 therms per 30 day month at $0.3130~~2663~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.5689~~3965~~ per therm
	All over 20 therms per 30 day month at $0.3130~~2663~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission~~ (NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions
U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

8 COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE
CLASSIFICATION NO. G-42

Availability
This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 10,000 therms and less than or equal to 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $5.3197~~4.8360~~ per day or $159.59~~145.08~~ per 30 day month

Winter Period:	First 1000* therms per 30 day month at $0.4458~~3606~~ per therm
	All over 1000 therms per 30 day month at $0.2952~~2402~~ per therm
Summer Period:	First 400* therms per 30 day month at $0.4458~~3606~~ per therm
	All over 400 therms per 30 day month at $0.2952~~2402~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

DATED: April 28, 2017 ISSUED BY: /s/James M. Sweeney
James M. Sweeney
EFFECTIVE: July 1, 2017 TITLE: President

Authorized by NHPUC Order No. xx,xxx dated Month Day,Year, in Docket No. DG 17-048

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. ~~–~~In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

9 COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-43

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage greater than 100,000 therms and a Winter Period usage greater than or equal to 67% of annual usage as determined by the Company's records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter: $22.8290~~20.7537~~ per day or $684.87~~622.61~~ per 30 day month

Winter Period: All therms per 30 day month at $0.2684~~2216~~ per therm

Summer Period: All therms per 30 day month at $0.1227~~1013~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause~~ (LDAC)~~, as in effect from time to time and on file with the N~~ew Hampshire Public Utilities~~ Commission~~ (NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

10 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-44

Availability

This rate is Mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-41.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$2.4097~~0956~~ per day or $72.29~~62.87~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.7396~~5155~~ per therm
	All over 100 therms per 30 day month at $0.4069~~3462~~ per therm
Summer Period:	First 20* therms per 30 day month at $0.7396~~5155~~ per therm
	All over 20 therms per 30 day month at $0.4069~~3462~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charge presented above is exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-41.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

11 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: MEDIUM ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-45

Availability
This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-42.

Character of Service
Natural gas or equivalent will be supplied at a heat content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter: $6.9157~~2868~~ per day or $207.47~~188.60~~ per 30 day month

Winter Period: First 1000* therms per 30 day month at $0.5795~~4688~~ per therm

All over 1000 therms per 30 day month at $0.3838~~3123~~ per therm

Summer Period: First 400* therms per 30 day month at $0.5795~~4688~~ per therm

All over 400 therms per 30 day month at $0.3838~~3123~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges
If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service
The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge
When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff. U.S. Department of Labor Standard Industry Classification Codes will determine eligibility for this tariff.

Meters are read and bills are presented monthly. ~~-~~In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-42.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

12 MANAGED EXPANSION PROGRAM COMMERCIAL/INDUSTRIAL SERVICE: HIGH ANNUAL USE, HIGH WINTER USE RATE CLASSIFICATION NO. G-46

Availability

This rate is mandatory for customers taking service in a Managed Expansion Program project area who otherwise would have qualified for Commercial/Industrial Rate G-43.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet. Should the customer's consumption fail to meet the availability requirements for this rate, the customer's service will be transferred to the otherwise applicable tariff as described under the terms and conditions of this tariff.

Delivery Charge

Customer Charge Per Meter: $29.6777~~26.9798~~ per day or $890.33~~809.39~~ per 30 day month

Winter Period: All therms per 30 day month at $0.2684~~2881~~ per therm

Summer Period: All therms per 30 day month at $0.1595~~1317~~ per therm

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to Page 74-A of this Tariff for firm rate schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to ~~Page 74-A of this Tariff for firm rate schedules~~ the Firm Rate Scheduleswhich present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is incurred in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00.

Terms and Conditions

To be eligible for this service, a customer must sign a contract for a one year period, which contract shall include the authority for the Company to monitor the customer's continued qualification for this service. In the event that the customer fails to meet the eligibility criteria set forth in the availability section of this schedule based on a monthly evaluation employing the most recent twelve (12) month period, the Company may require that the customer be billed prospectively under an alternative rate subject to the terms of the customer's Service Agreement. The Service Agreement may contain limitations as to maximum hourly, daily, or monthly consumption, provisions for charges for excess usage, and other terms and conditions of service.

Service under each Managed Expansion Program project will have a term of ten years. Customers initiating service under this rate must take service hereunder until ten years following the date that the first customer in the particular Managed Expansion Program project takes service. Once the term of service for a particular Managed Expansion Program project expires, customers will thereafter take service under Commercial/Industrial Rate G-43.

The customer shall declare maximum seasonal demands and estimated seasonal volumes at the time application for service is made. These declarations shall be updated annually, by August 1.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.

13 COMMERICAL/INDUSTRIAL SERVICE: LOW ANNUAL USE, LOW WINTER USE RATE CLASSIFICATION NO. G-51

Availability

This rate is for commercial, industrial and public authority customers in locations served by the Company's mains and for which the Company's facilities are adequate. A customer receiving service under this rate must have annual usage less than or equal to 10,000 therms and a Winter Period usage less than 67% of annual usage as determined by the Company’s records and procedures.

Character of Service

Natural gas or equivalent will be supplied at a thermal content of nominally one (1) therm in each one hundred (100) cubic feet.

Delivery Charge

Customer Charge Per Meter:	$1.8537~~6120~~ per day or $55.61~~48.36~~ per 30 day month
Winter Period:	First 100* therms per 30 day month at $0.3460~~2390~~ per therm
	All over 100 therms per 30 day month at $0.2060~~1553~~ per therm
Summer Period:	First 100* therms per 30 day month at $0.3460~~2390~~ per therm
	All over 100 therms per 30 day month at $0.2060~~1553~~ per therm

*The number of therms billed in the first block will be calculated by multiplying the therms in the first block of the rate by a fraction the numerator of which is the number of days in the billing period and the denominator of which is 30.

The above rates shall be adjusted to reflect the recovery of all applicable taxes. The Winter Period shall be the months of November through April inclusive. The Summer Period shall be the months of May through October inclusive.

Supplier Charges

If the customer purchases its gas from a third party, supplier charges will be as agreed upon between the customer and the third party supplier and will be billed directly by the third party supplier. If the customer does not purchase its gas from a third party, the gas supplied by the Company will be subject to a per therm cost of gas rate. The cost of gas rate is not included in the delivery charge presented above. Refer to ~~Page 74 of this Tariff for firm rate schedules~~ the Firm Rate Schedules which present both the delivery charge and cost of gas rates.

Other Charges for Delivery Service

The customer must also pay such charges and adjustments as are set forth in the Company’s Local Distribution Adjustment Clause ~~(LDAC)~~, as in effect from time to time and on file with the ~~New Hampshire Public Utilities~~ Commission ~~(NHPUC)~~. The delivery charges presented above are exclusive of these charges. Refer to Page 74 of this Tariff for firm rate schedules which present both the delivery charge and the LDAC rates.

Meter Account Charge

When the Company establishes or re-establishes a gas service account for a customer at a meter location, a meter account charge is made in addition to all other charges. The meter account charge is $20.00 when the visit to the meter location is scheduled at the mutual convenience of the Company and the customer. Otherwise, the charge is $30.00

Terms and Conditions

Eligibility shall be based on the reasonable discretion of the Company and subject to verification of heating usage. U.S. Department of Labor Standard Industry Classification Code will determine eligibility for this tariff. Dual fuel customers may be required to sign annual contracts with minimum usage requirements in order to qualify for service under this tariff.

Meters are read and bills are presented monthly. In the event a meter reader is unable to obtain a meter reading, an estimated bill will be rendered to the customer.

Amounts not paid prior to the due date; normally the next following meter reading date and a date not less than twenty-five (25) days from the date the bill is mailed - are subject to a late payment charge of one and one-half percent (1½%) per month on the unpaid balance - equivalent to an eighteen percent (18%) annual rate. There is a $15.00 charge for each bad check tendered for payment.

A customer must give at least four (4) days' notice before discontinuance of service and is responsible for all charges through the end of the notice period.

Service under this rate is subject to the rules and regulations and the published tariff, terms and conditions presently effective, or as filed from time to time, with the ~~New Hampshire Public Utilities~~ Commission.