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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-1 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024, COG filing and August 20 LDAC filing if relevant (hereinafter for the purposes of DOE Set 1 DRs "Sept 3, 2024, COG filing).

REQUEST:

Please provide all live Excel files that correspond to all the tables and schedules included in the Company's Winter 2024-25 and Summer 2024 COG filings. 'Live' files should include the formulas and allow the user to input new figures, if needed. If such Excel files are already provided, please identify the date and time of the email(s).

RESPONSE:

The confidential Excel model support for the Company's COG filing was submitted via email by SM NH Regulatory on September 3, 2024 at 2:38PM.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 — Date of Response: 9/18/24
Request No: DOE 1-2 (COG) — Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing

REQUEST:

In evaluating Liberty's filing, the DOE requires an "apples to apples" comparison between last year's COG approved rates and the Liberty's proposed rates, including over/under calculations and forecasting. Please provide the following:

a) Please cross-reference the schedules and tables provided in Liberty's current September 2024 filing with the schedules and tables Liberty filed in Docket No. DG 23-076, including the Company's October 23, 2023 updated schedules and tables. Please identify any changed assumption, categories or formula Liberty has made in this filing as compared to the DG 23-076 filing ultimately approved by the Commission in Order No. 26,898.

b) Liberty's testimony purports to provide a comparison of Winter 2023-2024 rates and the proposed Winter 2024-2025 rates based upon 'rates effective November 1, 2023'. See R. Garcia and A. Maston Testimony at 0012. Does Liberty's proposed rates include any RDAF under-collection for an uncollected amount from decoupling year 3, decoupling year 4 and decoupling year 5? If so, please specify uncollected amounts, i.e. reconcile RDAF amounts included in Winter 2023-2024 rates and show any under or over collection that was rolled into decoupling year 6, individually by prior decoupling year.

c) Do Liberty's proposed rate calculations include what Liberty states is a decoupling year under-collection of approximately $4 million stemming from decoupling year 1 and 2? *See* Docket No. DG 22-041. If yes, please explain why.

RESPONSE:

a) Please see the table below for a comparison of the schedules included in the Company's filing in DG 23-076 on October 23, 2023 to the schedules included in the Company's filing in DG 24-098 on September 3, 2024.

Docket No. DG 24-098 Request No. DOE 1-2 (COG)

Schedules filed in DG 23-076 on October 23, 2023	**Equivalent Schedules filed in DG 24-098 on September 3, 2024**
Pk Summary	Pk Summary
Pk Schedule 1	None
Pk Schedule 2	None
Pk Schedule 3	Pk Schedule 3
Pk Schedule 4	Pk Schedule 4
Pk Schedule 5A	Pk Schedule 5
Pk Schedule 5B	Pk Schedule 5
Pk Schedule 5C	Pk Schedule 5
Pk Schedule 5D	Pk Schedule 5D
Pk Schedule 6	Pk Schedule 6
Pk Schedule 7	None
Pk Schedule 8	Pk Schedule 8
Pk Schedule 9	Pk Schedule 9
Pk Schedule 10A	Pk Schedule 10A
Pk Schedule 10B	Pk Schedule 10B
Pk Schedule 11A	Pk Schedule 11
Pk Schedule 11B	Pk Schedule 11
Pk Schedule 11C	Pk Schedule 11
Pk Schedule 11D	Pk Schedule 11D
Pk Schedule 12	Pk Schedule 12
Pk Schedule 13	Pk Schedule 13
Pk Schedule 14	Pk Schedule 14
Pk Schedule 15	Pk Schedule 15
Pk Schedule 16	Pk Schedule 16
Pk Schedule 17	Pk Schedule 17
Pk Schedule 21	Pk Schedule 21
Pk Schedule 22	Pk Schedule 22
Pk Schedule 23	Pk Schedule 23
Pk Schedule 24	Pk Schedule 24
Pk Schedule 25	Pk Schedule 25
Pk Schedule 26	Pk Schedule 26
OP Summary	OP Summary
OP Schedule 1	None
OP Schedule 2	None
OP Schedule 3	OP Schedule 3
OP Schedule 4	OP Schedule 4
OP Schedule 5A	OP Schedule 5
OP Schedule 5B	OP Schedule 5
OP Schedule 5C	OP Schedule 5

OP Schedule 6	OP Schedule 6
OP Schedule 7	None
OP Schedule 8	OP Schedule 8
OP Schedule 10A	OP Schedule 10A
OP Schedule 10B	Pk Schedule 10B
OP Schedule 11A	OP Schedule 11
OP Schedule 11B	OP Schedule 11
OP Schedule 11C	OP Schedule 11
OP Schedule 12	Pk Schedule 12
OP Schedule 13	OP Schedule 13

The changes made to the schedules above were made to improve accuracy and transparency. Many of the changes made were to remove unnecessary and/or duplicative information or to reformat schedules to increase clarity and efficiency. The most significant revisions to the schedules were made to Pk and OP Schedules 5 and 6, where demand, supply, and commodity costs for the peak and off-peak seasons are estimated. The Company has updated the methods of allocating these costs between the peak and off-peak seasons in an effort to include more accurate estimated costs in the initial cost of gas rates for both seasons. Further discussion of the changes made to the schedules above can be found in the R. Garcia and A. Maston Testimony beginning at Bates 0007.

b) The rates effective November 1, 2023 shown at Bates 0012 are Cost of Gas rates, and do not include any RDAF recovery as that information is included in the proposed LDAC rates that were filed separately by the Company on August 20, 2024 into DG 24-098.

c) No. The Company did not include the under-collection of approximately $4 million stemming from decoupling years 1 and 2 consistent with the prior year’s filing.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-3 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing

REQUEST:

Liberty has provided "customer bill impacts of the proposed firm sales cost of gas rate on an average heating customer's winter bill as compared to the winter rates in effect last year." See R. Garcia and A. Maston Testimony at 0021. Please provide tables for "Customer Bill Impacts" for just COG Supply rates for both Winter 2024-2025 and Summer 2025.

Are the assumptions, methodology(ies) and formula Liberty applied in this docket identical to the assumptions, methodology(ies) and formula applied by the Company in calculating customer bill impacts in Docket No. DG. 23-076? Please explain in detail.

If Liberty's customer bill impacts are based upon the proposed LDAC in whole or in part, see Company's August 20, 2024 LDAC filing, please re-calculate the bill impacts for all customers, exclusively using the LDAC rates currently in effect for the entire period. See Garcia & Maston Testimony, chart at 0015. The Department notes that Liberty's proposed LDAC may not be approved for effective February 1, 2024 and is not yet authorized.

RESPONSE:

Please see Attachment 24-098 DOE 1-3 (COG).xlsx for peak and off-peak bill impact schedules, updated to reflect the currently effective LDAC rates for the entire period covered on both schedules. The dollar and percentage change calculations for each rate class have also been broken out to show the COG and LDAC impacts separately.

The assumptions, methodologies, and formulas that the Company applied in calculating customer bill impacts are unchanged from DG 23-076.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 | Date of Response: 9/18/24
Request No: DOE 1-4 (COG) | Respondent: Joshua Tilbury

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Please provide data, any associated models, and a narrative description of how the Company forecasts its sales (in therms) and how the Company forecasts the associated number of customers. Please identify any changes Liberty has made in assumptions, formulas or calculation as compared the Company forecast Liberty made in Docket No. DG 23-076.

Liberty's response should include but should not be limited to:

a) an explanation regarding why Liberty's forecasted sendout requirements for sales customers for Winter 2024-2025 is approximately 4.3 million therms lower than the normalized actual sendout for firm sales customers for the November 1, 2023 to April 30, 2024 period; and

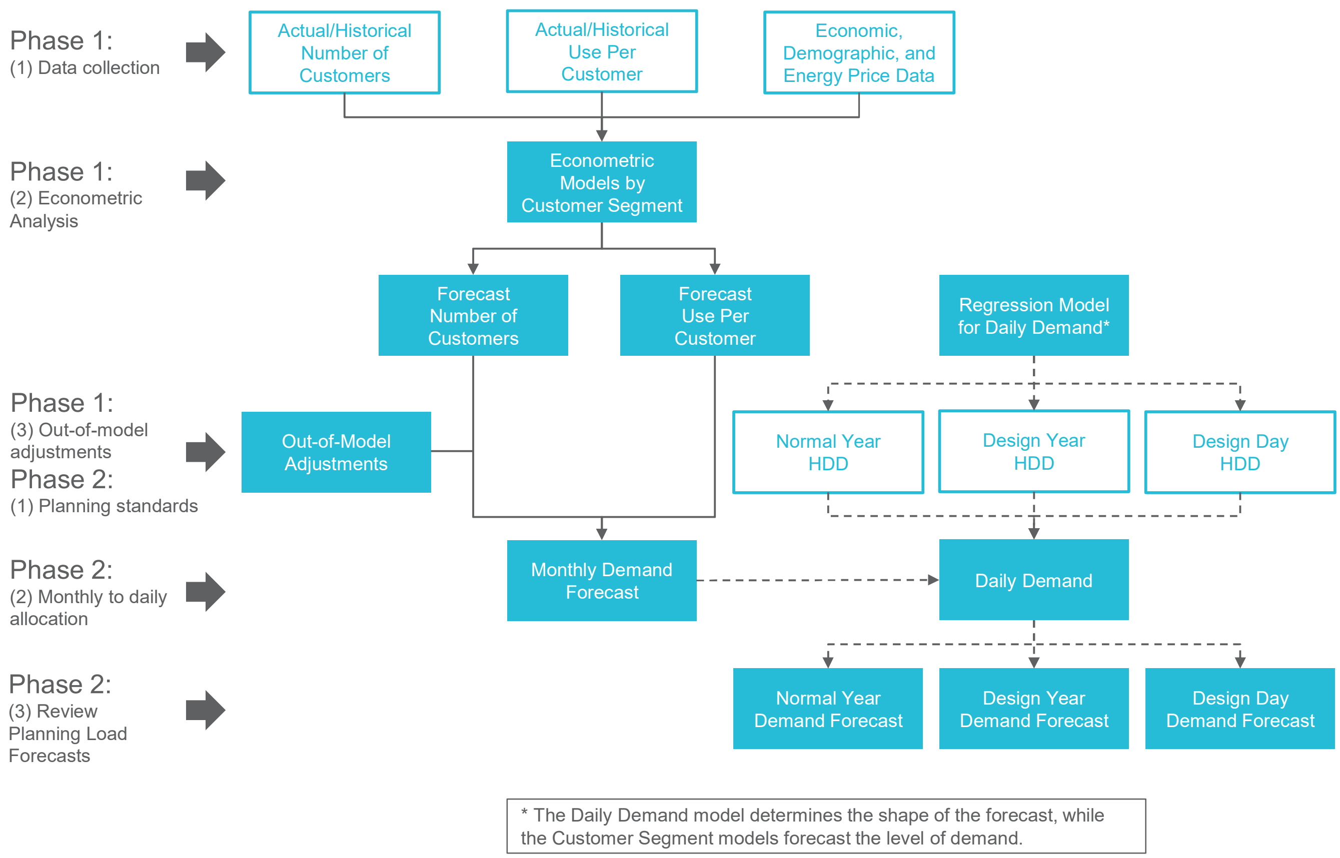
b) why Liberty's 'design weather requirements' are "approximately 10 percent greater than normal sendout requirements for weather that is 10 percent colder than normal." See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0036.

RESPONSE:

There have been no changes to the methodology or assumptions that comprise the Company's demand forecast process, which is as follows.

- Phase 1 includes a comprehensive econometric analysis to forecast levels of natural gas demand for the Company's service territory, with adjustments for discrete loads that are calculated outside of the econometric models, energy efficiency, and unaccounted for gas.
- Phase 2 includes the development of planning standards and estimation of daily loads under various weather and growth scenarios to facilitate supply and capacity analysis.

Figure 1: Demand Forecast Methodology



In Phase 1 of the demand forecast process, Liberty developed econometric models for the number of customers and use per customer-by-customer segment to forecast total monthly demand requirements. The purpose of the customer segment forecasts[1] is to develop long-term projections of Planning Load based on forecasted changes in economic and demographic conditions in the Company's service territory.

In Phase 2 of the demand forecast process, Normal Year, Design Year, and Design Day planning standards were developed to reflect weather conditions that inform the level of firm volume that the Company must plan for to maintain reliable service. Once the planning standards were determined, the Company then translated the monthly demand forecast into a forecast of daily requirements using a daily regression model.

The Company followed this process in developing the demand forecast used in this filing.

a) The company identified a mistake in the normalized actual sendout for firm sale customers for the November 1, 2023 to April 30, 2024 period. The correct sales amount should be

[1] All forecasts represent firm demand only (i.e., firm sales and capacity-assigned, and capacity-exempt transportation) and exclude interruptible and special contract demand.

88,011,120 therms instead of the originally reported 92,395,519 therms. This normalized actual sendout is 87,974 therms lower than the forecasted sendout of 88,099,094 therms for the period of November 1, 2024 to April 30, 2025. The files have been updated to include 2024–25 forecast data. Please see Attachment 24-098 DOE 1-4.1 (COG).xlsx and Attachment 24-098 DOE 1-4.2 (COG).xlsx.

b) Liberty's "design weather requirements" is the Company's demonstration that the supplies procured for the winter period will not only satisfy normal requirements but will also satisfy a high-case scenario such as a design winter. This measure is simply in place to demonstrate winter readiness. This standard measure of winter readiness under a high-case scenario has been in place and approved in all COG dockets over the past many years.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-5 (COG) Respondent: Kelly Esposito

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Does the Company intend to use renewable natural gas (RNG) to meet any customer requirements (or potential requirements) in the Winter 2024-2025 or Summer 2025 period? Please explain and provide documentation. Liberty's answer should include what Liberty describes as "brown RNG" i.e., RNG without environmental attributes whether transported through pipes or trucked

a) If yes, has or will the Company invest in any renewable natural gas infrastructure, including but not limited to decompression skid(s)? Please explain and provide documentation. If yes, please include an explanation of the accounting treatment to be given any costs associated with the procurement of or use of any decompression skid(s) including but not limited to those the Company may propose to employ to increase pipeline pressure.

b) If the Company intends to use, or may use, RNG (see above) please provide the results of the Company's RFP process, including the RFP and identify any winning bidders, including how the Company scored and selected the winning bidder(s). Did the Company contract with any bidders? Please provide a copy of any RFP, a summary of bidder responses and explain why the Company elected to contract with the bidder(s) it did.

c) Please explain how the Company "consulted with DOE" on all issues related to RNG RFPs.

d) If winning bidders were determined and/or suppliers contracted with what quantity of RNG does Liberty have the option to purchase, from whom, when and how? Will purchased quantities exceed 5 percent of the Company's total gas volume delivered?

e) What are "the monetary benefits of the proposed use of RNG to utility customers and the state (see RSA 362-I:2 II). Please provide any documentation and analysis Liberty has done, including but not limited to a cost-benefit analysis, if performed.

f) What incremental costs to utility customers are associated with Liberty's use of RNG? Does Liberty expect to obtain any 'value of any environmental attributes' or carbon off-sets, relative to the incremental costs to gas utility customers necessary to achieve those benefits? See RSA 362-I:2, II.

g) To what extent does Liberty's proposed or potential use of RNG advance the objectives of the energy policy of the state, the state's 10-year energy strategy or other state policy, including enhancing consumer choice and improving gas system resiliency through diversification of supply options? See RSA 362-I:2, II.

h) Please provide information and documentation regarding the following: market terms, price, conditions, availability, service quality, economic benefits to participating and non-participating customers, and job creation as a result of the Company's use of RNG. See RSA 362-I:2, II, V.

RESPONSE:

No. At present time, the Company has no plan or agreements in place to serve customers with RNG during the winter 2024/2025 or summer 2025 periods.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-6 (COG) Respondent: Kelly Esposito

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

The Company states "Since its 2023/2024 Cost of Gas filing (Docket No. DG 23-076, the Company has issued several requests for proposals (RFPs)" for supply for the upcoming winter period. Please list all RFPs that have been issued, identify the winning bidder(s) and provide a copy of the new contract. See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0032-33.

a) Please list all RFPs that have been issued for LNG supply and propane supply and identify the winning bidder(s) and provide a copy of the new contract(s). See Tilbury, Esposito and Summerfield at 0033-34.

b) Do Liberty's existing contracts (and/or existing storage) fully account for all of Liberty's projected supply requirements?

RESPONSE:

a) Please see Confidential Attachments 24-098 DOE 1-6.1a COG through DOE 1-6.8 COG for copies of the new contracts. Also, please see the table below for a list of RFPs that have been awarded. Please note that the Company is still in the process of finalizing one of the contracts.

	List of all RFPs		Winning Bidder(s)	Copies of Contracts
[redacted]				
Term	**Asset**	**Description**	**Winning Bidder**	**Signed Contracts**
Winter 2024-25	LNG	LNG Refill	Gaz Metro LNG	Y,Y,
Winter 2024-25	Propane	Propane Refill	Ray Energy	Y
Winter 2024-25	Canadian interconnect PNGTS/Dracut	PXP Path	Emera Energy Services, Inc	Y
Winter 2024-25	Canadian interconnect with Iroquois	Dawn to Waddington	Citadel Energy Marketing LLC	Y
Winter 2024-25	Canadian to citygate	Niagara	Emera Energy Services, Inc	Y
Winter 2024-25	TGP Longhaul from Gulf	Longhaul	Tenaska Marketing Ventures	
Winter 2024-25	Baseload TGP Z6	Basis Hedge	Citadel Energy Marketing LLC	Y
Winter 2024-25	TGP Zone 6 or Dracut	Call 1	Citadel Energy Marketing LLC	Y
Winter 2024-25	TGP Zone 6 or Dracut	Call 2	Citadel Energy Marketing LLC	Y

Confidential Attachments 24-098 DOE 1-6.1a COG through DOE 1-6.8 COG contain third-party pricing and other information that is “confidential, commercial, or financial information” and is thus protected from disclosure by RSA 91-A:5, IV, and presumed to be confidential in cost of gas proceedings pursuant to Puc 201.06(a)(11). Therefore, pursuant to that statute and Puc 203.08(d) and Puc 201.01.06(a)(11)(g) (protecting “responses to data requests related to a. through f. above”), the Company has a good faith basis to seek confidential treatment of this information and asserts confidentiality pursuant to those rules.

b) Yes, Liberty’s existing contracts (and/or existing storage) fully account for all of Liberty’s projected supply requirements.

Citadel Energy Marketing

Confirmation Date: May 24, 2024
Transaction Date: May 23, 2024
Transaction Number: 1988402
Transaction Type: Basis Physical Gas

This Confirmation constitutes a "Transaction Confirmation" for the purposes of, and supplements, forms a part of, and is subject to the Base Contract General Terms and Conditions for Sale and Purchase of Natural Gas between Buyer and Seller, as amended and supplemented by Buyer and Seller from time to time.

Buyer (Liberty Utilities (EnergyNorth Natural Gas) Corp.)		**Seller (Citadel Energy Marketing LLC)**	
Trader		**Trader**	Mohammad Siddique
Attn		**Attn**	
Phone	(603)216-3606	**Phone**	312-395-3805
Email	kelly.esposito@libertyutilities.com	**Email**	Energy_Confirms@citadel.com

Delivery Period:	1/1/2025 - 1/31/2025
Quantity:	10,000 mmbtu per DAY
Delivery Pipeline:	TGPL
Delivery Point:	POOLING PT - 200 LEG NORTH - ZN 6
Product:	NG
Performance Obligation:	Firm
Pricing:	[redacted]
Additional Fees:	

Special Provisions	This delivery is firm to any of EnergyNorth Citygates points listed on the RFP

Liberty Utilities (EnergyNorth Natural Gas) Corp.		**Citadel Energy Marketing LLC** **By Citadel Advisors LLC, its Manager**	
Signature	John Patton Digitally signed by John Patton Date: 2024.05.28 09:07:11 -04'00'	**Signature**	AJEdgar
Name	John Patton	**Name**	Anthony Edgar
Title	VP, Technical Services - Gas	**Title**	Authorized Signatory
Date	5/28/2024	**Date**	5/24/2024 9:30:33 AM

Citadel Energy Marketing

Confirmation Date: May 24, 2024
Transaction Date: May 23, 2024
Transaction Number: 1988403
Transaction Type: Basis Physical Gas

This Confirmation constitutes a "Transaction Confirmation" for the purposes of, and supplements, forms a part of, and is subject to the Base Contract General Terms and Conditions for Sale and Purchase of Natural Gas between Buyer and Seller, as amended and supplemented by Buyer and Seller from time to time.

Buyer (Liberty Utilities (EnergyNorth Natural Gas) Corp.)		**Seller (Citadel Energy Marketing LLC)**	
Trader		**Trader**	Mohammad Siddique
Attn		**Attn**	
Phone	(603)216-3606	**Phone**	312-395-3805
Email	kelly.esposito@libertyutilities.com	**Email**	Energy_Confirms@citadel.com

Delivery Period:	2/1/2025 - 2/28/2025
Quantity:	5,000 mmbtu per DAY
Delivery Pipeline:	TGPL
Delivery Point:	POOLING PT - 200 LEG NORTH - ZN 6
Product:	NG
Performance Obligation:	Firm
Pricing:	[redacted]
Additional Fees:	

Special Provisions	This delivery is firm to any of EnergyNorth Citygates points listed on the RFP

Liberty Utilities (EnergyNorth Natural Gas) Corp.		**Citadel Energy Marketing LLC** **By Citadel Advisors LLC, its Manager**	
Signature	John Patton Digitally signed by John Patton Date: 2024.05.28 09:09:19 -04'00'	**Signature**	AJEdgar
Name	John Patton	**Name**	Anthony Edgar
Title	VP, Technical Services - Gas	**Title**	Authorized Signatory
Date	5/28/2024	**Date**	5/24/2024 3:07:06 PM

Confidential

AMA Transaction Confirmation
Liberty Utilities (EnergyNorth Natural Gas) Corp.

TRANSACTION CONFIRMATION AND ASSET MANAGEMENT ARRANGEMENT

Date: July 16th, 2024

Transaction Confirmation #:

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated September 1, 2010. This Transaction Confirmation will not become binding until executed by both parties.

SELLER:
Emera Energy Services, Inc.
5151 Terminal Road
Halifax, Nova Scotia
B3J 1A1
Trader: Natalie Davis
Phone: 902-474-2135

Transporters: Enbridge Gas Inc. dba Union Gas (“Union”); Portland Natural Gas Transmission System (“PNGTS”); and TC Energy Corporation (“TC Energy”).

BUYER:
Liberty Utilities (EnergyNorth Natural Gas) Corp.
15 Buttrick Road
Londonderry, NH
03053
Trader: Kelly Esposito
Phone: 603-401-8439

Contract Price: See Special Conditions, below

Delivery Period: November 1, 2024 through to and including October 31, 2025

Performance Obligation and Contract Quantity: See Special Conditions, below

Delivery Point(s): Dracut, MA (PNGTS); and at Seller’s sole discretion and upon mutual agreement between Seller and Buyer, Buyer’s city gates located in Tennessee Zone 6 North.

Special Conditions:

A. Definitions

“Assets” means the firm transportation entitlements as set forth in the table below:

Pipeline	Quantity (MMBtu/Day)*	Quantity (GJs/Day)*	Receipt Point	Delivery Point
Union	5,069	5,348	Dawn	Parkway
TC Energy	5,009	5,285	Parkway	E. Hereford
PNGTS	Up to 5,000	-	E. Hereford/Pittsburg	Dracut

*Estimated Capacity Release Quantity is subject to monthly fluctuations due to Buyer’s Retail Choice Customer Program, and the Seller’s delivery obligations in Section B.3 below shall be adjusted accordingly.

"Credit Support Provider" means Emera Incorporated.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Service, Inc. or its successor.

"S&P" means S&P Global Ratings, Inc. or its successor.

"Seller's Affiliate" means Emera Energy Limited Partnership, by its general partner, Emera Energy General Partner Inc.

B. Gas Service and Capacity Release

1. **Release/Assignment of Assets:** [redacted]

2. **Secondary Delivery Points:** Buyer has secondary delivery point rights on the PNGTS portion of the Assets as follows. Secondary deliveries to points not listed below may be subject to additional variable charges on PNGTS and shall be Seller's sole responsibility:

Meter #	Name	Operator
05-0525	Westbrook	M&NE
05-0600	Westbrook	Granite State
05-0725	Eliot	Granite State
05-1000	Haverhill	Tennessee Gas

3. **Gas Supply Requirements**

   Daily Call: Each Day during the Delivery Period, the Buyer shall have the option to require the Seller to sell and deliver on a Firm basis up to 5,000 MMBtus/Day (the "DCQ") at the Delivery Point. The transportation capacity of the Assets may fluctuate due to Buyer's Retail Choice Customer Program, and the Seller's delivery obligation in this Section B.3 shall be adjusted accordingly. The DCQ may be modified during the Delivery Period to account for changes in fuel retention percentages related to the Assets. Seller is under no obligation to use the Assets for deliveries of Gas pursuant to this Section B.3.

Buyer shall make nominations to Seller for delivery of Gas via telephone or by electronic means before 10:00 a.m. EPT on the Business Day prior to the Gas flow date. Friday nominations shall be effective for Saturday through Monday flow. Holidays are as determined by ICE and shall be treated the same as weekends (i.e., nominated ratably on the business day prior to the Holiday).

4. **Termination Option:** If at any time during the Delivery Period, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall (or revoke assignment of) the Assets. For the purpose of the preceding sentence, a failure means that Seller has failed to deliver an amount equal to or greater than 96% of the Contract Quantity to be delivered on a particular Day, which failure is not excused because of Buyer's non-performance or by Force Majeure.

C. Price

The Contract Price applicable to Daily Call purchases shall be the "Dawn, Ontario" midpoint price listed in Platts' *Gas Daily*, Final Daily Price Survey under the heading Upper Midwest for the applicable Day, and where deliveries are made to Buyer's city gates located in Tennessee Zone 6 North, the Contract Price shall include Tennessee Gas Pipeline variables and fuel from Dracut to Zone 6 North.

D. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Delivery Period, Seller shall make a payment to Buyer of [redacted] payable in twelve (12) equal monthly installments of [redacted] on the Payment Date of each Month of the Delivery Period. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month and shall be subject to netting under Section 7.7 of the Base Contract.

E. Credit Provisions

Independent Amount. In the event Seller or its Credit Support Provider (i) has a Credit Rating below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated, in a commercially reasonable manner, as a function of price volatilities as well as the notional volume; provided however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at a *Gas Daily* or ICE index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller, or its Credit Support Provider has a Credit Rating of at least BBB- from S&P and/or Baa3 from Moody's, and (ii) no Event of Default with respect to Seller has occurred an is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit. The "Collateral Requirement" for Buyer means zero (0), provided, however, that this will not preclude Seller from being able to request Adequate Assurance to the extent it has grounds to do so under Section 10.1 of the Base Contract.

"Exposure" means the amount, if any, that would be payable by Seller to Buyer if this Transaction Confirmation were terminated and shall be calculated as the net sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus

(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus

(iii) the mark to market amount for each Day remaining in the Delivery Period for each transaction under this Transaction Confirmation, calculated in a commercially reasonable manner; reduced by

(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

F. Changes in Law

If the FERC or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

G. Trade Representations

Each party represents that it is a producer, processor or commercial user of, or a merchant handling the commodity or commodities which are the subject of any commodity option transactions entered into hereunder, or the products or by-products thereof, and is offering (or being offered, as the case may be) or entering into such transactions solely for purposes related to its business as such. The parties confirm their intention that any such commodity option transactions be physically settled, such that if exercised, they result in the sale of an exempt commodity for either immediate or deferred shipment or delivery.

H. Asset Management Arrangement

Buyer and Seller record their intent and desire that this Transaction Confirmation satisfies the requirements of Section 284.8(h)(3) of the Regulations of FERC and FERC Order 712, for a release to an asset manager exempt from bidding requirements, and direct that any ambiguity be construed in favor of the full satisfaction of such requirements. It is the intention of the parties that this Transaction Confirmation, together with the applicable provisions, if any, of the applicable tariff(s), as it may be amended from time to time, contain all of the terms and conditions governing the release to Seller of the Assets.

I. Counterparts

This Transaction Confirmation may be executed in multiple counterparts, each of which shall constitute an original and all of which together shall constitute one and the same instrument. Signatures transmitted by facsimile or by email of a .pdf file are deemed to be their original signatures for all purposes.

Emera Energy Services, Inc.	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**
By: A. Michael Burnell	By: Joshua Tilbury Digitally signed by Joshua Tilbury Date: 2024.07.16 12:31:39 -04'00'
Name: A. Michael Burnell	Name: Josh Tilbury
Title: President	Title: Director Energy Procurement
Date: July 17, 2024	Date: 7/16/24

Transaction Confirmation
Asset Management Arrangement

Citadel Energy Marketing	Date: August 7, 2024

This Transaction Confirmation is subject to the Base Contract (including Special Provisions) between Seller and Buyer, dated August 22, 2023 (the "Base Contract"). Buyer and Seller are individually referred to as a "Party" and collectively as the "Parties." The terms of this Transaction Confirmation will be binding upon execution by both Parties. This Transaction Confirmation sets forth the terms of an asset management arrangement ("AMA") pursuant to applicable FERC regulations and FERC Order No. 712, as defined below, under which (i) Seller shall release certain natural gas transportation capacity (the "Release Capacity", as defined further below) to Buyer in accordance with this Transaction Confirmation and (ii) Seller shall act as Buyer's asset manager with respect to the Release Capacity and will sell natural gas to Buyer as provided for in this Transaction Confirmation consistent with and subject at all times to the requirements of FERC Order No. 712 and FERC regulations.

SELLER: Citadel Energy Marketing LLC c/o Citadel Americas LLC Southeast Financial Center 200 S. Biscayne Blvd., Suite 3300 Miami, FL 33131 Attn: Mohammad Siddique Phone: 203-900-6110 Email: Energy_Confirms@citadel.com	**BUYER:** Liberty Utilities (EnergyNorth Natural Gas) Corp. 15 Buttrick Road Londonderry, NH 03053 Attn: Kelly Esposito Phone: (603) 401-8439 Email: Kelly.Esposito@libertyutilities.com Transporters: Union Gas Ltd. ("Union Gas") and TransCanada Pipelines Limited ("TC Energy") Transporter Contract Number:

Contract Price: See Special Conditions, below

Term: November 1, 2024 through to and including October 31, 2025

Delivery Period: November 1, 2024 through to and including March 31, 2025

Performance Obligation and Contract Quantity: See Special Conditions, below

Delivery Points for Transfer of Title: The interconnection between the facilities of TC Energy and Iroquois Gas Transmission System, L.P. at Waddington, NY.

Special Conditions:

A. Definitions.

"Assets" means the firm transportation entitlements as set forth in the table below:

	Transporter (Pipeline)	**Receipt Point**	**Delivery Point**	**Maximum Daily Quantity ("MDQ") (MMBtu/Day)***	**Maximum Daily Quantity ("MDQ") (Gj/day)***
	Union Gas	Dawn	Parkway	Up to 4,092	Up to 4,317
	TC Energy	Parkway	Waddington	Up to 4,047	Up to 4,270

* Estimated Assigned Capacity subject to monthly fluctuations due to Buyer's Retail Choice Program.

"FERC" means the Federal Energy Regulatory Commission, or any successor.

"FERC Order No. 712" means the FERC Order No. 712, 123 FERC ¶ 61,286 (2008); Order No. 712-A, 125 FERC ¶ 61,216 (2008); and Order 712-B, 127 FERC ¶ 61,051 (2009), et seq., and the regulations promulgated at 18 C.F.R. § 284.8(h)(3).

"Fuel" means the charge assessed by Transporter, whether in-kind or otherwise, for the quantity of Gas consumed by Transporter in transporting the quantity of Gas nominated by Buyer each Day pursuant to the provisions of this Transaction Confirmation, and includes any charge, provision or right by Transporter to recover (in kind) lost and accounted for Gas, as determined in the Tariff.

"Assigned Capacity" means a portion of the capacity, which shall be released/assigned from Buyer to Seller as set forth in Special Conditions.

"Reservation Charges" means the Buyer's contract rate under the applicable TSA for natural gas pipeline service applicable to the Assigned Capacity.

"Tariff" means Transporter's currently effective FERC Gas Tariffs, as may be amended from time to time.

"Transporter" means Union Gas Ltd. ("Union Gas") and TransCanada Pipelines Limited ("TC Energy"), or its successor-in-interest, on which Seller has acquired the Assigned Capacity from Buyer under the terms of this Transaction Confirmation.

"TSA" means Seller's Transportation Service Agreements under Transporter's Rate Schedule FTS.

"Variable Charges" means the Variable Charge set forth in Transporter's Tariff applicable to the TSA.

B. Gas Service and Assigned Capacity

1. Assignment of Assets: [redacted]

2. Baseload: Each Day during the months of November 2024 through and including March 2025, (Delivery Period), the Seller shall sell and deliver, and Buyer shall purchase and receive on a Firm basis a quantity of Gas up to 4,047 MMBtus/Day at the Waddington Delivery Point, subject to fluctuations due to Buyer's Retail Choice Program (the DCQ). Buyer shall provide Seller with the firm DCQ no later than five (5) Business Days prior to the start of each Month's gas flow.

3. Termination Option: If at any time during the Delivery Period, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall (or revoke assignment of) the Assets. For the purpose of the preceding sentence, a failure means that Seller has failed to deliver an amount equal to or greater than 96% of the Contract Quantity to be delivered on a particular Day, which failure is not excused because of Buyer's non-performance or by Force Majeure.

C. Price.

The Contract Price for all Gas delivered and sold pursuant to Section B2 shall be equal to the monthly [redacted] as posted in Platts' Inside FERC Gas Market Report for the applicable Month, plus imputed Variable Charges and Fuel to transport Gas from Dawn to Waddington.

D. Asset Management Fee.

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the Assets for its own account. In exchange for such right, during the Term Seller shall make a payment to Buyer of [redacted] payable in twelve (12) equal monthly installments of [redacted]Monthly AMA Payment") in accordance with the Base Contract. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month and shall be subject to netting under Section 7.7 of the Base Contract.

E. Monthly Invoice and Monthly Settlement Amount.

For each month during the Delivery Period, Seller shall provide a written invoice to Buyer, in accordance with Section 7 of the Base Contract of the Monthly Settlement Amount, which shall be calculated as follows:

Monthly Settlement Amount = [redacted] [redacted] [redacted]

F. Change in Law, Severability and Compliance with Law.

If the FERC, Canadian Energy Regulator, Ontario Energy Board, the CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

G. General Standards of Performance.

1.With respect to any Assigned Capacity, Buyer shall perform the asset management services contemplated hereunder in a good, workmanlike, and commercially reasonable manner and in accordance with (a) applicable law and regulatory approvals, and (b) the terms of the TSA and the Tariff.

2.Buyer and Seller will promptly provide timely notice to the other of known operational changes that will affect the ability of each Party to deliver or receive Gas at the Delivery Points set forth in this Transaction Confirmation.

H. GENERAL.

1. This Transaction Confirmation constitutes the entire agreement between the Parties regarding the AMA services to be provided, and supersedes and replaces any prior and contemporaneous communications, understandings and agreements between Seller and Buyer related to such subject matter, whether written or verbal, express or implied. No modification, amendment, supplementation, or alteration of the terms and provisions of this Transaction Confirmation shall be or become effective except by written amendment executed by the duly authorized representatives of the Parties. The Parties acknowledge that the rights and obligations herein constitute valid and binding consideration, the sufficiency of which is hereby acknowledged and agreed.

2. Notwithstanding anything in the Base Contract to the contrary, neither Party may assign this Transaction Confirmation, without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided however, in order to be effective, any consent to such assignment must also be permitted by applicable law, including without limitation FERC regulations concerning AMAs and capacity release rules.

3. The Parties agree to execute and deliver such additional instruments or documents as may be necessary to carry out the purposes of this Transaction Confirmation.

4. Each of the Parties represents and warrants that, as of the date hereof, (i) it has full and complete authority to enter into and perform this Transaction Confirmation, (ii) the person who executes this Transaction Confirmation on its behalf has full and complete authority to do so and is empowered to bind it thereby, and (iii) it is not insolvent and has not sought and does not anticipate seeking in the foreseeable future protection from its creditors under the United States Bankruptcy Code, or under any similar laws.

5. Each Party represents and warrants to the other Party that, as of the date hereof, it is an entity eligible to file as a debtor for bankruptcy under the Chapter 7 and Chapter 11 of the U.S. Bankruptcy Code, 11 U.S.C. § 101, et seq. (the "Bankruptcy Code")

6. The Parties stipulate and agree that this Transaction Confirmation sets forth a "forward contract" as defined in Section 101(25) of the Bankruptcy Code and that Seller and Buyer are "Forward Contract Merchants" as defined in Section 101(26) of the Bankruptcy Code, and as such each Party shall have the rights and remedies provided for, or protected by the Bankruptcy Code in the event of the commencement of a bankruptcy proceeding by the other Party, including, without limitation, Sections 362, 546, 553 and 556 of the Bankruptcy Code.

I. IMPORT/EXPORT REPORTING.

Any import/export reporting requirements applicable to the quantities of natural gas delivered to Buyer hereunder, whether of the Canadian Energy Regulator, the U.S. Department of Energy Office of Fossil Energy, the U.S. Customs Service, or any other regulatory body having jurisdiction over the volumes, are the responsibility of the Seller and Seller shall comply with such import/export reporting requirements.

Seller: Citadel Energy Marketing LLC By: Citadel Advisors LLC, its Manager	Buyer: Liberty Utilities (EnergyNorth Natural Gas) Corp.
DocuSigned by: By: ______ 192A62265C91460...	By: Joshua Tilbury Digitally signed by Joshua Tilbury Date: 2024.08.09 08:52:29 -04'00'
Name: Antonia Peabody	Name: ______
Title: Authorized Signatory	Title: ______
Date: August 8, 2024	Date: ______

KOG

AMA Transaction Confirmation
Liberty Utilities (EnergyNorth Natural Gas) Corp.

TRANSACTION CONFIRMATION AND ASSET MANAGEMENT ARRANGEMENT

Date: July 16th, 2024

Transaction Confirmation #:

This Transaction Confirmation is subject to the Base Contract between Seller and Buyer, dated September 1, 2010. This Transaction Confirmation will not become binding until executed by both parties.

SELLER:
Emera Energy Services, Inc.
5151 Terminal Road
Halifax, Nova Scotia
B3J 1A1
Trader: Natalie Davis
Phone: 902-474-2135

Transporters: Tennessee Gas Pipeline, L.L.C. ("TGP")

BUYER:
Liberty Utilities (EnergyNorth Natural Gas) Corp.
15 Buttrick Road
Londonderry, NH
03053
Trader: Kelly Esposito
Phone: 603-401-8439

Contract Price: See Special Conditions, below

Delivery Period: November 1, 2024 through to and including October 31, 2025

Performance Obligation and Contract Quantity: See Special Conditions, below

Delivery Point(s): TGP - Nashua, NH (Primary Delivery Meter #42-0132) and TGP - Manchester, NH (Primary Delivery Meter #42-0133)

Special Conditions:

A. Definitions

"Assets" means the firm transportation entitlements as set forth in the table below:

Pipeline	Capacity Release Quantity (MMBtu/Day)*	Receipt Point	Delivery Point
TGP	2,400	Niagara, NY (Primary Receipt Meter #41-0902)	Nashua, NH (Primary Delivery Meter #42-0132) and Manchester, NH (Primary Delivery Meter #42-0133)

*Estimated Capacity Release Quantity is subject to monthly fluctuations due to Buyer's Retail Choice Customer Program, and the Seller's delivery obligations in Section B.2 below shall be adjusted accordingly.

"Credit Support Provider" means Emera Incorporated.

"Dekatherm" or "Dth" or "dt" means one (1) MMBtu.

"FERC" means the Federal Energy Regulatory Commission.

"Letter of Credit" means an irrevocable, non-transferable, standby letter of credit issued by a major U.S. commercial bank, a U.S. branch office of a foreign bank, or U.S. financial institution, in any case with a credit rating of at least "A-" by S&P and "A3" by Moody's, in a form reasonably acceptable to the Buyer. All costs related to any Letter of Credit shall be for the account of the Seller.

"Moody's" means Moody's Investors Service, Inc. or its successor.

"S&P" means S&P Global Ratings, Inc. or its successor.

B. Gas Service and Capacity Release

1. **Release/Assignment of Assets:** During the Delivery Period, Buyer will release the Assets to Seller at a [redacted]

2. **Gas Supply Requirements**

   Daily Call: On each day during the Delivery Period, Buyer shall have the option to require the Seller to sell and deliver on a Firm basis at the Delivery Point(s) a quantity of Gas equal to the following amounts ("Daily Call Quantity"):

Month	Capacity Release* (MMBtu/day)	Baseload Quantity (MMBtu/day)	Daily Call Quantity (MMBtu/day)
November 2024	2400	0	2400
December 2024	2400	0	2400
January 2025	2400	0	2400
February 2025	2400	0	2400
March 2025	2400	0	2400
April 2025	2400	0	2400
May 2025	2400	0	2400
June 2025	2400	0	2400
July 2025	2400	0	2400
August 2025	2400	0	2400
September 2025	2400	0	2400
October 2025	2400	0	2400

   Seller is under no obligation to use the Assets for deliveries of Gas pursuant to Section B.2. Buyer shall make nominations to Seller for delivery of Gas via telephone or by electronic means before 10:00 a.m. EPT on the Business Day prior to the Gas flow date. Friday nominations shall be effective for Saturday through Monday flow. Holidays are as determined by ICE and shall be treated the same as weekends (i.e., nominated ratably on the business day prior to the Holiday).

3. **Termination Option:** If at any time during the Delivery Period, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall (or revoke assignment of) the Assets. For the purpose of the preceding sentence, a failure means that Seller has failed to deliver an amount equal to or greater than 96% of the Contract Release Quantity to be delivered on a particular Day, which failure is not excused because of Buyer's non-performance or by Force Majeure.

C. Price

[redacted]

D. Asset Management Fee

Subject to the delivery obligations set forth above, Seller shall have the right to optimize the assigned capacity for its own account. In exchange for such right, during the Delivery Period, Seller shall make a payment to Buyer of [redacted] payable in twelve (12) equal monthly installments of [redacted] on the Payment Date of each Month of the Delivery Period. This payment shall be reflected as a credit to Buyer in Seller's invoice for the applicable Month and shall be subject to netting under Section 7.7 of the Base Contract.

E. Credit Provisions

Independent Amount. In the event Seller or its Credit Support Provider (i) has a Credit Rating at or below BBB- from S&P and/or Baa3 from Moody's, or (ii) is unrated, Seller shall provide Buyer with an Independent Amount in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB by S&P and/or Baa2 by Moody's, (b) cash, or (c) a Letter of Credit, in either case, in an amount equal to 10% of the potential mark to market exposure for the transactions hereunder calculated, in a commercially reasonable manner, as a function of price volatilities as well as the notional volume; provided however, that the potential mark to market exposure shall be zero (0) when Seller's price is set at a *Gas Daily,* or ICE index.

Collateral Requirement. The "Collateral Requirement' for Seller means the Exposure (as defined below), minus the sum of (i) the amount of cash previously transferred by Seller to Buyer, (ii) the amount of cash held by Buyer as posted collateral as the result of drawing under any Letter of Credit maintained by Seller for the benefit of Buyer, and (iii) the undrawn value of each such Letter of Credit; provided, however that the Collateral Requirement for Seller will be deemed to be zero (0) if (i) Seller, or its Credit Support Provider has a Credit Rating of at least BBB- from S&P and/or Baa3 from Moody's, and (ii) no Event of Default with respect to Seller has occurred an is continuing. Seller may provide the Collateral Requirement in the form of either (a) a guaranty from a Credit Support Provider rated at least BBB- by S&P and/or Baa3 by Moody's, (b) cash, or (c) a Letter of Credit. The "Collateral Requirement" for Buyer means zero (0), provided, however, that this will not preclude Seller from being able to request Adequate Assurance to the extent it has grounds to do so under Section 10.1 of the Base Contract.

"Exposure" means the amount, if any, that would be payable by Seller to Buyer if this Transaction Confirmation were terminated and shall be calculated as the net sum of:

(i) all amounts that have been invoiced, but not yet paid for the transactions under this Transaction Confirmation; plus
(ii) all amounts that have been accrued, but not yet invoiced for the transactions under this Transaction Confirmation; plus
(iii) the mark to market amount for each Day remaining in the Delivery Period for each transaction under this Transaction Confirmation, calculated in a commercially reasonable manner; reduced by
(iv) the Independent Amount, if any, previously provided by the Seller to the Buyer.

F. Changes in Law

If the FERC or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

G. Trade Representations

Each party represents that it is a producer, processor or commercial user of, or a merchant handling the commodity or commodities which are the subject of any commodity option transactions entered into hereunder, or the products or by-products thereof, and is offering (or being offered, as the case may be) or entering into such transactions solely for purposes related to its business as such. The parties confirm their intention that any such commodity option transactions be physically settled, such that if exercised, they result in the sale of an exempt commodity for either immediate or deferred shipment or delivery.

H. Asset Management Arrangement

Buyer and Seller record their intent and desire that this Transaction Confirmation satisfies the requirements of Section 284.8(h)(3) of the Regulations of FERC and FERC Order 712, for a release to an asset manager exempt from bidding requirements, and direct that any ambiguity be construed in favor of the full satisfaction of such requirements. It is the intention of the parties that this Transaction Confirmation, together with the applicable provisions, if any, of the applicable tariff(s), as it may be amended from time to time, contain all of the terms and conditions governing the release to Seller of the Assets.

I. Counterparts

This Transaction Confirmation may be executed in multiple counterparts, each of which shall constitute an original and all of which together shall constitute one and the same instrument. Signatures transmitted by facsimile or by email of a .pdf file are deemed to be their original signatures for all purposes.

Emera Energy Services, Inc.	**Liberty Utilities (EnergyNorth Natural Gas) Corp.**
By: A. Michael Burnell	By: Joshua Tilbury Digitally signed by Joshua Tilbury Date: 2024.07.16 12:29:49 -04'00'
Name: A. Michael Burnell	Name: Josh Tilbury
Title: President	Title: Director Energy Procurement
Date: July 17, 2024	Date: 7/16/24

Transaction Confirmation
Asset Management Arrangement

Citadel Energy Marketing	Date: August 7, 2024

This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas (including Special Provisions) between Seller and Buyer, dated August 22, 2023 (the "Base Contract"). Buyer and Seller are individually referred to as a "Party" and collectively as the "Parties." The terms of this Transaction Confirmation will be binding upon execution by both Parties. This Transaction Confirmation sets forth the terms of an asset management arrangement ("AMA") pursuant to applicable FERC regulations and FERC Order No. 712, as defined below, under which (i) Seller shall release certain natural gas transportation capacity (the "Release Capacity", as defined further below) to Buyer in accordance with this Transaction Confirmation and (ii) Seller shall act as Buyer's asset manager with respect to the Release Capacity and will sell natural gas to Buyer as provided for in this Transaction Confirmation consistent with and subject at all times to the requirements of FERC Order No. 712 and FERC regulations.

SELLER: Citadel Energy Marketing LLC c/o Citadel Americas LLC Southeast Financial Center 200 S. Biscayne Blvd., Suite 3300 Miami, FL 33131 Attn: Mohammad Siddique Phone: 203-900-6110 Email: Energy_Confirms@citadel.com Transporters: Tennessee Gas Pipeline, L.L.C. Transporter Contract Number:	**BUYER:** Liberty Utilities (EnergyNorth Natural Gas) Corp. 15 Buttrick Road Londonderry, NH 03053 Attn: Kelly Esposito Phone: (603) 401-8439 Email: Kelly.Esposito@libertyutilities.com Transporters: Tennessee Gas Pipeline, L.L.C. Transporter Contract Number:

Contract Price: See Special Conditions, below

Term: November 1, 2024 through to and including April 30, 2025

Delivery Period: November 1, 2024 through to and including April 30, 2025

Performance Obligation and Contract Quantity: See Special Conditions, below

Delivery Points:

TGP Zone 6 primary deliver meter(s):
#42-0426 – Laconia
#42-0133 – Manchester
#42-0132 – Nashua

Special Conditions:

A. Definitions.

"Assets" means the firm transportation entitlements as set forth in the table below:

Month	Transporter (Pipeline)	Primary Receipt Point	Primary Delivery Points	Maximum Daily Quantity ("MDQ") (MMBtu/Day)
	TGP	Dracut-meter #41-2538	Laconia – meter #42-0426 Manchester -meter #42-0133 Nashua – meter #42-0132	
November 2024				25,000
December 2024				15,000
January 2025				10,000
February 2025				10,000
March 2025				25,000
April 2025				20,000

"FERC" means the Federal Energy Regulatory Commission, or any successor.

"FERC Order No. 712" means the FERC Order No. 712, 123 FERC ¶ 61,286 (2008); Order No. 712-A, 125 FERC ¶ 61,216 (2008); and Order 712-B, 127 FERC ¶ 61,051 (2009), et seq., and the regulations promulgated at 18 C.F.R. § 284.8(h)(3).

"Fuel" means the charge assessed by Transporter, whether in-kind or otherwise, for the quantity of Gas consumed by Transporter in transporting the quantity of Gas nominated by Buyer each Day pursuant to the provisions of this Transaction Confirmation, and includes any charge, provision or right by Transporter to recover (in kind) lost and accounted for Gas, as determined in the Tariff.

"Release Capacity" means a portion of the capacity, which shall be released from Buyer to Seller as set forth in the definition of Assets above under the column Maximum Daily Quantity.

"Reservation Charges" means the Buyer's contract rate under the applicable TSA for natural gas pipeline service applicable to the Release Capacity.

"Tariff" means Transporter's currently effective FERC Gas Tariffs, as may be amended from time to time.

"Transporter" means Tennessee Gas Pipeline, L.L.C. ("TGP"), or its successor-in-interest, on which Seller has acquired the Release Capacity from Buyer under the terms of this Transaction Confirmation.

"TSA" means Seller's Transportation Service Agreements under Transporter's Rate Schedule FTA.

"Variable Charges" means the Variable Charge set forth in Transporter's Tariff applicable to the TSA.

B. Gas Service and Capacity Release

1. Release of Assets: In accordance with FERC Order No. 712 (where applicable), FERC's regulations (where applicable), and the terms of the Transporter's Tariff, during the Term, Buyer will release the Assets to the Seller. Buyer shall provide all requisite notifications to Transporter, including that each such release is made to an asset manager (Seller), is exempt from bidding pursuant to Sections 284.8(h)(1)(i) and 284.8 (h)(3) of FERC's regulations and Transporter's applicable Tariff provisions, the volumetric level of Buyer's purchase obligations, and the period during which that obligation is in effect. Buyer shall be responsible for obtaining any required consents from Transporter as well as making any required posting(s) on Transporter's website or electronic bulletin board. Buyer and Seller shall reasonably cooperate and take the reasonable steps necessary to effectuate the releases of capacity contemplated by this Transaction Confirmation.

[redacted]

2. Daily Call: Each Day during the Term Buyer has the option to call on Seller to deliver Gas up to the MDQ to Buyer and Seller shall be obligated to deliver such amount to Buyer at the Delivery Point. Buyer shall make nominations to Seller for delivery of the Gas before 10:00AM EST for the following flow date. Weekend and holiday nominations shall be ratable as standard ICE physical gas calendar.

3. Termination Option: If at any time during the Delivery Period, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall (or revoke assignment of) the Assets. For the purpose of the preceding sentence, a failure means that Seller has failed to deliver an amount equal to or greater than 96% of the Contract Quantity to be delivered on a particular Day, which failure is not excused because of Buyer's non-performance or by Force Majeure.

C. Price.

[redacted]

D. Asset Management Fee.

[redacted]) [redacted]

E. Monthly Invoice and Monthly Settlement Amount.

For each month during the Delivery Period, Seller shall provide a written invoice to Buyer, in accordance with Section 7 of the Base Contract of the Monthly Settlement Amount, which shall be calculated as follows:

Monthly Settlement Amount = [redacted]

F. Change in Law, Severability and Compliance with Law.

If the FERC, the CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

G. General Standards of Performance.

1.With respect to any Release Capacity, Buyer shall perform the asset management services contemplated hereunder in a good, workmanlike, and commercially reasonable manner and in accordance with (a) applicable law and regulatory approvals, and (b) the terms of the TSA and the Tariff.

2.Buyer and Seller will promptly provide timely notice to the other of known operational changes that will affect the ability of each Party to deliver or receive Gas at the Delivery Points set forth in this Transaction Confirmation.

H. GENERAL.

1. This Transaction Confirmation constitutes the entire agreement between the Parties regarding the AMA services to be provided, and supersedes and replaces any prior and contemporaneous communications, understandings and agreements between Seller and Buyer related to such subject matter, whether written or verbal, express or implied. No modification, amendment, supplementation, or alteration of the terms and provisions of this Transaction Confirmation shall be or become effective except by written amendment executed by the duly authorized representatives of the Parties. The Parties acknowledge that the rights and obligations herein constitute valid and binding consideration, the sufficiency of which is hereby acknowledged and agreed.

2. Notwithstanding anything in the Base Contract to the contrary, neither Party may assign this Transaction Confirmation, without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided however, in order to be effective, any consent to such assignment must also be permitted by applicable law, including without limitation FERC regulations concerning AMAs and capacity release rules.

3. The Parties agree to execute and deliver such additional instruments or documents as may be necessary to carry out the purposes of this Transaction Confirmation.

4. Each of the Parties represents and warrants that, as of the date hereof, (i) it has full and complete authority to enter into and perform this Transaction Confirmation, (ii) the person who executes this Transaction Confirmation on its behalf has full and complete authority to do so and is empowered to bind it thereby, and (iii) it is not insolvent and has not sought and does not anticipate seeking in the foreseeable future protection from its creditors under the United States Bankruptcy Code, or under any similar laws.

5. Each Party represents and warrants to the other Party that, as of the date hereof, it is an entity eligible to file as a debtor for bankruptcy under the Chapter 7 and Chapter 11 of the U.S. Bankruptcy Code, 11 U.S.C. § 101, et seq. (the "Bankruptcy Code")

6. The Parties stipulate and agree that this Transaction Confirmation sets forth a "forward contract" as defined in Section 101(25) of the Bankruptcy Code and that Seller and Buyer are "Forward Contract Merchants" as defined in Section 101(26) of the Bankruptcy Code, and as such each Party shall have the rights and remedies provided for, or protected by the Bankruptcy Code in the event of the commencement of a bankruptcy proceeding by the other Party, including, without limitation, Sections 362, 546, 553 and 556 of the Bankruptcy Code.

Seller:	Buyer:
Citadel Energy Marketing LLC By: Citadel Advisors LLC, its Manager	Liberty Utilities (EnergyNorth Natural Gas) Corp.
DocuSigned by: By: ____ 091201E333DC4B0...	By: John Patton Digitally signed by John Patton Date: 2024.08.09 11:11:37 -04'00'
Name: Christopher L. Ramsay	Name:
Title: Authorized Signatory	Title:
Date: August 7, 2024	Date:

KOG

Transaction Confirmation
Asset Management Arrangement

Citadel Energy Marketing	Date: August 7, 2024

This Transaction Confirmation is subject to the Base Contract for Sale and Purchase of Natural Gas (including Special Provisions) between Seller and Buyer, dated August 22, 2023 (the "Base Contract"). Buyer and Seller are individually referred to as a "Party" and collectively as the "Parties." The terms of this Transaction Confirmation will be binding upon execution by both Parties. This Transaction Confirmation sets forth the terms of an asset management arrangement ("AMA") pursuant to applicable FERC regulations and FERC Order No. 712, as defined below, under which (i) Seller shall release certain natural gas transportation capacity (the "Release Capacity", as defined further below) to Buyer in accordance with this Transaction Confirmation and (ii) Seller shall act as Buyer's asset manager with respect to the Release Capacity and will sell natural gas to Buyer as provided for in this Transaction Confirmation consistent with and subject at all times to the requirements of FERC Order No. 712 and FERC regulations.

SELLER: Citadel Energy Marketing LLC c/o Citadel Americas LLC Southeast Financial Center 200 S. Biscayne Blvd., Suite 3300 Miami, FL 33131 Attn: Mohammad Siddique Phone: 203-900-6110 Email: Energy_Confirms@citadel.com Transporters: Tennessee Gas Pipeline, L.L.C. Transporter Contract Number:	**BUYER:** Liberty Utilities (EnergyNorth Natural Gas) Corp. 15 Buttrick Road Londonderry, NH 03053 Attn: Kelly Esposito Phone: (603) 401-8439 Email: Kelly.Esposito@libertyutilities.com Transporters: Tennessee Gas Pipeline, L.L.C. Transporter Contract Number:

Contract Price: See Special Conditions, below

Term: November 1, 2024 through to and including April 30, 2025

Delivery Period: November 1, 2024 through to and including April 30, 2025

Performance Obligation and Contract Quantity: See Special Conditions, below

Delivery Points:

TGP Zone 6 primary deliver meter(s):

#42-0931 – Londonderry

Special Conditions:

A. Definitions.

"Assets" means the firm transportation entitlements as set forth in the table below:

Transporter (Pipeline)	Primary Receipt Point	Primary Delivery Point	Maximum Daily Quantity ("MDQ") (MMBtu/Day)
TGP	Dracut - meter #41-2538	Londonderry #42-0931	30,000

"FERC" means the Federal Energy Regulatory Commission, or any successor.

"FERC Order No. 712" means the FERC Order No. 712, 123 FERC ¶ 61,286 (2008); Order No. 712-A, 125 FERC ¶ 61,216 (2008); and Order 712-B, 127 FERC ¶ 61,051 (2009), et seq., and the regulations promulgated at 18 C.F.R. § 284.8(h)(3).

"Fuel" means the charge assessed by Transporter, whether in-kind or otherwise, for the quantity of Gas consumed by Transporter in transporting the quantity of Gas nominated by Buyer each Day pursuant to the provisions of this Transaction Confirmation, and includes any charge, provision or right by Transporter to recover (in kind) lost and accounted for Gas, as determined in the Tariff.

"Release Capacity" means a portion of the capacity, which shall be released from Buyer to Seller as set forth in the definition of Assets above under the column Maximum Daily Quantity.

"Reservation Charges" means the Buyer's contract rate under the applicable TSA for natural gas pipeline service applicable to the Release Capacity.

"Tariff" means Transporter's currently effective FERC Gas Tariffs, as may be amended from time to time.

"Transporter" means Tennessee Gas Pipeline, L.L.C. ("TGP"), or its successor-in-interest, on which Seller has acquired the Release Capacity from Buyer under the terms of this Transaction Confirmation.

"TSA" means Seller's Transportation Service Agreements under Transporter's Rate Schedule FTA.

"Variable Charges" means the Variable Charge set forth in Transporter's Tariff applicable to the TSA.

B. Gas Service and Capacity Release

1. Release of Assets: In accordance with FERC Order No. 712 (where applicable), FERC's regulations (where applicable), and the terms of the Transporter's Tariff, during the Term, Buyer will release the Assets to the Seller. Buyer shall provide all requisite notifications to Transporter, including that each such release is made to an asset manager (Seller), is exempt from bidding pursuant to Sections 284.8(h)(1)(i) and 284.8 (h)(3) of FERC's regulations and Transporter's applicable Tariff provisions, the volumetric level of Buyer's purchase obligations, and the period during which that obligation is in effect. Buyer shall be responsible for obtaining any required consents from Transporter as well as making any required posting(s) on Transporter's website or electronic bulletin board. Buyer and Seller shall reasonably cooperate and take the reasonable steps necessary to effectuate the releases of capacity contemplated by this Transaction Confirmation.

[redacted]

2. Daily Call: Each Day during the Term Buyer has the option to call on Seller to deliver Gas up to the MDQ to Buyer and Seller shall be obligated to deliver such amount to Buyer at the Delivery Point. Buyer shall make nominations to Seller for delivery of the Gas before 10:00AM EST for the following flow date. Weekend and holiday nominations shall be ratable as standard ICE physical gas calendar.

3. Termination Option: If at any time during the Delivery Period, Seller fails to deliver Gas required to be delivered hereunder, unless such failure is excused by the Buyer's non-performance or caused by Force Majeure, Buyer shall have the right to terminate this Transaction Confirmation and recall (or revoke assignment of) the Assets. For the purpose of the preceding sentence, a failure means that Seller has failed to deliver an amount equal to or greater than 96% of the Contract Quantity to be delivered on a particular Day, which failure is not excused because of Buyer's non-performance or by Force Majeure.

C. Price.

[redacted]

D. Asset Management Fee.

[redacted]) [redacted]

E. Monthly Invoice and Monthly Settlement Amount.

For each month during the Delivery Period, Seller shall provide a written invoice to Buyer, in accordance with Section 7 of the Base Contract of the Monthly Settlement Amount, which shall be calculated as follows:

Monthly Settlement Amount = [redacted]

F. Change in Law, Severability and Compliance with Law.

If the FERC, the CFTC, or other applicable regulatory body shall implement any change in law, rule, regulation, tariff or practice that is binding on Seller or Buyer and materially and adversely affects such party's ability to perform its obligations hereunder, the parties shall negotiate in good faith an amendment to this Agreement or take other appropriate action the effect of which is to restore each party, as closely as possible, to its same position as prior to such change. If, within sixty (60) Days after the implementation of such change, the parties are unable to agree on such amendment or such other appropriate action, each party will continue to perform its obligations hereunder to the maximum extent possible under the applicable law, rule, regulation, tariff or practice, taking all reasonable steps to mitigate the effect of such change on each other.

G. General Standards of Performance.

1.With respect to any Release Capacity, Buyer shall perform the asset management services contemplated hereunder in a good, workmanlike, and commercially reasonable manner and in accordance with (a) applicable law and regulatory approvals, and (b) the terms of the TSA and the Tariff.

2.Buyer and Seller will promptly provide timely notice to the other of known operational changes that will affect the ability of each Party to deliver or receive Gas at the Delivery Points set forth in this Transaction Confirmation.

H. GENERAL.

1. This Transaction Confirmation constitutes the entire agreement between the Parties regarding the AMA services to be provided, and supersedes and replaces any prior and contemporaneous communications, understandings and agreements between Seller and Buyer related to such subject matter, whether written or verbal, express or implied. No modification, amendment, supplementation, or alteration of the terms and provisions of this Transaction Confirmation shall be or become effective except by written amendment executed by the duly authorized representatives of the Parties. The Parties acknowledge that the rights and obligations herein constitute valid and binding consideration, the sufficiency of which is hereby acknowledged and agreed.

2. Notwithstanding anything in the Base Contract to the contrary, neither Party may assign this Transaction Confirmation, without the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed; provided however, in order to be effective, any consent to such assignment must also be permitted by applicable law, including without limitation FERC regulations concerning AMAs and capacity release rules.

3. The Parties agree to execute and deliver such additional instruments or documents as may be necessary to carry out the purposes of this Transaction Confirmation.

4. Each of the Parties represents and warrants that, as of the date hereof, (i) it has full and complete authority to enter into and perform this Transaction Confirmation, (ii) the person who executes this Transaction Confirmation on its behalf has full and complete authority to do so and is empowered to bind it thereby, and (iii) it is not insolvent and has not sought and does not anticipate seeking in the foreseeable future protection from its creditors under the United States Bankruptcy Code, or under any similar laws.

5. Each Party represents and warrants to the other Party that, as of the date hereof, it is an entity eligible to file as a debtor for bankruptcy under the Chapter 7 and Chapter 11 of the U.S. Bankruptcy Code, 11 U.S.C. § 101, et seq. (the "Bankruptcy Code")

6. The Parties stipulate and agree that this Transaction Confirmation sets forth a "forward contract" as defined in Section 101(25) of the Bankruptcy Code and that Seller and Buyer are "Forward Contract Merchants" as defined in Section 101(26) of the Bankruptcy Code, and as such each Party shall have the rights and remedies provided for, or protected by the Bankruptcy Code in the event of the commencement of a bankruptcy proceeding by the other Party, including, without limitation, Sections 362, 546, 553 and 556 of the Bankruptcy Code.

Seller: Citadel Energy Marketing LLC By: Citadel Advisors LLC, its Manager	Buyer: Liberty Utilities (EnergyNorth Natural Gas) Corp.
By: DocuSigned by: 091201E333DC4B0...	By: Joshua Tilbury Digitally signed by Joshua Tilbury Date: 2024.08.09 08:51:18 -04'00'
Name: Christopher L. Ramsay	Name:
Title: Authorized Signatory	Title:
Date: August 7, 2024	Date:

KOG

TRANSACTION CONFIRMATION No. 8
(for Baseload LNG deliveries)

This Transaction Confirmation is dated and effective as of April ___, 2024, by and between Gaz Métro LNG, L.P. ("**GM LNG**") and Liberty Utilities (EnergyNorth Natural Gas) Corp. ("**Customer**"). (GM LNG and Customer, each a "**Party**" and collectively the "**Parties**"). The Parties hereto are entering into this Transaction Confirmation regarding the purchase and sale of LNG pursuant to and subject to the Master Liquefied Natural Gas Supply and Delivery Agreement dated as of September 17, 2019 (the "**Agreement**") by and between the Parties.

Delivery Term: December 1, 2024 to February 28, 2025

This Transaction Confirmation shall remain in effect during the Delivery Term unless earlier terminated by either Party pursuant to the terms and conditions of the Agreement. Such termination shall not affect or excuse performance under any provision surviving such termination.

Quantity: GM LNG agrees to sell and make available to Customer at the Delivery Point(s) and Customer agrees to purchase and accept, on a firm basis, subject to the terms and conditions set forth in the Agreement, a firm daily quantity of three (3) Loads (approximately 2,550 MMBtu) of LNG per day, Monday through Friday, for the month of December and a firm daily quantity of five (5) Loads (approximately 4,250 MMBtu) of LNG per day, every day, for the months of January and February.

Delivery Point(s): Any of the following Buyer's facilities**:**

i. 20, Broken Bridge Rd. Concord, NH 03301; ("**Concord**")
ii. 130 Elm St., Manchester, NH 03101; ("**Manchester**")
iii. 20 Tilton Rd., Tilton, NH 03276. ("**Tilton**")

Price of the LNG: Customer shall pay to GM LNG the following Price of the LNG:

i. A commodity charge per MMBtu composed of the following components (the "**Commodity Charge**"):

   a. [redacted]

   b. [redacted]

   c. [redacted]

ii. A demand charge of [redacted]

iii. **Excess Quantities**: For any quantities delivered to the Customer over the Total Contract Quantity, the Customer shall pay [redacted]

Price for Transportation: [redacted]

i. [redacted]

a. [redacted]

b. [redacted]

Additional Terms and Conditions: The following terms and conditions shall govern the LNG purchases and sales under this Transaction Confirmation:

1. **Schedule**: Customer will work with GM LNG and its Transporters to establish a weekly delivery schedule.

2. **Nomination**: GM LNG will use commercially reasonable efforts to deliver LNG to Customer that is nominated outside of GM LNG's nomination protocols set forth in the Agreement.

3. **Additional Charges**: Any detention, surcharges or other accessorial charges will be billed in addition to the Transportation Price.

   a. **Waiting time**: [redacted]

   b. **Routing**: [redacted]

   c. **Holidays**: [redacted]

      i. [redacted]
      ii. [redacted]

   d. Cancellation Fee: [redacted]

4. **Terms**: Capitalized terms used herein and not defined shall have the meaning ascribed to them under the Agreement.

[1] https://www.eia.gov/petroleum/gasdiesel/

5. **Truck Transportation** [redacted] If during the Delivery Term, Transporter, is in default of the conditions provided in the agreement between Transporter and Seller, or incapable to provide the transportation services to Customer for reasons other than GM LNG default, GM LNG shall notify in writing to Customer including a copy of notification from Transporter to Seller all reasonable justifications for said incapability. GM LNG will provide replacement options to Customer, including quotes for transportation fees. The parties shall then collaborate to elect a new transporter and will adjust the Price of Transportation to reflect the prices of the new transporter. If no replacement is mutually agreed on within a reasonable delay, but not exceeding [5] days following the notification made by GM LNG or any other delay agreed in writing between the Parties, any Party can cancel this Transaction Confirmation, without any liability..

IN WITNESS WHEREOF, the Parties, by their respective duly authorized representatives, have executed this Transaction Confirmation effective as of the date hereabove written. This Transaction Confirmation will not become effective as to either Party unless and until executed by both Parties.

GAZ MÉTRO LNG, L.P., acting through its General Partner Gaz Métro GNL inc.

926-00187

Name : Étienne Champagne
Title : President

Name : Denise Dériger
Title : Corporate Secretary

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.

John Patton
Digitally signed by John Patton
Date: 2024.06.10 09:40:49 -04'00'

Name : John Patton
Title : Vice President, Technical Services - Gas

TRANSACTION CONFIRMATION No. 9
(for Call-option LNG deliveries)

This Transaction Confirmation is dated and effective as of April ___, 2024, by and between Gaz Métro LNG, L.P. ("**GM LNG**") and Liberty Utilities (EnergyNorth Natural Gas) Corp. ("**Customer**"). (GM LNG and Customer, each a "**Party**" and collectively the "**Parties**"). The Parties hereto are entering into this Transaction Confirmation regarding the purchase and sale of LNG pursuant to and subject to the Master Liquefied Natural Gas Supply and Delivery Agreement dated as of September 17, 2019 (the "**Agreement**") by and between the Parties.

Delivery Term: November 1, 2024 to March 31, 2025

This Transaction Confirmation shall remain in effect during the Delivery Term unless earlier terminated by either Party pursuant to the terms and conditions of the Agreement. Such termination shall not affect or excuse performance under any provision surviving such termination.

Quantity: GM LNG agrees to sell and make available to Customer at the Delivery Point(s) on a firm basis, subject to the terms and conditions set forth in the Agreement, (i) a maximum daily quantity ("MDQ") of up to five (5) Loads of LNG per day; and (ii) a total contract quantity ("**Total Contract Quantity**") not to exceed 250,000 MMBtu during the Delivery Term, plus any additional quantities required to fill a final truck to capacity.

Delivery Point(s): Any of the following Buyer's facilities**:**

i. 20, Broken Bridge Rd. Concord, NH 03301; ("**Concord**")
ii. 130 Elm St., Manchester, NH 03101; ("**Manchester**")
iii. 20 Tilton Rd., Tilton, NH 03276. ("**Tilton**")

Price of the LNG: Customer shall pay to GM LNG the following Price of the LNG:

i. A commodity charge per MMBtu composed of the following components (the "**Commodity Charge**"):

a. [redacted]

b. [redacted]

c. [redacted]

ii. A demand charge of [redacted] which shall be paid in five (5) equal installments of [redacted] of the Delivery Term.

Transportation Price: Customer shall pay to GM LNG the following Transportation Price:

i. [redacted]

a. [redacted]

b. [redacted]

ii. [redacted]

Additional Terms and Conditions: The following terms and conditions shall govern the LNG purchases and sales under this Transaction Confirmation:

1. **Schedule**: Customer will work with GM LNG and its Transporters to establish a weekly delivery schedule.

2. **Nomination**: GM LNG will use commercially reasonable efforts to deliver LNG to Customer that is nominated outside of GM LNG's nomination protocols set forth in the Agreement.

3. **Additional Charges**: Any detention, surcharges or other accessorial charges will be billed in addition to the Transportation Price.

   a. **Waiting time**: [redacted]

   b. **Routing**: [redacted]

   c. **Cancellation Fee**: [redacted]

4. **Terms**: Capitalized terms used herein and not defined shall have the meaning ascribed to them under the Agreement.

5. **Truck Transportation** : [redacted] If during the Delivery Term, Transporter , is in default of the conditions provided in the agreement between Transporter and Seller, or incapable to provide the transportation services to Customer for reasons other than GM LNG default, GM LNG shall notify in writing to Customer including a copy of notification from Transporter to Seller all reasonable justifications for said incapability. GM LNG will provide replacement options to Customer, including quotes for transportation fees. The

[1] https://www.eia.gov/petroleum/gasdiesel/

parties shall then collaborate to elect a new transporter and will adjust the Price of Transportation to reflect the prices of the new transporter. If no replacement is mutually agreed on within a reasonable delay, but not exceeding [5] days following the notification made by GM LNG or any other delay agreed in writing between the Parties, any Party can cancel this Transaction Confirmation, without any liability..

IN WITNESS WHEREOF, the Parties, by their respective duly authorized representatives, have executed this Transaction Confirmation effective as of the date hereabove written. This Transaction Confirmation will not become effective as to either Party unless and until executed by both Parties.

GAZ MÉTRO LNG, L.P., acting through its General Partner Gaz Métro GNL inc.

Name : Étienne Champagne
Title : President

926-00187

Name : Denise Dériger
Title : Corporate Secretary

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP.

John Patton Digitally signed by John Patton
Date: 2024.06.10 09:42:21 -04'00'

Name : John Patton
Title : Vice President, Technical Services - Gas

RAY ENERGY CORP

Ray Energy Corp.
2794 Seventh Ave
Troy, NY 12180
United States

Propane Index Contract

To: **Liberty Utilities (Energy North Natural Gas) Corp**
15 Buttrick Road
Londonderry, NH
United States
03053

Negotiated Date: July 23, 2024
Contract Ref: 510440

Buyer Contact
Liberty Utilities (Energy North Natural Gas) Corp
Josh Tilbury

Seller Contact
Ray Energy Corp.
Stephen Heffron - VP of Marketing
Email: sheffron@rayenergy.com

Ray Energy Corp. (Seller) agrees to sell and deliver, and Liberty Utilities (Energy North Natural Gas) Corp (Buyer) agrees to purchase and accept as per the following:

PRODUCT: **Propane - Odorized**
CONTRACT TERM: **11/01/2024 to 03/31/2025**
PAYMENT TERMS: **Net 10 Days from Date of Delivery**
TOTAL CONTRACT QUANTITY: **250,000 usg**

DELIVERY POINT: Liberty Utilities (Amherst, NH)
DELIVERY TERMS: FOB Destination (See Delivery Point above)
SOURCE: Bellows Falls Terminal, VT
EFFECTIVE DATE: 11/01/2024 to 03/31/2025
DELIVERY MODE: Truck
PRICE: [redacted]

SLH

DELIVERY SCHEDULE: (Volumes in United States Gallons)

Date	Volume	Date	Volume	Date	Volume	Date	Volume
Nov 2024	0	Dec 2024	0	Jan 2025	0	Feb 2025	0
Mar 2025	0						

DELIVERY POINT: Liberty Utilities (Manchester, NH)
DELIVERY TERMS: FOB Destination (See Delivery Point above)
SOURCE: Bellows Falls Terminal, VT
EFFECTIVE DATE: 11/01/2024 to 03/31/2025
DELIVERY MODE: Truck
PRICE: [redacted]

SLH

DELIVERY SCHEDULE: (Volumes in United States Gallons)

Date	Volume	Date	Volume	Date	Volume	Date	Volume
Nov 2024	0	Dec 2024	0	Jan 2025	0	Feb 2025	0
Mar 2025	0						

DELIVERY POINT: Liberty Utilities (Tilton, NH)
DELIVERY TERMS: FOB Destination (See Delivery Point above)
SOURCE: Bellows Falls Terminal, VT
EFFECTIVE DATE: 11/01/2024 to 03/31/2025
DELIVERY MODE: Truck
PRICE: [redacted]

SLH

DELIVERY SCHEDULE: (Volumes in United States Gallons)

Date	Volume	Date	Volume	Date	Volume	Date	Volume
Nov 2024	0	Dec 2024	0	Jan 2025	0	Feb 2025	0
Mar 2025	0						

DELIVERY POINT: Liberty Utilities (Nashua, NH)
DELIVERY TERMS: FOB Destination (See Delivery Point above)
SOURCE: Bellows Falls Terminal, VT
EFFECTIVE DATE: 11/01/2024 to 03/31/2025
DELIVERY MODE: Truck
PRICE: [redacted]

SLH

DELIVERY SCHEDULE: (Volumes in United States Gallons)

Date	Volume	Date	Volume	Date	Volume	Date	Volume
Nov 2024	0	Dec 2024	0	Jan 2025	0	Feb 2025	0
Mar 2025	0						

GENERAL TERMS AND CONDITIONS:

I have read and I accept all pages of this Contract including attached Terms and Conditions.

Accepted and Agreed to this day by:

Ray Energy Corp.

Stephen Heffron

Stephen Heffron
Title: VP of Marketing
Date: 8-6-24

Liberty Utilities (Energy North Natural Gas) Corp

Joshua Tilbury Digitally signed by Joshua Tilbury Date: 2024.08.06 15:50:21 -04'00'

Josh Tilbury

Date:

RAYENERGY

GENERAL TERMS AND CONDITIONS

Specifications and measure: The quantity of the Product being Delivered to *Buyer* shall be measured by means of slip tube, outage gauge, weighing, meter or other method chosen by the *Seller* which is consistent with the industry practice. *Buyer* shall be invoiced for actual number of US gallons of the Product Delivered, and when the Product is Delivered to *Buyer* by *Seller* or its agent, such amount invoiced shall be subject to a variance of up to two percent (2%) of the total Delivered volume recorded on the bill of lading. All Product Delivered to *Buyer* by Seller or its agent shall comply with GPA 2140-HD specifications as published by the Natural Gas Processors Association and in effect on the date that the Product is so Delivered (the "Specifications"). The ethane content of the Product shall be less than 2%. Acceptance by the *Buyer* of the Product received under this Contract shall constitute a waiver of any claim against the *Seller* based on the failure of the Product to meet such Specifications.

~~**Storage:** In the event the *Buyer* fails to purchase or lift all or any part of the designated periodic quantity of Product as set forth in the Delivery/Lift schedule above, any under-lifted monthly volumes remaining on or after the last day of the applicable month shall be subject to a storage fee, payable by Buyer, based on market conditions as determined by *Seller*.~~ SLH

Quantity: ~~*Buyer* acknowledges that *Seller* has scheduled Product to arrive at the relevant terminal based on *Buyer's* adherence to the Delivery/Lift schedule set forth in this Contract and *Buyer* agrees to lift the Product in accordance with such Delivery/Lift schedule, including, without limitation, lifting the Product on a pro rata basis each month, based on the number of weeks in each such month (by way of example: 10,000 gallons are to be lifted each week in a month in which there are four (4) weeks and 40,000 gallons are scheduled to be Delivered or Lifted per the schedule set forth on page 1 of this Contract), as applicable. *Buyer* acknowledges and agrees that *Buyer's* failure to adhere to the Product quantities set forth in the Delivery/Lift schedule will cause *Seller* and *Seller's* other customers to incur considerable additional costs for which *Buyer* shall be liable. *Seller* may make additional quantities of Product available to the *Buyer*, in the *Seller's* sole discretion, provided, however, the *Seller* shall not be obligated to supply *Buyer* with Product in excess of monthly volume specified in this Contract. Additional volumes (as available) over and above the contracted monthly volume set forth in this Contract will be priced at a mutually agreeable price. In the event *Buyer* fails to lift and/or take Delivery of the Product in accordance with the Delivery/Lift schedule set forth in this Contract, *Seller*, in addition to any other remedies available to it at law or equity, shall have the right, at its sole discretion, to do any or all of the following:~~ SLH

- ~~a. *Seller* may reduce the monthly volumes remaining on this Contract.~~
- ~~b. *Seller* may require the *Buyer* to take any under lifted volume of Product, together with the next month's scheduled volume of Product.~~
- ~~c. *Seller* may sell all or any portion of the volume of Product that *Buyer* failed to lift and/or take Delivery of (the "Remaining Volume") on terms and at such price(s) as *Seller*, in its sole discretion, deems appropriate under the then-existing circumstances, in which case *Buyer* shall pay to *Seller* the amount by which the price (as set forth in this Contract) of Remaining Volume exceeds the Net Price *Seller* receives in connection with the sale of such Remaining Volume. For purposes of this Section, the term "Net Price" shall mean the gross proceeds received by *Seller* in connection with the sale of the Remaining Volume, less (i) all of *Seller's* costs and expenses associated with the sale(s) of the Remaining Volume, (ii) a sales commission equal to ten percent (10%) of the gross proceeds of such sale(s) of the Remaining Volume, and (iii) any additional fees incurred by *Seller* arising out of, or in any way connected with, *Buyer's* failure to lift and/or take Delivery of the Remaining Volume, including, without limitation, any imbalance charges and additional storage and/or transportation costs. In the event that *Seller* is unable to resell all or any portion of the Remaining Volume, *Buyer* shall pay to *Seller* the price (as set forth in this Contract) of such Remaining Volume.~~ SLH

Buyer has the right to call on up to 3 trucks/day at the delivery points listed above. Propane deliveries from Seller shall be available to Buyer on a daily, weekly and/or monthly basis. Buyer to give Seller forty-eight (48) hours' notice to any deliveries of propane. Exact volume, dates, times, etc. to be coordinated between Buyer and Seller during the Term.

SLH

2794 Seventh Avenue, Troy, NY 12180
518-874-4510 • Fax: 518-874-4509
www.rayenergy.com

RAYENERGY

Without limiting the generality of the foregoing, if the *Buyer* fails to lift and/or take delivery of the Product in accordance with the ~~schedule set forth in this~~ Contract Term, *Buyer* shall remain liable for the payment in full of all such Product.

SLH SLH

Taxes: In addition to the purchase price of the Product, *Buyer* shall have sole liability for and shall pay all taxes, fees or other charges, including all existing and/or new or increased sales and/or excise taxes imposed by any governmental authority upon the manufacture, sale, use, receipt or Delivery of the Product sold hereunder. If the *Buyer* is exempt from the payment of taxes, fees, or other charges, *Buyer* shall, prior to receipt or Delivery of the Product, furnish to *Seller* proper exemption certificates satisfactory to *Seller* to cover the Products purchased.

Compliance with laws: All agents, employees, and licensees of *Buyer* shall comply with all of *Seller*'s safety regulations and procedures. *Buyer* shall strictly comply with all applicable laws, rules, regulations and instructions at the Delivery location at which *Buyer* receives the Product. *Seller* and its agent(s) reserves the right to refuse to provide Product to *Buyer* if and when *Buyer* or its agent(s) fails to comply with any applicable law, rule, regulation or instruction or when *Seller*, in its sole discretion, believes *Buyer*'s equipment is not suitable for receiving, transporting or storing the Product.

SLH

Title, risk of loss and responsibility for damage: Delivery of the Product ("Delivery") shall be deemed to occur when title to and risk of loss of the Product pass to *Buyer*. Title to Product, as well as sole risk of any loss of or damage thereto, shall pass to *Buyer* when the Product passes the flange at the ~~origin terminal to the transport vehicle of Seller, Seller's agent, Buyer or Buyer's agent, as the case may be~~. Buyer's Delivery Point. From and after the time of Delivery of Product by *Seller* to *Buyer*, *Buyer* shall be solely liable and responsible for the Product such that Buyer releases Seller and shall defend, indemnify, and hold *Seller*, its affiliates, and their officers and employees harmless from and against all loss of Product and for all costs (including attorney's fees and costs of defense), losses, demands, liabilities, claims, and causes of action for or relating to loss, damages, personal injuries, including death, and property damage caused by possession, transport, consumption, or use of any Product delivered under this Contract. *Buyer* agrees at all times during the term of this Contract to carry such insurance as *Seller* shall request from time to time.
Seller has been provided a copy of Buyer's Unloading Procedure and agrees to follow those policies

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Liquefied Petroleum Gas ("LPG"): *Buyer* acknowledges that it is informed and is aware of the hazards and risks associated with the handling and use of LPG, specifically, including propane. *Buyer* agrees that it will inform its employees, contractors and customers of such hazards and risks, including the need for odorization as required by law and that odorization may fade. *Buyer* will comply with applicable law and shall distribute instructions for the safe handling of LPG under pressure to its employees and contractors. *Buyer* shall immediately inform *Seller* in writing of any accident in which LPG acquired from *Seller* is involved. Unless otherwise agreed by the parties, *Seller* shall provide ethyl mercaptan for the odorization of LPG. *Buyer* acknowledges and represents that it is knowledgeable in the chemical and physical properties and limitations, storage, use and handling of odorant and propane, whether odorized or non-odorized.

Buyer covenants and agrees that it will inspect and test the odorant level in LPG obtained from *Seller* at the time that *Buyer* receives such Product, and again if and when *Buyer* provides and/or delivers Product to a third party. *Buyer* further covenants and agrees to monitor and maintain the odorant in LPG obtained from *Seller* and will not commingle such Product with unodorized propane or with other Products containing odorant in concentrations less than those concentrations mandated by law. *Buyer* acknowledges and agrees that certain conditions may occur which will render properly odorized propane undetectable, including without limitation: (a) odorant may fade over a period of time or if subject to certain metals or conditions of metal; (b) odorant may be absorbed or adsorbed by tanks, piping, soil, masonry or other building materials; (c) stratification of odorized propane may occur, thereby changing the intensity of the odorant

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different levels; (d) some individuals lack a sense of smell or possess a diminish sense of smell; and (e) individuals with normal sense of smell may be temporarily prevented from detecting odorant due to certain physical conditions such as allergies, head colds or masking odors. *Seller* shall have no responsibility to ensure that the Product Delivered under this Contract remains properly odorized after Delivery to Buyer and *Buyer* hereby releases Seller and shall, indemnify, defend and hold *Seller* harmless from and against any and all claims, demands, suits, losses (including without limitation, costs of defense and reasonable attorney's fees, penalties and interest), damages, causes of action and liabilities of every type and character without regard to the amount and without limitation for personal injury, death or property damage caused by, arising out of or resulting from the use of ethyl mercaptan or any other legal substance as an odorant or arising out of *Buyer* or *Buyer*'s consignee's certification, delivery, receipt, use, transportation, or storage of LPG after title of the Product has passed to *Buyer*. *Buyer*'s indemnification shall include but shall not be limited to any claim against *Seller* as described above whether based on Product liability, negligence, breach of warranty of other fault or any other cause of action, whether legal or equitable in nature.

Force Majeure: *Seller* shall not be liable for its failure to perform hereunder due to any occurrence beyond its reasonable control, including but not limited to *Seller*'s failure to produce, provide, transport, receive, store or Deliver Product due to any event of force majeure. Events of force majeure shall include acts of God, fires, floods, wars, sabotage, accidents, endemic, pandemic, labor disputes or shortages, governmental laws, ordinances, rules and regulations, whether valid or invalid (Including but not limited to priorities, requisitions, allocations and price adjustment restrictions), supply chain issues or other inability to procure or obtain material, equipment or transportation, unavailability of feedstocks, and any other similar or different occurrences beyond the control of *Seller*. The delivery period for Product shall not be extended due to any event of force majeure. If *Seller* is unable to make any delivery or deliveries at the time or times required under this Contract due to force majeure, *Seller* shall have the right to allocate its available supply of the Product among its customers as *Seller* deems appropriate. In no event shall *Seller* be obligated to purchase Product from others in order to enable it to provide the Product to *Buyer* hereunder due to any event of force majeure. Seller shall not be liable for any loss or damage of any kind or for any consequences thereof resulting from delay or inability to provide the Product as a result of an event of force majeure.

Warranties: *Seller* warrants that it has good and valid title to all Product Delivered in accordance with the Delivery/Lift Schedule hereunder and that such Product will be free from all liens and claims of others at the time of such Delivery and sale. *Seller* warrants that the Product transported by *Seller* to *Buyer* meets the Specifications in this Contract. *SELLER* EXPRESSLY DISCLAIMS AND NEGATES ALL OTHER WARRANTIES OF CONDITION, INCLUDING IN THIS DISCLAIMER, EXPRESS WARRANTIES NOT EXPLICITLY STATED OR REFERENCED IN THIS CONTRACT, AND ALL IMPLIED WARRANTIES, INCLUDING WITHOUT LIMITATION THOSE OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE.

Claims Receipt by *Buyer* of any Product Delivered hereunder shall be an unqualified acceptance, and waiver by *Buyer*, of any and all claims with respect to that Product, unless *Buyer* gives *Seller* written notice of a claim within 5 days after the date the Product is Delivered. *Buyer* assumes all risk and liability for the results obtained by the use in manufacturing processes or in combination with other substances of any Product delivered to *Buyer* that meets the specifications for the Product contained in or referenced in this Contract. *SELLER'S* LIABILITY WITH RESPECT TO ALL PRODUCT SOLD HEREUNDER SHALL BE LIMITED TO THE PURCHASE PRICE OF THE PRODUCT IN RESPECT OF WHICH DAMAGES ARE CLAIMED. IN NO EVENT SHALL *SELLER* BE LIABLE FOR SPECIAL, INDIRECT, CONSEQUENTIAL, OR PUNITIVE DAMAGES FOR ANY PERFORMANCE OR NONPERFORMANCE OF THIS CONTRACT, WHETHER CHARATERIZED AS A CONTRACT BREACH, PRODUCTS LIABILITY, OR OTHER TORT.

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Government Regulations: *Buyer* warrants that it may lawfully receive, sell, use and transport Product in interstate and intrastate commerce.

Notices: Any notice, request report, statement or other communication to be given in writing under this Contract shall be deemed to have been given by either party to the other party upon (a) the date of transmittal by facsimile with receipt confirmed, or (b) the date of mailing to the other party by recognized overnight courier to the applicable address set forth in this Contract or at such other address as a party may specify from time to time in writing.

Law and dispute resolution: This Contract shall be interpreted in accordance with, and *Seller*'s and *Buyer*'s respective rights, obligations and liabilities hereunder shall be determined by the laws of the State of New York, without giving effect to any choice of law or conflict of law provision or rule that could otherwise cause the application of the laws of any jurisdiction other than the State of New York. In the event of any dispute between the parties regarding interpretation of this Contract, their respective rights and liabilities hereunder, or any other matter arising out of or in connection with this Contract, a party shall give written notice of the dispute to the other party, and each party will designate a duly authorized person to negotiate with the other party concerning the dispute. If the dispute has not been resolved by negotiation within 30 days of the initial dispute notice, or if the complaining party fails to send an initial dispute notice, the dispute shall be resolved by arbitration in Albany, New York, to the exclusion of any other forum or jurisdiction, by one disinterested arbitrator with at least ten years' experience in the LPG Industry, appointed by agreement of the parties. If an agreement is not reached within 30 days of the request either party may apply for an appointment by the Chief Judge of the United States District Court for the Northern District of New York, who shall have power to make the appointment. Except otherwise set forth herein, the arbitration shall be conducted in accordance with the Commercial Arbitration Rules of the American Arbitration Association, and the determination of the arbitrator shall be conclusive on the parties and shall include a statement of reason for the decision. Either party may apply to the arbitrator to seek injunctive relief until the arbitration award is rendered or the controversy is otherwise resolved. Either party may also, without waiving any right or remedy under this Contract, seek from any court having jurisdiction, any interim or provisional relief that is necessary to protect the rights or property of that party, pending the selection or appointment of an arbitrator. In any arbitration arising out of or related to this Contract, the arbitrator shall award to the prevailing party, if any, the costs and attorneys' fees reasonably incurred by the prevailing party in connection with the arbitration. If the arbitrator determines a party to be the prevailing party under circumstances where the prevailing party won on some but not all of the claims and counterclaims, the arbitrator shall award the prevailing party an appropriate percentage of the costs and attorneys' fees reasonably incurred by the prevailing party in connection with the arbitration. Unless a party requests arbitration within two years of the occurrence of dispute, all claims related to the occurrence are barred, unless otherwise required by law.

Miscellaneous: No modification of, addition to, or waiver of any of the terms of this Contract shall be binding upon either party unless in a writing which specifically references this Contract and which is signed by an authorized representative of the party. Notwithstanding the foregoing, no modification of, addition to, or waiver of any of the terms of this Contract shall be effected by the acknowledgement or acceptance of a purchase order or other forms containing additional or different terms or conditions, whether or not signed by an authorized representative of the party. This Contract shall extend to and be binding upon the successors and assigns of the parties, but neither this Contract nor any part shall be assigned or transferred by *Buyer* without the prior written consent of the *Seller*, and any assignment or transfer made by *Buyer* without the *Seller*'s written consent need not be recognized by and shall not be binding upon the *Seller*. No waiver by either party of any breach by the other party of any of the terms of this Contract shall be construed as a waiver or any subsequent breach, whether of the same or of different term of this Contract. The rights and remedies of the parties set forth in this Contract shall not be exclusive except as to the parties' obligation to arbitrate disputes, and are in addition to

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all other rights and remedies of the parties. This Contract sets forth the entire Contract between the parties with respect to the subject matter of this Contract, and supersedes all prior understandings, negotiations, and dealings between the parties with respect to its subject matter. Any and all matters pertaining to this Contract are considered confidential between both parties.

SLH

Pricing Terms: The price set forth herein excludes any federal, state or local taxes or charges ~~or PERC~~ or any other applicable fees. If applicable, these additional costs will be paid by the Buyer. Price is in US dollars. The price set forth is subject to rail surcharge, supplier transportation and/or pipe tariff and/or terminal fee increase during the term of the Contract. In the event the Product is not available at the origin point listed above, the price of the Product and/or the Product Transportation Fee listed above will be subject to change at the sole discretion of the Seller. Buyer shall be responsible for demurrage charges based on wait times greater than one hour at the pipeline or rail loading facilities for any reason and regardless of whether Buyer is the cause of such wait. For loads less than 90% of the maximum legal load size, the Seller reserves the right to charge the Buyer full freight based on the maximum legal load size. The price per gallon set forth above shall not apply to purchases of Product in excess of the gallons listed in this Contract.

Payment Terms: Payment shall be made in US dollars, in full without discount, withholding, setoff or counterclaim, in immediate available funds. If Buyer fails to pay the full amount due to the Seller when due, interest will accrue at the maximum lawful rate of interest and Seller, in its sole discretion and without notice to Buyer, shall be permitted to reduce and/or eliminate the remaining monthly volumes of Product to be delivered under this Contract.

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REDACTED

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-7 (COG) Respondent: Kelly Esposito

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

The Company states that "the approximate five percent unfilled portion of FS-MA storage provides a buffer that allows the Company operational flexibility to inject some of its supply into storage if needed due to weather fluctuations during the month of November." See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0033.

a) What 'supply' does the Company anticipate may be 'injected into storage' and how much does that 'supply' cost per therm? What vendor(s) would provide that supply? Why is this specific to the month of November?

RESPONSE:

The Company requires some open space in storage for injections in the event of extreme warm weather conditions, operational constraints on upstream pipelines, or reverse migration from the Company's Retail Choice program. Although a determination of which supply to inject would be made on the day in question, it would likely be the long-haul supply which is contracted to [redacted] and priced at [redacted]. Additionally, gas injected as part of reverse migration would be injected at the Company's weighted average cost of gas (WACOG).

The shaded or redacted information above is "confidential, commercial, or financial information" and is thus protected from disclosure by RSA 91-A:5, IV, and presumed to be confidential in cost of gas proceedings pursuant to Puc 201.06(a)(11). Therefore, pursuant to that statute and Puc 203.08(d) and Puc 201.01.06(a)(11)(g) (protecting "responses to data requests related to a. through f. above"), the Company has a good faith basis to seek confidential treatment of this information and asserts confidentiality pursuant to those rules.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-8 (COG) Respondent: Mark Summerfield

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Liberty states that, "... 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." See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0035. Liberty also states that "The estimated percentage used for pressure support purposes of 8.7% stayed the same based on the marginal cost study used for the rate design approved in Docket No. DG 20-105." See R. Garcia and A. Maston Testimony at 0013.

a) Please comment on capital improvements made at any facility following the DG 20-105 rate case; specifically, weren't improvement made to improve system pressure support and change the estimated 8.7 percentage?

b) Did the Company undertake any additional projects for capital improvements as of September 1 2023 that would have increased, maintained or reduced the estimated 8.7 percentage? Since Dkt. No. 20-105 has the estimated pressure support percentage dropped below 8.7%?

c) Please identify all 'facilities' referenced directly or implicitly by R. Garcia, A. Maston, J. Tilbury, K. Esposito and M. Summerfield in their pre-filed testimony; the description should include but not be limited to the type of "facility", when the Company acquired or rented /it or them and where they are located. "Facilities" includes but is not limited to "vaporization facilities" that the Company states exist in Concord, Manchester and Tilton.

d) Please explain why the Company conclude it would "utilize more vaporization capacities from its LNG facilities." Did the Company conduct a cost-benefit analysis? If so, please provide that analysis, if not why not? See Tilbury, Esposito and Summerfield Testimony at 0034.

e) Please provide a copy of portions of the MCOSS in Docket No. DG 20-105 that the Company believes are relevant to the estimated 8.7 percentage calculation. Please show or reference calculations the Company asserts result in an 8.7 percentage for the current filing.

RESPONSE:

a) Below is a list of capital improvements that have been completed following the DG 20-105 rate case.

As discussed in testimony, the estimated percentage used for pressure support purposes of 8.7% remains unchanged because it was based on the marginal cost of service (MCOS) study that was used for the rate design approved in Docket No. DG 20-105. While some of these projects can improve system pressure support, in any given year the Company may experience a higher or lower need for pressure support depending on the weather and demands on the system during a given period. It is not possible to adjust the allocation based solely on a review of discreet projects. A new MCOS study would have to be performed to support any change to the currently approved 8.7% figure.

2020:
- LP Air Compressor overhaul, Manchester LP,
- Nashua Vaporizer #1 burner control upgrade,
- SCADA/PLC upgrade Tilton LNG, install manual operation panel

2021:
- Tilton LNG Tank withdrawal valve replacement
- Concord LNG Boil off vaporizer, replace
- Nashua Vaporizer #2, burner control upgrade

2022:
- LNG Pump replacement, Manchester LNG
- Nashua Vaporizer #3 conversion to natural gas
- Concord LNG, provided equipment redundancy by installing second LNG offload pump, temporary second hot water boiler and all piping, electrical and ancillary mods to meet Gas Supply base load objectives.

2023:
- Nashua LP, Repair stressed pump piping at tank 1.
- Manchester, Fire call box replacement
- Provide weather shelter shed for Manchester LNG offload station
- Provide weather shelter shed for Concord LNG offload station.
- Replacement LNG relief valve – Concord
- Install 2nd LNG offload pump Concord LNG

2024:
- Nashua, Verify & Calibrate LP Air flow meters for mixing system with prover, make correction to auto mix sys.
- Fixed Gas detector heads, replace/rebuild all Plants
- LP Tank relief valves, test replace/rebuild all LP locations
- Complete 2nd offload pump install

b) Please see response in (a) above.

c) The Company owns and operates three LNG facilities located in Tilton, Manchester, and Concord. The Company owns and operates four propane facilities located in Tilton, Manchester, Nashua, and Amherst. Note: the Amherst facility is a storage facility with no vaporization; it is not connected to the distribution system.

d) The Company requires additional LNG supply and trucking to maintain our working supply capacity of 12,600 MMBtu's and to maintain pressure support. As we utilize our LNG storage additional trucking and supply is required to maintain our inventory volumes and reliability. This is not a new approach or policy; it is standard procedure.

e) Please see Attachment 24-098 DOE 1-8e (COG).pdf for the MCOS study where the 8.7 percentage is calculated. This comes from DG 17-048, the rate case prior to DG 20-105, and was determined to still be appropriate for use during both the DG 20-105 rate case and the ongoing DG 23-067 rate case. We have no reason to believe it is not appropriate for the current filing.

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Incremental Production Cost Summary - LNG Peaker Unit

Line No.	Description	Company Total	Explanation
	Cost of Production-related Distribution System Reinforcement		
1	Cost of Incremental Production Capacity (2016$)		
2	Cost of Incremental LNG Capactity	$ 6,417,840	WP-MFB-1 p1 , Line12
3	Incremental Capacity	10,000	WP-MFB-1 p1 Line 13
4	Unit Cost of Incremental Production Capacity	$642	Line 2 / Line 3
5	Year of System Pressure Support Analysis	2016	
6	Base year of MCS study	2016	
7	Years Before production-related Pressure Support	0	Line 6 - Line 5
8	Discount (Inflation) rate	1.10%	MFB-7 p1 Line 17
9	Present Worth of Capacity Cost	$ 642	Line 4 x ((1 + Line 8)^ Line 7))
10	Percentage Related to Pressure Support	8.7%	MFB-1 p2 Line 10
11	Production Plant for Distribution Function (Pressure Support)	$56.05	Line 9 x Line 10

Liberty Utilities (EnergyNorth Natural Gas) Corp. MCS Study
Distribution-related Production Plant Investment

Local Production Facilities

Line No.	Plant Name	Location	Type	Rating, mscfg	Heat Rate	Hours per Day	Design Day Dth	Explanation
1	38 Bridge St	Nashua	LP-Air	600	1,250	24	18,000	Company Data
2	130 Elm St	Manchester	LP-Air	600	1,250	24	18,000	Company Data
3	130 Elm St	Manchester	LNG	220	1,050	24	5,544	Company Data
4	Broken Bridge	Concord	LNG	220	1,050	24	5,544	Company Data
5	Tilton Plant	Tilton	LP-Air	60	1,250	24	1,800	Company Data
6	Tilton Plant	Tilton	LNG	350	1,050	24	8,820	Company Data
7	Total			2,050			57,708	Σ line 1 to Line 6

Production Requirements in lieu of Distribution investments
Output Required for Pressure Support

Line No.	Plant Name	Location	Type	Rating, mscfg	Heat Rate	Hours per Day	Design Day Dth	
8	Tilton Plant	Tilton	LNG	200	1,050	24	5,040	Company Data
9	Total			200			5,040	

10	Production Allocated to Pressure Support Function	8.7%	Line 9 / Line 7

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marginal Capacity Related Distribution Plant Costs for Reinforcements

Selected Model: Distribution Plant Additions for Reinforcements 2016$ = F(Design Day Demand, Design Day Demand x Dummy$_{2018 \text{ to } 2026}$)

Dependent Variable				
Cumulative Annual Distribution Plant Additions for Reinforcements 2016$ $_{(2016 - 2026)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	-7,420,454	-6.99	0.000
Design Day Demand	Design demand	55.15	8.34	0.000
Interactive: Design Day Demand x Years 2018 to 2026	I_18_26xDD	8.18	6.39	0.000
Model Statistics				
R_Squared	0.984			
Mean Absolute % Error (MAPE)	5.999			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Distribution Plant Additions for Reinforcements = - $7,420,454 + $55.15 x Design demand + $8.18 x I_18_26xDD

For the period prior to 2018:

∂ Distribution Plant Additions for Reinforcements / ∂ Design Day Demand = $55.15 per Dth

For the period 2018 and beyond:

$\boxed{\text{∂ Distribution Plant Additions for Reinforcements / ∂ Design Day Demand = \$63.33 per Dth}}$

Docket No. DG 24-096
Attachment DOE 1-8A
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Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marginal Capacity Related Distribution Plant Costs for Main Extensions

Selected Model: Distribution Plant Additions for Main Extensions 2016$ = F(Design Day Demand, Design Day Demand x $\text{Dummy}_{2012\text{ to }2016}$, Dummy_{2000}, $\text{Dummy}_{2012\text{ to }2016}$, $\text{Dummy}_{2002\text{ to }2004}$)

Dependent Variable				
Cumulative Annual Distribution Plant Additions for Main Extensions 2016$ $_{(1989\text{ - }2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	-154,293,378	-17.74	0.000
Design Day Demand	Design Day Demand	1,672.54	23.34	0.000
Interactive: Design Day Demand x Years 2012 to 2016	I_12_16	-1,167.36	-2.95	0.007
Dummy: 2000	D_00	-19,451,333	-3.05	0.006
Dummy: 2012 to 2016	D_12_16	181,754,420	3.04	0.006
Dummy: 2002 to 2004	D_02_04	21,550,107	5.60	0.000
Model Statistics				
R_Squared	0.977			
Mean Absolute % Error (MAPE)	15.480			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Distribution Plant Additions for Main Extensions = - $154,293,378 + $1,672.54 x Design Day Demand + - $1,167.36 x I_12_16 + - $19,451,333 x D_00 + $181,754,420 x D_12_16 + $21,550,107 x D_02_(

For the period prior to 2012:

∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $1,672.54 per Dth

For the period 2012 and beyond:

∂ Distribution Plant Additions for Main Extensions / ∂ Design Day Demand = $505.18 per Dth

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Services and Meters Plant Investment

Line No.	Description	R-1	R-3 R-4	G-41	G-42	G-43	G-51	G-52	G-53	G-54	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
1	**Service Costs**										
2	Representative Cost	$4,918	$4,918	$4,918	$7,300	$10,913	$4,918	$7,300	$23,006	$54,416	Company Data
3	Customers per Service	1.32	1.32	1.32	1.00	1.00	1.32	1.00	1.00	1.00	Company Data
4	Average Service Cost per Customer	$3,738	$3,738	$3,738	$7,300	$10,913	$3,738	$7,300	$23,006	$54,416	Line 2 / Line 3
5	**Meter Costs**										
6	Current Unit Cost for Metering	$310	$310	$979	$2,433	$6,025	$979	$1,617	$7,312	$9,675	Company Data
7	Meters per Customer	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	Company Data
8	Average Meter Cost per Customer	$310	$310	$979	$2,433	$6,025	$979	$1,617	$7,312	$9,675	Line 6 * Line 7
9	Total	$4,048	$4,048	$4,717	$9,733	$16,937	$4,717	$8,917	$30,318	$64,091	Line 4 + Line 8

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marginal Capacity Related Production (Pressure Support) Expense

Selected Model: Capacity Related Production Expense 2016$ = F(Design Day Demand, Design Day Demand x Dummy$_{2006\ to\ 2016}$, Dummy$_{2006\ to\ 2016}$, Lag 1)

Dependent Variable				
Total Capacity Related Production Expense 2016$ $_{(1989\ -\ 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	2,515,397	4.55	0.000
Design Day Demand	Design Day Demand	-13.92	-2.87	0.009
Interactive: Design Day Demand x Years 2006 to 2016	I_06_16	34.49	2.62	0.015
Dummy: 2006 to 2016	D_06_16	-4,861,773	-2.64	0.015
Autoregressive Term Lag 1	Lag 1	0.56	2.91	0.008
Model Statistics				
R_Squared	0.769			
Mean Absolute % Error (MAPE)	16.892			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Capacity Related Production Expense = $2,515,397 + - $13.92 x Design Day Demand + $34.49 x I_06_16 + - $4,861,773 x D_06_16 + $0.56 x Lag 1

For the period prior to 2006:

∂ Capacity Related Production Expense / ∂ Design Day Demand = - $13.92 per Dth

For the period 2006 and beyond:

∂ Capacity Related Production Expense / ∂ Design Day Demand = $20.57 per Dth			
Percentage Related to Distribution Function		8.7%	MFB-1 p1, Line 10
Distribution Related O&M Expense	$	1.80	Line 23 x Line 24

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marginal Capacity Related Distribution Operations & Maintenance Expense

Selected Model: Capacity Related Distribution Operations & Maintenance Expense 2016$ = F(Design Day Demand, $Dummy_{2010,}$ $Dummy_{2014\ to\ 2016}$)

Dependent Variable				
Total Capacity Related Distribution Operations & Maintenance Expense 2016$ $_{(1989\ -\ 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	422,350	0.57	0.575
Design Day Demand	Design Day Demand	29.43	4.86	0.000
Dummy: 2010	D_10	1,200,663	2.10	0.047
Dummy: 2014 to 2016	D_14_16	2,312,231	5.84	0.000
Model Statistics				
R_Squared	0.845			
Mean Absolute % Error (MAPE)	8.626			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Capacity Related Distribution Operations & Maintenance Expense = $422,350 + $29.43 x Design Day Demand + $1,200,663 x D_10 + $2,312,231 x D_14_16

$\boxed{\partial \text{ Capacity Related Distribution Operations \& Maintenance Expense } / \ \partial \text{ Design Day Demand} = \$29.43 \text{ per Dth}}$

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Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marginal Customer Related Distribution Operations & Maintenance Expense

1 **Selected Model:** Customer Related Distribution Operations & Maintenance Expense 2016$ = F(Annual Customers, $\text{Dummy}_{2003\text{ to }2013}$, Dummy_{2012}, Dummy_{2010}, Dummy_{2014}, $\text{Dummy}_{2009\text{ and beyond}}$, $\text{Dummy}_{2000\text{ and beyond}}$, Annual Customers x $\text{Dummy}_{1989\text{ to }1998}$, $\text{Dummy}_{1989\text{ to }1998}$, Dummy_{2002}, Dummy_{2008})

2

Line	Explanatory Variables	Database variable name	Coefficient value	t test	Significance
3	Dependent Variable				
4	Total Customer Related Distribution Operations & Maintenance Expense 2016$ $_{(1989\text{ - }2016)}$				
5	Explanatory Variables	Database variable name	Coefficient value	t test	Significance
6	Constant	Constant	1,580,466	1.32	0.205
7	Annual Customers	Annual Customers	45.81	2.76	0.014
8	Dummy: 2003-2013	D_03_13	-1,338,653	-11.56	0.000
9	Dummy: 2012	D_12	-802,921	-3.85	0.001
10	Dummy: 2010	D_10	757,108	3.53	0.003
11	Dummy: 2014	D_14	794,581	3.75	0.002
12	Dummy: 2009 and After	D_09_After	808,377	4.55	0.000
13	Dummy: 2000 and After	D_00_After	-781,318	-3.27	0.005
14	Interactive: Annual Customers x Years 1989 to 1998	I_89_98	-116.91	-4.89	0.000
15	Dummy: 1989 to 1998	D_89_98	8,302,254	5.11	0.000
16	Dummy: 2002	D_02	-1,025,833	-4.70	0.000
17	Dummy: 2008	D_08	562,638	2.68	0.016
18	Model Statistics				
19	R_Squared	0.981			
20	Mean Absolute % Error (MAPE)	2.184			
21	Passes ACF/PACF	Yes			

22

23 Marginal Cost Calculation

24 Customer Related Distribution Operations & Maintenance Expense = $1,580,466 + $45.81 x Annual Customers + - $1,338,653 x D_03_13 + - $802,921 x D_12 + $757,108 x D_10 + $794,581 x D_14 + $808,377 x D_09_After + - $781,318 x D_00_After + - $116.91 x I_89_98 + $8,302,254 x D_89_98 + - $1,025,833 x D_02 + $562,638 x D_08

25

26 For the period prior to 1999:

27 ∂ Customer Related Distribution Operations & Maintenance Expense / ∂ Annual Customers = - $71.09 per Customer

28

29 For the period 1999 and beyond:

30 ∂ Customer Related Distribution Operations & Maintenance Expense / ∂ Annual Customers = $45.81 per Customer

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Class Weighted Customer Related Expense

Customer Weightings					Customer Weightings		
Line No.	Customer Groups	Test Year Number of Customers	Service and Meter Plant per customer	Total Cost	Relative Weight Per Customer	System Average Marginal Cost per Customer	Weighted Marginal Cost Per Customer
	(A)	(B)	(C)	(D)	(E)	(F)	(G)
		WP-MFB-BillingDets, Col (E) Lines 2 to 12	MFB-2 p1, Line 9	Col (B) x Col (C)	Col (C) Line n / Line 11	Col (G) Line 10	Col (E) x (F)
1	R-1	3,036	$4,048	12,289,041	0.946	$45.81	$43.35
2	R-3, R-4	76,093	$4,048	308,014,867	0.946	$45.81	$43.35
3	G-41	8,517	$4,717	40,171,435	1.103	$45.81	$50.51
4	G-42	1,714	$9,733	16,679,624	2.275	$45.81	$104.23
5	G-43	51	$16,937	856,504	3.959	$45.81	$181.38
6	G-51	1,251	$4,717	5,901,435	1.103	$45.81	$50.51
7	G-52	309	$8,917	2,750,838	2.084	$45.81	$95.49
8	G-53	34	$30,318	1,017,677	7.087	$45.81	$324.68
9	G-54	27	$64,091	1,760,359	14.981	$45.81	$686.35
10	Total	91,031		389,441,781			$45.81
11	Avg Cost per Customer		$4,278				

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Marignal Customer Accounting & Marketing Expense

Selected Model: Customer Related Expense 2016$ = F(Annual Customers, Dummy_{2012}, Annual Customers x $\text{Dummy}_{2005\ \text{to}\ 2016}$, $\text{Dummy}_{2005\ \text{to}\ 2016}$, Dummy_{2011}, $\text{Dummy}_{2001\ \text{to}\ 2002}$, Dummy_{1989})

Dependent Variable				
Total Customer Related Expense 2016$ $_{(1989 - 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	14,283,323	10.12	0.000
Annual Customers	Annual Customers	(136.00)	-6.57	0.000
Dummy: 2012	D_12	5,491,884	11.29	0.000
Interactive: Annual Customers x Years 2005 to 2016	I_05_16	214.30	4.05	0.001
Dummy: 2005 to 2016	D_05_16	(16,278,569)	-3.70	0.001
Dummy: 2011	D_11	3,469,154	7.13	0.000
Dummy: 2001 to 2002	D_01_02	(2,497,309)	-6.56	0.000
Dummy: 1989	D_89	(1,327,716)	-2.57	0.018
Model Statistics				
R_Squared	0.943			
Mean Absolute % Error (MAPE)	6.863			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Customer Related Expense = $14,283,323 + - $136.00 x Annual Customers + $5,491,884 x D_12 + $214.30 x I_05_16 + - $16,278,569 x D_05_16 + $3,469,154 x D_11 + - $2,497,309 x D_01_02 + - $1,327,716 x D_89

For the period prior to 2005:

∂ Customer Related Expense / ∂ Annual Customers = - $136.00 per Customer

For the period 2005 and beyond:

∂ Customer Related Expense / ∂ Annual Customers = $78.30 per Customer

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Class Weighted Bad Debt Accounts Expense

Line No.	Rate Class	Gross Bad Debt Expense 2016	Percent of Total	Adjusted Bad Debt Accounts Expense	Total Normalized Distribution Revenues	Bad Debt Expense Percentage
	(A)	(B) Company Data	(C) Col (B) line (n) / Col (B) Line 10	(D) Col (C) line(n) x Col (D) Line 10	(E) WP-MFB-BillingDets, Col (F)	(F) Col (D) / Col (E)
1	R-1	$ 73,686	2.73%	$40,772	$694,481	5.87%
2	R-3, R-4	$ 2,349,579	87.17%	$1,300,068	$37,445,217	3.47%
3	G-41	$ 156,699	5.81%	$86,705	$11,202,908	0.77%
4	G-42	$ 47,970	1.78%	$26,542	$12,451,487	0.21%
5	G-43	$ -	0.00%	$0	$2,244,971	0.00%
6	G-51	$ 36,289	1.35%	$20,080	$1,390,812	1.44%
7	G-52	$ 31,077	1.15%	$17,196	$1,585,741	1.08%
8	G-53	$ -	0.00%	$0	$1,376,073	0.00%
9	G-54	$ -	0.00%	$0	$931,478	0.00%
10	Total	2,695,300	100.00%	1,491,362	69,323,169	2.15%

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Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Plant Related A&G Marginal Loading Factor

Selected Model: Plant Related A&G = F(Total Utility Plant, Total Utility Plant x $\text{Dummy}_{2012\text{ to }2016}$, Total Utility Plant x $\text{Dummy}_{2003\text{ to }2011}$, Dummy_{2000}, Dummy_{2011}, $\text{Dummy}_{1989\text{ to }2000}$)

Dependent Variable				
Total Plant Related A&G $_{(1989 - 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	147,260	0.50	0.623
Total Utility Plant	Total Utility Plant	0.0044	2.91	0.008
Interactive: Total Utility Plant x Years 2012 to 2016	I_12_16	-0.0023	-2.58	0.018
Interactive: Total Utility Plant x Years 2003 to 2011	I_03_11	-0.0024	-3.29	0.004
Dummy: 2000	D_00	595,156	3.11	0.005
Dummy: 2011	D_11	-461,470	-2.37	0.027
Dummy: 1989 to 2000	D_89_00	695,819	4.67	0.000
Model Statistics				
R_Squared	0.875			
Mean Absolute % Error (MAPE)	12.647			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Plant Related A&G = $147,260 + $0.00443 x Total Utility Plant + - $0.002 x I_12_16 + - $0.0024 x I_03_11 + $595,156 x D_00 + - $461,470 x D_11 + $695,819 x D_89_00

For the period prior to 2003:

∂ Plant Related A&G / ∂ Total Utility Plant = $0.0044 per dollar of Utility Plant

For the period 2003-2011:

∂ Plant Related A&G / ∂ Total Utility Plant = $0.0021 per dollar of Utility Plant

For the period 2012 and beyond:

∂ Plant Related A&G / ∂ Total Utility Plant = $0.0021 per dollar of Utility Plant

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Non-Plant Related A&G Marginal Loading Factor

Selected Model: Non-Plant Related A&G = F(Adjusted O&M, Adjusted O&M x $\text{Dummy}_{2003\text{ to }2016}$, $\text{Dummy}_{2003\text{ to }2016}$, $\text{Dummy}_{2012\text{ to }2013}$, $\text{Dummy}_{1989\text{ to }2001}$)

Dependent Variable Total Non-Plant Related A&G (1989 - 2016)				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	12,211,225	4.79	0.000
Adjusted O&M	Adjusted O&M	-1.150	-3.21	0.004
Interactive: Adjusted O&M x Years 2003 to 2016	I_03_16	1.698	4.61	0.000
Dummy: 2003 to 2016	D_03_16	-12,337,744	-4.35	0.000
Dummy: 2012 to 2013	D_12_13	6,232,487	7.03	0.000
Dummy: 1989 to 2001	D_89_01	5,502,395	3.18	0.004
Model Statistics				
R_Squared	0.860			
Mean Absolute % Error (MAPE)	11.001			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Non-Plant Related A&G = $12,211,225 + - $1.15 x Adjusted O&M + $1.70 x I_03_16 + - $12,337,744 x D_03_16 + $6,232,487 x D_12_13 + $5,502,395 x D_89_01

For the period prior to 2003:

∂ Non-Plant Related A&G / ∂ Adjusted O&M = - $1.150 per dollar of O&M

For the period 2003 and beyond:

$\boxed{\partial \text{ Non-Plant Related A\&G} / \partial \text{ Adjusted O\&M} = \$0.548 \text{ per dollar of O\&M}}$

Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

Materials & Supplies and Prepayments Marginal Loading Factor

Selected Model: Materials & Supplies and Prepayments = F(Total Utility Plant, Total Utility Plant x $\text{Dummy}_{2012 \text{ to } 2016}$, Total Utility Plant x $\text{Dummy}_{2003 \text{ to } 2011}$, $\text{Dummy}_{2003 \text{ to } 2011}$, Dummy_{2013})

Dependent Variable				
Materials & Supplies and Prepayments $_{(1989 - 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	4,518,784	5.60	0.000
Total Utility Plant	Total Utility Plant	-0.015	-2.67	0.014
Interactive: Total Utility Plant x Years 2012 to 2016	I_12_16	0.017	4.52	0.000
Interactive: Total Utility Plant x Years 2003 to 2011	I_03_11	0.025	3.04	0.006
Dummy: 2003 to 2011	D_03_11	-6,846,387	-3.56	0.002
Dummy: 2013	D_13	-2,473,288	-3.12	0.005
Model Statistics				
R_Squared	0.863			
Mean Absolute % Error (MAPE)	106.631			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

Materials & Supplies and Prepayments = $4,518,784 + - $0.02 x Total Utility Plant + $0.02 x I_12_16 + $0.03 x I_03_11 + - $6,846,387 x D_03_11 + - $2,473,288 x D_13

For the period prior to 2003:

∂ Materials & Supplies and Prepayments / ∂ Total Utility Plant = - $0.015 per dollar of Utility Plant

For the period 2003-2011:

∂ Materials & Supplies and Prepayments / ∂ Total Utility Plant = $0.010 per dollar of Utility Plant

For the period 2012 and beyond:

∂ Materials & Supplies and Prepayments / ∂ Total Utility Plant = $0.002 per dollar of Utility Plant

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Liberty Utilities (Energy North Natural Gas) Corp.
Marginal Cost Study

General Plant Marginal Loading Factor

Selected Model: General Plant = F(Total Utility Plant, $\text{Dummy}_{2012 \text{ to } 2014}$)

Dependent Variable				
General Plant $_{(1989 - 2016)}$				
Explanatory Variables	Database variable name	Coefficient value	t test	Significance
Constant	Constant	2,565,407	4.40	0.000
Total Utility Plant	Total Utility Plant	0.040	16.22	0.000
Dummy: 2012 to 2014	D_12_14	-7,295,432	-8.75	0.000
Model Statistics				
R_Squared	0.914			
Mean Absolute % Error (MAPE)	8.418			
Passes ACF/PACF	Yes			

Marginal Cost Calculation

General Plant = $2,565,407 + $0.040 x Total Utility Plant + - $7,295,432 x D_12_14

$\boxed{\partial \text{ General Plant } / \partial \text{ Total Utility Plant} = \$0.040 \text{ per dollar of Utility Plant}}$

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study

Summary of Levelized Fixed Carrying Charge Rates

Line No.	Description	Engineer's Fixed Charge Rate	Economist's Fixed charge Rate	Explanation
	(A)	(B)	(C)	(D)
1	Fixed Charge Rate Results			
2	Levelized Cost for:		Over Book Life	
3	Production Plant	12.95%	11.42%	MFB-7 p3, Line 13
4	Mains (Cap-related Dist)	12.45%	10.58%	MFB-7 p4, Line 13
5	Services Investment	12.01%	10.39%	MFB-7 p5, Line 13
6	Meters Investment	13.32%	11.92%	MFB-7 p6, Line 13
7	Cost of Capital			
8	Debt	4.43%	50.00%	WP-MFB-7 p1, Line 1
9	Preferred	0.00%	0.00%	WP-MFB-7 p1, Line 2
10	Common	10.30%	50.00%	WP-MFB-7 p1, Line 3
11	Other	0.00%	0.00%	WP-MFB-7 p1, Line 4
12	Weighted Cost of Capital		7.363%	
13	After Tax Cost of New Capital		6.49%	WP-MFB-7 p1, Line 8
14	Incremental Tax Rate		39.41%	WP-MFB-7 p1, Line 6
15	Tax Effected Cost of Capital		10.71%	WP-MFB-7 p1, Line 5
16	Property Tax Rate		2.91%	WP-MFB-7 p1, Line 7
17	Inflation Rate		1.10%	WP-MFB-7 p1, Line 9
18	Property Tax Escalation Rate		2.50%	WP-MFB-7 p1, Line 10

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Levelized Fixed Carrying Charge Analysis, Input Data

Line No.	Variable	Peaking Plant	Capacity - Related Distribution	Services	Meters	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)
1	Plant Data					
2	Capitalized Cost	$1,000	$1,000	$1,000	$1,000	
3	Book Life	35	59	45	29	MFB-7 p8, Col (D)
4	Salvage Value	0%	-15%	-60%	0%	MFB-7 p8, Col (E)
5	MACRS Life	20	20	20	20	
6	Capital Structure					
7	Debt Ratio	50.00%	50.00%	50.00%	50.00%	MFB-7 p1, Col (C), Line 8
8	Preferred Ratio	0.00%	0.00%	0.00%	0.00%	MFB-7 p1, Col (C), Line 9
9	Common Ratio	50.00%	50.00%	50.00%	50.00%	MFB-7 p1, Col (C), Line 10
10	Other	0.00%	0.00%	0.00%	0.00%	MFB-7 p1, Col (C), Line 11
11	Cost of Capital					
12	Debt Cost	4.43%	4.43%	4.43%	4.43%	MFB-7 p1, Col (B), Line 8
13	Preferred Cost	0.00%	0.00%	0.00%	0.00%	MFB-7 p1, Col (B), Line 9
14	Common Cost	10.30%	10.30%	10.30%	10.30%	MFB-7 p1, Col (B), Line 10
15	Other	0.00%	0.00%	0.00%	0.00%	MFB-7 p1, Col (B), Line 11
16	Wtd Cost Of Capital	7.36%	7.36%	7.36%	7.36%	(Line 7 xLine 12) + (Line 8 xLine 13) + (Line 9xLine 14) + (Line 10xLine 15)
17	After Tax Cost of Capital	6.49%	6.49%	6.49%	6.49%	MFB-7 p1, Col (C), Line 13
18	Tax Data					
19	Tax Rate	39.41%	39.41%	39.41%	39.41%	MFB-7 p1, Col (C), Line 14
20	Property Tax Rate	2.91%	2.91%	2.91%	2.91%	MFB-7 p1, Col (C), Line 16
21	Property Insurance	0.01%	0.01%	0.01%	0.01%	WP-MFB-7 p2, Line 3
22	Property Tax Basis	Dep Bal	Dep Bal	Dep Bal	Dep Bal	
23	Misc. Data					
24	Inflation Rate	1.10%	1.10%	1.10%	1.10%	MFB-7 p1, Col (C), Line 17
25	Prop Tax Escalation Rate	2.50%	2.50%	2.50%	2.50%	MFB-7 p1, Col (C), Line 18
26	Return on Rate Base calculation	EOY	EOY	EOY	EOY	

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Levelized Fixed Carrying Charge Analysis
Peaker Plant

		-- Current Dollars -- (Engineer's FCR)		-- Constant Dollars -- (Economist's FCR)	
Line No.	Item	Current Levelized Dollars	Percent Of Capital Investment	Constant Levelized Dollars	Percent Of Capital Investment
	(A)	(B) MFB-7 p7A	(C) Col (B) x 0.001	(D) MFB-7 p7A	(E) Col (D) x 0.001
1	Interest On Debt	$12.69	1.27%	$11.19	1.12%
2	Return On Preferred	$0.00	0.00%	$0.00	0.00%
3	Return On Common	$29.55	2.95%	$26.05	2.61%
4	Return	$42.24	4.22%	$37.24	3.72%
5	Depreciation	$28.57	2.86%	$25.19	2.52%
6	Income Tax	$14.22	1.42%	$12.54	1.25%
7	Deferred Taxes	$5.00	0.50%	$4.40	0.44%
8	Income Tax	$19.22	1.92%	$16.94	1.69%
9	Revenue Tax	$0.00	0.00%	$0.00	0.00%
10	Property Tax	$39.27	3.93%	$34.63	3.46%
11	Property Insurance	$0.17	0.02%	$0.15	0.01%
12	Other	$39.44	3.94%	$34.78	3.48%
13	Total Revenue Required	$129.48	12.95%	$114.15	11.42%

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Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Levelized Fixed Carrying Charge Analysis
Capacity Related Distribution

		Current Dollars (Engineer's FCR)		Constant Dollars (Economist's FCR)	
Line No.	Item	Current Levelized Dollars	Percent Of Capital Investment	Constant Levelized Dollars	Percent Of Capital Investment
	(A)	(B) MFB-7 p7B	(C) Col (B) x 0.001	(D) MFB-7 p7B	(E) Col (D) x 0.001
1	Interest On Debt	$13.08	1.31%	$11.11	1.11%
2	Return On Preferred	$0.00	0.00%	$0.00	0.00%
3	Return On Common	$30.44	3.04%	$25.86	2.59%
4	Return	$43.51	4.35%	$36.98	3.70%
5	Depreciation	$19.42	1.94%	$16.51	1.65%
6	Income Tax	$12.54	1.25%	$10.66	1.07%
7	Deferred Taxes	$7.26	0.73%	$6.17	0.62%
8	Income Tax	$19.80	1.98%	$16.82	1.68%
9	Revenue Tax	$0.00	0.00%	$0.00	0.00%
10	Property Tax	$41.64	4.16%	$35.38	3.54%
11	Property Insurance	$0.17	0.02%	$0.15	0.01%
12	Other	$41.81	4.18%	$35.53	3.55%
13	Total Revenue Required	$124.54	12.45%	$105.83	10.58%

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Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study

Levelized Fixed Carrying Charge Analysis

Services Investment

		Current Dollars (Engineer's FCR)		Constant Dollars (Economist's FCR)	
Line No.	Item	Current Levelized Dollars	Percent Of Capital Investment	Constant Levelized Dollars	Percent Of Capital Investment
	(A)	(B) MFB-7 p7C	(C) Col (B) x 0.001	(D) MFB-7 p7C	(E) Col (D) x 0.001
1	Interest On Debt	$10.60	1.06%	$9.17	0.92%
2	Return On Preferred	$0.00	0.00%	$0.00	0.00%
3	Return On Common	$24.67	2.47%	$21.34	2.13%
4	Return	$35.27	3.53%	$30.51	3.05%
5	Depreciation	$35.56	3.56%	$30.75	3.08%
6	Income Tax	$13.73	1.37%	$11.88	1.19%
7	Deferred Taxes	$2.31	0.23%	$2.00	0.20%
8	Income Tax	$16.05	1.60%	$13.88	1.39%
9	Revenue Tax	$0.00	0.00%	$0.00	0.00%
10	Property Tax	$33.06	3.31%	$28.60	2.86%
11	Property Insurance	$0.15	0.01%	$0.13	0.01%
12	Other	$33.21	3.32%	$28.73	2.87%
13	Total Revenue Required	$120.08	12.01%	$103.87	10.39%

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Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Levelized Fixed Carrying Charge Analysis
Metering Equipment

		Current Dollars (Engineer's FCR)		Constant Dollars (Economist's FCR)	
Line No.	Item	Current Levelized Dollars	Percent Of Capital Investment	Constant Levelized Dollars	Percent Of Capital Investment
	(A)	(B)	(C)	(D)	(E)
		MFB-7 p7D	Col (B) x 0.001	MFB-7 p7D	Col (D) x 0.001
1	Interest On Debt	$12.54	1.25%	$11.22	1.12%
2	Return On Preferred	$0.00	0.00%	$0.00	0.00%
3	Return On Common	$29.19	2.92%	$26.12	2.61%
4	Return	$41.74	4.17%	$37.34	3.73%
5	Depreciation	$34.48	3.45%	$30.85	3.09%
6	Income Tax	$15.34	1.53%	$13.73	1.37%
7	Deferred Taxes	$3.65	0.36%	$3.26	0.33%
8	Income Tax	$18.99	1.90%	$16.99	1.70%
9	Revenue Tax	$0.00	0.00%	$0.00	0.00%
10	Property Tax	$37.83	3.78%	$33.85	3.38%
11	Property Insurance	$0.17	0.02%	$0.15	0.01%
12	Other	$38.00	3.80%	$34.00	3.40%
13	Total Revenue Required	$133.20	13.32%	$119.19	11.92%

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream
Peaker Plant

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Taxes	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	1000.00						0.00	0.00								
1	967.91	21.42	0.00	49.85	37.50	3.7500%	28.57	3.52	73.34	28.90		29.12	0.15	161.53	16.15%	151.69
2	922.15	20.40	0.00	47.49	72.19	7.219%	28.57	17.19	34.76	13.70		29.85	0.15	157.36	15.74%	138.76
3	878.52	19.44	0.00	45.24	66.77	6.677%	28.57	15.05	36.47	14.37		30.60	0.15	153.43	15.34%	127.05
4	836.87	18.52	0.00	43.10	61.77	6.177%	28.57	13.08	37.93	14.95		31.36	0.15	149.74	14.97%	116.44
5	797.04	17.63	0.00	41.05	57.13	5.713%	28.57	11.25	39.19	15.44		32.15	0.16	146.26	14.63%	106.80
6	758.90	16.79	0.00	39.08	52.85	5.285%	28.57	9.57	40.23	15.85		32.95	0.16	142.98	14.30%	98.04
7	722.33	15.98	0.00	37.20	48.88	4.888%	28.57	8.00	41.09	16.19		33.78	0.16	139.88	13.99%	90.07
8	687.19	15.20	0.00	35.39	45.22	4.522%	28.57	6.56	41.76	16.46		34.62	0.16	136.97	13.70%	82.82
9	652.30	14.43	0.00	33.59	44.62	4.462%	28.57	6.32	39.40	15.53		35.49	0.16	134.10	13.41%	76.14
10	617.41	13.66	0.00	31.80	44.61	4.461%	28.57	6.32	36.44	14.36		36.37	0.17	131.25	13.12%	69.98
11	582.51	12.89	0.00	30.00	44.62	4.462%	28.57	6.32	33.46	13.19		37.28	0.17	128.42	12.84%	64.30
12	547.62	12.12	0.00	28.20	44.61	4.461%	28.57	6.32	30.51	12.02		38.21	0.17	125.62	12.56%	59.06
13	512.72	11.34	0.00	26.41	44.62	4.462%	28.57	6.32	27.53	10.85		39.17	0.17	122.84	12.28%	54.23
14	477.83	10.57	0.00	24.61	44.61	4.461%	28.57	6.32	24.58	9.69		40.15	0.17	120.08	12.01%	49.79
15	442.93	9.80	0.00	22.81	44.62	4.462%	28.57	6.32	21.60	8.51		41.15	0.17	117.35	11.73%	45.69
16	408.04	9.03	0.00	21.01	44.61	4.461%	28.57	6.32	18.64	7.35		42.18	0.18	114.64	11.46%	41.91
17	373.14	8.26	0.00	19.22	44.62	4.462%	28.57	6.32	15.67	6.17		43.24	0.18	111.96	11.20%	38.44
18	338.25	7.48	0.00	17.42	44.61	4.461%	28.57	6.32	12.71	5.01		44.32	0.18	109.30	10.93%	35.24
19	303.36	6.71	0.00	15.62	44.62	4.462%	28.57	6.32	9.74	3.84		45.42	0.18	106.67	10.67%	32.30
20	268.46	5.94	0.00	13.83	44.61	4.461%	28.57	6.32	6.78	2.67		46.56	0.18	104.07	10.41%	29.59
21	242.36	5.36	0.00	12.48	22.31	2.231%	28.57	(2.47)	26.86	10.59		47.72	0.19	102.44	10.24%	27.35
22	225.05	4.98	0.00	11.59	0.00		28.57	(11.26)	47.70	18.80		48.92	0.19	101.78	10.18%	25.52
23	207.74	4.60	0.00	10.70	0.00		28.57	(11.26)	46.23	18.22		50.14	0.19	101.16	10.12%	23.81
24	190.43	4.21	0.00	9.81	0.00		28.57	(11.26)	44.76	17.64		51.39	0.19	100.56	10.06%	22.23
25	173.11	3.83	0.00	8.92	0.00		28.57	(11.26)	43.29	17.06		52.68	0.19	99.99	10.00%	20.76
26	155.80	3.45	0.00	8.02	0.00		28.57	(11.26)	41.81	16.48		54.00	0.20	99.45	9.95%	19.39
27	138.49	3.06	0.00	7.13	0.00		28.57	(11.26)	40.34	15.90		55.35	0.20	98.95	9.90%	18.11
28	121.18	2.68	0.00	6.24	0.00		28.57	(11.26)	38.87	15.32		56.73	0.20	98.48	9.85%	16.93
29	103.87	2.30	0.00	5.35	0.00		28.57	(11.26)	37.40	14.74		58.15	0.20	98.05	9.80%	15.83
30	86.56	1.92	0.00	4.46	0.00		28.57	(11.26)	35.93	14.16		59.60	0.21	97.65	9.76%	14.80
31	69.25	1.53	0.00	3.57	0.00		28.57	(11.26)	34.46	13.58		61.09	0.21	97.29	9.73%	13.85
32	51.93	1.15	0.00	2.67	0.00		28.57	(11.26)	32.99	13.00		62.62	0.21	96.96	9.70%	12.96
33	34.62	0.77	0.00	1.78	0.00		28.57	(11.26)	31.51	12.42		64.18	0.21	96.68	9.67%	12.14
34	17.31	0.38	0.00	0.89	0.00		28.57	(11.26)	30.04	11.84		65.79	0.21	96.43	9.64%	11.37
35	0.00	0.00	0.00	0.00	0.00		28.57	(11.26)	28.57	11.26		67.43	0.22	96.22	9.62%	10.65
Total		$ 307.83	$ -	$ 716.53	$ 1,000.00	$ 1.00	$ 1,000.00	$ (0.00)	$ 1,182.59	$ 466.06	$ -	$ 1,599.76	$ 6.35	$ 4,096.52	409.65%	$ 1,774.02
Present Worth		$173.93	$ -	$ 404.85	$ 565.13	$ 0.57	$ 391.47	$ 68.44	$ 494.52	$ 194.89	$ -	$ 538.11	$ 2.32	$ 1,774.02	$1.77	$ 1,025.88
Levelized Payment Current		$12.69	$ -	$ 29.55	$ 41.25	$ 0.04	$ 28.57	$ 5.00	$ 36.09	$ 14.22	$ -	$ 39.27	$ 0.17	$ 129.48	12.95%	
Levelized Payment		$ 11.19	$ -	$ 26.05	$ 36.36	$ 0.04	$ 25.19	$ 4.40	$ 31.82	$ 12.54	$ -	$ 34.63	$ 0.15	$ 114.15	11.42%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream

Capacity Related Distribution

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Taxes	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	1000.00						0.00	0.00								
1	973.45	21.54	0.00	50.13	37.50	3.750%	19.42	7.12	64.66	25.48		29.12	0.15	152.98	15.30%	143.65
2	933.23	20.65	0.00	48.06	72.19	7.219%	19.42	20.80	26.56	10.47		29.85	0.15	149.40	14.94%	131.74
3	895.15	19.81	0.00	46.10	66.77	6.677%	19.42	18.66	28.74	11.33		30.60	0.15	146.07	14.61%	120.95
4	859.04	19.01	0.00	44.24	61.77	6.177%	19.42	16.69	30.67	12.09		31.36	0.15	142.96	14.30%	111.17
5	824.75	18.25	0.00	42.47	57.13	5.713%	19.42	14.86	32.40	12.77		32.15	0.16	140.08	14.01%	102.29
6	792.16	17.53	0.00	40.80	52.85	5.285%	19.42	13.17	33.91	13.36		32.95	0.16	137.39	13.74%	94.21
7	761.13	16.84	0.00	39.20	48.88	4.888%	19.42	11.61	35.24	13.89		33.78	0.16	134.89	13.49%	86.86
8	731.54	16.19	0.00	37.67	45.22	4.522%	19.42	10.17	36.38	14.34		34.62	0.16	132.57	13.26%	80.16
9	702.18	15.54	0.00	36.16	44.62	4.462%	19.42	9.93	34.49	13.59		35.49	0.16	130.29	13.03%	73.98
10	672.83	14.89	0.00	34.65	44.61	4.461%	19.42	9.93	32.00	12.61		36.37	0.17	128.04	12.80%	68.27
11	643.48	14.24	0.00	33.14	44.62	4.462%	19.42	9.93	29.50	11.63		37.28	0.17	125.80	12.58%	62.99
12	614.13	13.59	0.00	31.63	44.61	4.461%	19.42	9.93	27.01	10.65		38.21	0.17	123.59	12.36%	58.11
13	584.78	12.94	0.00	30.12	44.62	4.462%	19.42	9.93	24.51	9.66		39.17	0.17	121.41	12.14%	53.60
14	555.43	12.29	0.00	28.60	44.61	4.461%	19.42	9.93	22.02	8.68		40.15	0.17	119.24	11.92%	49.44
15	526.07	11.64	0.00	27.09	44.62	4.462%	19.42	9.93	19.52	7.69		41.15	0.17	117.10	11.71%	45.59
16	496.72	10.99	0.00	25.58	44.61	4.461%	19.42	9.93	17.03	6.71		42.18	0.18	114.99	11.50%	42.04
17	467.37	10.34	0.00	24.07	44.62	4.462%	19.42	9.93	14.53	5.73		43.24	0.18	112.90	11.29%	38.76
18	438.02	9.69	0.00	22.56	44.61	4.461%	19.42	9.93	12.04	4.75		44.32	0.18	110.84	11.08%	35.74
19	408.67	9.04	0.00	21.05	44.62	4.462%	19.42	9.93	9.54	3.76		45.42	0.18	108.81	10.88%	32.94
20	379.32	8.39	0.00	19.53	44.61	4.461%	19.42	9.93	7.05	2.78		46.56	0.18	106.80	10.68%	30.36
21	358.76	7.94	0.00	18.48	22.31	2.231%	19.42	1.14	27.61	10.88		47.72	0.19	105.76	10.58%	28.24
22	346.99	7.68	0.00	17.87	0.00		19.42	(7.65)	48.92	19.28		48.92	0.19	105.70	10.57%	26.50
23	335.22	7.42	0.00	17.26	0.00		19.42	(7.65)	47.92	18.88		50.14	0.19	105.66	10.57%	24.88
24	323.45	7.16	0.00	16.66	0.00		19.42	(7.65)	46.92	18.49		51.39	0.19	105.66	10.57%	23.36
25	311.68	6.90	0.00	16.05	0.00		19.42	(7.65)	45.92	18.10		52.68	0.19	105.68	10.57%	21.94
26	299.91	6.64	0.00	15.45	0.00		19.42	(7.65)	44.92	17.70		54.00	0.20	105.74	10.57%	20.61
27	288.14	6.38	0.00	14.84	0.00		19.42	(7.65)	43.92	17.31		55.35	0.20	105.83	10.58%	19.37
28	276.37	6.11	0.00	14.23	0.00		19.42	(7.65)	42.91	16.91		56.73	0.20	105.96	10.60%	18.21
29	264.61	5.85	0.00	13.63	0.00		19.42	(7.65)	41.91	16.52		58.15	0.20	106.12	10.61%	17.13
30	252.84	5.59	0.00	13.02	0.00		19.42	(7.65)	40.91	16.12		59.60	0.21	106.31	10.63%	16.12
31	241.07	5.33	0.00	12.42	0.00		19.42	(7.65)	39.91	15.73		61.09	0.21	106.55	10.65%	15.17
32	229.30	5.07	0.00	11.81	0.00		19.42	(7.65)	38.91	15.34		62.62	0.21	106.81	10.68%	14.28
33	217.53	4.81	0.00	11.20	0.00		19.42	(7.65)	37.91	14.94		64.18	0.21	107.12	10.71%	13.45
34	205.76	4.55	0.00	10.60	0.00		19.42	(7.65)	36.91	14.55		65.79	0.21	107.47	10.75%	12.67
35	193.99	4.29	0.00	9.99	0.00		19.42	(7.65)	35.91	14.15		67.43	0.22	107.85	10.79%	11.94
36	182.22	4.03	0.00	9.38	0.00		19.42	(7.65)	34.91	13.76		69.12	0.22	108.28	10.83%	11.26
37	170.46	3.77	0.00	8.78	0.00		19.42	(7.65)	33.91	13.36		70.85	0.22	108.75	10.88%	10.62

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream
Capacity Related Distribution

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Taxes	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
38	158.69	3.51	0.00	8.17	0.00		19.42	(7.65)	32.91	12.97		72.62	0.22	109.26	10.93%	10.02
39	146.92	3.25	0.00	7.57	0.00		19.42	(7.65)	31.91	12.58		74.43	0.23	109.82	10.98%	9.45
40	135.15	2.99	0.00	6.96	0.00		19.42	(7.65)	30.91	12.18		76.29	0.23	110.42	11.04%	8.93
41	123.38	2.73	0.00	6.35	0.00		19.42	(7.65)	29.91	11.79		78.20	0.23	111.07	11.11%	8.43
42	111.61	2.47	0.00	5.75	0.00		19.42	(7.65)	28.91	11.39		80.16	0.23	111.77	11.18%	7.97
43	99.84	2.21	0.00	5.14	0.00		19.42	(7.65)	27.91	11.00		82.16	0.24	112.52	11.25%	7.53
44	88.07	1.95	0.00	4.54	0.00		19.42	(7.65)	26.91	10.61		84.21	0.24	113.31	11.33%	7.12
45	76.31	1.69	0.00	3.93	0.00		19.42	(7.65)	25.91	10.21		86.32	0.24	114.16	11.42%	6.74
46	64.54	1.43	0.00	3.32	0.00		19.42	(7.65)	24.91	9.82		88.48	0.24	115.06	11.51%	6.38
47	52.77	1.17	0.00	2.72	0.00		19.42	(7.65)	23.91	9.42		90.69	0.25	116.01	11.60%	6.04
48	41.00	0.91	0.00	2.11	0.00		19.42	(7.65)	22.91	9.03		92.96	0.25	117.02	11.70%	5.72
49	29.23	0.65	0.00	1.51	0.00		19.42	(7.65)	21.91	8.63		95.28	0.25	118.09	11.81%	5.42
50	17.46	0.39	0.00	0.90	0.00		19.42	(7.65)	20.91	8.24		97.66	0.26	119.21	11.92%	5.14
51	5.69	0.13	0.00	0.29	0.00		19.42	(7.65)	19.91	7.85		100.10	0.26	120.40	12.04%	4.87
52	(6.08)	(0.13)	0.00	(0.31)	0.00		19.42	(7.65)	18.91	7.45		0.00	0.00	18.77	1.88%	0.71
53	(17.84)	(0.39)	0.00	(0.92)	0.00		19.42	(7.65)	17.91	7.06		0.00	0.00	17.51	1.75%	0.62
54	(29.61)	(0.66)	0.00	(1.53)	0.00		19.42	(7.65)	16.91	6.66		0.00	0.00	16.25	1.63%	0.54
55	(41.38)	(0.92)	0.00	(2.13)	0.00		19.42	(7.65)	15.91	6.27		0.00	0.00	14.99	1.50%	0.47
56	(53.15)	(1.18)	0.00	(2.74)	0.00		19.42	(7.65)	14.91	5.87		0.00	0.00	13.73	1.37%	0.41
57	(64.92)	(1.44)	0.00	(3.34)	0.00		19.42	(7.65)	13.91	5.48		0.00	0.00	12.47	1.25%	0.35
58	(76.69)	(1.70)	0.00	(3.95)	0.00		19.42	(7.65)	12.91	5.09		0.00	0.00	11.21	1.12%	0.29
59	(145.99)	(3.23)	0.00	(7.52)	145.99		19.42	49.88	(138.98)	(54.77)		0.00	0.00	3.78	0.38%	0.09
Total		$ 408.71	$ -	$ 951.35	$ 1,145.99	$ 1.00	$ 1,145.99	$ 0.00	$ 1,570.14	$ 618.79	$ -	$ 2,939.29	$ 10.16	$ 6,074.29	607.43%	$ 1,871.83
Present Worth		$196.53	$ -	$ 457.46	$ 568.71	$ 0.57	$ 291.94	$ 109.08	$ 478.23	$ 188.47	$ -	$ 625.78	$ 2.58	$ 1,871.83	187.18%	$ 1,002.53
Levelized Payment Current		$13.08	$ -	$ 30.44	$ 37.84	$ 0.04	$ 19.42	$ 7.26	$ 31.82	$ 12.54	$ -	$ 41.64	$ 0.17	$ 124.54	12.45%	
Levelized Payment		$ 11.11	$ -	$ 25.86	$ 32.15	$ 0.03	$ 16.51	$ 6.17	$ 27.04	$ 10.66	$ -	$ 35.38	$ 0.15	$ 105.83	10.58%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream
Services Investment

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Taxes	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	1000.00						0.00	0.00								
1	963.68	21.32	0.00	49.63	37.50	3.750%	35.56	0.77	79.97	31.51		29.12	0.15	168.06	16.81%	157.82
2	913.68	20.22	0.00	47.05	72.19	7.219%	35.56	14.44	41.03	16.17		29.85	0.15	163.44	16.34%	144.12
3	865.83	19.16	0.00	44.59	66.77	6.677%	35.56	12.30	42.38	16.70		30.60	0.15	159.06	15.91%	131.71
4	819.94	18.14	0.00	42.23	61.77	6.177%	35.56	10.33	43.48	17.13		31.36	0.15	154.91	15.49%	120.46
5	775.88	17.17	0.00	39.96	57.13	5.713%	35.56	8.50	44.37	17.49		32.15	0.16	150.97	15.10%	110.24
6	733.51	16.23	0.00	37.78	52.85	5.285%	35.56	6.82	45.05	17.76		32.95	0.16	147.24	14.72%	100.96
7	692.71	15.33	0.00	35.67	48.88	4.888%	35.56	5.25	45.55	17.95		33.78	0.16	143.70	14.37%	92.53
8	653.34	14.46	0.00	33.65	45.22	4.522%	35.56	3.81	45.87	18.08		34.62	0.16	140.32	14.03%	84.85
9	614.21	13.59	0.00	31.63	44.62	4.462%	35.56	3.57	43.14	17.00		35.49	0.16	137.00	13.70%	77.79
10	575.09	12.72	0.00	29.62	44.61	4.461%	35.56	3.57	39.83	15.70		36.37	0.17	133.70	13.37%	71.29
11	535.96	11.86	0.00	27.60	44.62	4.462%	35.56	3.57	36.49	14.38		37.28	0.17	130.42	13.04%	65.30
12	496.84	10.99	0.00	25.59	44.61	4.461%	35.56	3.57	33.18	13.07		38.21	0.17	127.16	12.72%	59.79
13	457.71	10.13	0.00	23.57	44.62	4.462%	35.56	3.57	29.84	11.76		39.17	0.17	123.93	12.39%	54.72
14	418.59	9.26	0.00	21.56	44.61	4.461%	35.56	3.57	26.52	10.45		40.15	0.17	120.72	12.07%	50.05
15	379.46	8.40	0.00	19.54	44.62	4.462%	35.56	3.57	23.19	9.14		41.15	0.17	117.53	11.75%	45.76
16	340.33	7.53	0.00	17.53	44.61	4.461%	35.56	3.57	19.87	7.83		42.18	0.18	114.37	11.44%	41.82
17	301.21	6.66	0.00	15.51	44.62	4.462%	35.56	3.57	16.54	6.52		43.24	0.18	111.24	11.12%	38.19
18	262.08	5.80	0.00	13.50	44.61	4.461%	35.56	3.57	13.22	5.21		44.32	0.18	108.13	10.81%	34.86
19	222.95	4.93	0.00	11.48	44.62	4.462%	35.56	3.57	9.89	3.90		45.42	0.18	105.05	10.50%	31.80
20	183.83	4.07	0.00	9.47	44.61	4.461%	35.56	3.57	6.57	2.59		46.56	0.18	101.99	10.20%	29.00
21	153.49	3.40	0.00	7.90	22.31	2.231%	35.56	(5.22)	26.29	10.36		47.72	0.19	99.91	9.99%	26.67
22	131.95	2.92	0.00	6.80	0.00		35.56	(14.01)	46.77	18.43		48.92	0.19	98.80	9.88%	24.77
23	110.41	2.44	0.00	5.69	0.00		35.56	(14.01)	44.94	17.71		50.14	0.19	97.71	9.77%	23.00
24	88.87	1.97	0.00	4.58	0.00		35.56	(14.01)	43.11	16.99		51.39	0.19	96.66	9.67%	21.37
25	67.32	1.49	0.00	3.47	0.00		35.56	(14.01)	41.28	16.27		52.68	0.19	95.64	9.56%	19.85
26	45.78	1.01	0.00	2.36	0.00		35.56	(14.01)	39.45	15.55		54.00	0.20	94.65	9.47%	18.45
27	24.24	0.54	0.00	1.25	0.00		35.56	(14.01)	37.62	14.82		55.35	0.20	93.70	9.37%	17.15
28	2.69	0.06	0.00	0.14	0.00		35.56	(14.01)	35.78	14.10		56.73	0.20	92.77	9.28%	15.95
29	(18.85)	(0.42)	0.00	(0.97)	0.00		35.56	(14.01)	33.95	13.38		0.00	0.00	33.54	3.35%	5.41
30	(40.39)	(0.89)	0.00	(2.08)	0.00		35.56	(14.01)	32.12	12.66		0.00	0.00	31.23	3.12%	4.73
31	(61.94)	(1.37)	0.00	(3.19)	0.00		35.56	(14.01)	30.29	11.94		0.00	0.00	28.92	2.89%	4.12
32	(83.48)	(1.85)	0.00	(4.30)	0.00		35.56	(14.01)	28.46	11.22		0.00	0.00	26.61	2.66%	3.56
33	(105.02)	(2.32)	0.00	(5.41)	0.00		35.56	(14.01)	26.63	10.49		0.00	0.00	24.31	2.43%	3.05
34	(126.57)	(2.80)	0.00	(6.52)	0.00		35.56	(14.01)	24.80	9.77		0.00	0.00	22.00	2.20%	2.59
35	(148.11)	(3.28)	0.00	(7.63)	0.00		35.56	(14.01)	22.97	9.05		0.00	0.00	19.69	1.97%	2.18
36	(169.65)	(3.75)	0.00	(8.74)	0.00		35.56	(14.01)	21.14	8.33		0.00	0.00	17.38	1.74%	1.81

Docket No: DG 24-096
DOE Technical Statement

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream
Services Investment

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Taxes	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
37	(191.20)	(4.23)	0.00	(9.85)	0.00		35.56	(14.01)	19.30	7.61		0.00	0.00	15.07	1.51%	1.47
38	(212.74)	(4.71)	0.00	(10.96)	0.00		35.56	(14.01)	17.47	6.89		0.00	0.00	12.77	1.28%	1.17
39	(234.28)	(5.18)	0.00	(12.07)	0.00		35.56	(14.01)	15.64	6.16		0.00	0.00	10.46	1.05%	0.90
40	(255.82)	(5.66)	0.00	(13.17)	0.00		35.56	(14.01)	13.81	5.44		0.00	0.00	8.15	0.82%	0.66
41	(277.37)	(6.14)	0.00	(14.28)	0.00		35.56	(14.01)	11.98	4.72		0.00	0.00	5.84	0.58%	0.44
42	(298.91)	(6.61)	0.00	(15.39)	0.00		35.56	(14.01)	10.15	4.00		0.00	0.00	3.54	0.35%	0.25
43	(320.45)	(7.09)	0.00	(16.50)	0.00		35.56	(14.01)	8.32	3.28		0.00	0.00	1.23	0.12%	0.08
44	(342.00)	(7.57)	0.00	(17.61)	0.00		35.56	(14.01)	6.49	2.56		0.00	0.00	(1.08)	-0.11%	(0.07)
45	(600.00)	(13.28)	0.00	(30.90)	600.00		35.56	222.45	(615.44)	(242.55)		0.00	0.00	(28.72)	-2.87%	(1.69)
Total		$ 184.63	$ -	$ 429.76	$ 1,600.00	$ 1.00	$ 1,600.00	$ 0.00	$ 709.29	$ 279.53	$ -	$ 1,160.90	$ 4.87	$ 3,659.69	365.97%	$ 1,740.93
Present Worth		$153.66	$ -	$ 357.68	$ 600.55	$ 0.57	$ 515.47	$ 33.53	$ 505.25	$ 199.12	$ -	$ 479.35	$ 2.13	$ 1,740.93	174.09%	$ 1,043.03
Levelized Payment Current		$10.60	$ -	$ 24.67	$ 41.42	$ 0.04	$ 35.56	$ 2.31	$ 34.85	$ 13.73	$ -	$ 33.06	$ 0.15	$ 120.08	12.01%	
Levelized Payment Constant		$ 9.17	$ -	$ 21.34	$ 35.83	$ 0.03	$ 30.75	$ 2.00	$ 30.14	$ 11.88	$ -	$ 28.60	$ 0.13	$ 103.87	10.39%	

Liberty Utilities (EnergyNorth Natural Gas) Corp. - Development of Revenue Requirements Stream
Metering Equipment

Year No.	Rate Base	Interest On Debt	Return On Preferred	Return On Common	Tax Depreciation	Tax Depreciation Rate	Book Depreciation	Deferred Tax	Taxable Income	Income Tax Payable	Revenue Tax	Property Tax	Property Insurance	Annual Revenue Requirements	% of Original Investment Revenue	Present Worth Of Revenue
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)
	1000.00						0.00	0.00								
1	964.33	21.34	0.00	49.66	37.50	3.750%	34.48	1.19	78.95	31.11		29.12	0.15	167.06	16.71%	156.88
2	914.98	20.24	0.00	47.12	72.19	7.219%	34.48	14.86	40.06	15.79		29.85	0.15	162.50	16.25%	143.30
3	867.78	19.20	0.00	44.69	66.77	6.677%	34.48	12.72	41.47	16.34		30.60	0.15	158.19	15.82%	130.99
4	822.54	18.20	0.00	42.36	61.77	6.177%	34.48	10.75	42.63	16.80		31.36	0.15	154.11	15.41%	119.84
5	779.13	17.24	0.00	40.13	57.13	5.713%	34.48	8.93	43.58	17.17		32.15	0.16	150.25	15.02%	109.71
6	737.41	16.32	0.00	37.98	52.85	5.285%	34.48	7.24	44.31	17.46		32.95	0.16	146.59	14.66%	100.51
7	697.26	15.43	0.00	35.91	48.88	4.888%	34.48	5.67	44.87	17.68		33.78	0.16	143.11	14.31%	92.15
8	658.54	14.57	0.00	33.91	45.22	4.522%	34.48	4.23	45.24	17.83		34.62	0.16	139.81	13.98%	84.54
9	620.06	13.72	0.00	31.93	44.62	4.462%	34.48	4.00	42.57	16.78		35.49	0.16	136.55	13.66%	77.54
10	581.59	12.87	0.00	29.95	44.61	4.461%	34.48	3.99	39.31	15.49		36.37	0.17	133.32	13.33%	71.09
11	543.11	12.02	0.00	27.97	44.62	4.462%	34.48	4.00	36.03	14.20		37.28	0.17	130.11	13.01%	65.15
12	504.64	11.17	0.00	25.99	44.61	4.461%	34.48	3.99	32.77	12.91		38.21	0.17	126.92	12.69%	59.68
13	466.16	10.31	0.00	24.01	44.62	4.462%	34.48	4.00	29.49	11.62		39.17	0.17	123.76	12.38%	54.64
14	427.69	9.46	0.00	22.03	44.61	4.461%	34.48	3.99	26.22	10.34		40.15	0.17	120.62	12.06%	50.01
15	389.21	8.61	0.00	20.04	44.62	4.462%	34.48	4.00	22.94	9.04		41.15	0.17	117.50	11.75%	45.75
16	350.73	7.76	0.00	18.06	44.61	4.461%	34.48	3.99	19.68	7.76		42.18	0.18	114.41	11.44%	41.83
17	312.26	6.91	0.00	16.08	44.62	4.462%	34.48	4.00	16.40	6.46		43.24	0.18	111.35	11.13%	38.23
18	273.78	6.06	0.00	14.10	44.61	4.461%	34.48	3.99	13.14	5.18		44.32	0.18	108.31	10.83%	34.92
19	235.30	5.21	0.00	12.12	44.62	4.462%	34.48	4.00	9.86	3.89		45.42	0.18	105.30	10.53%	31.88
20	196.83	4.35	0.00	10.14	44.61	4.461%	34.48	3.99	6.60	2.60		46.56	0.18	102.31	10.23%	29.09
21	167.14	3.70	0.00	8.61	22.31	2.231%	34.48	(4.80)	26.38	10.40		47.72	0.19	100.30	10.03%	26.78
22	146.25	3.24	0.00	7.53	0.00		34.48	(13.59)	46.91	18.49		48.92	0.19	99.25	9.93%	24.88
23	125.36	2.77	0.00	6.46	0.00		34.48	(13.59)	45.14	17.79		50.14	0.19	98.24	9.82%	23.13
24	104.47	2.31	0.00	5.38	0.00		34.48	(13.59)	43.36	17.09		51.39	0.19	97.26	9.73%	21.50
25	83.57	1.85	0.00	4.30	0.00		34.48	(13.59)	41.59	16.39		52.68	0.19	96.31	9.63%	19.99
26	62.68	1.39	0.00	3.23	0.00		34.48	(13.59)	39.81	15.69		54.00	0.20	95.39	9.54%	18.60
27	41.79	0.92	0.00	2.15	0.00		34.48	(13.59)	38.03	14.99		55.35	0.20	94.50	9.45%	17.30
28	20.89	0.46	0.00	1.08	0.00		34.48	(13.59)	36.26	14.29		56.73	0.20	93.65	9.37%	16.10
29	0.00	0.00	0.00	0.00	0.00		34.48	(13.59)	34.48	13.59		58.15	0.20	92.83	9.28%	14.99
Total		$ 267.61	$ -	$ 622.92	$ 1,000.00	$ 1.00	$ 1,000.00	$ (0.00)	$1,028.09	$ 405.17	$ -	$ 1,219.04	$ 5.08	$ 3,519.82	351.98%	$ 1,720.98
Present Worth		$162.04	$ -	$ 377.19	$ 565.13	$ 0.57	$ 445.51	$ 47.14	$ 502.90	$ 198.19	$ -	$ 488.74	$ 2.16	$ 1,720.98	172.10%	$ 1,037.41
Levelized Payment Current $		$12.54	$ -	$ 29.19	$ 43.74	$ 0.04	$ 34.48	$ 3.65	$ 38.92	$ 15.34	$ -	$ 37.83	$ 0.17	$ 133.20	13.32%	
Levelized Payment Constant $		$ 11.22	$ -	$ 26.12	$ 39.14	$ 0.04	$ 30.85	$ 3.26	$ 34.83	$ 13.73	$ -	$ 33.85	$ 0.15	$ 119.19	11.92%	

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Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study

Development of Weighted Plant Book Lives and Salvage

Line No.	Acct No.	Description	2016 Plant Balance	Average Service Life	Net Salvage Value
		(A)	(B)	(D)	(E)
			Company Data	Company Data	Company Data
1		**Hypothetical Production Plant**			
2	361	Structures and Improvements	$57,345	35	0%
3	363.5	Other Equipment	$7,646	35	0%
4		**Total Production Plant**	**$64,991**	**35**	**0%**
5		**Distribution Investment**			
6					
7	366.2	Structures and Improvements	$269,809	35	0%
8	366.3	Structures and Improvements - Other	$353,851	35	0%
9	367.0	Mains	$234,672,697	60	-15%
10	369.0	Measuring and Regulatin Station Equipment	$4,909,208	35	0%
11	387	Other Equipment	$908,013	19	0%
12		**Total Distribution Capacity-Related**	**$241,113,578**	**59**	**-15%**
13					
14	380	**Services**	**$146,720,226**	**45**	**-60%**
15					
16	381.0	Meters	$14,628,345	32	0%
17	381.1	Meters - Instrument	$188,398	32	0%
18	381.2	Meters - ERTs	$5,647,769	15	0%
19	382	Meter Installations	$14,360,005	32	0%
20		**Total Meters**	**$34,824,517**	**29**	**0%**

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Summary of Marginal Capacity Costs

Line No.	Description	Production in lieu of Reinforcement	Mains Reinforcement	Mains Extension	Total Distribution	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)
	Plant Investment					
1	Long-Run Unit Costs - $/Design Day Dth	$56.05	$63.33	$505.18	$624.56	MCS-1 Page 1 Line 11, MCS-1 Page 3 Line 21, MCS-1 Page 4 Line 24
2	General Plant Loading Factor	3.99%	3.99%	3.99%		MFB-6 p4, Line 17
3	Unit Costs + Loading Factor	58.29	65.85	525.32	$649.46	Line 1 + (Line 1 x Line 2)
4	Fixed Charge Rate	11.42%	10.58%	10.58%		MFB-7 Page 7A and 7B, Levelized Payment Constant $
5	A & G Exp Plant-Related Loading Factor	0.21%	0.21%	0.21%		MFB-6 p1, Line 28
6	Total Rate	11.63%	10.79%	10.79%		Line 4 + Line 5
7	Annualized Cost	$6.78	$7.11	$56.70	$70.58	Line 3 x Line 6
8	**Operating Expenses**					
9	Production capacity costs	$1.80			$1.80	MFB-3 p1, Line 25
10	Distribution capacity costs			$29.43	$29.43	MFB-4 p1, Line 18
11	A&G Exp Non-Plant Loading Factor	54.79%	54.79%	54.79%		MFB-6 p2, Line 24
12	Total O&M Expense	$2.78	$0.00	$45.55	$48.33	(Line 9 + Line 10) x (1 + Line 11)
13	**Working Capital**					
14	Materials & Supplies + Prepayments Rate	0.23%	0.23%	0.23%		MFB-6 p3, Line 27
15	M&S Cost	0.13	0.15	1.20	$ 1.48	Line 3 x Line 14
16	Working Cash O&M Allowance	$0.69	$0.52	$7.43	$ 8.64	Based on 26.53 days net lag
17	7.27%					
18	Total Working Capital	$0.83	$0.67	$8.63	$10.13	Line 15 + Line 16
19						
20	Working Capital Rev Req	$0.09	$0.07	$0.92	$1.08	Line 18 x Line 21
21	10.71%					MFB-7 p1, Line 15
22	System Seasonal Capacity Related Cost					
23	$/Design Day Dth	$9.65	$7.18	$103.18	$120.00	Line 7 + Line 12 + Line 20
24	Gross up for Sales/Sendout Factor	0.976	0.976	0.976	0.976	WP-MFB-6 p3&4A, Line 11
25	Inflation Adjustment	1.10%	1.10%	1.10%	1.10%	(1 + MFB-7 p1, Line 17)-1
26	**Seasonal Capacity Cost**	$9.98	$7.43	$106.78	$124.20	(Line 23 x (1- Line 24) + Line 23) x (1 + Line 25)

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Summary of Marginal Customer Costs

Line No.	Description	R-1	R-3, R-4	G-41	G-42	G-43	G-51	G-52	G-53	G-54	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)
	Plant Investment										
1	Meters and Regulators	$ 310.20	$ 310.20	$ 979.00	$ 2,433.20	$ 6,024.70	$ 979.00	$ 1,617.00	$ 7,311.70	$ 9,674.50	MFB-2 p1, Line 8
2	General Plant Loading Factor	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	MFB-6 p4, Line 17
3	Unit Costs + Loading Factor	$ 322.57	$ 322.57	$ 1,018.04	$ 2,530.22	$ 6,264.92	$ 1,018.04	$ 1,681.47	$ 7,603.24	$ 10,060.25	Line 1 + (Line 1 x Line 2)
4	Fixed Charge Rate	11.92%	11.92%	11.92%	11.92%	11.92%	11.92%	11.92%	11.92%	11.92%	MFB-7 p1, Line 6
5	Meter Carrying Costs	$ 38.45	$ 38.45	$ 121.34	$ 301.57	$ 746.70	$ 121.34	$ 200.41	$ 906.22	$ 1,199.06	Line 3 x Line 4
6	Services	3,737.68	3,737.68	3,737.68	7,299.74	10,912.52	3,737.68	7,299.74	23,006.43	54,416.35	MFB-2 p1, Line 4
7	General Plant Loading Factor	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	3.99%	MFB-6 p4, Line 17
8	Unit Costs and Loading Factor	3,886.71	3,886.71	3,886.71	7,590.80	11,347.64	3,886.71	7,590.80	23,923.77	56,586.10	Line 6 + (Line 6 x Line 7)
9	Fixed Charge Rate	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	MFB-7 p1, Line 5
10	Services Carrying Costs	403.70	403.70	403.70	788.44	1,178.65	403.70	788.44	2,484.91	5,877.47	Line 8 x Line 9
11	Total Plant Carrying Costs	$ 442.15	$ 442.15	$ 525.04	$ 1,090.01	$ 1,925.36	$ 525.04	$ 988.85	$ 3,391.12	$ 7,076.53	Line 5 + Line 10
12											
13	A&G Exp Plant-Related Loading Factor	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	0.21%	MFB-6 p1, Line 28
14	Annualized Cost	$ 443.08	$ 443.08	$ 526.14	$ 1,092.30	$ 1,929.40	$ 526.14	$ 990.93	$ 3,398.24	$ 7,091.39	(1 + Line 13) x Line 11
15	**Operating Expenses**										
16	Plant Related O&M $/Customer	43.35	43.35	50.51	104.23	181.38	50.51	95.49	324.68	686.35	MFB-5 p2, Col (G)
17	Customer Acctg & Mkg Expenses	78.30	78.30	78.30	78.30	78.30	78.30	78.30	78.30	78.30	MFB-5 p3, Line 26
18	A&G Exp Non-Plant Loading Factor	54.79%	54.79%	54.79%	54.79%	54.79%	54.79%	54.79%	54.79%	54.79%	MFB-6 p2, Line 24
19	Total O&M Expense	188.30	188.30	199.39	282.54	401.96	199.39	269.01	623.78	1183.62	Line 16 + Line 17 + ((Line 16 + Line 17) x Line 18)
20	**Working Capital- $/Customer**										
21	Materials & Supplies + Prepayments Rate	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	0.23%	MFB-6 p3, Line 27
22	M&S Cost	9.62	9.62	11.21	23.12	40.24	11.21	21.18	72.03	152.27	Line 21 x (Line 3 x Line 8)
23	Working Cash O&M Allowance	45.89	45.89	52.74	99.93	169.45	52.74	91.58	292.34	601.47	(Line 14 + Line 19) x (MFB-8 p1, Line 17)
24	Total Working Capital	55.51	55.51	63.94	123.05	209.69	63.94	112.76	364.37	753.73	Line 22 + Line 23
25	Working Capital Rev. Requirement	5.95	5.95	6.85	13.18	22.46	6.85	12.08	39.03	80.74	Line 24 x (MFB-7 p1, Line 15)
26	Annual Customer Related Cost $/Customer	$ 637.32	$ 637.32	$ 732.38	$ 1,388.02	$ 2,353.83	$ 732.38	$ 1,272.02	$ 4,061.05	$ 8,355.75	Line 14 + Line 19 + Line 25
27											
28	Inflation Adjustment	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	1.10%	(1 + MFB-7 p1, Line 17)-1
29	**Annual Customer Related Cost**	$644.34	$644.34	$740.44	$1,403.30	$2,379.73	$740.44	$1,286.02	$4,105.75	$8,447.72	Line 26 x (1 + Line 28)

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study
Summary of Marginal Cost Estimates

Line No.	Description	R-1	R-3, R-4	G-41	G-42	G-43	G-51	G-52	G-53	G-54	Total Company	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)
1	Uncollectible Factor	5.87%	3.47%	0.77%	0.21%	0.00%	1.44%	1.08%	0.00%	0.00%		
2												
3	Customer Charge $'s per month											
4	Monthly Customer Charge w/o Uncollectibles	$ 53.69	$ 53.69	$ 61.70	$ 116.94	$ 198.31	$ 61.70	$ 107.17	$ 342.15	$ 703.98		(MFB-9 p1, Line 29)/12
5	Adjustment for Uncollectibles	3.15	1.86	0.48	0.25	0.00	0.89	1.16	0.00	0.00		Line 1 x Line 4
6	Monthly Customer Charge Incl. Uncollectibles	$56.85	$ 55.56	$62.18	$117.19	$198.31	$62.59	$108.33	$342.15	$703.98		Line 4 + Line 5
7	Capacity-related: Winter Charges											
8	Distribution Demand Charge - Pressure Support	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98	9.98		MFB-8 p1, Col (B)
9	Distribution Demand Charge - Reinforcemen	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43	7.43		MFB-8 p1, Col (C)
10	Distribution Demand Charge - Main Extensions	106.78	106.78	106.78	106.78	106.78	106.78	106.78	106.78	106.78		MFB-8 p1, Col (D)
11	Adjustment for Uncollectibles	$7.29	$4.31	$0.96	$0.26	$0.00	$1.79	$1.35	$0.00	$0.00		(Line 8 + Line 9 + Line 10) x Line 1)
12	Winter Charges Incl. Uncollectibles	$131.49	$128.51	$125.16	$124.46	$124.20	$125.99	$125.54	$124.20	$124.20		Σ line 8 to Line 11
13	Summer Charges											
14	Capacity-related: Distribution Demand Charge	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00		
15	Adjustment for Uncollectibles	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		Line 1 x Line 14
16	Summer Charges Incl. Uncollectibles	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00		Line 14 + Line 15
17	Calendar Month Billing Determinants (2016)											
18	Customers	3,036	76,093	8,517	1,714	51	1,251	309	34	27	91,030.71	MFB-11 p1, Line 16
19	Design Day Dth -Sales and Transportation	587	70,684	28,529	39,806	10,491	2,868	4,420	5,305	3,995	166,685.93	MFB-11 p1, Line 17
20	Winter Dth -Sales and Transportation	47,405	4,667,572	1,815,526	2,710,035	744,316	249,820	445,206	587,060	830,701	12,097,641.21	MFB-11 p1, Line 18
21	Summer Dth -Sales and Transportation	21,069	1,028,925	313,071	650,208	214,952	126,172	269,819	401,365	895,275	3,920,856.16	MFB-11 p1, Line 19
22												
23	**Total Marginal Costs**											
24	Total Customer-related	$2,071,002	$50,731,826	$6,355,050	$2,409,999	$120,342	$939,802	$401,042	$137,816	$232,030	$63,398,907	Line 6 x Line 18 x 12
25	Capacity-related: Winter											
26	Winter Distribution Pressure Support	6,209	730,128	287,005	398,228	104,730	29,049	44,598	52,956	39,885	1,692,787.96	(1 + Line 1) x Line 8 x Line 19
27	Winter Distribution Reinforcements	4,621	543,418	213,611	296,392	77,948	21,621	33,193	39,414	29,686	1,259,903.95	(1 + Line 1) x Line 9 x Line 19
28	Winter Distribution Main Ext.	66,411	7,809,999	3,070,020	4,259,743	1,120,273	310,732	477,054	566,460	426,642	18,107,333.29	(1 + Line 1) x Line 10 x Line 19
29	Total Capacity-related: Winter	$ 77,241	$ 9,083,544	$ 3,570,636	$ 4,954,363	$ 1,302,952	$ 361,402	$ 554,845	$ 658,830	$ 496,212	$ 21,060,025	Σ line 26 to Line 28
30	Capacity-related: Summer											
31	Distribution Demand Charge	-	-	-	-	-	-	-	-	-	-	(1 + Line 1) x Line 14 x Line 21
32	Total Capacity-related:Summer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	Line 31
33	Customer Subtotal	$2,071,002	$50,731,826	$6,355,050	$2,409,999	$120,342	$939,802	$401,042	$137,816	$232,030	$63,398,907	Line 24
34	Distribution Subtotal	$77,241	$9,083,544	$3,570,636	$4,954,363	$1,302,952	$361,402	$554,845	$658,830	$496,212	$21,060,025	Line 26 + Line 27 + Line 28 + Line 31
35	**Total Annual Marginal Cost**	$ 2,148,243	$ 59,815,370	$ 9,925,686	$ 7,364,361	$ 1,423,293	$ 1,301,203	$ 955,887	$ 796,646	$ 728,243	$ 84,458,933	Σ line 33 to Line 34
36	**Share of Total Annual Marginal Cost**	2.5%	70.8%	11.8%	8.7%	1.7%	1.5%	1.1%	0.9%	0.9%	100.0%	Col (n) / Col (K)

Docket No. DG 24-098
Attachment 24-098 DOE 1-8A
Page 3 of 12

Liberty Utilities (EnergyNorth Natural Gas) Corp. Marginal Cost Study

Marginal Unit Costs per Dth

Line No.		R-1	R-3, R-4	G-41	G-42	G-43	G-51	G-52	G-53	G-54	Explanation
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(L)
1	Customer Charge										
2	Customer Charge (w/ Uncoll) $'s per Month	$56.85	$55.56	$62.18	$117.19	$198.31	$62.59	$108.33	$342.15	$703.98	MFB-10 p1, Line 6
3	Capacity-related Winter Unit Costs										
4	Winter Distribution Pressure Support	$0.1310	$0.1564	$0.1581	$0.1469	$0.1407	$0.1163	$0.1002	$0.0902	$0.0480	MFB-10 p1, Line 26 / Line 18
5	Winter Distribution Reinforcements	$0.0975	$0.1164	$0.1177	$0.1094	$0.1047	$0.0865	$0.0746	$0.0671	$0.0357	MFB-10 p1, Line 27 / Line 18
6	Winter Distribution Main Ext.	$1.4009	$1.6732	$1.6910	$1.5718	$1.5051	$1.2438	$1.0715	$0.9649	$0.5136	MFB-10 p1, Line 28 / Line 18
7	Capacity-related Summer Unit Cost										
8	Distribution Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	MFB-10 p1, Line 30 / Line 19
9	**Total Unit Cost Summary**										
10	Distribution										
11	Customer	$56.85	$55.559	$62.181	$117.191	$198.311	$62.594	$108.330	$342.146	$703.976	Line 2
12	Winter, $/Dth	$1.6294	$1.9461	$1.9667	$1.8282	$1.7505	$1.4466	$1.2463	$1.1223	$0.5973	Line 4 + Line 5 + Line 6
13	Summer, $/Dth	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	Line 8
14	Annual Avg, $/Dth	$1.1280	$1.5946	$1.6775	$1.4744	$1.3583	$0.9612	$0.7760	$0.6665	$0.2875	MFB-10 p1, Line 36 / Line 20
15	Test Year Calendar Month Billing Determinants - Sales And Transportation Loads (All Firm Loads)										
16	Customers Annual	3,036	76,093	8,517	1,714	51	1,251	309	34	27	WP-MFB-BillingDets, Col (E) Lines 2 to 12
17	Design Day Dths	587	70,684	28,529	39,806	10,491	2,868	4,420	5,305	3,995	WP-Design Day, Line 29
18	Winter Dths	47,405	4,667,572	1,815,526	2,710,035	744,316	249,820	445,206	587,060	830,701	(WP-MFB-BillingDets, Col (B), Lines 2 to 12) /10
19	Summer Dths	21,069	1,028,925	313,071	650,208	214,952	126,172	269,819	401,365	895,275	(WP-MFB-BillingDets, Col (C), Lines 2 to 12) /10
20	Total Annual Dths	68,473	5,696,497	2,128,598	3,360,243	959,268	375,992	715,025	988,425	1,725,976	Σ line 18 to Line 19

Melissa F. Bartos
Assistant Vice President

Ms. Bartos is a financial and economic consultant with 20 years of experience in the energy industry. In the last several years, she has focused on natural gas markets issues, including conducting comprehensive market assessments for various clients considering infrastructure investments and developing detailed demand forecasts for a number of gas distribution companies. Ms. Bartos has also designed, built, and enhanced numerous financial and statistical models to support clients in asset-based transactions, energy contract negotiations, reliability studies, asset and business valuations, rate and regulatory matters, cost-of-service analysis, and risk management. Her modeling experience includes building Monte-Carlo simulation models, designing an allocated cost-of-service model, statistical modeling using SPSS, and programming using Visual Basic for Applications (VBA). Ms. Bartos has also provided expert testimony regarding natural gas demand forecasting and supply planning issues, marginal cost studies, and incentive ratemaking.

REPRESENTATIVE PROJECT EXPERIENCE

Natural Gas Market Assessments

- Reviewed and evaluated long-term natural gas supply and demand, existing natural gas pricing dynamics, and future implications associated with new natural gas infrastructure in New England, New York, and New Jersey.
- Provided an analysis of the existing Gulf Coast natural gas market, the client's natural gas pipeline competitors, changing flows, and how those factors may affect transportation values to the client going forward.
- Prepared a comprehensive study examining the costs associated with improving natural gas pipeline access from western Canada and the eastern U.S. to Atlantic Canada.
- Produced a report on the benefits associated with incremental natural gas supplies delivered to New York City.
- Prepared an independent natural gas supply and pipeline transportation route assessment associated with natural gas for the client's proposed LNG export terminal.

Natural Gas Expansion

- Conducted a study that examined potential commercial and industrial conversions from oil-based fuels to natural gas in various east coast U.S. markets.
- Produced a report that identified growth potential in off-system stationary and mobile markets in the mid-west that could be served by compressed natural gas or liquefied natural gas.
- Performed an external audit and filed expert testimony associated with two natural gas utilities' hurdle rate/contribution in aid of construction calculations for new off main customers.
- Produced a report that identified and reviewed innovative cost model approaches that utilities and regulators are using across the U.S. that allow expansion of gas distributions systems to new communities.
- Assisted in developing a strategy to identify residential natural gas growth opportunities within the client's franchise area.

- Presented at two Northeast Gas Association conferences regarding "Regulatory Policy and Residential Main Extensions".

Demand Forecasting

- Filed expert testimony regarding the development of demand forecast models and the evaluation of natural gas resource plans for multiple northeast gas utilities.
- Provided litigation support regarding demand forecasting techniques with respect to certain natural gas pipeline and storage decisions for a mid-west gas utility.
- Reviewed demand forecasting practices and procedures and recommended certain changes to improve the methodology and accuracy of the forecast for a multi-state utility.
- For a mid-west gas utility, developed a natural gas demand forecast that was utilized for supply and capacity decisions.

Ratemaking and Utility Regulation

- Participated in the rate case of a large North American gas distribution company, which determined the client's five-year incentive regulation plan, including performing benchmarking and productivity analyses that were filed with the regulator.
- Developed and testified regarding marginal cost studies, including data collection, analysis, and testimony development in support of rate case filings for a number of New England utilities.
- Provided comprehensive analysis, drafted testimony and provided litigation support regarding the appropriate return on equity for a New England water utility, and for proposed wind and coal electric generation facility additions for a mid-west combination utility.
- Performed a detailed analysis of the components included in the client's lost and unaccounted for gas calculation.
- Conducted multiple natural gas portfolio asset optimization analyses to evaluate performance of the client's asset manager for regulatory purposes.
- On behalf of multiple New England gas companies, participated in the 2009 Avoided Energy Supply Cost Study Group (for New England), which worked with third-party consultants to develop the marginal energy supply costs that will be avoided due to reductions in the use of electricity, natural gas, and other fuels resulting from energy efficiency programs.
- Conducted a study to determine the cost of significantly reducing peak day natural gas demand for a northeast gas utility through energy efficiency, conservation and demand management measures. Project involved researching natural gas energy efficiency plans in multiple U.S. states and Canadian provinces, reviewing energy efficiency potential studies, and exploring geothermal, peak pricing and direct load control options.

PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2002 – Present)
Assistant Vice President
Project Manager
Senior Consultant

Navigant Consulting, Inc. (1996 – 2002)
Senior Consultant

PROFESSIONAL ASSOCIATIONS

Member of the American Statistical Association
Member of the Northeast Energy and Commerce Association
Member of the Northeast Gas Association

EDUCATION

M.S., Mathematics (Statistics), University of Massachusetts at Lowell, 2003
B.A., Mathematics and Psychology, Computer Science minor, College of the Holy Cross, magna cum laude, 1998

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Connecticut Public Utilities Regulatory Authority				
Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	2014	Connecticut Natural Gas Corporation & Southern Connecticut Gas Company	Docket No. 13-06-02	CIAC Hurdle Rate Calculation
Federal Energy Regulatory Commission				
PennEast Pipeline Company, LLC	2015	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
PennEast Pipeline Company, LLC	2016	PennEast Pipeline Company, LLC	Docket No. CP15-558	Market Conditions/Need
Millennium Pipeline Company, LLC	2017	Millennium Pipeline Company, LLC	Docket No. CP16-486	Market Conditions/Need
Maine Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	Docket No. 2011-526	Integrated Resource Plan; Demand Forecast
Massachusetts Department of Public Utilities				
New England Gas Company	2008	New England Gas Company	D.P.U. 08-11	Integrated Resource Plan; Demand Forecast; Supply Planning
New England Gas Company	2010	New England Gas Company	D.P.U. 10-61	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2010	Berkshire Gas Company	D.P.U. 10-100	Integrated Resource Plan; Demand Forecast
New England Gas Company	2012	New England Gas Company	D.P.U. 12-41	Integrated Resource Plan; Demand Forecast; Supply Planning
Berkshire Gas Company	2012	Berkshire Gas Company	D.P.U. 12-62	Integrated Resource Plan; Demand Forecast
NSTAR Gas Company	2014	NSTAR Gas Company	D.P.U. 14-63	Integrated Resource Plan; Demand Forecast

SPONSOR	DATE	CASE/APPLICANT	DOCKET NO.	SUBJECT
Berkshire Gas Company	2014	Berkshire Gas Company	D.P.U. 14-98	Integrated Resource Plan; Demand Forecast
Liberty Utilities (New England Gas Company)	2015	Liberty Utilities (New England Gas Company)	D.P.U. 15-75	Marginal Cost of Service Study
Berkshire Gas Company	2016	Berkshire Gas Company	D.P.U. 16-103	Integrated Resource Plan; Demand Forecast
Eversource Energy	2017	Eversource Energy (NSTAR Electric and WMECO)	D.P.U. 17-05	Marginal Cost of Service Study
New Hampshire Public Utilities Commission				
Northern Utilities, Inc.	2011	Northern Utilities	DG 2011-290	Integrated Resource Plan; Demand Forecast
New Jersey Board of Public Utilities				
South Jersey Gas Company	2015	South Jersey Gas Company	GR15010090	Energy Efficiency Cost Benefit Analysis
Ontario Energy Board				
Enbridge Gas Distribution	2012	Enbridge Gas Distribution	EB-2011-0354	Industry Benchmarking Study
Enbridge Gas Distribution	2013	Enbridge Gas Distribution	EB-2012-0459	Incentive Rate Making
Régie de l'énergie du Québec				
TransCanada Pipelines Ltd.	2014	TransCanada Pipelines Ltd.	R-3900-2014	Natural Gas Market Assessment
Washington Utilities and Transportation Commission				
Puget Sound Energy, Inc.	2015	Puget Sound Energy, Inc.	UG-151663	Distributed LNG Market Assessment

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 — Date of Response: 9/18/24
Request No: DOE 1-9 (COG) — Respondent: Joshua Tilbury

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

a) Does Liberty use a 10-year past period, 20-year past period, a 30-year past period, a 40-year past period, or a different interval to 'weather normalize' and/or determine 'peak design day' needs? Please explain why Liberty is using the interval(s) it does. If Liberty is not using a 10-year past period, please explain how Liberty accounts for recent warming trends.

RESPONSE:

a) Liberty uses a 30-year past period to prepare its design day, as agreed to in the settlement agreement in Docket No. DG 21-008, which the Commission approved in Order No. 26,551 (Nov. 12, 2021):

> SECTION 3. PLANNING STANDARDS
> 3.1 In Liberty's next least cost integrated resource plan, which is due on or before October 2, 2022 ("2022 LCIRP"), the Company shall present its design day analysis for the 2022 LCIRP based on weather data from the 30 years immediately preceding the year of the LCIRP filing.
>
> 3.2 The Company shall use the design day standard set forth in Section 3.1 as an input to the Company's supply deficiency analysis to be included in the 2022 LCIRP.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-10 (COG) Respondent: Mark Summerfield

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

What NYMEX data (and date of date) was used to forecast the first-of-the-month price for baseload quantities and the daily price (call option) when the COG petition was filed? Please provide documentation showing the NYMEX data and identify the date that was obtained and used.

a) What is the NYMEX data for first-of-the-month price for baseload quantities and the daily price (call option) as of September 10, 2024? How does this compare to the data EnergyNorth used in its forecast (percentage increase or percentage decrease)? Please identify the date(s) of the market data used in the September 3, 2024 filing.

b) Please confirm that Liberty requests a standard COG 25% cap such that, consistent with the traditional COG framework, Liberty—through monthly trigger filings—will be able to increase the Winter and/or Summer COG by an additional 25% without further Commission proceedings, and/or decrease the COG without restriction. If this is not the case, please explain further. See R. Garcia and A. Maston Testimony at 0015 ("What is the **current** percentage used to calculate the maximum increase in the Cost of Gas rate?" Emphasis added).

Docket No. DG 24-098 Request No. DOE 1-10 (COG)

RESPONSE:

a) For the 2024/2025 COG filing, which was filed on September 3, 2024, the NYMEX forecasted settlement price for each month in the period was obtained on July 23, 2024. The table below illustrates the NYMEX price difference between the July 23 projections and the September 10 projections, which on average decreased 6%. Daily forecasted settle prices are not forecasted in any publication, only monthly forecasted prices are available.

				NYMEX FORECAST FUTURE SETTLE								
Forecast Date												
	11/1/2024	12/1/2024	1/1/2025	2/1/2025	3/1/2025	4/1/2025	5/1/2025	6/1/2025	7/1/2025	8/1/2025	9/1/2025	10/1/2025
July 23,2024	$2.816	$3.349	$3.638	$3.485	$3.114	$2.928	$2.967	$3.126	$3.304	$3.344	$3.307	$3.369
September 10,2024	$2.527	$3.044	$3.334	$3.214	$2.905	$2.787	$2.834	$2.982	$3.138	$3.171	$3.150	$3.233
Change	0.289	0.305	0.304	0.271	0.209	0.141	0.133	0.144	0.166	0.173	0.157	0.136
% change	10%	9%	8%	8%	7%	5%	4%	5%	5%	5%	5%	4%

b) Yes, the Company requests the standard COG 25% cap consistent with the traditional COG framework.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-11 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Please provide a copy of all fixed-price-offer (FPO) letters (for both the EnergyNorth and for the Liberty-Keene division) sent (or that will be sent) to customers to alert them to Liberty's FPO offer. If the Company's letters do not identify a 'start' and 'end' date within which time a customer may elect FPO rates, please identify those periods. If the ENNE and/or Liberty-Keene letters are not final, please provide a current draft.

a) Please provide information on what percentage of customers accepted the FPO offer in the 2023-2024 (Winter), 2022-2023 (Winter) and 2021-2022 (Winter) seasons.

b) How many customers have already accepted the Company's FPO offer for the Winter 2024-25, to date, for EnergyNorth and Liberty-Keene respectively?

c) Liberty has identified a 'Fixed Price Option Administrative Costs' of $62,993. Please provide a break-down of this cost. See R. Garcia and A. Maston Testimony at 011

RESPONSE:

A copy of the FPO letter that will be sent to ENNG customers was provided as Attachment 1 in the Company's filing made into DG 24-098 on September 3, 2024, which includes an enrollment deadline of October 22, 2024. A copy of the FPO letter that will be sent to Keene customers was provided as Attachment 2 in the Company's filing made into DG 24-100 on September 9, 2024, which includes an enrollment deadline of October 19, 2024. At the time this response was prepared, these letters have not yet been sent to customers, but are in the process of being mailed and should reach customers within the coming week.

a) In the 2021-2022 Winter season, 9,657 customers, or 10.1% of ENNG customers accepted the FPO offer. For the same period, 128 customers, or 10.6% of Keene customers accepted the FPO offer.

In the 2022-2023 Winter season, 13,984 customers, or 14.3% of ENNG customers accepted the FPO offer. For the same period, 193 customers, or 16.4% of Keene customers accepted the FPO offer.

In the 2023-2024 Winter season, 13,002 customers, or 13.5% of ENNG customers accepted the FPO offer. For the same period, 99 customers, or 7.5% of Keene customers accepted the FPO offer.

b) At the time this response was prepared, the FPO offer letters for the Winter 2024-25 season had not yet reached customers, so no customers have enrolled in the program

c) The $62,993 included in the winter Cost of Gas for Fixed Price Option Administrative Costs was equal to the actual FPO costs incurred for the last winter season. The FPO offer letters for the Winter 2023-24 were sent through Kubra, which is the mailing vendor that also sends out other types of mailings for the Company each month. The Company only receives one monthly invoice from Kubra and had to recalculate the portion of the monthly invoice from September 2023 that was attributable to the FPO mailings. See Attachment 24-098 DOE 1-11 (COG).xlsx for this calculation.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 | Date of Response: 9/18/24
Request No: DOE 1-12 (COG) | Respondent: Kelly Esposito

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Does the Company consider this year's markets for supply less volatile than last year's markets? Why or why not? Please explain and provide any relevant documentation.

RESPONSE:

The Company does not consider this year's markets less volatile than last year's markets. Although the Company recognizes that forward-look pricing currently for the 2024/2025 plan year is below what was predicted at this time one year ago for the 2023/2024 plan year, the Company cannot predict future events which may or may not occur to disrupt market stability. The Company ensures that it has adequate supplies in place to serve customers under various conditions including normal year, and design year demand.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 | Date of Response: 9/18/24
Request No: DOE 1-13 (COG) | Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

The Company's testimony asserts that the "bad debt percentage in this filing is proposed as 1.99% changed from the actual bad debt percentage calculated in the Winter 2022-2023 Cost of Gas Reconciliation of 0.23%. See R. Garcia and A. Maston Testimony at 0014.

a) Is the Company referring to the "Winter Period 2022-2023 Cost of Gas Reconciliation" filed on July 29, 2024 or to the Company's "Post-Audit 2023-24 Winter Period Cost of Gas Reconciliation" filed on September 6, 2024? If relevant bad debt percentage calculation is the same in both filings, please so state and identify the page numbers. If different, please explain the changes made in the filing and identify the relevant percentage(s).

b) What are the reasons for this change from 0.23% to 1.99%?

c) How does the bad debt percentage for Winter 2023-2024 compare to the bad debt percentage for Winter 2017-2018?

d) Does Liberty have an arrearage program or other measures to reduce bad debt? Please explain.

RESPONSE:

a) The Testimony of R. Garcia and A. Maston Testimony at Bates 0014, lines 4-8, compares the bad debt rate proposed for use in the instant proceeding (1.99%), which was included in the Post-Audit 2023-24 Winter Period Cost of Gas Reconciliation filed on September 6, 2024, to the previous bad debt rate (0.23%), which was included in the Winter Period 2022-2023 Cost of Gas Reconciliation filed in DG 22-045 on September 1, 2023 and used in its Winter 2023-24 Cost of Gas filing made in DG 23-076, also on September 1, 2023. However, Liberty understands how the "Q." on line 7 of Bates 0014 might be confusing and will rephrase it in its revisions due by September 27, 2024.

b) The 0.23% bad debt rate was unusually low due to disruptions in the write-off routine following the Company's conversion to SAP. In December 2023 and January 2024, the backlog of write-offs were processed, inflating the 1.99% bad debt rate that is calculated based on revenue and charge off information from May 2023 through April 2024.

c) The bad debt percentages used for Winter 2017-2018 and every year since are reflected in the table below.

Docket	COG Period	BD %	Data used
DG 17-135	2017-18	1.11%	May 2016-April 2017
DG 18-137	2018-19	1.75%	May 2017-April 2018
DG 19-145	2019-20	1.11%	May 2018-April 2019
DG 20-141	2020-21	1.11%	May 2019-April 2020
DG 21-130	2021-22	0.70%	May 2020-April 2021
DG 22-045	2022-23	0.86%	May 2021-April 2022
DG 23-076	2023-24	0.23%	May 2022-April 2023
DG 24-098	2024-25	1.99%	May 2023-April 2024

d) Currently, ENNG does not have an arrearage program in place in NH. However, an Arrearage Management Plan was proposed in the ENNG rate case, Docket No. DG 23-067.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-14 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

a) Liberty seems to have identified a Winter Period 2024-2025 'Prior Period Over Collection of $306,763" (Emphasis added)'; which appears to be a reported under-collection. See R. Garcia and A. Maston Testimony at 0011. Please provide a narrative describing the components that resulted in this figure. Was it incorrectly identified as an over collection?

b) Similarly, Liberty seems to have identified a Summer 2025 'Prior Period (Over)/Under Collection of ($409,360)', which appears to be a reported over-collection. See R. Garcia and A. Maston Testimony at 0020. Please provide a narrative describing the components that resulted in this figure.

c) Please also confirm that for accounting and tracking purposes, Liberty considers the Winter (Peak) and Summer (Off-Peak) periods as wholly independent of each other.

RESPONSE:

a) The prior period balance of $306,763 is an undercollection and was incorrectly identified as an overcollection in the R. Garcia and A. Maston testimony at 0011. This undercollection was the actual balance as of April 30,2024, at the end of the prior winter period. This is a much smaller balance than has historically been in the winter deferral account at the end of the period and is a result of the trigger filings working well to adjust the rates being charged to customers each month based on actual usage and updated pricing projections.

b) The prior period overcollection of ($409,360) for the off-peak cost of gas is the projected October 31, 2024 balance per Liberty's most recent trigger filing update[1] less the projected refund the Company is requesting to issue to customers. See Attachment 24-098 DOE 1-14 (COG).xlsx for the calculation of the projected refund. The projected October 31, 2024 balance is ($6,263,306) and the projected refund that the Company is seeking is $5,853,946, which nets to the projected beginning balance of ($409,360). The Company will attend a hearing in DG 23-076 on September 26, 2024 to present the refund proposal to the PUC for approval.

c) Yes , for accounting and tracking purposes, Liberty considers the Winter (Peak) and Summer (Off-Peak) periods as wholly independent of each other. However, from a ratemaking perspective, Liberty notes that the customer base served during the two periods is largely the same and that there are more efficient means of addressing seasonal deferral balances than to accrue interest for six months until the next period.

[1] Please note that the Company did not file this trigger filing or change the COG rates being charged to customers because the trigger filing is calculating a negative cost of gas rate, but has completed the filing to arrive at an up to date projection of the October 31, 2024 balance to be used in this filing.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-15 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Please provide, the amount and percentage of Liberty EnergyNorth's Lost And Unaccounted For (LAUF) gas (excluding Liberty-Keene) by fuel type and/or location/facility and supporting documentation.

a) What steps is Liberty taking to reduce the Company's LAUF (inclusive of ENNE and Liberty-Keene to a percentage close to 2%? See Schedule-25 at 0115

b) What steps is Liberty taking to reduce the ENNE LAUF?

RESPONSE:

The Company does not yet have the necessary data to calculate individual LAUF percentages by fuel type. The LAUF calculation requires both sendout and Company use data as well as customer billing data. Customer billing information is not broken out by gas type, as the COG rate paid is a blended rate taking all types of gas into account. Further, such data may need to be calendarized. As indicated at the April 19, 2024, hearings in Docket 24-042, Liberty is working to develop reports that provide the necessary data to determine separate LAUFs by fuel type.

a) The LAUF calculation presented on Pk Schedule 25 at Bates 0115 is not inclusive of Liberty-Keene. A separate LAUF percentage is calculated for Keene during the separate Cost of Gas proceeding, and the LAUF percentage calculated during this proceeding only includes ENNG.

b) Major components that contribute to the LAUF percentage include gas leaks and billing and metering issues. The Company is consistently working on projects in those areas, such as identifying faulty meters not reporting correct usage to the billing system and improving gas leak response and prevention measures, which will contribute to reducing our LAUF percentage.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/10/24 Date of Response: 9/18/24
Request No: DOE 1-16 (COG) Respondent: Alyssa Maston

REFERENCE:

Liberty's September 3, 2024 COG filing; Order No. 26,898 (October 31 2023) in Dkt. No. DG 23-076 at 10

REQUEST:

a) Please describe the costs Liberty has tracked and allocated to be borne by shareholders due to the requirement that a second fixed-price-offer (FPO) letter be issued and mailed to customers, as well as efforts and costs associated with customer responses. Please provide a description and dollar value for each cost and a total cost. Please explain where these costs appear in Company accounts and the current filing.

b) Please describe all the costs Liberty has tracked and/or estimated and allocated to be borne by shareholders due to the billing error as described and documented in Docket No. 23-076 and Order No. 26,898 (October 31, 2023). Please provide a description and dollar value for each cost and a total cost. Please explain where costs appear in Company accounts and the current filing

c) Please identify the under/over collection for the Winter (Peak) period over the last four years, excluding the 2023-2024 period. What baseline amount for an under collection does Liberty deem appropriate as a potential off-set to the approximate $780K that Liberty calculated as interest due on the 2023-2024 Winter Period under collection identified by the Company (in writing) for the first time in its October 23, 2023 filing in Docket No. 23-076.

d) Please describe and calculate the impact of the Company's responses to "a" and "b" above upon Liberty's initial estimated under/over collection for the Winter 2024-25 and Summer 2025 periods before including the projected/estimated cost of supply for this period. Please reference relevant schedules and/or tables in the Company's COG Supply and/or LDAC filing in this docket.

e) In the opinion of the Company, if the present COG (Supply) filing free of any impacts from the SAP billing conversion that Liberty implemented in 2023? What is the basis for Liberty's opinion? Please explain and provide documentation if available.

RESPONSE:

a) The costs that the Company tracked related to the second FPO letter total $12,822.85. The Company was invoiced $9,965.32 for the mailing of the second FPO letter, which was booked to GL account 501500 – Advertising Expenses. The Company recorded $2,279.37 worth of labor costs, which include Communications and Customer Operations time to develop second FPO letter, printing and mailing, and time to process returned customer recissions. These costs were originally booked to the winter COG deferral account but subsequently removed and booked to GL account 502700 – Office Related Exp. The Company also provided $578.16 worth of bill credits to refund 876 customers who received the second FPO letter for return postage costs of $0.66 each, which was booked to GL account 410640 – Gas Rev Other Revenue. None of these costs were included in the Company's filing.

b) The "error" described in Order 26,898 was an error due to an accounting entry, not a billing error. With that clarification, Liberty responds as follows.

   In addition to costs related to the second FPO letter discussed in response to subpart (a), the Company also tracked how much interest would have been recorded in both the winter and summer deferral accounts had the correct accounting entries been made when they should have been. The result of this was that between October 1, 2022 and June 30, 2024, the interest that was recorded in the winter deferral account totaled $(530,424.29)[1] while the interest recalculated for the same time period assuming the entries had been made correctly and in a timely fashion totaled $257,259.39, resulting in an adjustment of $787,713.68. The same calculations were done for the summer deferral account, which had a total of $480,560.88 worth of interest actually booked to the GL between October 1, 2023 and June 30, 2024 and a recalculated interest total for the same time period of ($275,125.52)[2], resulting in an adjustment of ($755,656.40). The net of these two interest adjustments is $32,057.28, which would be a net increase to interest that customers owed to the Company between both the winter and summer periods. Please see Attachment 24-098 DOE 1-16b (COG).xlsx for these calculations.

   No other costs related to the accounting error were tracked by the Company, as any additional work required by regulatory, accounting, customer service, or legal staff would not have increased the amount of labor costs to the Company, nor do the salaries of those employees flow through any rate mechanisms that would increase the burden to customers as a result.

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[1] This figure is shown net of a $791,394.50 adjusting entry that was done by accounting during the 2023 year-end close process. This adjustment was made in an effort to true up interest to what it would have been if the accounting error had not occurred but is subject to further adjustment pending review of the DOE and OCA per Order No. 26,898 in DG 23-076.

[2] This figure is shown net of a ($779,331.71) adjusting entry that was done by accounting during the 2023 year-end close process. This adjustment was made in an effort to true up interest to what it would have been if the accounting error had not occurred but is subject to further adjustment pending review of the DOE and OCA per Order No. 26,898 in DG 23-076.

c) The average ending balance in the winter deferral account at the end of the four winter periods preceding the Winter 2023-24 season is $4,403,887, when considering the absolute value of all (over)/under collections. See Attachment 24-098 DOE 1-16c (COG).xlsx for this calculation and supporting data. The Company does not deem any balance appropriate as an off-set to the interest adjustments proposed in the response to "b" above, as the proposed adjustments to the winter and summer accounts offset each other almost completely, leaving a net increase of $32,057.28 to interest that customers owed to the Company. This increase is well within the historical range of interest booked to the cost of gas deferral accounts during the peak period, as can be seen in Attachment 24-098 DOE 1-16c (COG).xlsx.

d) None of the costs from "a" were included in the Company's initial estimated under/over collection for the Winter 2024-25 or Summer 2025 periods (nor are they recovered through any other rate mechanism) as directed in Order No. 26,898 in DG 23-076.

However, the Company's initial filing did include the adjustments made during the year-end close process to reflect what the interest would have been assuming the entries had been made correctly and in a timely fashion, as discussed in footnotes 1 and 2 in the response to "b" above. See Confidential Attachment 24-098 DOE 1-16d (COG).xlsx for an updated version of the model that removes those accounting interest adjustments from both Pk and OP Schedule 3. For the peak period, this changes the prior period (over)/under recovery from $306,763 to ($484,632), which results in a calculated peak cost of gas rate on Pk Page 95 of $0.6696 per therm instead of the $0.6792 per therm that was calculated in the initial filing. For the off-peak period, this changes the prior period (over)/under recovery from ($409,360) to ($360,151), which results in a calculated off-peak cost of gas rate on OP Page 92 of $0.0748 per therm instead of the $0.0724 per therm that was calculated in the initial filing.

e) No, the present filing is not free from the impacts of the Company's October 2022 conversion to SAP. With respect to SAP, what precipitated the magnitude of the accounting error was that a report needed to allocate billings between summer and winter deferral was not initially available after conversion, thereby increasing the total adjustments that needed to be made when the report became available in March 2023. The adjustments were then booked incorrectly between summer and winter deferrals, which impacts interest accrued. However, the Company and other parties have not yet reached an agreement on what the appropriate interest costs for the winter and summer deferral accounts should be at this time. The filing reflects the Company's initial attempts to remove any impacts of the conversion to SAP.

Confidential Attachment 24-098 DOE 1-16d (COG).xlsx contains pricing and other information that is "confidential, commercial, or financial information" and is thus protected from disclosure by RSA 91-A:5, IV, and presumed to be confidential in cost of gas proceedings pursuant to Puc 201.06(a)(11). Therefore, pursuant to that statute and Puc 203.08(d) and Puc 201.01.06(a)(11)(g) (protecting "responses to data requests related to a. through f. above"), the Company has a good faith basis to seek confidential treatment of this information and asserts confidentiality pursuant to those rules.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/20/24 Date of Response: 9/24/24
Request No: DOE 1-4 (COG) Supplemental Respondent: Danielle Ziv

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Reference: Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

Please provide data, any associated models, and a narrative description of how the Company forecasts its sales (in therms) and how the Company forecasts the associated number of customers. Please identify any changes Liberty has made in assumptions, formulas or calculation as compared the Company forecast Liberty made in Docket No. DG 23-076.

Liberty's response should include but should not be limited to:

a) an explanation regarding why Liberty's forecasted sendout requirements for sales customers for Winter 2024-2025 is approximately 4.3 million therms lower than the normalized actual sendout for firm sales customers for the November 1, 2023 to April 30, 2024 period; and

b) why Liberty's 'design weather requirements' are "approximately 10 percent greater than normal sendout requirements for weather that is 10 percent colder than normal." See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0036.

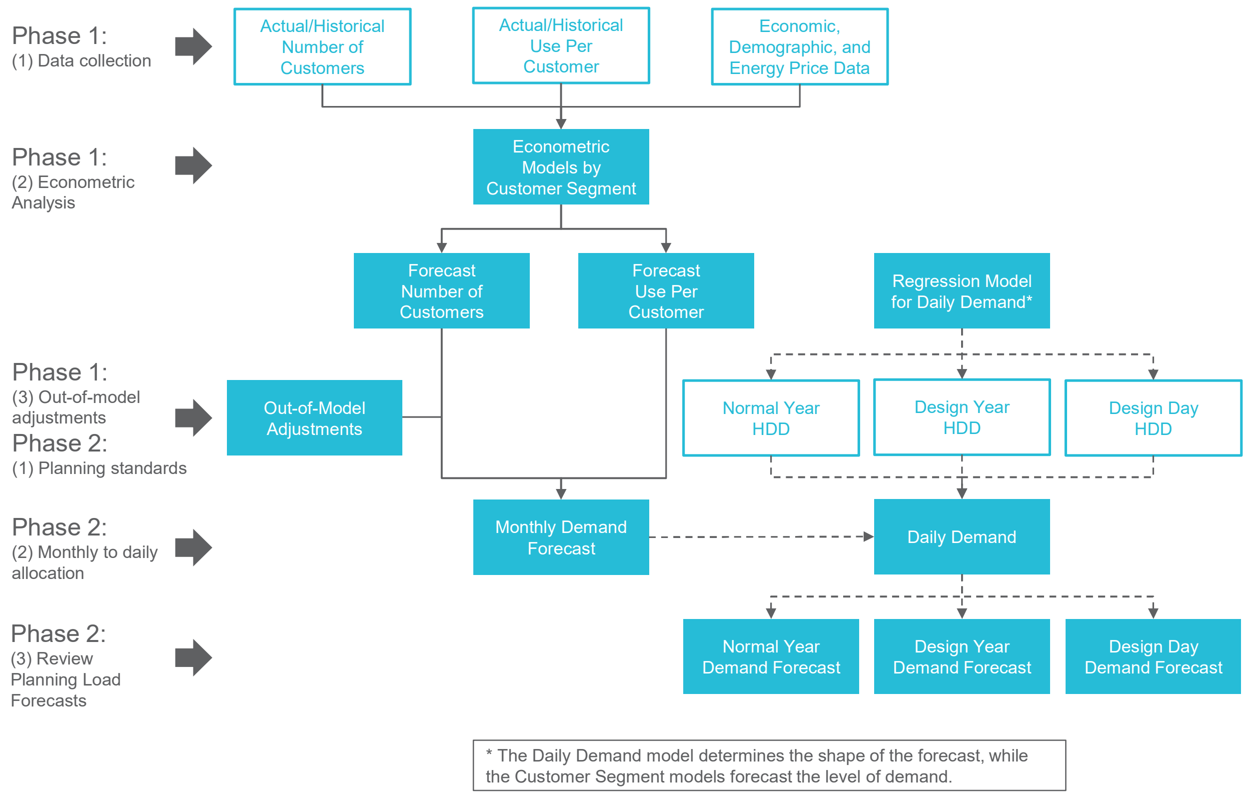
RESPONSE:

There have been no changes to the methodology or assumptions that comprise the Company's demand forecast process, which is as follows.

- Phase 1 includes a comprehensive econometric analysis to forecast levels of natural gas demand for the Company's service territory, with adjustments for discrete loads that are calculated outside of the econometric models, energy efficiency, and unaccounted for gas.
- Phase 2 includes the development of planning standards and estimation of daily loads under various weather and growth scenarios to facilitate supply and capacity analysis.

Docket No. DG 24-098 Request No. DOE 1-4 (COG) (Supplemental)

Figure 1: Demand Forecast Methodology



In Phase 1 of the demand forecast process, Liberty developed econometric models for the number of customers and use per customer-by-customer segment to forecast total monthly demand requirements. The purpose of the customer segment forecasts[1] is to develop long-term projections of Planning Load based on forecasted changes in economic and demographic conditions in the Company's service territory.

In Phase 2 of the demand forecast process, Normal Year, Design Year, and Design Day planning standards were developed to reflect weather conditions that inform the level of firm volume that the Company must plan for to maintain reliable service. Once the planning standards were determined, the Company then translated the monthly demand forecast into a forecast of daily requirements using a daily regression model.

The Company followed this process in developing the demand forecast used in this filing.

a) The company identified a mistake in the normalized actual sendout for firm sale customers for the November 1, 2023 to April 30, 2024 period. The correct sales amount should be 88,011,120 therms instead of the originally reported 92,395,519 therms. This normalized actual sendout is 87,974 therms lower than the forecasted sendout of 88,099,094 therms for the period of November 1, 2024 to April 30, 2025. The files have

[1] All forecasts represent firm demand only (i.e., firm sales and capacity-assigned, and capacity-exempt transportation) and exclude interruptible and special contract demand.

been updated to include 2024–25 forecast data. Please see Attachment 24-098 DOE 1-4.1 (COG).xlsx and Attachment 24-098 DOE 1-4.2 (COG).xlsx.

b) Liberty's "design weather requirements" is the Company's demonstration that the supplies procured for the winter period will not only satisfy normal requirements but will also satisfy a high-case scenario such as a design winter. This measure is simply in place to demonstrate winter readiness. This standard measure of winter readiness under a high-case scenario has been in place and approved in all COG dockets over the past many years.

SUPPLEMENTAL RESPONSE:

To normalize the winter data, the Company uses the average slope of the actual data (actual unit heat load therm/DD) and recalculates the usage by multiplying that slope times the normal HDD weather data for the period. The company then adds the baseload to that value to create the weather normal volume. In the case of a warm winter, such as the winter of 2023–24, the slope is likely lower than what a 'normal slope' would be and therefore it's reasonable to assume the total volume recalculated would render a lower volume than if the actual winter was in the normal range. Weather normalization is a guide, not exact. Please see Attachment 24-098 DOE 1-4.3.xlsx for the normalization calculation.

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

DG 24-098
Winter 2024-2025 and Summer 2025 Cost of Gas and LDAC Filing

Department of Energy Data Requests - Set 1 (COG)

Subject: ENNG 2024-2025 COG
Date Request Received: 9/20/24 Date of Response: 9/24/24
Request No: DOE 1-8 (COG) Supplemental Respondent: Joshua Tilbury

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REFERENCE:

Liberty's September 3, 2024 COG filing; RSA 362-I:2 (Supp 2022)

REQUEST:

Liberty states that, "... 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." See J. Tilbury, K. Esposito and M. Summerfield Testimony at 0035. Liberty also states that "The estimated percentage used for pressure support purposes of 8.7% stayed the same based on the marginal cost study used for the rate design approved in Docket No. DG 20-105." See R. Garcia and A. Maston Testimony at 0013.

a) Please comment on capital improvements made at any facility following the DG 20-105 rate case; specifically, weren't improvement made to improve system pressure support and change the estimated 8.7 percentage?

b) Did the Company undertake any additional projects for capital improvements as of September 1 2023 that would have increased, maintained or reduced the estimated 8.7 percentage? Since Dkt. No. 20-105 has the estimated pressure support percentage dropped below 8.7%?

c) Please identify all 'facilities' referenced directly or implicitly by R. Garcia, A. Maston, J. Tilbury, K. Esposito and M. Summerfield in their pre-filed testimony; the description should include but not be limited to the type of "facility", when the Company acquired or rented /it or them and where they are located. "Facilities" includes but is not limited to "vaporization facilities" that the Company states exist in Concord, Manchester and Tilton.

d) Please explain why the Company conclude it would "utilize more vaporization capacities from its LNG facilities." Did the Company conduct a cost-benefit analysis? If so, please provide that analysis, if not why not? See Tilbury, Esposito and Summerfield Testimony at 0034.

e) Please provide a copy of portions of the MCOSS in Docket No. DG 20-105 that the Company believes are relevant to the estimated 8.7 percentage calculation. Please show or reference calculations the Company asserts result in an 8.7 percentage for the current filing.

RESPONSE:

a) Below is a list of capital improvements that have been completed following the DG 20-105 rate case.

As discussed in testimony, the estimated percentage used for pressure support purposes of 8.7% remains unchanged because it was based on the marginal cost of service (MCOS) study that was used for the rate design approved in Docket No. DG 20-105. While some of these projects can improve system pressure support, in any given year the Company may experience a higher or lower need for pressure support depending on the weather and demands on the system during a given period. It is not possible to adjust the allocation based solely on a review of discreet projects. A new MCOS study would have to be performed to support any change to the currently approved 8.7% figure.

2020:
- LP Air Compressor overhaul, Manchester LP,
- Nashua Vaporizer #1 burner control upgrade,
- SCADA/PLC upgrade Tilton LNG, install manual operation panel

2021:
- Tilton LNG Tank withdrawal valve replacement
- Concord LNG Boil off vaporizer, replace
- Nashua Vaporizer #2, burner control upgrade

2022:
- LNG Pump replacement, Manchester LNG
- Nashua Vaporizer #3 conversion to natural gas
- Concord LNG, provided equipment redundancy by installing second LNG offload pump, temporary second hot water boiler and all piping, electrical and ancillary mods to meet Gas Supply base load objectives.

2023:
- Nashua LP, Repair stressed pump piping at tank 1.
- Manchester, Fire call box replacement
- Provide weather shelter shed for Manchester LNG offload station
- Provide weather shelter shed for Concord LNG offload station.
- Replacement LNG relief valve – Concord
- Install 2nd LNG offload pump Concord LNG

2024:
- Nashua, Verify & Calibrate LP Air flow meters for mixing system with prover, make correction to auto mix sys.
- Fixed Gas detector heads, replace/rebuild all Plants
- LP Tank relief valves, test replace/rebuild all LP locations
- Complete 2nd offload pump install

b) Please see response in (a) above.

c) The Company owns and operates three LNG facilities located in Tilton, Manchester, and Concord. The Company owns and operates four propane facilities located in Tilton, Manchester, Nashua, and Amherst. Note: the Amherst facility is a storage facility with no vaporization; it is not connected to the distribution system.

d) The Company requires additional LNG supply and trucking to maintain our working supply capacity of 12,600 MMBtu's and to maintain pressure support. As we utilize our LNG storage additional trucking and supply is required to maintain our inventory volumes and reliability. This is not a new approach or policy; it is standard procedure.

e) Please see Attachment 24-098 DOE 1-8e (COG).pdf for the MCOS study where the 8.7 percentage is calculated. This comes from DG 17-048, the rate case prior to DG 20-105, and was determined to still be appropriate for use during both the DG 20-105 rate case and the ongoing DG 23-067 rate case. We have no reason to believe it is not appropriate for the current filing.

<u>SUPPLEMENTAL RESPONSE</u>:

e) Please see Attachment 24-098 DOE 1-8e.1 (COG).xlsx for the live excel version of the MCOS study previously provided as Attachment 24-098 DOE 1-8e (COG).pdf. Please also see Attachment 24-098 DOE 1-8e.2 (COG).xlsx for the FCOS study that was prepared for DG 17-048. During the preparation of the DG 20-105 rate case, the Company developed an estimate of the costs of hypothetical additions that had occurred since DG 17-048, and upon review of engineering data, it was determined that the cost estimates and allocation to pressure support used in DG 17-048 were still current.