Liberty Utilities

REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-152

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Least Cost Integrated Resource Plan

POLICY AND GAS SUPPLY REBUTTAL TESTIMONY

OF

FRANCISCO C. DAFONTE, WILLIAM R. KILLEEN,
JAMES M. STEPHENS, AND KIM N. DAO

October 25, 2019

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I. INTRODUCTION

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

A. My name is Francisco C. DaFonte. I am Vice President, Regulated Infrastructure Development – Gas, of Liberty Utilities Co., which owns Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (hereinafter referred to as "EnergyNorth" or the "Company"). My business address is 15 Buttrick Road, Londonderry, New Hampshire.

My name is William R. (Bill) Killeen. I am Director, Energy Procurement of Liberty Utilities (Canada) Corp., the parent company of Liberty Utilities Co. My business address is 354 Davis Road, Oakville, Ontario, Canada.

My name is James M. Stephens. I am a Partner at ScottMadden, Inc. ("ScottMadden"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts.

My name is Kim N. Dao. I am a Director at ScottMadden. My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts.

Q. On whose behalf are you submitting this Rebuttal Testimony?

A. We are submitting this joint Rebuttal Testimony before the New Hampshire Public Utilities Commission (the "Commission" or "NHPUC") on behalf of EnergyNorth.

Q. Mr. DaFonte, please summarize your educational background and your business and professional experience.

A. I attended the University of Massachusetts Amherst where I majored in Mathematics with a concentration in Computer Science. In the summer of 1985, I was hired by

Commonwealth Gas Company (now NSTAR Gas Company), where I was employed primarily as a supervisor in gas dispatch and gas supply planning for nine years. In 1994, I joined Bay State Gas Company (now Columbia Gas of Massachusetts) where I held various positions including Director of Gas Control and Director of Energy Supply Services. In 2011, I was hired as the Director of Energy Procurement by Liberty Energy (NH) and promoted to Senior Director in July 2013 and Vice President in July 2014. In November 2016, I became Vice President, Regulated Infrastructure Development - Gas, of Liberty Utilities. Please refer to Attachment PGS-1 for a summary of my professional background.

Q. Mr. DaFonte, have you previously testified in regulatory proceedings before the Commission?

A. Yes, I have testified in multiple proceedings before the Commission.

Q. Mr. DaFonte, have you testified in other regulatory jurisdictions?

A. Yes. I have testified before the Massachusetts Department of Public Utilities, the Maine Public Utilities Commission, the Indiana Utility Regulatory Commission, the Missouri Public Service Commission, the Georgia Public Service Commission, and the Federal Energy Regulatory Commission (“FERC”).

Q. Mr. Killeen, are you the same William R. (Bill) Killeen who filed direct testimony in this proceeding?

A. Yes. I submitted direct testimony on April 30, 2019.

Q. Mr. Stephens, please summarize your educational background and your professional experience in the energy and utility industries.

A. I hold a Bachelor of Science degree in Management and a Master of Business Administration with a concentration in Operations Management from Bentley College. I have 30 years of experience in the energy industry and have held senior management positions at consulting firms, a retail energy marketing company, and natural gas local distribution companies ("LDCs"). In my role as a consultant, I have assisted numerous clients with various natural gas related engagements, including: the analysis of regional energy market dynamics and the associated drivers for new natural gas infrastructure; the evaluation of capacity opportunities associated with open seasons on various pipelines; the evaluation of new markets/opportunities; integrated resource plans; and natural gas supply portfolio evaluation and optimization. In addition, in my role as the President of a retail energy marketing firm, I was responsible for all aspects of business unit management including front, mid, and back-office functions. I was also responsible for Gas Supply Procurement and Portfolio Optimization for Colonial Gas Company, which is now a subsidiary of National Grid. A summary of my professional and educational background is provided as Attachment PGS-2.

Q. Mr. Stephens, have you previously provided testimony before the Commission?

A. Yes, I have submitted expert testimony to the Commission on behalf of Public Service Company of New Hampshire d/b/a Eversource Energy regarding its natural gas capacity contract filing in Docket No. DE 16-241, as well as expert testimony to the Commission on behalf of EnergyNorth regarding its natural gas supply strategy in Docket No. DG 17-198.

Q. Mr. Stephens, have you submitted expert testimony in other regulatory jurisdictions?

A. Yes, I have submitted expert testimony in several other regulatory jurisdictions, including the FERC, the states of Texas, Alaska, Massachusetts and Maine, and the Canadian provinces of Ontario, Québec, New Brunswick, Nova Scotia, and Alberta. A list of my past expert witness appearances is provided in Attachment PGS-2.

Q. Ms. Dao, please summarize your educational background and your professional experience.

A. I hold a Bachelor of Arts degree in economics from Clark University. I have 15 years of consulting experience in the energy and utility industries. In my role as a consultant, I have assisted clients in numerous engagements involving regulatory strategy and market analyses, including the evaluation of open seasons on various pipelines, regional energy market demand/supply dynamics, energy pricing and basis implications, and the associated drivers for new natural gas infrastructure; the development and evaluation of natural gas demand forecasts; and natural gas supply portfolio evaluation and optimization. A summary of my professional and educational background is provided as Attachment PGS-3.

Q. Ms. Dao, have you previously testified before any regulatory bodies?

A. No, I have not. However, I have provided analytical support for expert witness testimony on a variety of issues, including natural gas supply planning, demand forecasting, and cost of capital and capital structure in several regulatory jurisdictions, including the states of Massachusetts, New Hampshire, Maine, New Jersey, Maryland, the District of Columbia, and the Canadian provinces of Ontario and Nova Scotia.

II. EXECUTIVE SUMMARY

Q. Prior to discussing the objectives of your Rebuttal Testimony, please provide a summary of the Company's initial filing and related activities in this docket.

A. On October 2, 2017, the Company filed with the Commission its 2017 Least Cost Integrated Resource Plan ("LCIRP") for the five-year planning horizon from 2017/18 through 2021/22 ("Forecast Period"). Subsequent to that filing, EnergyNorth engaged with the Staff of the NHPUC ("Staff"), the Office of Consumer Advocate ("OCA"), Conservation Law Foundation ("CLF"), and other intervenors through the discovery process, intervenor discussions, and technical sessions on March 9, 2018, May 24, 2018, and November 5, 2018.

On April 30, 2019, EnergyNorth submitted a supplemental filing, which included the Direct Testimony of William R. Killeen, in response to the Commission's Order No. 26,225 (Mar. 13, 2019), which directed the Company "to submit a supplemental filing, including supporting testimony, to address each of the specific elements required under RSA 378:38 and RSA 378:39 that are not already addressed in its LCIRP, with adequate sufficiency to permit the Commission's assessment of potential environmental, economic, and health-related impacts of each option proposed in the LCIRP, as required by RSA 378:39."[1]

At subsequent technical sessions held on May 23, 2019, and June 20, 2019, Staff and other parties acknowledged that the standards governing the revised LCIRP statute were not clear, particularly as they relate to natural gas utilities, and that EnergyNorth was the first natural gas utility expected to meet these new and undefined standards. Nonetheless, parties expressed their views that Mr. Killeen's direct testimony should be supplemented with additional analysis. Subsequently, the Company filed additional testimony from Mr. Paul J. Hibbard, Ms. Sherrie Trefry, and Mr. Eric M. Stanley on June 28, 2019.

On September 6, 2019, the following intervenors filed direct testimony regarding the Company's 2017 LCIRP and its supplemental filings:

- Mr. Al-Azad Iqbal, Utility Analyst – Gas & Water Division, on behalf of Staff;
- Messrs. John Antonuk and John Adger of The Liberty Consulting Group ("Liberty Consulting") on behalf of Staff;
- Dr. Elizabeth A. Stanton of Applied Economics Clinic on behalf of CLF;
- Mr. Paul Chernick of Resource Insight, Inc. on behalf of CLF; and
- Mr. Terry Michael Clark.

1 Order No. 26,225 (Mar. 13, 2019), at 7.

Q. How is the Company's rebuttal filing organized?

A. The Company's rebuttal filing is supported by the rebuttal testimonies of the following witnesses:

- This Rebuttal Testimony of Francisco C. DaFonte, William R. Killeen, James M. Stephens, and Kim N. Dao (hereinafter referred to as the Company's "Policy and Gas Supply Rebuttal Testimony"), which will discuss the Company's 2017 LCIRP and its associated supplemental filings in response to (i) Messrs. Antonuk and Adger of Liberty Consulting on behalf of Staff; (ii) Mr. Chernick on behalf of CLF; and (iii) Mr. Clark.
- Rebuttal Testimony of William R. Killeen, William J. Clark, Eric M. Stanley, James M. Stephens, and Adam J. Perry (hereinafter referred to as the Company's "Demand Forecast Rebuttal Testimony"), which will discuss the Company's Demand Forecast approach and results in response to (i) Messrs. Antonuk and Adger of Liberty Consulting on behalf of Staff; and (ii) Mr. Chernick on behalf of CLF.
- Rebuttal Testimony of Paul J. Hibbard, which will discuss the Company's environmental and health-related impact analysis in response to (i) Dr. Stanton on behalf of CLF; (ii) Mr. Chernick on behalf of CLF; and (iii) Mr. Clark.

Q. How is your joint Policy and Gas Supply Rebuttal Testimony organized?

A. Prior to presenting our response to the testimony of each intervening witness (i.e., Messrs. Antonuk and Adger of Liberty Consulting, Mr. Chernick, and Mr. Clark in

Sections IV through VI, respectively), we provide certain, necessary context regarding the 2017 LCIRP and the Company's resource planning process, which are generally supported by Staff as further detailed in Section III. This context is provided in response to certain criticisms of the Company's 2017 LCIRP in the direct testimonies of the other intervening witnesses (i.e., CLF and Mr. Clark).

III. <u>PURPOSE OF THE LCIRP AND THE COMPANY'S RESOURCE PLANNING PROCESS</u>

Q. Please summarize the Company's 2017 LCIRP.

A. EnergyNorth's 2017 LCIRP sets forth the Company's resource plan to meet its expected customer requirements over the five-year Forecast Period from 2017/18 to 2021/22 using currently accepted resource planning processes, standards, and methods.[2] As concluded in the 2017 LCIRP, (i) the Company's modeling demonstrates a growth in customer requirements over the Forecast Period; (ii) the Company employed Planning Standards, which are reasonable and appropriate; and (iii) the resource strategies described therein are in the best interests of its customers and result in a reliable, best-cost supply and capacity portfolio to meet the forecasted demand.

Q. What are the goals and objectives of EnergyNorth's resource planning process?

A. As noted in the 2017 LCIRP, the primary goal of the Company's resource planning process is to "acquire and manage resources that provide reliable service under various demand scenarios while focusing on a best-cost resource portfolio for its customers."[3]

[2] 2017 LCIRP, at Bates 005.
[3] Ibid, at Bates 007.

EnergyNorth balances cost considerations with the Company's resource planning objectives,[4] which include:

- Maintaining reliability and supply security;
- Providing diversity and contract and portfolio flexibility; and
- Promoting the acquisition of viable resources.

Q. Please describe the Company's resource planning process.

A. At a high-level, EnergyNorth's resource planning process consists of the following four steps:

1. Develop a Demand Forecast for the five-year Forecast Period;
2. Develop appropriate Planning Standards;
3. Evaluate and develop a best-cost resource portfolio to meet the expected customer requirements under various growth and weather scenarios; and
4. Ensure compliance with Commission orders and statutory requirements.

Q. Please discuss the first step (i.e., development of the Demand Forecast) of the resource planning process.

A. The process to develop the Company's Demand Forecast[5] includes the following steps:

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4 *See*, also, the Company's response to Staff 2-23. All responses to discovery referenced throughout our Rebuttal Testimony (excluding spreadsheets and voluminous attachments, such as detailed SENDOUT® reports) are provided collectively as Attachment PGS-4, unless otherwise noted. For ease of reference, the discovery responses included in that attachment are provided in numerical sequence by requesting party.

5 Please note, the Company's Demand Forecast was updated subsequent to the 2017 LCIRP filing and provided in the response to Staff Tech 1-7; the Updated Demand Forecast was developed using the same process, but reflected modifications to certain assumptions related to the out-of-model adjustments.

1. Develop econometric models to forecast total demand;
2. Include out-of-model adjustments to account for events and trends not captured in the econometric models;
3. Account for energy efficiency;
4. Adjust for unaccounted for gas and unbilled sales; and
5. Translate monthly demand forecast to daily demand requirements.

Q. Please discuss the second step (i.e., develop Planning Standards) of the resource planning process.

A. As detailed in the 2017 LCIRP, in addition to the Normal Year standard, EnergyNorth established the Design Year and Design Day standards, which reflect weather conditions that inform the level of firm volume that the Company must plan for to maintain reliable service.[6] EnergyNorth also developed High and Low Growth scenarios to determine the adequacy of the Company's supply portfolio under a range of demand scenarios using the same approach relied upon and approved by the Commission in the 2010 and 2013 LCIRPs.[7]

Q. Did Staff support the Company's approach to developing the Demand Forecast and Planning Standards (i.e., steps 1 and 2 of the resource planning process)?

A. Yes, Messrs. Antonuk and Adger of Liberty Consulting supported the Company's overall approach to estimating its demand requirements, including (i) the econometric models

6 2017 LCIRP, at Bates 032.
7 *See*, also, the Company's responses to Staff 2-21 and CLF Tech 1-4.

and results of the econometric forecast;[8] (ii) the need for an adjustment to the econometric forecast to account for events and trends not captured in the econometric models;[9] (iii) the energy efficiency savings;[10] (iv) the adjustments for unaccounted for gas and unbilled sales;[11] and (v) the approach used to develop daily demand requirements,[12] as well as the approach and results of the Company's Planning Standards,[13] but identified certain issues. Please see the Company's Demand Forecast Rebuttal Testimony for the Company's detailed response to these issues.

Q. Please discuss the third step (i.e., evaluate and develop a best-cost resource portfolio) of the resource planning process.

A. As described in the 2017 LCIRP, the evaluation and development of a best-cost resource portfolio consists of the following:

1. A review of the incremental demand requirements compared to the Company's existing supply resource portfolio to determine resource need;
2. Identify resource options that are available to EnergyNorth;
3. Evaluate the available resource options based on quantitative (i.e., price factors) and qualitative (i.e., non-price factors) analyses; and

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8 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 008.
9 Ibid, at Bates 011.
10 Ibid, at Bates 008.
11 Ibid, at Bates 012.
12 Ibid.
13 Ibid, at Bates 015.

4. Make appropriate resource decisions to achieve a best-cost supply and capacity portfolio.[14]

Q. Please summarize the Company's supply resource portfolio as presented in the 2017 LCIRP.

A. As detailed in Section V.B. of the 2017 LCIRP, to meet customer load requirements, the Company's supply resource portfolio is comprised of pipeline transportation and underground storage capacity contracts, as well as on-system LNG and propane facilities. Specifically, the Company has:

- Firm transportation contracts on TGP (106,833 Dth/day) and PNGTS (1,000 Dth/day) to provide a total daily deliverability of 107,833 Dth/day to its city-gates;[15]
- Three peaking LNG facilities in Concord, Manchester, and Tilton, which have a combined operational vaporization and storage capacity of approximately 12,600 Dth; and
- Four propane facilities in Manchester, Nashua, Tilton, and Amherst,[16] which have a combined design (or nameplate) vaporization rate of approximately 34,600 Dth/day.

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14 *See*, also, the Company's response to Staff 2-14.

15 As shown in Table 34 of the 2017 LCIRP, nearly all of the Company's existing pipeline transportation and underground storage contracts are scheduled to expire and require notice of renewal during the Forecast Period.

16 The propane facility in Amherst is used solely for storage.

Thus, in total, EnergyNorth has Design Day resources of approximately 155,033 Dth/day.

Q. Given the Company's supply resource portfolio, did EnergyNorth determine there was a need for incremental resources to meet its forecasted demand requirements in the 2017 LCIRP?

A. Yes, the Company concluded in the 2017 LCIRP that EnergyNorth would need incremental resources to meet the forecasted increase in demand requirements over the Forecast Period.[17]

Q. Did Staff support the Company's conclusion that there is a need for incremental resources?

A. Yes, Messrs. Antonuk and Adger of Liberty Consulting concluded that they "expect that EnergyNorth will continue to add customers during the LCIRP forecast period, and thus some amount of additional supply capacity will be required during that period."[18] Liberty Consulting further stated that "there exists a need for some addition to gas supplies, both capacity and commodity, during the LCIRP forecast period."[19]

[17] 2017 LCIRP, at Bates 057 to 058.
[18] Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 020.
[19] Ibid, at Bates 022.

Q. Please discuss the identification of the resource options available to the Company to meet the incremental needs presented in the 2017 LCIRP.

A. As noted in the 2017 LCIRP, "[b]ased on EnergyNorth's review of available and viable resources in the marketplace to meet the Company's existing and projected load requirements, the following gas supply options [were] identified:

- ENGIE delivered supply to the EnergyNorth city-gates and LNG facilities;
- Repsol delivered supply to Dracut, Massachusetts;
- Pipeline transportation capacity from the Dawn Hub on the TCPL Mainline and PNGTS pipeline systems to Dracut, Massachusetts; and
- Increasing on-system LNG storage and vaporization capacity with additional infrastructure to access new gas supplies."[20]

In addition to the identification of gas supply options, the Company also assessed the delivery options associated with those gas supplies since the Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP") Concord Lateral, which is, for all intents and purposes, the only feed to EnergyNorth's service territory, has no additional capacity.[21] Specifically, the Company evaluated "the option to enhance its distribution system reliability, diversity and flexibility through an extension of its system,"[22] which was later identified as the proposed Granite Bridge Pipeline in Docket No. DG 17-198.[23]

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20 2017 LCIRP, at Bates 053. *See*, also, the Company's response to Staff 2-16.

21 As noted in the 2017 LCIRP, EnergyNorth's service territory is exclusively served by the TGP Concord Lateral except for the City of Berlin, which is served by PNGTS. *See*, 2017 LCIRP, at Bates 037.

22 Ibid, at Bates 054.

23 *See*, also, the Company's response to Staff 2-19.

Q. Please describe the process used by EnergyNorth to evaluate the resource options in the 2017 LCIRP.

A. The Company's evaluation of the available resource options consisted of a review of price factors, using the SENDOUT® portfolio optimization model, and non-price factors, including reliability, flexibility, diversity, reliability, viability, and contract term to determine the best-cost, most reliable options to meet the Company's resource need.[24]

Q. Did Staff support the Company's identification and evaluation of the gas supply options?

A. Yes, Messrs. Antonuk and Adger of Liberty Consulting supported the identification of the gas supply options and the approach and process used by the Company to evaluate those options. Specifically, Liberty Consulting stated, "EnergyNorth's selection of the ENGIE, Repsol and TCPL/PNGTS supply options [was] appropriate. Their specification to the SENDOUT modeling was based on actual contract parameters or offers of supply, which allowed for proper cost comparisons."[25] Messrs. Antonuk and Adger also noted that the Company's "use of SENDOUT modeling to support its analysis and to justify its conclusions appropriate."[26] Liberty Consulting further concluded that "EnergyNorth's identification of available supply options [was] sufficient, and its analysis of them sound and comprehensive."[27]

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24 2017 LCIRP, at Bates 052 to 058. *See*, also, the Company's response to Staff 2-14.
25 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 020.
26 Ibid.
27 Ibid, at Bates 022.

Q. What were the Company's conclusions and resource decisions that were laid out in the 2017 LCIRP?

A. As concluded in the 2017 LCIRP, under all weather and growth scenarios, EnergyNorth would be able to meet its customers' load requirements throughout the Forecast Period with: (i) renewal of all legacy pipeline and storage contracts that were set to expire during the five-year Forecast Period; (ii) an increase in delivery capacity through an extension of its system (i.e., the proposed Granite Bridge Pipeline); and (iii) incremental supply resources.[28]

Q. Did Staff support the Company's conclusions and resource decisions presented in the 2017 LCIRP?

A. Messrs. Antonuk and Adger of Liberty Consulting supported the renewal/extension of the Company's legacy pipeline and storage capacity contracts that are set to expire during the Forecast Period, specifically stating that the "[FERC's] incremental-pricing policy makes this supply capacity lower in price than alternatives for replacing it."[29] In addition, as discussed above, Liberty Consulting acknowledged the need for incremental supply capacity, and noted that the "ENGIE contract [was] an appropriate portfolio element for planning purposes."[30] With respect to the Company's existing on-system resources, Liberty Consulting believes that the "information available supports continuing value for the Company and customers in continuing operation of its existing [propane] facilities."[31]

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[28] 2017 LCIRP, at Bates 057 to 058.
[29] Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 021.
[30] Ibid.
[31] Ibid, at Bates 018.

Finally, regarding the system extension (i.e., the proposed Granite Bridge Pipeline), Messrs. Antonuk and Adger stated, "[w]hether such an extension will be required during the LCIRP forecast period remains to be examined."[32] The Company's response to these issues is provided in Section IV below.

Q. Please discuss the fourth and last step (i.e., ensure compliance with Commission orders and statutory requirements) of the resource planning process.

A. In Section VI of the 2017 LCIRP, EnergyNorth summarized the directives from the Commission's order in Docket No. DG 13-313 (the "2013 IRP Order") and the actions taken by the Company to comply with those directives, which included the 2017 LCIRP's compliance with the statutes that govern LCIRPs (i.e., RSA 378:37 through RSA 378:40).

Q. Did Staff support the Company's conclusions regarding the compliance of the 2017 LCIRP and supplemental filings with Commission orders and statutory requirements?

A. Yes. Staff Witness Mr. Al-Azad Iqbal supported the assessment provided in the Company's 2017 LCIRP, supplemented by the Direct Testimony of William R. Killeen on April 30, 2019, and further supplemented by the Direct Testimonies of Paul J. Hibbard, Sherrie Trefry, and Eric M. Stanley on June 28, 2019, and found the Company's filings addressed the Commission's orders and the statutory requirements of RSA 378:38 and RSA 378:39. Specifically, Mr. Iqbal stated, "Staff believes that the Company has

[32] Ibid, at Bates 021.

addressed environmental as well as health related aspects in their supplemental filings at this time. Staff believes the information provided is responsive to the statutory requirements, given the absence of clear guidelines."[33]

IV. RESPONSE TO THE LIBERTY CONSULTING GROUP ON BEHALF OF STAFF

Q. Please summarize the issues raised by Messrs. Antonuk and Adger of Liberty Consulting regarding the Company's 2017 LCIRP.

A. While Staff Witnesses Messrs. Antonuk and Adger of Liberty Consulting generally agreed with the Company's approach and process used in the development of the Demand Forecast and Planning Standards, as well as the Company's approach and process used to evaluate and develop a best-cost resource portfolio, Liberty Consulting expressed some concerns about certain aspects of the Company's Demand Forecast and resource portfolio plan. Specifically, with respect to the Demand Forecast, Messrs. Antonuk and Adger raised some concerns regarding the out-of-model adjustments and overall growth rates associated with the Demand Forecast.[34] The Company's response to these issues is provided in the Demand Forecast Rebuttal Testimony, which demonstrates that while customer growth may be lower than the projected customer additions, EnergyNorth's load projections for the 2017/18 and 2018/19 split-years are consistent

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33 Direct Testimony of Al-Azad Iqbal, at Bates 041.

34 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 011 and 014.

with normalized actual demand over the past two years. Therefore, the Company continues to believe that its Demand Forecast is reasonable.

In addition, Liberty Consulting opined on the Company's resource strategy and future portfolio decisions, including the strategy associated with (i) the existing propane facilities, (ii) alternative gas supply options, and (iii) the delivery option evaluated by the Company to increase deliverability to the Company's city-gates (i.e., the system extension). The Company's response to each of these issues is discussed in detail below.

A. Propane Facilities

Q. Please summarize Liberty Consulting's concerns regarding the Company's propane facilities.

A. Messrs. Antonuk and Adger believe there is confusion over whether the Company views the retirement of the propane facilities as an option or necessity.[35] In addition, Liberty Consulting concluded that continued reliance on these propane facilities is warranted.[36]

Q. Please summarize the Company's position with respect to its propane facilities.

A. The Company has significant reliance on its propane facilities, particularly for meeting demand on a Design Day or during a prolonged cold snap. Specifically, the propane facilities represent over 22 percent (i.e., 34,600 Dth/day of 155,033 Dth/day) of the Company's gas supply portfolio with respect to deliverability should the Company experience demand associated with, or near, Design Day weather conditions.

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35 Ibid, at Bates 012.
36 Ibid, at Bates 018.

Q. Has the Company expressed certain concerns regarding its reliance on the propane facilities?

A. Yes, it has. The Company has discussed the following three concerns with the growing reliance on its propane facilities to meet demand during extreme weather conditions:

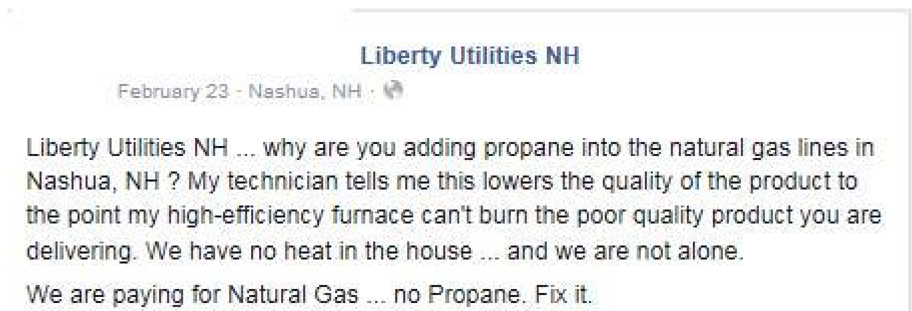
1. The introduction of higher amounts of propane into the Company's distribution system affects customers' high-efficiency equipment.
2. The Company is increasing its exposure to (i.e., reliance on) the ability of the propane facilities to provide the full design (or nameplate) deliverability during extreme weather conditions.
3. The Company is increasing its dependence on propane facilities that are well beyond the life expectancy for such facilities.

Q. Please provide more detail regarding the Company's first concern, i.e., the effects of propane on high-efficiency equipment.

A. Volume from propane facilities first requires a blending with compressed air to reduce the high Btu content, and then additional blending with natural gas to further reduce the higher Btu content of propane. Even with an appropriate blending of natural gas with propane, the Company has received customer complaints because the comingling of propane causes significant problems with high efficiency heating equipment. As indicated in the 2017 LCIRP, EnergyNorth's customers have experienced problems with their high efficiency furnaces at various times when these propane facilities are used extensively. This issue was discussed at length by the Company in the Northeast Energy

Direct ("NED") proceeding (Docket No. DG 14-380), and also in the Company's response to Staff 2-12 in this docket:

> In addition, from a system operations perspective, the Company has received multiple complaints from customers with new high-efficiency heating equipment as a result of EnergyNorth's use of the propane facilities. These complaints are generally attributable to the limited tolerance of more modern equipment to varying natural gas heating values, and at times has led to "no heat" calls by customers. As an example, the Company received the following complaint from a customer via Facebook in February 2015:



> Additionally, the Company has received reports from HVAC contractors that service accounts near to one of EnergyNorth's propane facilities who indicated they had received numerous customer calls due to noise from their high-efficiency boilers, including certain customers that were uncomfortable remaining in their homes while this was occurring. One of the HVAC contractors noted that it was "selling more and more" of the high efficiency boilers "due to rebates that incent their installation."[37]

Also, as noted in the Company's response to Staff 2-12: "With the incentives for customers to replace older, less efficient furnaces, the conversion of oil and propane

[37] Company's response to Staff 2-12; *see*, also, Attachment PGS-5 (an email from Joyce Cooling and Heating, stating "Customers with high end heating units, mostly modulating gas boiler, will have a very loud rumbling noise…After we receive several calls from the same neighborhood we now [sic] that there has been propane added into the gas lines…Usually this happens on extreme cold mornings"); and Attachment PGS-6 (letter from St. Anselm's College stating, "During almost every winter we have had critical boilers for buildings trip out during really cold storms").

customers to higher efficiency natural gas heating equipment, and simply the phasing out of the manufacturing of low efficiency heating equipment, this issue will only get worse unless propane can be phased out of the Company's resource portfolio. Further, it may act as a deterrent for customers who want to be more energy efficient and, quite frankly, take advantage of the Company's award winning energy efficiency programs."[38]

Lastly, the full operational capability of the propane facilities assumes sufficient "flow by" natural gas. With a curtailment on the TGP Concord Lateral, or disruption upstream on the TGP system, there would not be sufficient "flow by" natural gas to blend with propane, significantly reducing the operational capability of the propane facilities.

Q. Please discuss the second concern identified by the Company regarding the propane facilities, i.e., increasing reliance on the deliverability of the design, or nameplate, capacity.

A. The Company's resource plan assumes that the full design (or nameplate) vaporization capacity of the propane facilities is available to meet demand during extreme weather conditions. Specifically, the Company's gas supply plan identifies 34,600 Dth/day of deliverability of propane to meet demand under Design Day weather conditions.

Q. Has the Company dispatched the full deliverability of the propane facilities over the duration of one full day?

A. No, it has not. While the Company has assumed the full design (or nameplate) vaporization capacity of the propane facilities (i.e., 34,600 Dth/day) is available to meet

[38] Company's response to Staff 2-12.

Design Day demand in all SENDOUT® model runs presented in the 2017 LCIRP, the propane facilities have never operated at that level for an entire 24-hour period. Notably, there have only been four days over the past six years during which the three propane facilities in Manchester, Nashua, and Tilton operated on the same day (on March 4 and 5, 2014, and on December 28 and 29, 2015). Operational records indicate that for five hours on March 5, 2014, from the hour ending 0400 to 0800, all three facilities were operating at full to near full propane production capacity.[39]

Q. Is the Company assessing the ability of the propane facilities to provide the full deliverability of 34,600 Dth?

A. Yes, it is. The Company has initiated an internal team to review and analyze the ability of the propane facilities to provide the full nameplate deliverability. This team is comprised of internal experts from operations, distribution, and gas supply. The Company will provide the results of this study once completed.

Q. Please discuss the last concern identified by the Company regarding the propane facilities, i.e., the general age of the propane facilities.

A. While the expected useful life of propane peaking facilities is generally 40 years,[40] the Company's propane facilities have been in service for well beyond their useful life expectancy. Specifically, as shown in Table 1 below, the Company's two largest propane facilities in Manchester and Nashua have been in service for over 70 years. As such, the

[39] *See*, also, the Company's revised response to OCA TS 1-1 in Docket No. DG 17-198.
[40] *See*, for example, Yankee Gas Services Company, Final Decision, Docket No. 01-05-19RE02, November 12, 2003, at 24.

Company has a concentration risk where it has a significant reliance on propane facilities that are approaching 75-years of age and are expected to produce over 34,000 Dth/day of gas supply during extreme weather conditions. In addition, and most importantly, as the Company increases its demand requirements on Design Day, the propane facilities will be required to perform at levels not seen in the past, thus increasing the Company's and its customers' risk of a mechanical failure at one of the facilities.

Table 1: EnergyNorth's On-System Propane Facilities

Location	Design Vaporization (Dth/day)	In-Service Date
Manchester	21,600	1948
Nashua	11,000	1947
Tilton	2,000	1972

B. Alternative Gas Supply Options and Exposure to Dracut Supplies and Pricing

Q. Please summarize Liberty Consulting's conclusions regarding the available natural gas supply options.

A. While Liberty Consulting agreed that the Company's "selection of the ENGIE, Repsol and TCPL/PNGTS supply options [was] appropriate,"[41] and that the "specification [of these supply options] to the SENDOUT modeling… allowed for proper cost comparisons",[42] Messrs. Antonuk and Adger do not specifically address the lack of

41 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 020.
42 Ibid.

alternative gas supply options in the current marketplace[43] and do not provide any context regarding the current challenges faced by the Company, particularly with respect to the Company's exposure to Dracut supplies and associated pricing, given the regional natural gas market dynamics.

Q. Please discuss the Company's current upstream gas supply sources and exposure to Dracut supplies.

A. As discussed above in Section III and in the 2017 LCIRP, EnergyNorth's existing resource portfolio includes firm transportation contracts on TGP (106,833 Dth/day) and PNGTS (1,000 Dth/day), which provide the Company with access to various gas supply sources. Table 2 below summarizes the existing firm transportation capacity by upstream gas supply source.

Table 2: EnergyNorth Upstream Gas Supply Sources

Gas Supply	Contract MDQ (Dth/day)	% of Total
Canadian Supply	8,122	8%
Dracut	50,000	46%
Long-line	21,596	20%
Storage	28,115	26%
Total Firm Transportation	107,833	100%

As illustrated by Table 2, the transportation contracts from Dracut represent the single largest component of the Company's total firm pipeline capacity. Stated differently,

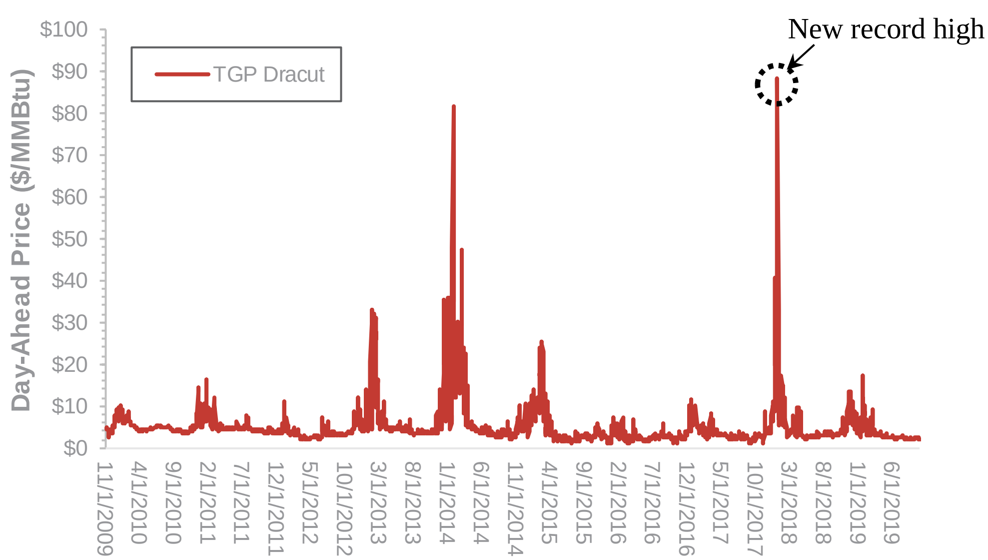
[43] In addition, as discussed in Section V of our Rebuttal Testimony, Mr. Chernick believes that imported LNG supply would be readily available in the New England natural gas marketplace. *See*, Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 28 to 29.

nearly half of the Company's total firm pipeline capacity originates at Dracut; and about one-third of the Company's entire Design Day resource portfolio (i.e., 50,000 Dth/day of 155,033 Dth/day) is at Dracut. Therefore, EnergyNorth and its customers have significant exposure to Dracut supplies and its associated high winter price levels and price volatility.

Q. Please discuss the record natural gas price levels experienced at the TGP Dracut price index since the initial filing of the Company's 2017 LCIRP.

A. Please see Figure 1 below for a chart of the daily TGP Dracut price index over the November 1, 2009, through September 30, 2019, time period, and Table 3 below for a summary of the average TGP Dracut prices over the 2009/10 through 2018/19 split-years.

Figure 1: TGP Dracut Day-Ahead Prices (Nov. 1, 2009 – Sep. 30, 2019)[44]



44 Source: S&P Global Market Intelligence.

Table 3: TGP Dracut Day-Ahead Prices (2009/10 – 2018/19)[45]

Split-Year (Nov-Oct)	Average TGP Dracut Winter Price ($/MMBtu)	Max. TGP Dracut Winter Price ($/MMBtu)	Boston Winter Heating Degree Days ("HDD")	Winter HDD Difference from Normal[46]
2009/10	$5.84	$10.10	4,116	(308)
2010/11	$6.46	$16.50	4,543	119
2011/12	$3.85	$11.02	3,548	(877)
2012/13	$9.28	$33.25	4,343	(82)
2013/14	$15.76	$81.50	4,806	382
2014/15	$8.95	$25.50	4,987	563
2015/16	$3.07	$7.40	3,692	(732)
2016/17	$4.92	$11.60	4,170	(254)
2017/18	$8.71	$88.30	4,449	25
2018/19	$5.77	$17.25	4,270	(155)

As shown in Figure 1 and Table 3 above, the TGP Dracut price index has exceeded $10 per MMBtu during each winter period (except for the warmer-than-normal winter of 2015/16), and reached a record high of approximately $90 per MMBtu during the winter of 2017/18.[47] As discussed, given the Company's current resource portfolio, the Company has significant exposure to Dracut supplies and associated pricing. If the Company were to purchase its full amount of Dracut volumes (i.e., 50,000 Dth/day) at the spot gas price level of $90 per MMBtu, gas costs to customers associated with that purchase for one day would be $4.5 million.

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45 Sources: S&P Global Market Intelligence; and NOAA National Centers for Environmental Information, Daily Summaries for Boston, MA.

46 Boston, MA has a total normal winter HDD of 4,424. A negative difference from normal indicates warmer-than-normal weather, and a positive difference from normal indicates a colder-than-normal winter. Source: NOAA National Centers for Environmental Information, Summary of Monthly Normals 1981-2010 for Boston, MA.

47 Please note, since gas typically trades on Friday for delivery on Saturday, Sunday, and Monday, the TGP Dracut price was approximately $90 per MMBtu on three consecutive dates (i.e., January 5, 2018, January 6, 2018, and January 7, 2018).

Q. Please discuss the volatility of the TGP Dracut prices.

A. The TGP Dracut price index has exhibited higher price levels and more volatility relative to the Dawn and Henry Hub price indices. Figure 2 below is a scatterplot showing the historical natural gas price volatility[48] (on the x-axis) and the average winter price (on the y-axis) for the TGP Dracut, Dawn, and Henry Hub price indices over the winters of 2009/10 through 2018/19. The scatterplot is divided into four quadrants with a vertical line parallel to the y-axis, which separates observations with relatively lower volatility (less than 150 percent) in quadrants III and IV and higher volatility (greater than 150 percent) in quadrants I and II, and a horizontal line parallel to the x-axis, which separates observations with an average winter price level of less than $5 per MMBtu in quadrants II and III or greater than $5 per MMBtu in quadrants I and IV.

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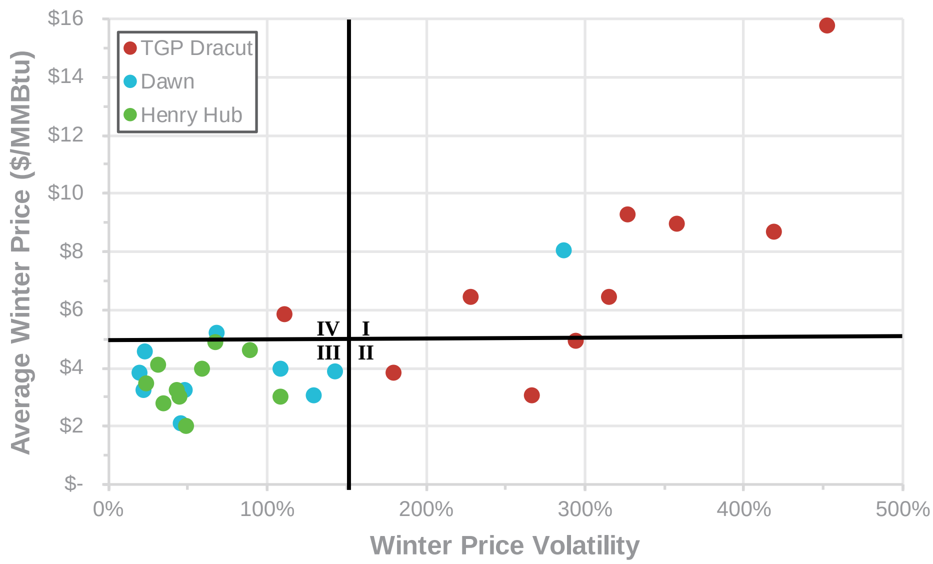
[48] Please note, the historical natural gas price volatility measures the degree of variation in daily natural gas prices as defined by the U.S. Energy Information Administration in the August 2007 report titled “An Analysis of Price Volatility in Natural Gas Markets.”

Figure 2: Average Winter Prices and Volatility (2009/10 – 2018/19)[49]



As shown in Figure 2 above, on a comparative basis, there are ten observations in Quadrants I and II, which are the higher volatility quadrants, and nine of those ten observations are the TGP Dracut price index. Specifically, for the TGP Dracut price index, six of ten observations are in quadrant I, which reflect higher price and higher volatility; three observations in quadrant II with higher volatility and average winter prices between $3 to $5 per MMBtu; and one observation in quadrant IV with an average winter price of nearly $6 per MMBtu and winter price volatility of over 110 percent.

Q. In addition to high price levels and volatility, are there other concerns regarding the TGP Dracut price index?

A. Yes, there also are liquidity concerns associated with the TGP Dracut price index. There are limited gas supply options and counterparties at the TGP Dracut point. [redacted]

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49 Based on ScottMadden's analysis of data from S&P Global Market Intelligence.

[redacted] the lack of liquidity at Dracut in general, and on the TGP Concord Lateral in particular. [redacted] the Company would be forced to rely solely on spot gas purchases at Dracut and would not be able to execute its basis hedging plan, exposing our customers to significant price volatility.[52]

Q. What alternative gas supply options are available to the Company in the current marketplace?

A. The Company presented in its 2017 LCIRP an analysis of various supply alternatives that may be available to meet the demand requirements of EnergyNorth's customers over the Forecast Period. Specifically, as discussed in Section III above, EnergyNorth identified and analyzed delivered supply from CLNG (formerly, ENGIE), Repsol supply from Canaport LNG, and pipeline transportation capacity on TCPL/PNGTS.[53] Subsequently, in late 2017, the Company presented an analysis of natural gas supply options (i.e.,

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50 *See*, Docket No. DG 18-137.
51 *See*, Docket No. DG 19-145.
52 Furthermore, S&P Global Platts has recently disaggregated the Tennessee Zone 6 pricing into four price points -- TGP Zone 6 delivered, TGP Zone 6 delivered North, TGP Zone 6 delivered South, and TGP Zone 6 (300 Leg) delivered. This will not only negatively impact the price liquidity and volatility of the Tennessee Zone 6 pricing, but also the TGP Dracut index. Source: S&P Global Platts, Methodology and specifications guide, North American natural gas, November 2018.
53 2017 LCIRP, at Bates 056.

CLNG/ENGIE, Repsol, TCPL/PNGTS pipeline capacity, and the proposed Granite Bridge LNG facility) to meet the long-term demand requirements of EnergyNorth's customers.[54] However, since 2017, there have been major natural gas market changes impacting the overall availability and pricing of natural gas supplies in New England.

Q. Please discuss the changes in the regional natural gas market that may limit or impact the future availability of natural gas supplies in New England.

A. The natural gas market issues discussed in the Company's 2017 LCIRP (at Bates 044 to 050) continue to pose significant natural gas supply and capacity challenges for the New England region in general and for the Company in particular. One of the primary sources of natural gas supply to the New England region, the Sable Offshore Energy Project ("SOEP") and Deep Panuke Offshore Gas Development Project ("Deep Panuke"), has permanently shut down production, which not only reduces natural gas supply options, but also places price pressure on other natural gas supply sources. In addition, the primary source of imported LNG to the New England region, the Everett LNG facility, is undergoing commercial changes,[55] which may impact the future availability and pricing of natural gas supply from CLNG. Furthermore, other than the Portland XPress ("PXP") Project, which the Company has already contracted for pipeline transportation service as part of its long-term natural gas supply strategy in Docket No. DG 17-198, there have

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[54] Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project, Docket No. DG 17-198, December 21, 2017.

[55] Exelon Generation Company, LLC ("Exelon") completed the acquisition of the Everett LNG facility from ENGIE in October 2018. Exelon's subsidiary (CLNG) is responsible for purchasing and selling LNG to gas utilities, marketers, and other market participants throughout New England. *See*, Motion of Constellation LNG, LLC for Leave to Intervene Out-of-Time, Docket No. DG 17-198, December 12, 2018.

been no new announcements of pipeline projects that would provide service to EnergyNorth.

1. Offshore Natural Gas Supplies

Q. In the 2017 LCIRP, the decline of offshore Nova Scotia natural gas production was reviewed in detail. Has the situation changed?

A. Yes, it has. Specifically, there is no longer any natural gas production from SOEP and Deep Panuke. The Canada-Nova Scotia Petroleum Board announced that production from SOEP has been permanently shut down as of December 31, 2018,[56] and natural gas production from Deep Panuke has been permanently shut down since May 2018.[57]

Q. What are the implications for New England given the recent developments associated with SOEP and Deep Panuke production?

A. Given the permanent production shut down of SOEP and Deep Panuke, the New England and Maritime Canada regions no longer have access to natural gas supply flowing into the Maritimes & Northeast Pipeline ("MNE") system from offshore Nova Scotia, which is a significant supply loss – at times reaching as high as 470 MMcf per day. The loss of offshore Nova Scotia natural gas production places pressure on other natural gas supply sources and leaves re-vaporized LNG from Repsol's Canaport LNG facility as the only gas supply option available from Maritime Canada[58] for the New England market.

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56 *See*, Canada-Nova Scotia Offshore Petroleum Board, Weekly Operations Report, January 3, 2019. https://www.cnsopb.ns.ca/sites/default/files/pdfs/Jan0319.pdf
57 Ibid.
58 Excludes certain limited volume from Corridor Resources.

2. <u>Imported LNG Supplies</u>

Q. Please summarize the developments associated with the Everett LNG facility over the past two years.

A. As discussed in the Company's 2017 LCIRP, the Everett LNG facility is a primary source of imported LNG supplies to the New England region. In 2018, the Everett LNG facility was acquired by Exelon[59] and is currently undergoing commercial changes. Specifically, a subsidiary of Exelon, Constellation Mystic Power, LLC ("Mystic"), filed a request with the FERC in May 2018 for approval of a cost-of-service agreement between Mystic, Exelon, and ISO New England ("ISO-NE"), which would support the continued operation of the Mystic 8 and 9 natural gas-fired generating units.[60] In its order issued on December 20, 2018, in Docket No. ER18-1639-000, the FERC approved the cost-of-service agreement, with certain conditions, to maintain the fuel security needs of the ISO-NE region through May 2024.[61] In addition, the FERC determined that Mystic can recover 91 percent of the cost of ownership and operation of the Everett LNG facility and ordered the implementation of an incentive mechanism to promote third-party sales of LNG from the Everett LNG facility.[62]

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59 Exelon completed the acquisition of the Everett LNG facility from ENGIE in October 2018. *See*, Motion of Constellation LNG, LLC for Leave to Intervene Out-of-Time, Docket No. DG 17-198, December 12, 2018.

60 The Mystic 8 and 9 units are solely supplied by the Everett LNG facility and, in fact, Mystic is the largest customer of the Everett LNG facility. *See*, Prepared Answering Testimony of Richard L. Levitan on behalf of ISO New England, Inc., FERC Docket No. ER18-1639-000, August 16, 2018.

61 *See*, Federal Energy Regulatory Commission, Order Accepting Agreement, Subject to Condition, and Directing Briefs, FERC Docket No. ER18-1639-000, December 20, 2018, Para. 133-134.

62 Ibid.

Q. What are the market implications of the commercial changes related to the Everett LNG facility?

A. Exelon's filing with the FERC and associated commercial strategy for the Everett LNG facility may impact the future availability and pricing of LNG from the facility. While the Company's delivered service contracts with ENGIE that are part of Docket No. DG 17-198 have been assigned to CLNG, a subsidiary of Exelon, there is uncertainty associated with the duration and pricing of service from the Everett LNG facility beyond the current term of the contracts. To that point, certain intervenors in FERC Docket No. ER18-1639-000 raised concerns related to incentives in the cost-of-service compensation agreement, which could cause Exelon to act in a way that may have the effect of raising or lowering the natural gas prices in the Northeast.[63] Because Exelon will be operating the Mystic and Everett LNG facilities under a new cost recovery framework, it is unclear: (i) if Exelon will change the operations of the Everett LNG facility in response to the new incentives; (ii) how those changes will affect natural gas supply and prices in New England; or (iii) if CLNG will offer similar products and services (e.g., liquefied natural gas for refill). Regardless, the commercial changes at the Everett LNG facility will increase uncertainty associated with type and availability of service offerings and associated price signals.

[63] Ibid, Para. 213-216.

Q. Is there evidence that these commercial changes will impact the Company and its customers?

A. [redacted]

3. <u>Incremental Pipeline Capacity</u>

Q. Please discuss the increase in pipeline deliverability into the New England region over the past two years.

A. Recent pipeline expansions that provide incremental capacity to the region, which are discussed in the Company's 2017 LCIRP, are the Algonquin Incremental Market, TGP Connecticut Expansion, and Atlantic Bridge Phase I projects.[65] Since the 2017 LCIRP filing, the PNGTS PXP Project, which is part of the Company's natural gas supply strategy in Docket No. DG 17-198, has initiated service. As detailed in Docket No. DG 17-198, EnergyNorth has executed a precedent agreement with PNGTS associated with the PXP Project. This agreement provides the Company with firm transportation capacity of up to 5,000 Dth per day from the Dawn Hub to Dracut, Massachusetts, the interconnection point between the Joint Facilities[66] and Tennessee. Phase I of the

64 *See*, Docket No. DG 19-145.
65 2017 LCIRP, at Bates 048.
66 The "Joint Facilities" refers to the portion of the PNGTS system from Westbrook, Maine to Dracut, Massachusetts, which is owned jointly by PNGTS and MNE-US.

PNGTS PXP Project commenced service as of November 1, 2018, which provides the Company with supply diversity at Dracut, but not added capacity given that there is no additional capacity available on the TGP Concord Lateral. However, as discussed in Section IV.C. below, if the proposed Granite Bridge Pipeline is placed in-service, the contracted PXP Project capacity will be able to provide incremental Design Day supply to EnergyNorth's city-gates.

Q. Have there been any new pipeline projects for New England announced since 2017?

A. Yes, there have been. However, while those projects may bring additional supply to very specific parts of the New England region, there have been no new announcements of pipeline projects that would provide service to EnergyNorth's distribution system in New Hampshire. Specifically, PNGTS announced the Westbrook XPress Project, which is an expansion of the PNGTS system to Westbrook, Maine, but not to the Joint Facilities (i.e., downstream to Dracut). In addition, Tennessee announced the TGP 261 Upgrade Project, which is a pipeline looping and compressor upgrade project to provide service from Dracut to delivery points in western Massachusetts. Finally, the other natural gas pipelines that serve the region, Iroquois Gas Transmission System, L.P., Algonquin Gas Transmission LLC, and MNE, have not announced any new projects to provide incremental capacity to New England.

4. Summary of Regional Natural Gas Market Dynamics

Q. Please summarize how the recent changes in the New England natural gas market will impact the gas supply options available to serve EnergyNorth's customers.

A. The recent changes in the New England natural gas market bring into question the availability and long-term feasibility of certain natural gas supply options to serve the New England region in general, and EnergyNorth in particular. As discussed above, with the loss of offshore Nova Scotia production, Repsol's Canaport LNG facility is now the only gas supply option into MNE from the north to serve the New England and Maritime Canada markets. There is uncertainty regarding the types and availability of service offerings and associated pricing from the Everett LNG facility and how that uncertainty may affect services offered by CLNG to the Company. In addition, there have been no new pipeline capacity projects announced over the past two years that could provide incremental deliverability and supply to the Company's service territory.

These natural gas supply challenges exacerbate the Company's concerns regarding the availability of certain natural gas supply options, regional natural gas supply and transportation constraints, and associated price spikes and high volatility levels, particularly in the winter period.

C. System Extension

Q. Please summarize Liberty Consulting's concern regarding the delivery option evaluated by EnergyNorth to increase deliverability to the Company's city-gates, i.e., the system extension.

A. Liberty Consulting believes additional information is required to evaluate the system extension (i.e., the proposed Granite Bridge Pipeline). Specifically, Messrs. Antonuk and Adger stated, "[w]hether such an extension will be required during the LCIRP forecast period remains to be examined."[67]

Q. Would the Company be able to meet its forecasted demand requirements with the existing pipeline delivery capacity?

A. No, the Company would not be able to meet its forecasted requirements over the Forecast Period with its existing delivery infrastructure. EnergyNorth, for all intents and purposes, is solely reliant on the TGP Concord Lateral for deliveries of gas supplies to the Company's service territories.[68] As discussed in the 2017 LCIRP, as well as in prior filings before the Commission, the TGP Concord Lateral is fully subscribed and, therefore, that supply feed has no additional capacity to meet the Company's growing demand requirements. Any additional requests to increase capacity and deliverability on the TGP Concord Lateral will, at a minimum, require incremental facilities.

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67 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 021.

68 Except for the City of Berlin, which is served by PNGTS.

Q. Is the need for incremental resources recognized by Staff?

A. Yes, it is. As discussed in Section III above, Messrs. Antonuk and Adger of Liberty Consulting concluded that "there exists a need for some addition to gas supplies, both capacity and commodity, during the LCIRP forecast period"[69] as they "expect that EnergyNorth will continue to add customers."[70] In addition, Liberty Consulting acknowledges the deliverability constraints on the existing TGP Concord Lateral, and thus, suggested that the CLNG/ENGIE contract is "an appropriate portfolio element for planning purposes"[71] since the CLNG/ENGIE supply can be delivered directly to the Company's city-gates.

Q. Did the Company evaluate incremental delivery capacity options in the 2017 LCIRP?

A. Yes, as discussed in the 2017 LCIRP, EnergyNorth evaluated the option to enhance its distribution system reliability, diversity, and flexibility through an extension of its system.[72] A system extension, which was later identified as the proposed Granite Bridge Pipeline in Docket No. DG 17-198, would provide a second delivery feed to the Company's service territories, and provide the Company with access to incremental gas supply and capacity options.

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69 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 022.
70 Ibid, at Bates 020.
71 Ibid, at Bates 021.
72 2017 LCIRP, at Bates 054.

Q. Did the Company evaluate alternatives to the proposed Granite Bridge Pipeline?

A. Yes, the Company evaluated the only other alternative to the proposed Granite Bridge Pipeline. Specifically, EnergyNorth had various discussions with Tennessee regarding an expansion of the existing TGP Concord Lateral to provide incremental delivery capacity to the Company's city-gates. These discussions commenced immediately following Kinder Morgan's announcement of the cancellation of the TGP NED Project. Based on the confidential information provided by Tennessee, the Company conducted a quantitative and qualitative comparison of a TGP Concord Lateral expansion to the proposed Granite Bridge Pipeline, which are further detailed in the Company's filing in Docket No. DG 17-198.

Q. Please summarize the results of the quantitative and qualitative assessment of the two delivery options, i.e., TGP Concord Lateral expansion and the proposed Granite Bride Pipeline from Docket No. DG 17-198.

A. Based on the Company's quantitative analysis in Docket No. DG 17-198, the estimated daily rate for constructing the proposed Granite Bridge Pipeline was significantly lower than the daily rates provided by Tennessee for an expansion of the TGP Concord Lateral.[73] In addition, the proposed Granite Bridge Pipeline provides significantly more qualitative benefits than an expansion of the TGP Concord Lateral. Importantly, the Granite Bridge Pipeline would provide a second feed to the Company, which increases the diversity and flexibility of EnergyNorth's delivery infrastructure, and significantly

[73] Direct Testimony of William R. Killeen and James M. Stephens, Docket No. DG 17-198, at Bates 175R to 178R.

increases the reliability and security of gas supply deliveries.[74] Finally, the proposed Granite Bridge Pipeline is a feasible and viable option that is within the New Hampshire Department of Transportation ("NHDOT") right-of-way along Route 101, which is designated as one of the state's Energy Infrastructure Corridors; whereas, the existing TGP Concord Lateral runs from Dracut, Massachusetts through highly populated and congested areas along Interstate 93, and terminating near Concord, New Hampshire, the expansion of which is therefore not as feasible as Granite Bridge Pipeline.

In summary, the Company's quantitative and qualitative assessments of the two delivery options in Docket No. DG 17-198 demonstrate that the Granite Bridge Pipeline is the best-cost incremental capacity option for EnergyNorth and its customers.

Q. How did EnergyNorth model the proposed Granite Bridge Pipeline in its analysis of the resource portfolio in the 2017 LCIRP?

A. Since the forecasted demand requirements exceeded the Company's existing resource portfolio, the Company included the proposed Granite Bridge Pipeline in all of the SENDOUT® model runs, because the proposed Granite Bridge Pipeline would be capable of accessing incremental deliveries of natural gas supplies to serve incremental demand requirements.

[74] Ibid, at Bates 178R to 181R.

Q. Did the SENDOUT® results in the 2017 LCIRP demonstrate a need for the proposed Granite Bridge Pipeline?

A. Yes, it did. The SENDOUT® results for the various demand scenarios (i.e., Base Case, Low Growth, and High Growth), as well as weather scenarios (i.e., Normal Year and Design Year), demonstrated that there were incremental gas supply needs over the LCIRP Forecast Period, which all required delivery on the proposed Granite Bridge Pipeline. Stated differently, absent the inclusion of the proposed Granite Bridge Pipeline, the SENDOUT® model runs would result in an infeasible solution because of the deliverability constraints on the TGP Concord Lateral to the Company's city-gates.

Q. Does the Company agree with Liberty Consulting's conclusions with respect to the system extension?

A. No, the Company does not. While Liberty Consulting concluded that "[w]hether such an extension will be required during the LCIRP forecast period remains to be examined",[75] the results of the various SENDOUT® model runs included in the 2017 LCIRP demonstrated that there is a need for additional delivery capability to the Company's city-gates to access incremental gas supplies to meet the growing demand requirements of EnergyNorth's customers. Stated differently, absent incremental and, importantly, timely incremental delivery capacity, the Company will be faced with a similar situation as other New England LDCs (e.g., Berkshire Gas Company and Columbia Gas of Massachusetts)

[75] Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 021.

resulting in a moratorium on the ability of customers to choose natural gas for end-use applications.

V. RESPONSE TO MR. PAUL CHERNICK ON BEHALF OF CLF

Q. Please summarize the concerns raised by Mr. Chernick regarding the Company's 2017 LCIRP.

A. In his direct testimony, Mr. Chernick raised a number of concerns that he believes are issues with respect to the Company's 2017 LCIRP. At a high-level, Mr. Chernick takes issue with EnergyNorth's overall resource planning process as outlined above in Section III, including the Company's Demand Forecast methodology, the Company's evaluation and development of a best-cost resource portfolio, and the Company's compliance with Commission orders and statutory requirements.

A. Demand Forecast Methodology

Q. Please outline the issues raised by Mr. Chernick with respect to EnergyNorth's Demand Forecast methodology.

A. The testimony of Mr. Chernick identified three areas where he disagrees with the Company's Demand Forecast methodology. First, as a matter of policy, Mr. Chernick proposes that EnergyNorth not engage in any promotional activity supporting customer additions as Mr. Chernick opines that providing New Hampshire homeowners and businesses with the option to choose natural gas is not in the public interest. Second, Mr. Chernick states that the Company misapplied the forecasted reductions for energy efficiency in its Demand Forecast. Finally, Mr. Chernick opines that the Company's

2017 LCIRP "shows only minimal amounts of energy-efficiency load reductions"[76] and argues that the EnergyNorth failed to consider additional "cost-effective" energy efficiency and demand-side programs.

Q. Please summarize Mr. Chernick's position regarding the Company's promotion of natural gas.

A. Mr. Chernick asserts that it is imprudent to shift energy load in New Hampshire to natural gas.[77] He concludes that the Company's Demand Forecast, and thus its need for additional resources, would be lower if "Liberty were not promoting the shifting of customer loads from other fuels to natural gas."[78] In addition, Mr. Chernick states that "demand growth that Liberty has proposed would be eliminated by ceasing Liberty's efforts to promote new gas space and water heating (and some other end uses)."[79] Finally, he insists that the Company "has not shown that such increases in natural gas combustion are in the public interest."[80]

Q. Does the Company agree with Mr. Chernick that providing customers with the option to choose natural gas is not in the public interest?

A. No, it does not. The Company vehemently opposes the draconian measures outlined by Mr. Chernick that would eliminate natural gas as a fuel choice for customers. The customer choice moratorium proposed by Mr. Chernick removes from the customer the

[76] Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 24.
[77] Ibid, at 3.
[78] Ibid, at 9.
[79] Ibid, at 23.
[80] Ibid, at 9.

ability to make a uniquely individual decision -- what fuel to heat their home, use in their restaurant, or install in their development/business. While CLF and Mr. Chernick may believe they are the only entities able to decide the appropriate fuel choice for New Hampshire homeowners and business owners, the Company firmly believes that the customer has always been, and should always be, the appropriate decision maker. It is, and has always been, EnergyNorth's position that the customer should have a choice. The Company provides New Hampshire homeowners and businesses with the option to choose natural gas, and customers are electing to switch to natural gas from other fuels because it is the better fuel option for them based on their individual decisions.

Further, the Company has proposed innovative programs to provide New Hampshire homeowners and businesses with fuel choice, which programs the Commission has approved, finding them to be in the public interest.[81] It is important to note that the Company's Commission-approved programs provide a choice for customers and do not force natural gas use on any customer. Fuel choice, with natural gas as an option, is supported by the Chambers of Commerce in Greater Concord, Greater Derry-Londonderry, Exeter Area, Greater Hudson, Greater Manchester, Greater Nashua, and Souhegan Valley, as well as the Business and Industry Association, which is New Hampshire's statewide Chamber of Commerce, who represent businesses in and around the Company's service territory, as they have supported EnergyNorth's various growth projects. In addition, developers that are creating jobs want natural gas as an option. The

[81] *See*, for example, Docket Nos. DG 13-198 (improving EnergyNorth's line extension tariff), and DG 16-447 (approving the Managed Expansion Program and further changes to the line extension tariff).

Company recommends that the Commission reject any policy that allows an entity to control fuel choices for individual customers by eliminating options as a matter of "public policy".

Q. Please summarize the Company's response to Mr. Chernick's conclusions regarding the Company's energy efficiency and demand-side programs.

A. First, as detailed in the Company's Demand Forecast Rebuttal Testimony, contrary to Mr. Chernick's assertions, the Company's increasing energy efficiency goals are fully and reasonably incorporated in the Demand Forecast. The approach used to account for energy efficiency in the Demand Forecast is similar to: (i) the methodology used by the Company and approved by the Commission in the NED proceeding; and (ii) approaches used by other regional LDCs. With respect to the level of savings, the Company has relied on the energy efficiency goals that were developed through a rigorous and collaborative process involving numerous stakeholders, including CLF, and reviewed and approved by the Commission.

B. Evaluation and Development of a Best-Cost Resource Portfolio

Q. What are the issues raised by Mr. Chernick with respect to the Company's evaluation and development of a best-cost resource portfolio?

A. There are four main issues identified in Mr. Chernick's testimony with respect to the Company's evaluation and development of a best-cost resource portfolio for its customers. First, Mr. Chernick asserts that it is imprudent to shift energy load in New

Hampshire to natural gas[82] and that EnergyNorth should have evaluated options, such as heat pumps, as alternatives to natural gas.[83] Second, he concludes that the Company "does not include an evaluation of alternatives to new natural gas infrastructure investments"[84] as part of its 2017 LCIRP. Third, Mr. Chernick claims that the Company should not acquire or develop natural gas resources as "[t]here is significant risk that the [Company's resource] plan will result in future stranded costs and higher customer costs."[85] Finally, he proposes that "[f]or meeting the remainder of the load, above current supply, Liberty's options include… limited imports of LNG."[86]

Q. Please discuss Mr. Chernick's argument that heat pumps should have been considered as an alternative to natural gas in the 2017 LCIRP.

A. Prior to discussing Mr. Chernick's arguments regarding alternatives to natural gas, it is important to reiterate that EnergyNorth provides homeowners and businesses in New Hampshire with the option to choose natural gas, and these customers are making the decision to switch to natural gas from other fuels as evidenced by the growth in demand for natural gas. Mr. Chernick's proposed policy, if implemented, removes choice from the very people and businesses that are best positioned to decide what fuel to use for various end use applications. Furthermore, while Mr. Chernick asserts that the Company "fails to reasonably address future need in light of the availability of cleaner and lower

82 Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 3.
83 Ibid.
84 Ibid.
85 Ibid.
86 Ibid, at 23.

cost resources, including…electric heat pumps,"[87] Mr. Chernick's views on electric heat pumps rest on several fundamental flaws as detailed in the Rebuttal Testimony of Paul J. Hibbard.

First, Mr. Chernick provides no basis for his conclusions that heat pumps are a feasible solution for cold weather climates like New Hampshire. In fact, a recent report issued by the American Gas Association ("AGA") stated that, "[a]ctual space heating efficiency [for heat pumps] varies based on winter temperatures, with efficiency declining as the temperature becomes colder", and further concluded that "electric heat pump efficiency is lowest" on the coldest winter days.[88] The same AGA report noted that:

> …heat pump installations are often sized to meet air conditioning load requirements rather than heating requirements. Oversizing a heat pump to meet peak winter requirements results in more expensive equipment, lower operating efficiency, and additional wear and tear on the equipment during the summer cooling season.
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> ***
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> In addition, at very low temperatures, heat pumps typically cannot provide adequate heat and require some form of back-up energy, typically electric resistance heat.[89]

In addition, as discussed in the Rebuttal Testimony of Paul J. Hibbard, actual installations of heat pumps by homeowners and businesses of New Hampshire have been minimal, and there is no evidence to suggest that installations of electric heat pumps in New

87 Ibid, at 3.
88 American Gas Association, Implications of Policy-Driven Residential Electrification, July 2018, at 4 and 7.
89 Ibid, at 16.

Hampshire will experience a significant increase over the term of the 2017 LCIRP or beyond.

Finally, Mr. Chernick fails to acknowledge that heat pumps actually require consumption of natural gas to generate electricity since natural gas is the marginal fuel in the regional power system (i.e., ISO-NE),[90] and on the coldest winter days, the region increases its reliance on oil- and coal-fired generation. For example, ISO-NE noted that during the extreme cold spell from December 26, 2017, to January 9, 2018, oil-fired generation accounted for 27 percent of the regional fuel mix, with natural gas representing 24 percent, and coal representing 6 percent.[91]

Q. Does EnergyNorth agree with Mr. Chernick's conclusion that the Company "does not include an evaluation of alternatives to new natural gas infrastructure investments"[92] in its 2017 LCIRP?

A. No, it does not. To meet the natural gas demand requirements of existing and new customers, EnergyNorth employed a multi-step approach to identify and evaluate available natural gas capacity and supply options to develop a reliable, best-cost resource portfolio. Specifically, as detailed in the initial 2017 LCIRP filing, EnergyNorth identified a wide range of resource options available in the marketplace.[93] Then, the

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90 As Mr. Chernick has indicated in his testimony, "the real-time marginal energy supply was from natural gas over 70% of the time" in the ISO-NE region. *See*, Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 13.

91 *See*, ISO-NE, About Us, Key Grid and Market Stats, Resource Mix, https://www.iso-ne.com/about/key-stats/resource-mix/, accessed October 9, 2019.

92 Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 3.

93 2017 LCIRP, at Bates 053.

Company evaluated the available, viable supply alternatives, which included CLNG/ENGIE liquid/vapor service, Repsol supply, and PNGTS/TCPL transportation capacity, using the SENDOUT® model, the results of which were provided in Table 36 on Bates 057 and in Appendix 6.A through Appendix 6.F of the 2017 LCIRP. As discussed in Section IV above, Staff "found EnergyNorth's selection of the ENGIE, Repsol and TCPL/PNGTS supply options appropriate,"[94] and concluded that the Company's "analysis of them sound and comprehensive."[95] The Company also conducted a qualitative assessment of the available supply alternatives.[96] Thus, Mr. Chernick's assertions that the Company did not evaluate alternatives to new natural gas infrastructure investments are not aligned with Staff's conclusions, and not supported by the analysis submitted in this docket.

Q. Please summarize Mr. Chernick's position regarding the risk of stranded costs associated with the Company's resource portfolio plan.

A. With respect to the Company's conclusions and resource decisions that are outlined in the 2017 LCIRP (also summarized in Section III above), Mr. Chernick states that EnergyNorth "has not demonstrated that the planned investments and commitments will be beneficial to customers, even in the near term."[97] He also asserts that the Company "is unlikely to need the delivery capacity for very long, leaving its customers vulnerable to having to pay for stranded assets."[98] Finally, Mr. Chernick concludes that there is

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94 Direct Testimony of John Antonuk and John Adger of The Liberty Consulting Group, at Bates 020.
95 Ibid, at Bates 022.
96 2017 LCIRP, at Bates 052 to 058. *See*, also, the Company's response to Staff 2-14.
97 Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 20.
98 Ibid.

"significant risk that the resources will not remain economic through their expected terms of service."[99]

Q. Does the Company agree with Mr. Chernick that it should not continue to acquire or develop natural gas resources because of the risk of stranded costs?

A. No, it does not. As a preliminary matter, any discussion of hypothetical stranded costs in a five-year LCIRP is simply misplaced, given the relatively short time horizon covered in this docket. However, to respond to Mr. Chernick's position, the Company and its predecessors have been providing natural gas service to homes and businesses in New Hampshire for decades, and have served some locations for well over 100 years. As a public utility, the Company has an obligation to provide reliable service to those customers who have chosen or who decide to choose natural gas – those choices are long-term decisions and investments by customers. EnergyNorth as a public utility needs to invest capital in long-term infrastructure or contracts, which include distribution investments as well as gas supply investments, to reliably serve existing and new customers.

With respect to its resource portfolio, EnergyNorth reviews contracts and assets that, when combined with the existing portfolio, increases the reliability of gas supply delivery; provides diversity such that concentration risk is mitigated; increases the flexibility of the portfolio to respond to changing weather conditions; provides more resiliency in the portfolio to adjust to changing market trends or unforeseen

[99] Ibid.

circumstances; and is accomplished in a cost-effective manner. It is the overall resource portfolio that enables the Company to provide reliable service to customers, and these contracts and assets are underpinned by long-term capital investments. Mr. Chernick's position completely ignores the resource planning goals and objectives and the rigorous resource planning process employed by the Company to evaluate and develop a reliable, best-cost resource portfolio for customers who expect continuous service over decades.[100]

Q. Please discuss Mr. Chernick's conclusions regarding imported LNG as a supply option for EnergyNorth.

A. Mr. Chernick proposes that the Company should rely on imported LNG to meet load requirements above current supply.[101] Mr. Chernick states that "[w]hile the LCIRP may be painting the lack of demand for LNG in the New England market as some sort of problem, it is in fact an advantage for gas buyers, since import (and associated storage) capacity is readily available."[102] He further asserts that "[i]f New England needs some supplemental gas, before the regional transition to electricity reduces gas load below the capacity of the existing pipeline system, LNG should be available."[103]

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100 In addition, Mr. Chernick provides no source documentation, data, and/or analysis to support his arguments regarding the risk of stranded assets. *See*, Mr. Chernick's response to LU 1-28.

101 Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 23.

102 Ibid, at 28.

103 Ibid.

Q. Is Mr. Chernick correct in assuming that natural gas supply from the regional LNG import facilities is readily available to meet EnergyNorth's incremental load requirements?

A. No, he is not. As a preliminary matter, Mr. Chernick's reliability standard of "should be available" does not meet the reliability requirement of the Company, which has been approved by the Commission, nor would it meet the reliability requirement of customers during a severe winter weather event. Furthermore, although Mr. Chernick admits he has no experience negotiating LNG supply contracts,[104] he nevertheless instructs the Company on availability of service offered by LNG importation facility owners. Clearly, the commercial strategies and negotiating leverage of the owners of the LNG importation facilities will drive their services and price offers, which affect the costs incurred by the Company to provide gas supply to its customers.

With respect to the two regional LNG import facilities, Mr. Chernick conflates lack of utilization with availability. The lack of utilization at the regional LNG import facilities reflects the commercial strategies and opportunities of the two entities that control those facilities. It is important to recognize that the import LNG facilities are not governed by the FERC open access rules that are applied to natural gas pipelines. As such, the capacity and service from the import LNG facility is directed by the commercial motivation of the owner. Stated differently, service from the import LNG facility and associated contract terms will reflect the competitive advantages and disadvantages of the

[104] *See*, Mr. Chernick's response to LU 1-32.

two parties negotiating the deal. The recent regional natural gas market dynamics have resulted in fewer gas supply options[105] and, therefore, more advantage to the owners of the LNG importation facilities. By way of example, and as mentioned earlier, in response to the Company's most recent RFP, [redacted] As discussed in Section IV.B. above, the shutdown of the offshore Nova Scotia gas supplies places pressure on other natural gas supply sources and leaves re-vaporized LNG from Repsol's Canaport LNG facility as the only gas supply option available from Maritime Canada[106] to serve the Maritime Canada and New England regions. Notably, the Maritime Canada market participants (LDCs and other end-users) have underpinned long-term pipeline capacity contracts and on-system assets, thus providing those market participants with supply asset diversity and the avoidance of concentration risk.

Finally, Mr. Chernick fails to recognize that incremental natural gas volumes from a regional LNG importation facility are not deliverable to EnergyNorth's city-gates absent new infrastructure. Stated differently, without incremental delivery capacity provided by the proposed Granite Bridge Pipeline, imported LNG supply cannot reach the Company's customers and is simply not an option "[f]or meeting the remainder of the load, above current supply"[107] as Mr. Chernick suggests.

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105 The limited natural gas supply options are further evidenced by the high TGP Dracut prices experienced during peak winter periods, and the reliance on oil- and coal-fired generation during the coldest winter days by the ISO-NE region.

106 Excludes certain limited volume from Corridor Resources.

107 Direct Testimony of Paul Chernick on behalf of Conservation Law Foundation, at 23.

C. Compliance with Commission Orders and Statutory Requirements

Q. Please summarize the assertions made by Mr. Chernick regarding the Company's compliance with Commission orders and statutory requirements.

A. Mr. Chernick claims that EnergyNorth's 2017 LCIRP does not reasonably address the environmental and health-related implications of its resource options, which is "not consistent with New Hampshire's planning requirements"[108] and not in compliance with statutory requirements. Mr. Chernick also asserts that "New Hampshire would be well advised to similarly reflect"[109] the resource decisions of other states.

Q. Does the Company agree with Mr. Chernick's conclusions?

A. No, the Company does not agree with Mr. Chernick's conclusions. First, EnergyNorth's 2017 LCIRP complies with New Hampshire's current planning requirements. Any comparison to what other states require – or what New Hampshire would be "well advised" to require – is not relevant. The Company, as a New Hampshire based utility with nearly 95,000 customers,[110] operates under the guidance of New Hampshire regulation and not that of other states.

Furthermore, the Company's approach to developing and managing a gas supply resource portfolio is driven by the natural gas demand of our existing and new customers, the Planning Standards that reflect the New Hampshire climactic conditions, the reliability standard required to service human needs during severe weather events, in a cost-

[108] Ibid, at 3.
[109] Ibid, at 4.
[110] EnergyNorth's 2018 Annual Report.

effective manner. The approach used by other LDCs may not be relevant to the approach used by the Company and approved by the Commission in prior LCIRPs and prior pre-approval of capacity contracts.

Finally, EnergyNorth responded to the direction of the Commission and suggestions of intervening parties by submitting a comprehensive evaluation of the environmental and health-related implications of the identified delivery and supply options. The Company's approach and analysis were reviewed and assessed by Staff as addressing the guidelines. Specifically, as detailed in Section III above, Staff found the Company's analysis of environmental and health-related implications to be responsive to the statutory requirements.

VI. RESPONSE TO MR. TERRY MICHAEL CLARK

Q. Please summarize the concerns expressed by Mr. Clark regarding the Company's 2017 LCIRP.

A. While Mr. Clark admits that he is not an expert on any topic discussed in his testimony,[111] he provides his opinions regarding continued natural gas usage in New Hampshire and EnergyNorth's resource planning process. Specifically, Mr. Clark expresses his support for "a rapid transition to electrification"[112] and opines that the Company's resource portfolio plan hinges on "the perceived 'reliability' of natural gas."[113]

111 Direct Testimony of Terry Michael Clark, at 3.
112 Ibid.
113 Ibid, at 34.

Q. Does the Company agree with Mr. Clark that there needs to be "a rapid transition to electrification" [114]?

A. No, the Company does not. As detailed in the Company's response to Mr. Chernick in Section V above, it is EnergyNorth's position that the customer should have a choice and EnergyNorth provides customers in New Hampshire with the option to choose natural gas. Contrary to Mr. Clark's opinion that natural gas is not what "the citizens of Keene and New Hampshire, as a whole, want,"[115] existing and new customers in the Company's service territories are making the decision to switch to natural gas from other fuels as evidenced by the Company's growth in demand for natural gas. By way of example, and as detailed in the Company's Demand Forecast Rebuttal Testimony, the towns of Windham and Pelham are very supportive of the expansion of natural gas to their communities. Similar to CLF and Mr. Chernick, Mr. Clark advocates for a policy that, if implemented, removes choice from the very people and businesses that are best positioned to decide what fuel to use for various end use applications.

Q. Does Mr. Clark provide any support for his opinion regarding the perceived "reliability" of natural gas?

A. No, he does not.

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[114] Ibid, at 3.
[115] Ibid, at 4.

Q. Is natural gas a reliable energy source?

A. Yes, it is. Estimates from both the U.S. Energy Information Administration ("EIA") and the Potential Gas Committee ("PGC"), a research entity affiliated with the Colorado School of Mines, support the long-term durability of domestic U.S. natural gas supply.

Q. Please describe the estimate of natural gas resources published by the EIA.

A. The EIA provides an annual estimate of Proved Reserves of natural gas, which are defined by the EIA as "the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions."[116] Over the past ten years, the EIA has increased its estimate of the total Proved Reserves in the U.S. by 80 percent from approximately 244 Tcf in 2008 to over 438 Tcf in its most recent 2017 estimate.[117]

Q. How much domestic U.S. natural gas supply is potentially recoverable based on the PGC estimate?

A. The PGC provides a biennial estimate of technically recoverable natural gas resources in the U.S., which are additive to the EIA's estimate of Proved Reserves.[118] The estimates

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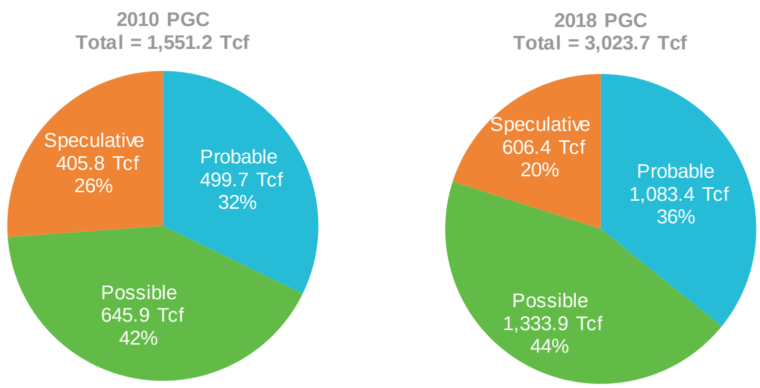
116 U.S. Energy Information Administration, https://www.eia.gov/dnav/ng/TblDefs/ng_enr_sum_tbldef2.asp, accessed on October 9, 2019.

117 U.S. Energy Information Administration, Dry Natural Gas Proved Reserves as of 12/31 (Summary), November 28, 2018.

118 While the EIA estimate of Proved Reserves identifies the economically recoverable resources under existing circumstances, the PGC estimate includes resources that are expected to be recoverable based on expected economic conditions, proximate resource performance, and expected technological developments. *See*, Potential Gas Committee, http://potentialgas.org/what-we-do-2, accessed on October 9, 2019.

of potential resources are classified by the PGC as Probable Resources,[119] Possible Resources,[120] and Speculative Resources.[121] As shown in Figure 3, the PGC estimate of total potential natural gas resources in the U.S. has increased by 95 percent from approximately 1,551 Tcf to 3,024 Tcf between 2010 and 2018, respectively.[122]

Figure 3: PGC Estimates of Total Potential Resources in the U.S.[123]



Q. Please summarize the total U.S. domestic gas supplies based on the EIA and PGC estimates.

A. As demonstrated by the EIA and PGC estimates, there has been a significant increase in U.S. reserves estimates, which supports the long-term durability of domestic U.S. natural

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119 A Probable Resource is defined as discovered but unconfirmed resources associated with known fields and field extensions; also undiscovered resources in new pools in both productive and nonproductive areas of known fields.

120 A Possible Resource is undiscovered resources associated with new field/pool discoveries in known productive formations in known productive areas.

121 A Speculative Resource is undiscovered resources associated with new field/pool discoveries in as-yet nonproductive areas.

122 Total resource potential represents the PGC estimates for the lower 48 U.S. states. Sources: The Potential Gas Agency, Colorado School of Mines, "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee, December 31, 2010," April 2011; and The Potential Gas Agency, Colorado School of Mines, "Potential Supply of Natural Gas in the United States – Report of the Potential Gas Committee, December 31, 2018," July 2019.

123 Ibid.

gas supply. To provide context, assuming an annual overall U.S. natural gas consumption level of approximately 30 Tcf,[124] the combined EIA Proved Reserves and PGC potential resource estimates would provide sufficient supply for all U.S. natural gas demand for over 115 years. Stated differently, contrary to Mr. Clark's opinion, there is an abundance of domestic U.S. natural gas supply available to reliably meet the energy needs of the U.S. for decades to come.

VII. <u>CONCLUSIONS</u>

Q. Please summarize your conclusions regarding the Company's overall resource planning process.

A. As discussed in the initial filing of the 2017 LCIRP, the responses to various data requests, and herein, the Company has conducted a sound resource planning process, which included a detailed and rigorous analysis of the various components associated with an LCIRP filing, including:

- Developing an econometric model with appropriate adjustments to reflect a reasonable estimate of natural gas demand over the Forecast Period. Notably, the Company's normalized actual volumes from 2017/18 and 2018/19 YTD are consistent with, albeit slightly higher, than the Company's projections;
- Using a Commission approved approach that is consistent with past Company practice to adjust the Demand Forecast for energy efficiency programs, lost and

124 Represents the total annual natural gas consumption in the U.S. in 2018. Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, September 30, 2019.

unaccounted for gas, unbilled sales, and events not in, or captured by, the econometric models;

- Developing appropriate Planning Standards for weather conditions, such as Design Day;
- Conducting a detailed and reasonable approach to identifying potential gas supply alternatives that are available in the marketplace;
- Evaluating the gas supply options using quantitative (i.e., SENDOUT® modeling) and qualitative (e.g., reliability) analyses; and
- Complying with all statutory requirements and Commission orders associated with an LCIRP filing, including the assessment of environmental and health related impacts.

Q. Please summarize the Company's conclusions regarding the adequacy of the existing resource portfolio to meet forecasted demand requirements over the Forecast Period.

A. Based on the forecasted increase in demand requirements and the need to provide reliable and cost-effective service to customers, the Company has reached the following conclusions:

- The Company's legacy contracts with the upstream providers are necessary to provide reliable service and should be renewed;
- The Company has a significant reliance on its propane facilities and that reliance is growing given the increase in natural gas demand and the time required to

permit and develop natural gas infrastructure. To assess this growing reliance on aging facilities, the Company has initiated certain analyses, including the effect of higher propane volumes on high-efficiency equipment and the ability of the facilities to provide the nameplate capacity;

- Under all planning scenarios evaluated in the 2017 LCIRP, the Company needs incremental capacity and supply to its city-gates to meet the customer requirements over the Forecast Period;

With respect to supply options, the CLNG/ENGIE combination contract is the only available third-party gas supply that can be delivered on a primary firm basis to the Company's service territory; this service also provides a liquid refill supply for the Company's on-system LNG facilities. However, the pipeline deliverability associated with the CLNG/ENGIE service is limited to their contracted capacity on the TGP Concord Lateral;

- The Company assessed the only two delivery options available: (i) increasing capacity on the TGP Concord Lateral; or (ii) developing a system extension, i.e., the proposed Granite Bridge Pipeline. The reliability benefits associated with a second feed that the proposed Granite Bridge Pipeline would provide to the EnergyNorth system are significant as the Company would diversify its delivery infrastructure and provide redundancy of delivery, better positioning the Company to respond to unforeseen circumstances and events; and

- Finally, the decisions for certain incremental resources require infrastructure expansions and long-term contract commitments, as such, the Company evaluated its requirements and resource portfolio over a longer-term planning horizon and proposed a natural gas supply strategy as part of its petition in Docket No. DG 17-198.

It is important that the Company's resource strategy and portfolio decisions balance cost considerations with those related to reliability, supply security, contract and portfolio flexibility, and supply viability based on the best information available to EnergyNorth, at the time the decision is made. To assemble a reliable and flexible resource portfolio that can reasonably respond to the changing requirements of EnergyNorth's customers, the Company's resource strategy and portfolio decisions need to account for market conditions. The New England natural gas marketplace has seen several major changes over the past two years, including: the complete shutdown of the off-shore Nova Scotia natural gas production removing significant gas supply from the region; changes to the ownership and regulatory approach for the CLNG/ENGIE LNG importation facility influencing services and associated prices; an increase in concentration risk associated with purchases at the TGP Dracut point; and significant volatility and record high natural gas prices at TGP Dracut approaching $100 per MMBtu.

Q. Does the Company have any final thoughts with respect to certain intervenors' proposed limitation on customer choice?

A. Yes. With respect to the opinions of CLF and Mr. Clark, the Company believes that the ability of customers to choose a fuel for their individual circumstances should not be managed or directed by a third-party such as CLF, but rather remain with the customer. The Company, with Commission approval, has developed and implemented various programs to expand choice for customers, which not only provides choices and options for more customers but also allows costs to be recovered from a larger volume base. Banning customer choice over individual fuel decisions is simply not good public policy.

Q. Does this conclude your Rebuttal Testimony?

A. Yes.