Liberty Utilities

REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-___

Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities
Approval of Natural Gas Supply Strategy

PRE-FILED DIRECT TESTIMONY

OF

WILLIAM R. KILLEEN

AND

JAMES M. STEPHENS

December 21, 2017

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I. INTRODUCTION

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

A. My name is William R. (Bill) Killeen. I am Director, Energy Procurement of Liberty Utilities (Canada) Corp., the parent of Liberty Utilities Co. ("Liberty Utilities"), which is the parent company of Liberty Energy Utilities (New Hampshire) Corp. ("Liberty Energy (NH)"). My business address is 345 Davis Road, Oakville, Ontario, Canada.

My name is James M. Stephens. I am a Partner of ScottMadden, Inc. ("ScottMadden"). My business address is 1900 West Park Drive, Suite 250, Westborough, Massachusetts 01581.

Q. On whose behalf are you submitting this testimony?

A. We are submitting this joint testimony before the New Hampshire Public Utilities Commission (the "Commission" or "NHPUC") on behalf of Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities (hereinafter referred to as "EnergyNorth" or the "Company"), a subsidiary of Liberty Energy (NH).

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

A. I earned a Bachelor of Engineering Science (Chemical) degree from the University of Western Ontario (now Western University) in 1985. I also earned a Master's degree in Business Administration from the Ivey School of Business at Western University in 1989.

I have 28 years of professional experience in the energy and utilities industries in the areas of regulation, supply, operations, and customer service. I have worked at natural gas and electric utilities, as well as in consulting, marketing, and government positions. Early in my career, I was employed by Union Gas Limited, a major natural gas utility serving over 1.4 million customers in Ontario, Canada, for twelve years in varying capacities, including regulatory and supply. Prior to joining Liberty Utilities in February 2014, I was employed by Enersource Hydro Mississauga Inc., a major electric utility serving the City of Mississauga, Ontario, for three years as Manager, Regulatory Affairs. In between my employment at these two large utilities, I was employed at various other companies, always retaining responsibility for oversight of regulatory affairs and supply, typically in Ontario or eastern Canada. These companies included Engage Energy Canada Inc., Direct Energy as Manager, Regulatory Affairs and a consulting company, ECNG Energy LP, as Director, Supply and Regulatory Affairs for eight years. Following ECNG, I spent a brief tenure within the Ministry of Energy of the Ontario Government. Please refer to Exhibit WRK/JMS-1 for a summary of my professional background.

Q. Mr. Killeen, have you previously testified before any regulatory bodies?

A. Yes, I have. In the United States, I have provided testimony in a number of proceedings in Arizona, California, Arkansas, Montana, Georgia, and Texas. In Canada, I have testified in approximately 18 natural gas and electric utility pricing cases and facility approval cases before the Ontario Energy Board. Please refer to Exhibit WRK/JMS-1 for a summary of my past testimony appearances.

Q. Mr. Stephens, please summarize your education 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 Exhibit WRK/JMS-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.

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 Federal Energy Regulatory Commission ("FERC"), the states of Massachusetts and Maine, and the Canadian provinces of Ontario, Québec, New Brunswick, and Alberta. A list of my past expert witness appearances is provided as Exhibit WRK/JMS-3.

II. EXECUTIVE SUMMARY

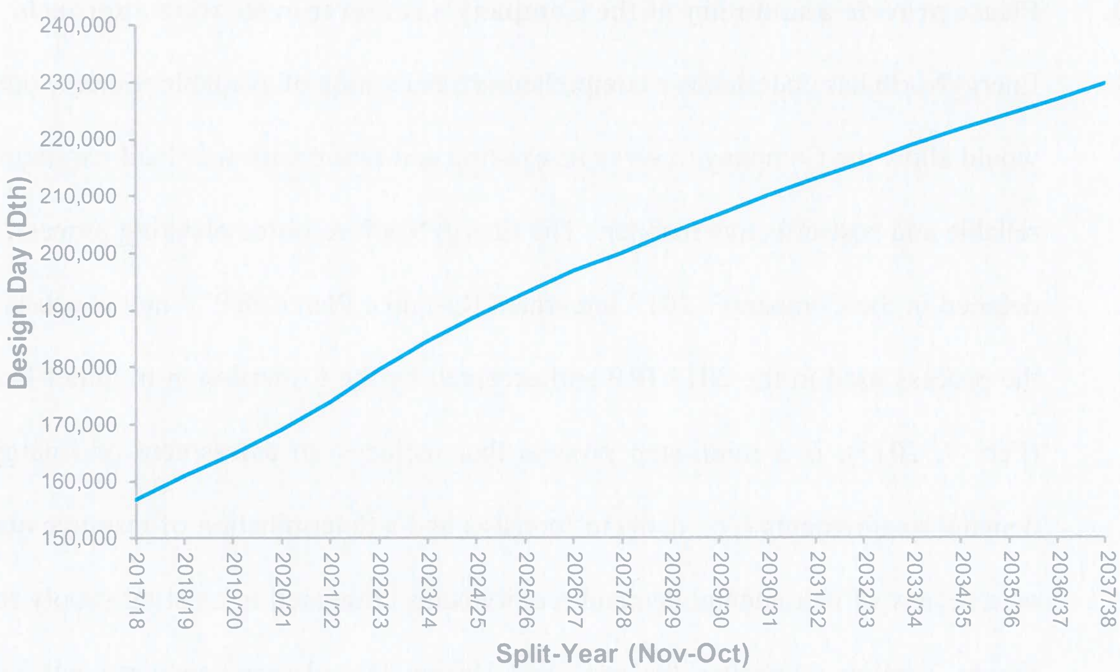
Q. What is the purpose of your testimony in this proceeding?

A. The purpose of our joint testimony is to present to the Commission, for its review, the various market factors that have influenced EnergyNorth's natural gas supply strategy and associated infrastructure development and contract decisions to meet its projected long-term (i.e., 2017/18 through 2037/38) natural gas demand requirements. In addition, our testimony reviews the process and analyses undertaken by the Company to evaluate the available resource options and determine the best-cost portfolio for EnergyNorth and its customers. Finally, our testimony reviews the contract terms and details regarding each of the Company's capacity contract decisions and proposed infrastructure development projects that comprise its natural gas supply strategy.

Q. Please provide an overview of the Company's projected growth in demand and the factors that have affected EnergyNorth's natural gas supply strategy.

A. As demonstrated in this filing, EnergyNorth has experienced an increase in demand for natural gas and is forecasting continued growth in both winter period[1] and Design Day demand. As shown in Figure 1 below, the Company's Design Day demand for natural gas is projected to increase by a compound annual growth rate ("CAGR") of approximately 1.9% from 156,822 dekatherms ("Dth")[2] in 2017/18 to 229,590 Dth in 2037/38.

Figure 1: EnergyNorth Design Day Demand Forecast



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1 For purposes of this testimony, the winter period is defined as the five-month gas supply planning period from November to March, the summer period is the seven months from April to October, and a split-year is the 12-month period from November to October.

2 For purposes of this testimony, we have assumed that 1 Dth = 1 thousand cubic feet ("Mcf") = 1 million British thermal units ("MMBtu").

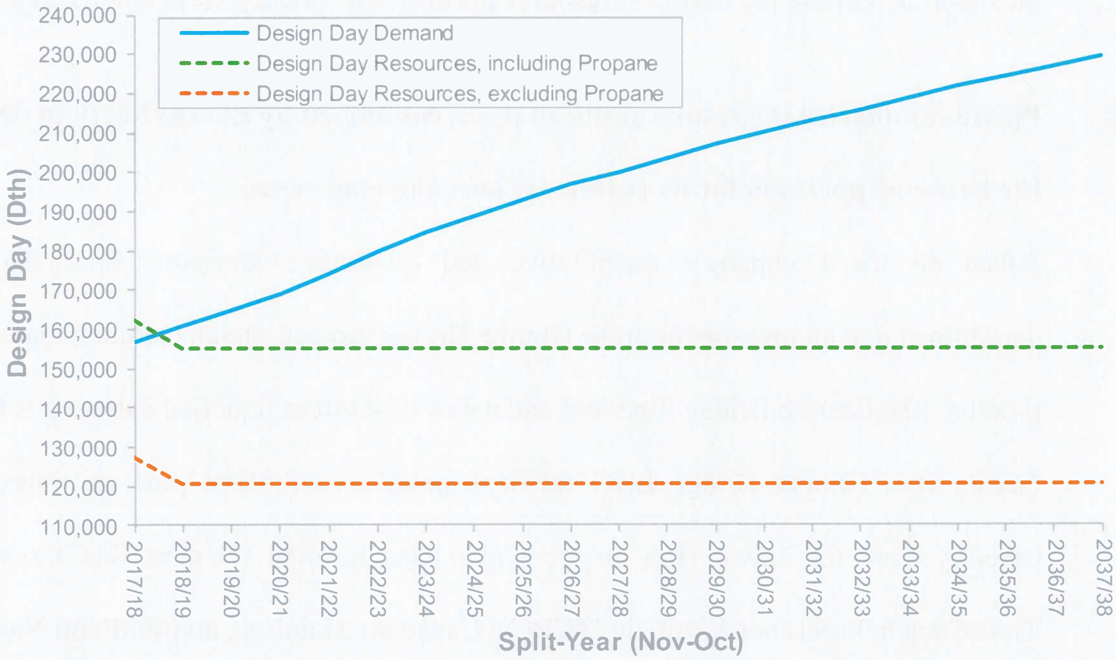
This expected increase in natural gas demand is coupled with certain natural gas supply realities, including: the reduction in natural gas production from off-shore Nova Scotia; the continued growth in U.S. natural gas production; the complexity and time required to construct incremental pipeline capacity into New England; and the existing structure of the EnergyNorth natural gas supply portfolio, including the inevitable retirement of the Company's aging propane facilities. These and other factors detailed in the remainder of our testimony have resulted in incremental natural gas capacity and supply requirements for EnergyNorth.

Q. Please provide a summary of the Company's resource evaluation approach.

A. EnergyNorth has undertaken a comprehensive evaluation of available resource options that would allow the Company to serve its existing and future customer load requirements in a reliable and cost-effective manner. The EnergyNorth resource planning process, which is detailed in the Company's 2017 Integrated Resource Plan ("IRP")[3] and is consistent with the process used in the 2013 IRP and accepted by the Commission in Order No. 25,762 (Feb. 9, 2015), is a multi-step process that includes an assessment of EnergyNorth's demand requirements (i.e., demand forecast) and a determination of resource need based on a review of incremental demand requirements compared to existing supply resources. Figure 2 below illustrates the projected Design Day demand requirements relative to EnergyNorth's existing Design Day resources, and the Company's growing resource deficit on Design Day.

[3] The Company's 2017 IRP was filed with the Commission on October 2, 2017, in Docket No. DG 17-152.

Figure 2: EnergyNorth Design Day Demand and Resources[4]



As illustrated in Figure 2 above, EnergyNorth has incremental resource requirements on Design Day of 5,956 Dth beginning in the 2018/19 split-year, growing to 74,557 Dth by the end of the analysis period, and this need is more pronounced assuming the retirement of the Company's aging propane facilities. Specifically, the EnergyNorth resource requirement on Design Day would increase by 34,600 Dth (from 74,557 Dth to 109,157 Dth by 2037/38), which is the current daily deliverability of the propane facilities. Once the determination that incremental resources were required to meet projected demand, the

[4] The 2017/18 Design Day resources include a contract with ENGIE Gas & LNG LLC ("ENGIE") for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018. *See*, Docket No. DG 17-135.

Company identified certain resource options and analyzed both quantitative and qualitative factors to determine the best-cost resource portfolio for EnergyNorth and its customers.

Q. Please summarize the results of the analyses conducted by EnergyNorth to determine the best-cost portfolio for its customers over the long-term.

A. Based on the Company's quantitative and qualitative analyses, EnergyNorth has determined that an investment in the Granite Bridge Project, which includes a new in-state pipeline (the Granite Bridge Pipeline) and a new on-system liquefied natural gas ("LNG") facility (the Granite Bridge LNG facility), coupled with firm pipeline transportation capacity from the Dawn Hub on the Union Gas Limited ("Union Gas") system, the TransCanada PipeLines Limited ("TCPL") Canadian Mainline, and Portland Natural Gas Transmission System ("PNGTS")[5] and the Company's existing supply portfolio, results in the most cost-effective resource portfolio for the customers of EnergyNorth over the long-term. In addition, the Company's long-term supply strategy, which leverages the flexibility of the individual assets and contracts, as well as the overall portfolio capability, increases reliability for its customers.

The Granite Bridge Pipeline will increase the security of gas supply deliveries and enable a more reliable, flexible, and diversified upstream gas supply portfolio by providing a

[5] Gas supplies from the Dawn Hub are transported on Union Gas to the interconnection with the TCPL Canadian Mainline at Parkway, Ontario. As discussed further in Section VII.B, the Union Gas capacity is a component of the TCPL Canadian Mainline via a transportation-by-others ("TBO") and, therefore, for purposes of our testimony, references to the TCPL/PNGTS path from the Dawn Hub include the Union Gas component. The TCPL Canadian Mainline connects to the Trans-Québec and Maritimes Pipeline ("TQM"), which is jointly owned by TCPL and Gaz Métro, and the TQM system connects to PNGTS at the Québec/New Hampshire border at East Hereford.

second delivery feed to the Company's service territory. The Granite Bridge LNG facility will provide EnergyNorth with a cost-effective, flexible, and reliable on-system asset to meet the growing Design Day and peak winter demand requirements. Finally, the TCPL/PNGTS capacity will provide the Company with additional resource flexibility and supply diversification, complementing the Granite Bridge LNG facility and allowing the Company to meet its growing demand requirements.

Q. Given the lead time required to develop the Granite Bridge Project, is there a need for certain interim gas supply resources?

A. Yes. Given the lead time required to develop and construct the Granite Bridge Project, EnergyNorth developed an interim gas supply strategy to meet the Company's incremental demand requirements in the near-term (i.e., 2018/19 through 2021/22). Specifically, EnergyNorth has contracted with ENGIE for incremental natural gas supply delivered to the EnergyNorth city-gates or to its existing LNG facilities, which will assist the Company with meeting near-term demand requirements and liquid refill needs. The ENGIE contract, which is the only available resource option in the near-term that can be delivered, on a firm basis, to the EnergyNorth city-gates, will provide the Company with a cost-effective solution to meet its near-term incremental demand requirements while the Granite Bridge LNG facility and Granite Bridge Pipeline are being developed.

While the contract with ENGIE provides EnergyNorth with significant flexibility, it does not provide enough peaking deliverability to meet the Company's projected near-term demand requirements. As a temporary solution, EnergyNorth will need to increase the utilization of the Company's existing LNG facilities by cycling the LNG storage capacity to meet the resource deficit until the proposed Granite Bridge Pipeline is available to deliver incremental supplies to the city-gates. At this time, EnergyNorth has not contracted for additional liquid-only supply or dedicated trucking service. The Company typically conducts a comprehensive request for proposals ("RFP") process for liquid refill and trucking requirements for the upcoming winter period on a year-to-year basis, which would be reviewed by the Commission in the Company's annual cost of gas filings.

Q. Please summarize the EnergyNorth natural gas supply strategy for which the Company seeks Commission approval.

A. As outlined in the joint testimony of Susan L. Fleck and Francisco C. DaFonte (the "Fleck/DaFonte Testimony"), EnergyNorth is seeking approval from the Commission for the following supply and capacity contract decisions together with two proposed infrastructure development projects to support the Company's natural gas supply strategy:

- A contract with ENGIE for 90-day winter, combination (i.e., liquid and/or vapor) service with a maximum daily quantity ("MDQ") of 7,000 Dth per day for the winters of 2018/19 through 2021/22;
- A precedent agreement with PNGTS, which outlines the Company's binding request for 5,000 Dth per day of firm transportation capacity[6] from the Dawn Hub,

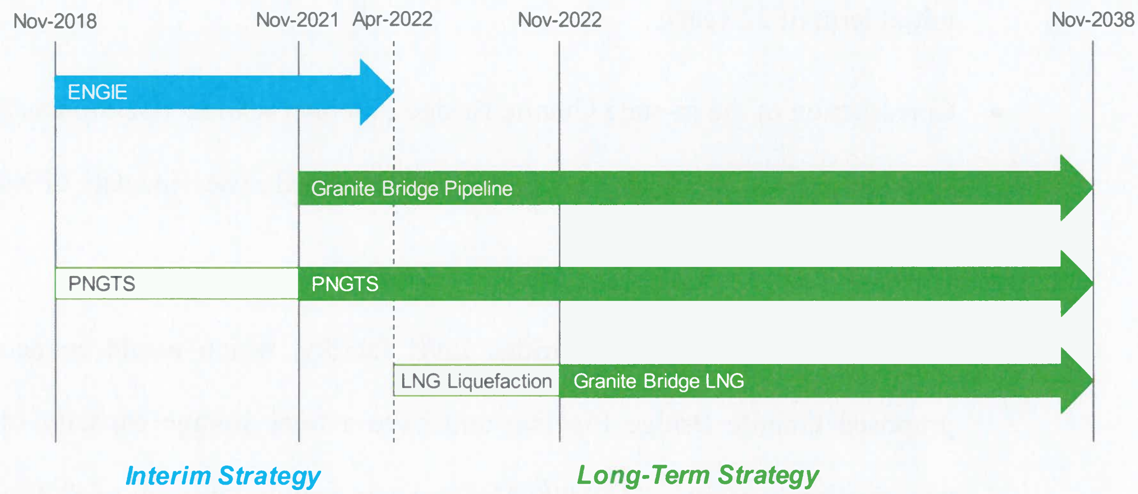
[6] As detailed in Section VII.B, the structure of the PNGTS precedent agreement has a TBO component that allows EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut, Massachusetts (i.e., capacity on Union Gas, TCPL Canadian Mainline, and PNGTS).

with phased-in service over three years starting November 1, 2018, and with an initial term of 22 years;

- Construction of the in-state Granite Bridge Pipeline, with an operating capacity of approximately 150,000 Mcf per day and an expected in-service date of November 1, 2021; and
- Construction of the Granite Bridge LNG facility, which would connect to the proposed Granite Bridge Pipeline and have a total storage capacity of 2 Bcf, vaporization capacity of 150,000 Mcf per day, and liquefaction of 8,000 Mcf per day, to be in-service by April 1, 2022.

Together these supply and capacity contracts and proposed infrastructure projects comprise the Company's interim and long-term natural gas supply strategy as summarized in Figure 3 below.

Figure 3: EnergyNorth Natural Gas Supply Strategy[7]



Q. Is the Company's strategy regarding an interim and long-term gas supply portfolio reasonable?

A. Yes, it is. The ENGIE contract will help meet the Company's near-term resource needs, provide flexibility and supply diversification, and allow the Company to transition to the long-term resource portfolio. The TCPL/PNGTS transportation capacity[8] will provide supply diversification in the near-term, and will provide additional reliability and flexibility benefits (i.e., increased access to the Dawn Hub, one of the more liquid natural gas pricing points with significant access to storage) once the proposed Granite Bridge Pipeline is in-service. In the long-term, the Granite Bridge Pipeline and Granite Bridge LNG facility

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7 Note, as discussed later in this testimony, the PNGTS capacity will be phased-in over three years beginning on November 1, 2018, but given the current deliverability on Tennessee's Concord Lateral, the PNGTS contract will not provide incremental supply to the Company's city-gates until the proposed Granite Bridge Pipeline is on-line.

8 As detailed in Section VII.B, the structure of the PNGTS precedent agreement has a TBO component that allows EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut, Massachusetts (i.e., capacity on Union Gas, TCPL Canadian Mainline, and PNGTS).

will significantly increase the reliability of the Company's gas supply portfolio by adding a second feed for deliveries, increase the Company's on-system assets, and better align the Company's demand profile and supply portfolio; enhance the flexibility of the gas supply portfolio by providing access to supplies from more sources, and the on-system LNG facility provides for load following service; and diversify the supply assets since the on-system LNG facility is a peaking resource for a growing peak demand. Finally, the interim and long-term supply portfolio provides cost-effective resources for EnergyNorth to meet its demand requirements, while allowing the option for retirement of the Company's aging propane facilities.

Q. How is the remainder of your testimony organized?

A. The remainder of our testimony is organized as follows:

- Section III – Regional Demand/Supply Dynamics: This section provides appropriate context regarding the regional natural gas market issues that the Company is currently facing. Specifically, the historical and projected natural gas demand drivers and regional natural gas supply trends have implications for the Company in terms of natural gas supply strategy and planning.

- Section IV – Review of EnergyNorth's Natural Gas Demand: In this section, we review the Company's significant growth in natural gas demand over the past five years, and summarize EnergyNorth's projected natural gas demand over the long-term forecast horizon. The approach, methodology, and results of the demand forecast are consistent with the natural gas demand forecast filed with the Commission as part of the Company's 2017 IRP.

- Section V – Review of EnergyNorth's Current Natural Gas Portfolio: This section reviews and details the Company's existing natural gas resource portfolio.
- Section VI – EnergyNorth's Resource Evaluation Approach and Results: In this section, we summarize the primary objectives for the EnergyNorth resource portfolio and the criteria used to assess the resource options, review the process used to evaluate the Company's supply resource options, and discuss the quantitative and qualitative analyses undertaken by the Company to determine the best-cost portfolio for EnergyNorth and its customers.
- Section VII – Summary of EnergyNorth's Supply Strategy: In this section, we present details regarding each of the resource options that comprise the Company's interim and long-term strategies, including a review of tolls/rates, operational parameters, key contract terms, and timing of resource availability.
- Section VIII – Conclusion: This section summarizes our overall observations and conclusions regarding the EnergyNorth natural gas supply strategy.

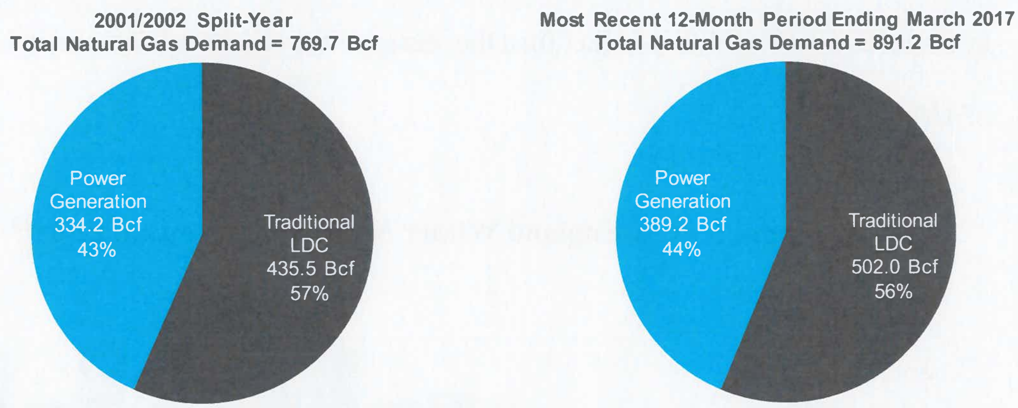
III. REGIONAL DEMAND/SUPPLY DYNAMICS

A. Natural Gas Demand Drivers

Q. Has the demand for natural gas increased in New England?

A. Yes, it has. The demand for natural gas in New England has significantly increased over the past 15 years. As illustrated in Figure 4, total annual natural gas demand in the region has increased by 16% from approximately 770 Bcf in the 2001/02 split-year to approximately 891 Bcf in the 12-month period ending March 2017.[9]

Figure 4: New England Annual Natural Gas Consumption by Sector[10]



The power generation and LDC sectors have exhibited similar growth trends over the past 15 years. As shown in Figure 4, total annual natural gas consumption by the power generation sector has increased from approximately 334 Bcf to 389 Bcf (an increase of 16%), while consumption by the traditional LDC segments (i.e., residential, commercial, and industrial) has increased from approximately 435 Bcf to 502 Bcf (an increase of 15%).[11]

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9 Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine, release date May 31, 2017. Data for April through June 2016, September 2016, and January through March 2017 are based on ScottMadden estimates.

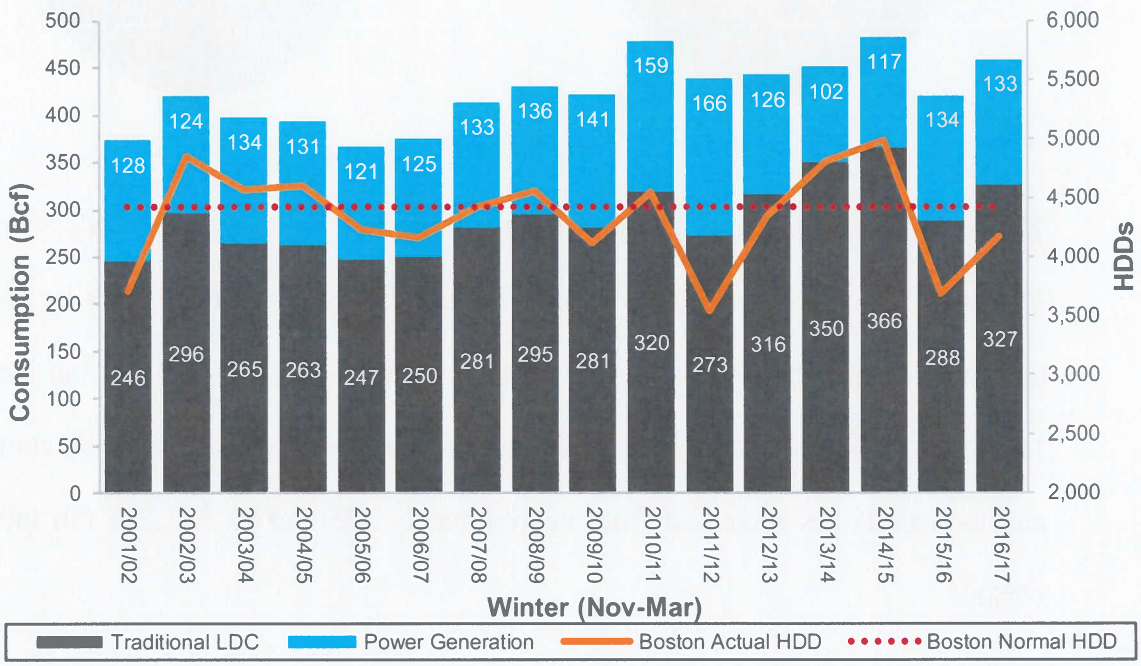
10 Ibid.

11 Ibid.

Q. Please discuss the New England demand for natural gas in the winter, which is the peak season consumption for the traditional LDC segments.

A. Overall, as illustrated in Figure 5 below, total winter natural gas demand in New England has increased by 23% from a total of approximately 374 Bcf in winter 2001/02 to 459 Bcf in winter 2016/17, which is higher than the increase in total annual demand in New England of 16%.[12]

Figure 5: New England Winter Natural Gas Consumption[13]



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12 Ibid.

13 Sources: National Oceanic and Atmospheric Administration, National Climatic Data Center, Daily Summaries for Boston, Massachusetts; and U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont, and Maine, release date May 31, 2017. Data for April through June 2016, September 2016, and January through March 2017 are based on ScottMadden estimates.

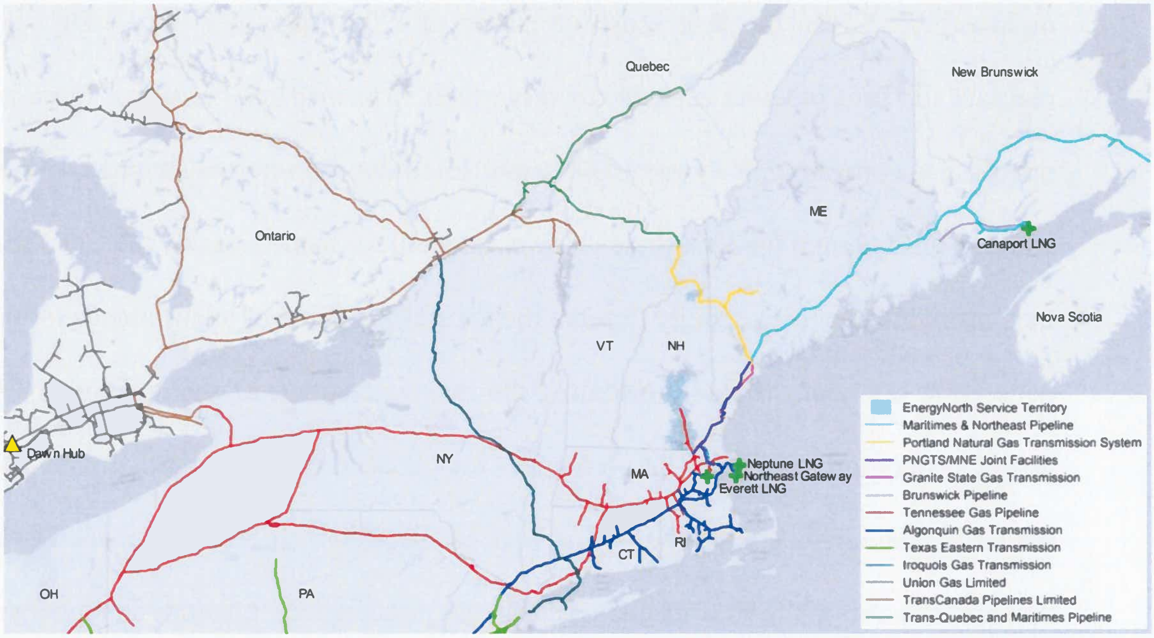
As shown by Figure 5 above, the demand for natural gas in New England fluctuates based on weather. Given the heat sensitive nature of LDC load, and since LDCs generally contract for firm pipeline capacity to serve their firm load requirements, there is higher natural gas consumption by the LDC sector in colder-than-normal winters. Whereas in warmer-than-normal winters, there is lower demand for natural gas by the LDC sector and thus available pipeline capacity to serve the natural gas demand requirements of the power generation segment. Stated differently, the two segments (i.e., the traditional LDC and power generation segments) may compete for pipeline capacity, particularly during the winter season. This competition for winter gas supplies, all else being equal, will place upward pressure on the New England natural gas price indices, resulting in higher and more volatile gas supply costs for entities that purchase gas supplies at these price indices.

B. Natural Gas Supply Trends

Q. What are the primary sources of natural gas supply for New England?

A. As illustrated in Figure 6 below, the New England region is served by six natural gas pipelines: Tennessee Gas Pipeline Company, LLC ("Tennessee" or "TGP"), Algonquin Gas Transmission LLC ("Algonquin" or "AGT"), Iroquois Gas Transmission System, L.P. ("Iroquois" or "IGT"), Granite State Gas Transmission, Inc. ("GSGT"), PNGTS, and Maritimes & Northeast Pipeline ("MNE"). These pipelines provide access to various natural gas supply sources, including Canadian natural gas supplies (e.g., gas supply hub at Dawn, Ontario ("Dawn Hub") and off-shore Nova Scotia supplies), U.S. domestic production (e.g., from the Gulf Coast and Appalachian basin), and imported LNG (e.g., the ENGIE Everett LNG and Canaport LNG facilities).

Figure 6: New England Natural Gas Infrastructure[14]



Q. Please summarize the natural gas supply issues facing the New England market in general, and EnergyNorth in particular.

A. The New England region is currently faced with the following natural gas supply trends:

- Dwindling natural gas supplies from off-shore Nova Scotia, which are a major supply source for MNE to serve natural gas demand in the Canadian Maritimes (i.e., Nova Scotia and New Brunswick) and New England markets.

- A significant increase in domestic U.S. natural gas production and reserves estimates, which supports the development of new natural gas infrastructure to deliver natural gas to various locations, including the Dawn Hub.

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14 Source: S&P Global Market Intelligence [modified by ScottMadden].

- Complexity and time required to construct incremental pipeline capacity.
- Seasonal focus of imported LNG volumes to serve the New England region.

Consequently, each of these supply trends impact the availability and feasibility of natural gas resource options for EnergyNorth and its customers as discussed in more detail below.

1. Off-Shore Nova Scotia Supplies

Q. Please describe the natural gas supplies from off-shore Nova Scotia.

A. The New England market has access to natural gas resources from off-shore Nova Scotia via the MNE system, which extends from Goldboro, Nova Scotia, through New Brunswick to a point at the Canada-U.S. border near Baileyville, Maine (i.e., MNE-Canada), and continues through Maine and New Hampshire into Massachusetts (i.e., MNE-US).[15] Specifically, the natural gas supplies from off-shore Nova Scotia are comprised of the Sable Offshore Energy Project ("SOEP") and Deep Panuke Offshore Gas Development Project ("Deep Panuke").

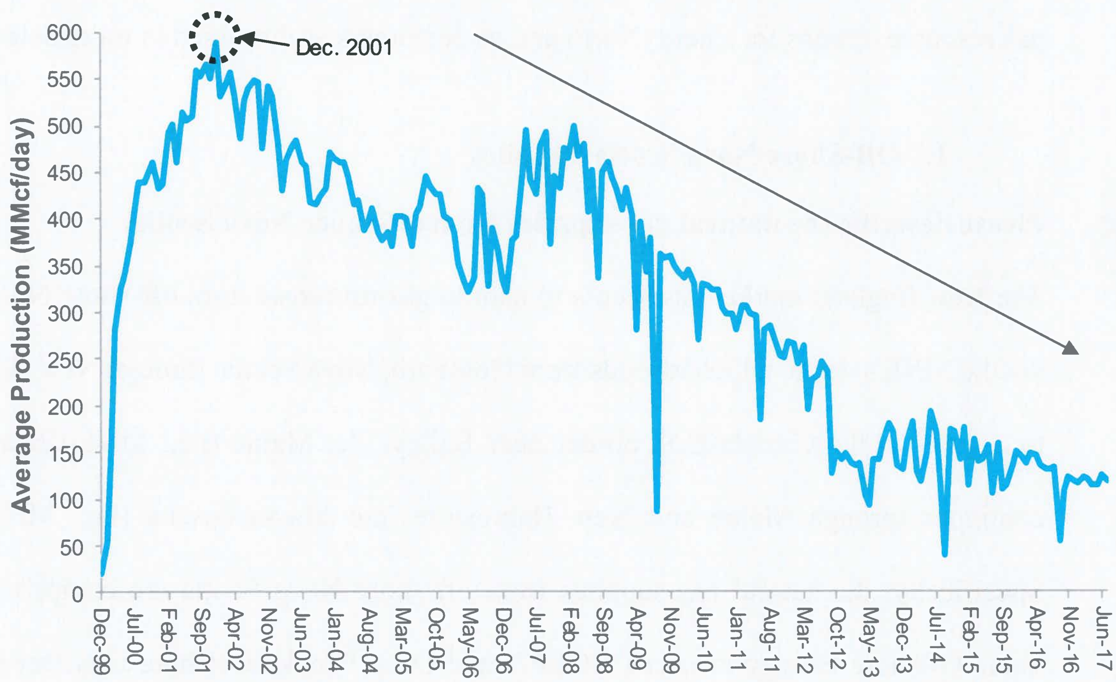
Q. Please describe the current status of natural gas production from SOEP.

A. SOEP, which has been producing natural gas since late 1999, has been in a steady decline since 2009. As shown in Figure 7 below, average daily production from SOEP was approximately 120 million cubic feet ("MMcf") per day this past winter of 2016/17, which

15 A portion of the MNE-US system from Westbrook, Maine, to Dracut is owned jointly by PNGTS and MNE and referred to as the "Joint Facilities."

is an 80% decrease from its peak production in December 2001 of nearly 600 MMcf per day.[16]

Figure 7: Average Daily SOEP Production[17]



Q. Please describe the natural gas production trends from Deep Panuke.

A. Natural gas production from Deep Panuke, which began in the summer of 2013, was expected to augment the natural gas supplies from SOEP, but Deep Panuke production has fallen short of expectations. Since inception, natural gas production from Deep Panuke

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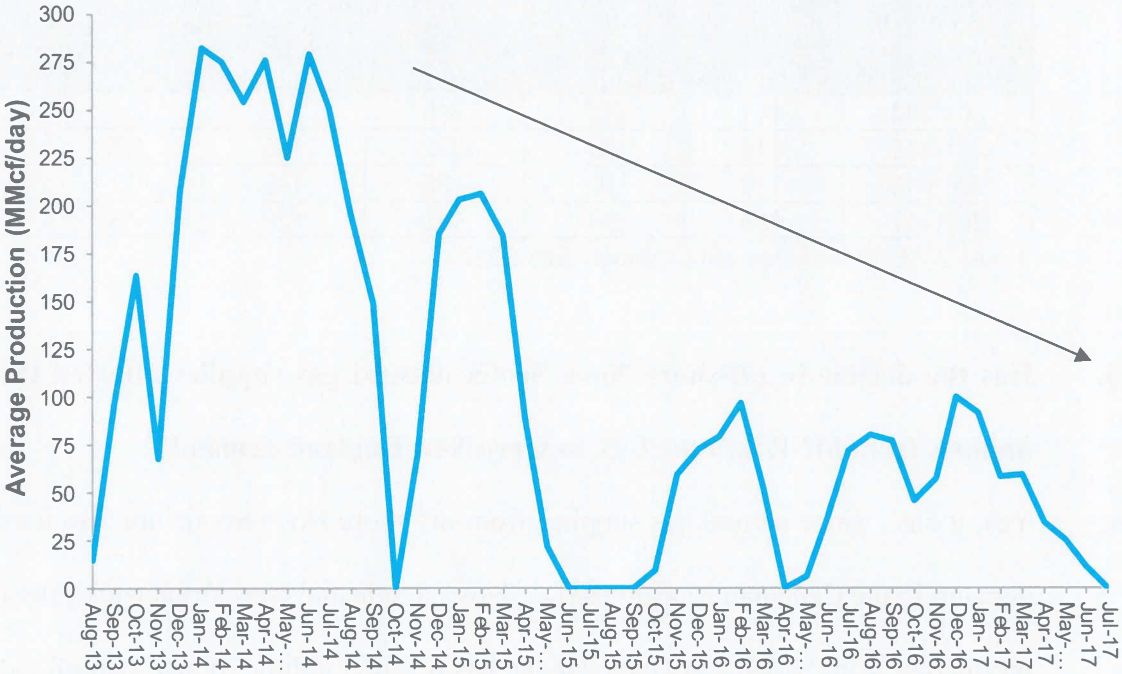
16 Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date September 6, 2017.

17 Ibid.

has been variable with daily production averaging less than 100 MMcf per day since April 2015,[18] which is only one-third of the expected production level of 300 MMcf per day.[19]

Figure 8: Average Daily Deep Panuke Production[20]



Q. In summary, what is the current annual and winter natural gas production from SOEP and Deep Panuke and how does that compare to recent history?

A. As shown in Table 1 below, the combined average daily production from SOEP and Deep Panuke was approximately 193 MMcf per day this past winter (i.e., winter 2016/17), which

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18 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

19 Source: Nova Scotian Department of Energy; The Future of Natural Gas Supply for Nova Scotia. Prepared by ICF Consulting Canada, Inc., March 2013, at 35.

20 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

is less than one-half of the average daily production of 365 MMcf per day in winter 2013/14, the first winter period after Deep Panuke was placed in-service.

Table 1: Average Daily SOEP and Deep Panuke Production[21]

Split-Year (Nov-Oct)	Average Annual (MMcf/day)			Average Winter (MMcf/day)		
	SOEP	Deep Panuke	Total	SOEP	Deep Panuke	Total
2013/14	141	205	346	148	217	365
2014/15	141	80	222	153	170	323
2015/16	130	56	186	143	72	214
2016/17	119	66	185	120	73	193

Note: 2016/17 includes data through July 2017.

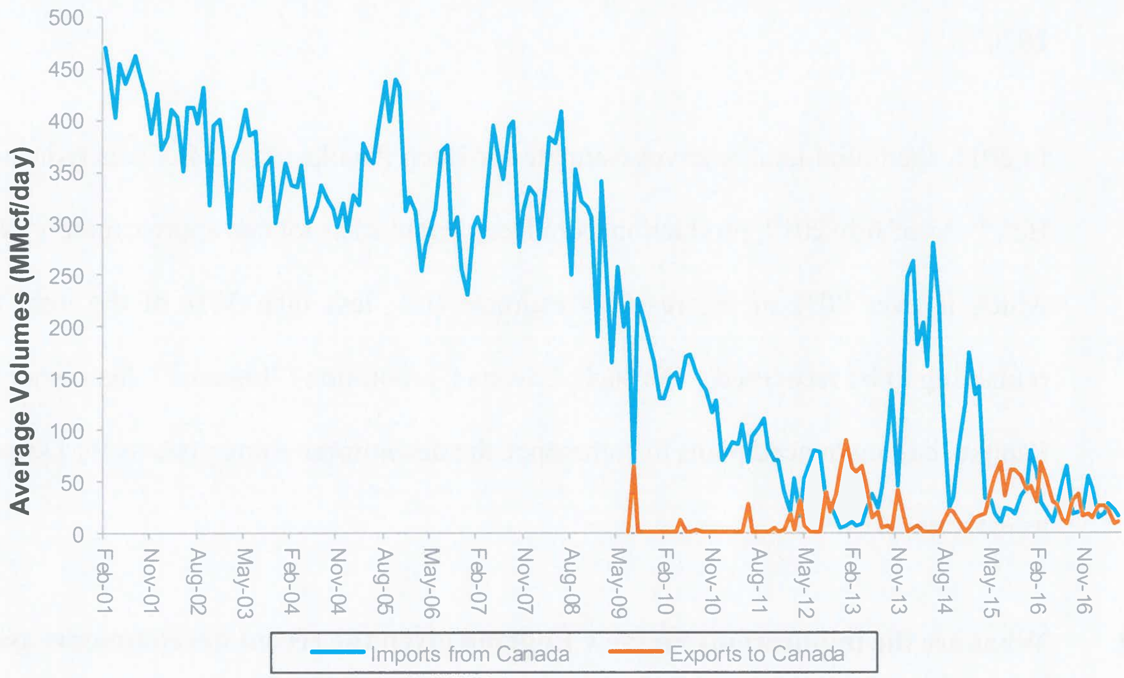
Q. Has the decline in off-shore Nova Scotia natural gas supplies affected the level of imports from MNE into the U.S. to serve New England demand?

A. Yes, it has. Since natural gas supplies from off-shore Nova Scotia are also used to serve demand in the Canadian Maritimes (i.e., Nova Scotia and New Brunswick), the decline in production from SOEP and Deep Panuke has resulted in little, if any, natural gas supplies available for the New England market. As shown in Figure 9 below, the average daily imports at Baileyville, Maine (i.e., the interconnection between MNE-Canada and MNE-US) has declined to an average of less than 30 MMcf per day in winter 2016/17. Conversely, during certain months the flow of natural gas has reversed and the Canadian Maritimes has imported natural gas from the U.S. Stated differently, as illustrated in Figure 9, during certain months the volumes of natural gas exported from the U.S. to Canada at

21 Sources: Canada-Nova Scotia Offshore Petroleum Board, Sable and Deep Panuke Monthly Production Reports, access date September 6, 2017.

the Baileyville, Maine point has exceeded the volumes imported to serve the New England region.

Figure 9: Average Daily Imports and Exports at Baileyville, Maine[22]



Q. What is the expected long-term availability of natural gas supplies from off-shore Nova Scotia?

A. Both SOEP and Deep Panuke are expected to be decommissioned over the next few years. Production from SOEP from December 1999 to July 2017 has totaled approximately 2.1

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[22] Sources: National Energy Board of Canada, Natural Gas Exports - Monthly Summary by Port - Volume, access date September 6, 2017; and National Energy Board of Canada, Natural Gas Imports - Monthly Summary by Port - Volume, access date September 6, 2017. Data for imports and exports at the St. Stephen, New Brunswick point.

Tcf,[23] which is 90% of the total estimated reserves from SOEP of approximately 2.3 Tcf.[24] It is estimated that less than 10% of the total reserves from SOEP is remaining to be recovered. ExxonMobil Canada ("ExxonMobil"), operator and majority owner of SOEP, has recently initiated the decommissioning process for SOEP, with targeted completion by 2020.[25]

In 2015, the initial total reserves estimate for Deep Panuke of 400 Bcf was reduced to 200 Bcf.[26] As of July 2017, production from Deep Panuke has totaled approximately 146 Bcf,[27] which is over 70% of the reserves estimate (i.e., less than 30% of the total reserves remaining to be recovered). As such, Encana Corporation ("Encana"), the owner of Deep Panuke, has announced plans to commence the decommissioning process for Deep Panuke as early as 2019.[28]

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

A. The decommissioning activity at SOEP and the announcements by Encana with respect to Deep Panuke paint a very stark supply picture for SOEP and Deep Panuke – there will likely be limited to no natural gas supplies from off-shore Nova Scotia by 2020. Therefore,

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23 Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date September 6, 2017.

24 The initial total reserves estimate of 3.0 Tcf was reduced to less than 2.3 Tcf in 2004. *See*, Natural Gas Intelligence, "Sable Producers Cut Reserves Estimates, But Analyst Optimistic on Continued Development," February 4, 2004.

25 *See*, Platts, "ExxonMobil Canada begins work to decommission Sable Island project," November 9, 2017.

26 *See*, Natural Gas Intelligence, "Deep Panuke Nat Gas Reserves Halved by Encana," February 26, 2015.

27 Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date September 6, 2017.

28 *See*, The Chronicle Herald, "Nova Scotia's Deep Panuke natural gas projects drying up," May 29, 2017.

the only currently available supply source into MNE from the north is Repsol's Canaport LNG facility. Absent new natural gas supply sources in the Canadian Maritimes (i.e., Nova Scotia and New Brunswick), natural gas supplies will no longer be exported to the U.S. from MNE.

2. Domestic U.S. Supplies

Q. Please briefly discuss the trends in domestic U.S. natural gas production.

A. Since 2008, there has been a significant increase in U.S. domestic natural gas production with an associated decline in natural gas prices. As illustrated in Figure 10 below, total annual natural gas production has increased from approximately 55 Bcf per day in 2008 to approximately 72 Bcf per day in 2016.[29] Over that same time period, the Henry Hub spot price decreased from an annual average of $8.86 per MMBtu to $2.52 per MMBtu.[30]

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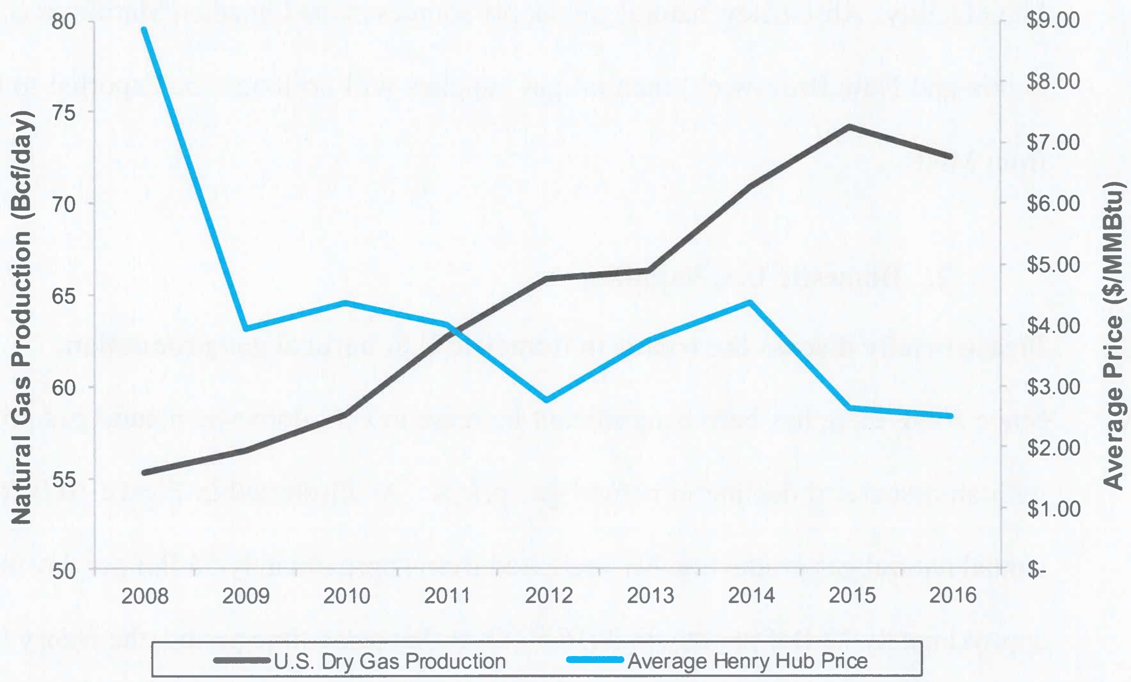
[29] Source: U.S. Energy Information Administration, Natural Gas Dry Production, release date August 31, 2017.
[30] Source: S&P Global Market Intelligence.

Figure 10: Henry Hub Pricing and U.S. Domestic Natural Gas Production[31]



Q. Is the increase in U.S. domestic natural gas production expected to continue?

A. Yes, it is. As illustrated in Figure 11 below, the U.S. Department of Energy/Energy Information Administration ("EIA") Annual Energy Outlook ("AEO") projects total U.S. domestic natural gas production will reach approximately 110 Bcf per day by 2050.[32]

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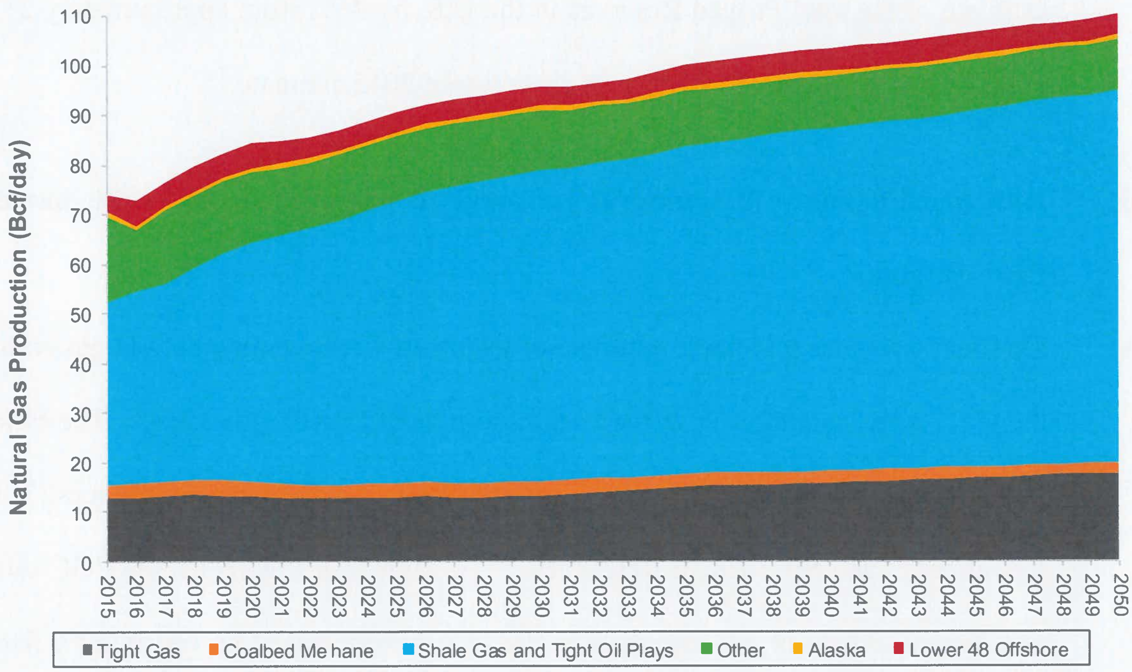
[31] Sources: U.S. Energy Information Administration, Natural Gas Spot and Futures Prices (NYMEX), release date August 30, 2017; and U.S. Energy Information Administration, Natural Gas Dry Production, release date August 31, 2017.

[32] Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, Table 14. Oil and Gas Supply, release date January 5, 2017.

Figure 11: EIA U.S. Natural Gas Production Forecast[33]



Q. Are there sufficient natural gas resources to sustain that level of natural gas production?

A. Yes, based on estimates produced by both the EIA and the Potential Gas Committee ("PGC"), a research entity affiliated with the Colorado School of Mines, there are significant reserves of domestic U.S. natural gas.

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

[33] Ibid.

reservoirs under existing economic and operating conditions." The EIA has increased its estimate of the total Proved Reserves in the U.S. by 46% from approximately 211 Tcf in 2006 to approximately 308 Tcf in its most recent 2015 estimate.[34]

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.[35] The estimates of potential resources are classified by the PGC as Probable Resources,[36] Possible Resources,[37] and Speculative Resources.[38] As shown in Figure 12, the PGC estimate of total potential natural gas resources in the U.S. has increased by nearly 60% from 1,551 Tcf to 2,465 Tcf between 2010 and 2016, respectively.[39]

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[34] Source: U.S. Energy Information Administration, Dry Natural Gas Proved Reserves as of 12/31 (Summary), release date December 14, 2016.

[35] 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*, http://potentialgas.org/what-we-do-2, access date June 28, 2017.

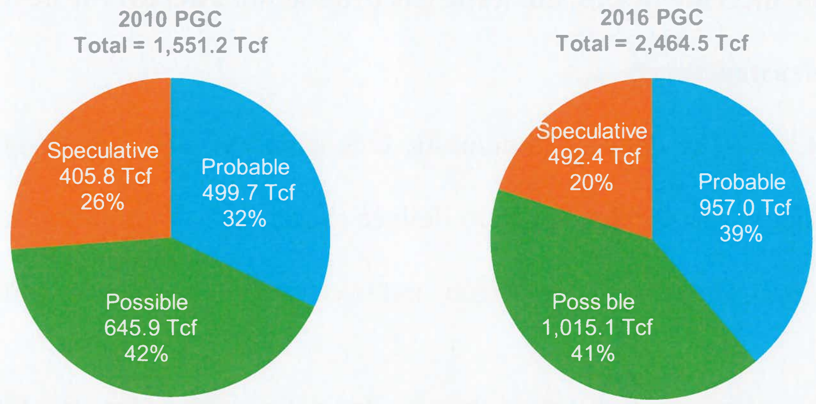
[36] A Probable Resource is defined as a discovered but unconfirmed resource associated with known fields and field extensions, also undiscovered in new pools in both productive and nonproductive areas of known fields.

[37] A Possible Resource is an undiscovered resource associated with new field/pool discoveries in known productive formations in known productive areas.

[38] A Speculative Resource is an undiscovered resource associated with new field/pool discoveries in as-yet nonproductive areas.

[39] 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, 2016," July 2017.

Figure 12: PGC Estimates of Total Potential Resources in the U.S.[40]



Q. Please provide a summary of 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 gas supply. To provide context, assuming an annual overall U.S. natural gas consumption level of 27.5 Tcf,[41] the combined EIA Proved Reserves and PGC potential resource estimates would provide sufficient supply for all U.S. natural gas demand for over 100 years.

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40 Ibid.

41 Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use, release date May 31, 2017. Represents the total annual consumption in the U.S. for 2016.

3. Incremental Pipeline Capacity

Q. Has the increase in U.S. domestic gas production affected the development of natural gas infrastructure?

A. Yes, it has. The increase in domestic U.S. supply is also supporting the development of new natural gas infrastructure to deliver natural gas to various locations, including the Dawn Hub, Gulf Coast/Henry Hub, and to other areas of the U.S. and Canada.

Q. Are there projects to increase the pipeline deliverability into the New England region?

A. Yes, there are, although most of the volumes associated with incremental New England supply projects are targeting southern New England markets. Specifically, the shippers on certain recent projects (the Algonquin Incremental Market, TGP Connecticut Expansion, and Atlantic Bridge projects) are LDCs and end-users predominantly located in the southern New England area, with certain volumes on the Atlantic Bridge project associated with shippers in Maine and the Canadian Maritimes. These three projects will increase the total pipeline capacity into the New England region by approximately 550,000 Dth per day, with 85% of the total capacity contracted by project shippers located in southern New England.

Q. Please discuss the project development process associated with incremental pipeline capacity.

A. There is significant complexity and increasing lead times required for development of incremental pipeline capacity projects into the New England region. Most recently, two major projects proposed to deliver incremental natural gas supplies to the New England region have faced development challenges. The Access Northeast and TGP NED Market Path projects were both major pipeline expansion projects in terms of incremental capacity, significant project facilities, and long lead times.

Q. Please briefly review the Access Northeast Project.

A. The proposed Access Northeast project was structured to deliver up to 900,000 Dth per day of incremental capacity via an expansion of the existing Algonquin system from New York to Massachusetts and new LNG storage facilities. An initial open season for the Access Northeast project was conducted in early 2015; however, the project was withdrawn from the FERC pre-filing review process in June 2017.[42]

Q. Please describe the TGP NED Market Path Project.

A. The TGP NED Market Path project, which has been cancelled, would have involved the construction of greenfield pipeline from Wright, New York, to Dracut, Massachusetts, to deliver up to 1,200,000 Dth per day of incremental supplies to the New England region. The open season for the TGP NED Market Path project was initially conducted in early 2014, and the original in-service date for the project was November 2018, a lead time of nearly four years.[43]

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[42] Sources: Algonquin Gas Transmission, LLC, Letter Request for Approval of Pre-Filing Review for the Access Northeast Project, FERC Docket No. PF16-1-000, November 3, 2015; and Algonquin Gas Transmission, LLC, Withdrawal from Pre-Filing Review of the Access Northeast Project, FERC Docket No. PF16-1-000, June 29, 2017.

[43] Sources: Tennessee Gas Pipeline, L.L.C., Application for a Certificate of Public Convenience and Necessity, FERC Docket No. CP16-21-000, November 20, 2015; and Tennessee Gas Pipeline, L.L.C., Notice of Withdrawal of Certificate Application, FERC Docket No. CP16-21-000, May 23, 2016.

Q. Please discuss the natural gas supply implications for the regional LDCs with respect to the development challenges associated with large scale pipeline projects.

A. Given the complexity and long lead times needed to develop large incremental interstate pipeline capacity projects, the regional LDCs may need to increase their reliance on existing infrastructure that requires limited facilities for expansion and invest in on-system resources that address each LDC's unique circumstances.

4. Imported LNG Supplies

Q. Please briefly describe the LNG importation facilities in New England.

A. There are three import LNG terminals located in New England: ENGIE's LNG facility in Everett, Massachusetts, and two off-shore LNG facilities near Cape Ann, Massachusetts (ENGIE's Neptune LNG facility[44] and Excelerate Energy's Northeast Gateway Deepwater Port). In addition, the New England market has access via the MNE-US system to natural gas supplies from the Canaport LNG facility, which is a partnership between Repsol (75%) and Irving Oil (25%).[45] Table 2 below summarizes the existing capabilities of the four LNG importation facilities in the New England/Maritimes Canada region.

[44] In early 2017, Neptune LNG filed for a permit to commence decommissioning work on the facility. *See*, U.S. Army Corps of Engineers, "Neptune LNG seeks permit to work in U.S. waters to decommission deepwater LNG port off Marblehead," February 28, 2017.

[45] The Brunswick Pipeline connects the Canaport LNG facility to MNE-US at Calais, Maine.

Table 2: Regional LNG Importation Facilities[46]

LNG Import Facility	Storage Capacity	Vaporization Capacity
ENGIE Everett LNG	3.4 Bcf	1.035 Bcf/day
ENGIE Neptune LNG	n/a	0.4 Bcf/day
Northeast Gateway	n/a	0.8 Bcf/day
Canaport LNG	10 Bcf	1.0 Bcf/day

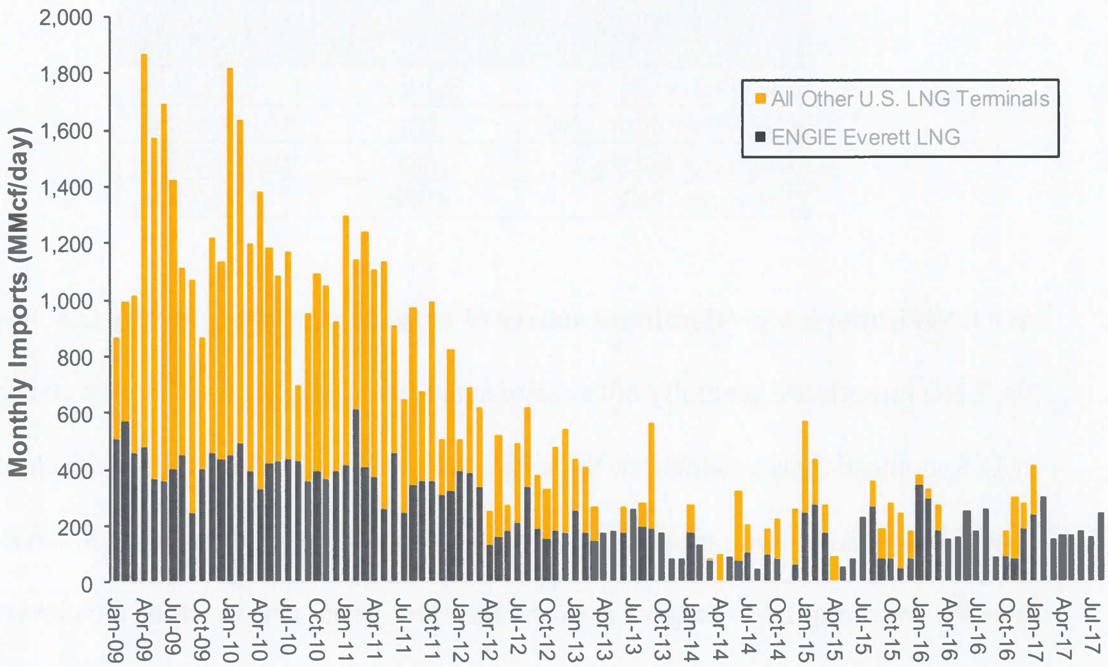
Q. Are LNG imports a predominant source of natural gas supply for the U.S. in general?

A. No, LNG imports are generally not a major source of supply for the U.S. Given the increase in U.S. domestic gas production, there has been a trend in the U.S. for developing LNG export facilities. In fact, most of the LNG importation facilities in the U.S. have not been actively importing LNG cargoes over the past few years, and seven of the eleven existing U.S. LNG import terminals are in various stages of developing LNG export capability.[47] As shown in Figure 13 below, the ENGIE Everett LNG facility in New England has accounted for the majority of imported LNG volumes to the U.S. since 2013.

46 Source: FERC, North American LNG Import/Export Terminals: Existing, release date May 1, 2017.

47 Sources: FERC, North American LNG Import/Export Terminals: Existing, release date May 1, 2017; and FERC, North American LNG Import/Export Terminals: Approved, release date May 1, 2017.

Figure 13: Imported LNG Volumes to U.S.[48]

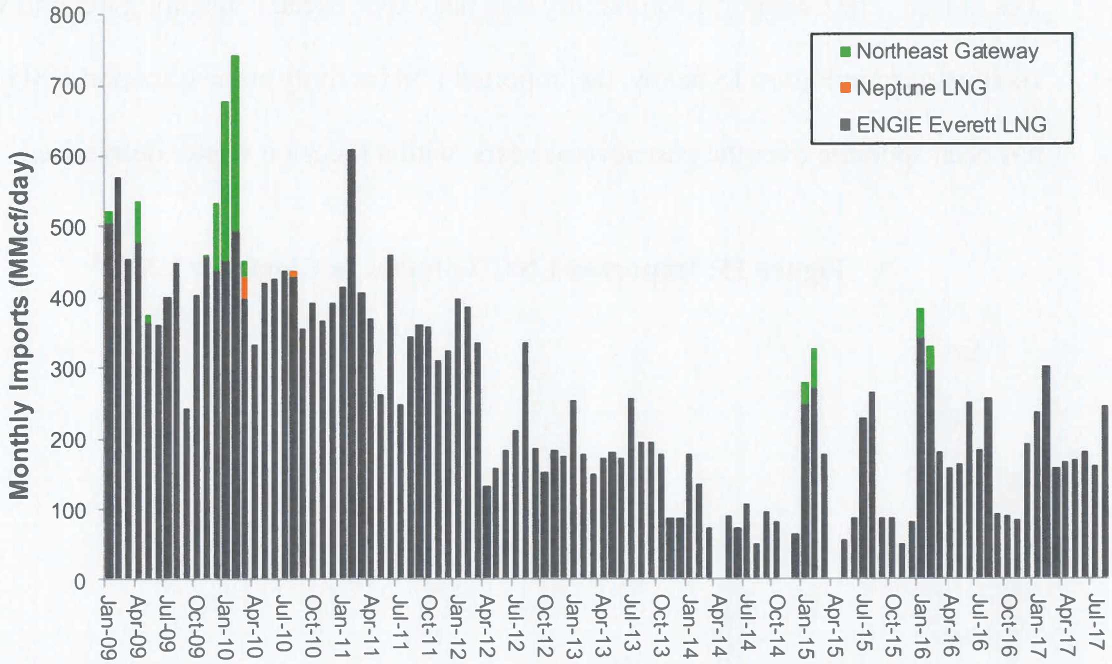


Q. **Please discuss trends in imported LNG volumes to the New England importation facilities.**

A. As illustrated in Figure 14 below, the two off-shore LNG importation facilities, Northeast Gateway and Neptune LNG, have had limited activity since commencing service in 2009 and 2010, respectively, and the ENGIE Everett LNG facility has become more winter season focused.

48 Source: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on October 25, 2017.

Figure 14: Imported LNG Volumes to New England[49]



In addition, as shown in Figure 14, there has been significant variability in the volumes of LNG imported to the region. Over the past four split-years (2013/14 through 2016/17), there has been less baseload volumes and more winter-focused deliveries. In the peak winter months, total imported LNG volumes to New England ranged from an average of less than 65 MMcf per day to approximately 340 MMcf per day over the past four winter periods (i.e., winters of 2013/14 through 2016/17).[50]

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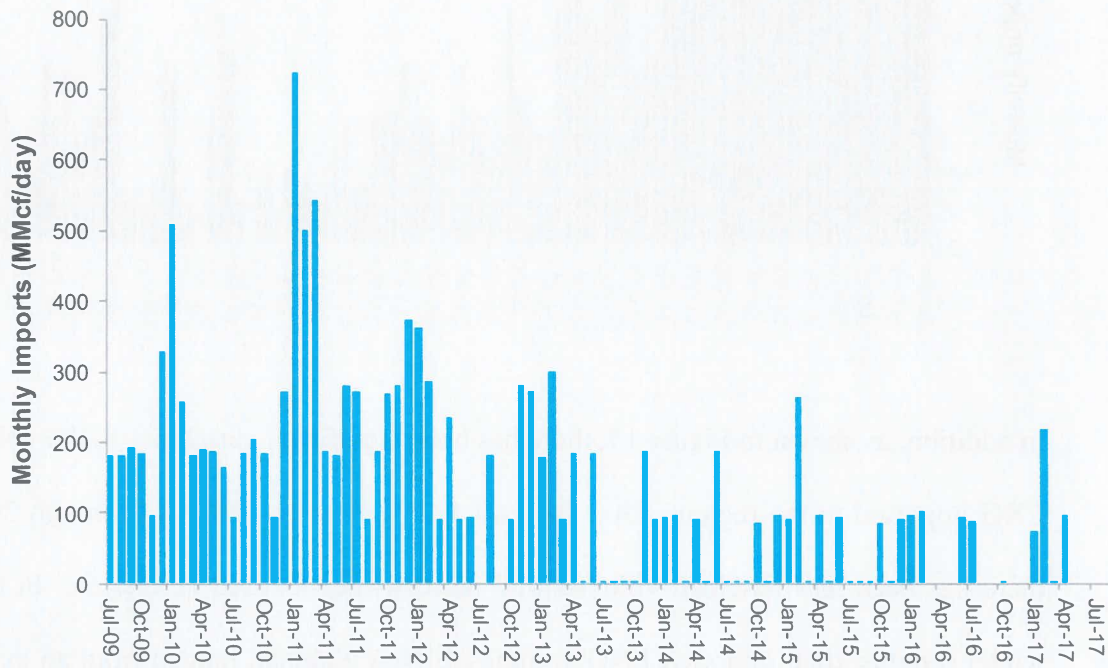
49 Ibid.

50 Ibid.

Q. Has the Canaport LNG terminal experienced similar trends in LNG import activity?

A. Yes, it has. The Canaport LNG facility also has experienced a declining trend in volumes. As illustrated in Figure 15 below, the imported LNG activity at the Canaport LNG terminal has been sporadic over the past several years, with a focus on winter deliveries.

Figure 15: Imported LNG Volumes to Canaport LNG[51]



Q. What are the likely market issues that have influenced imported LNG volumes to the New England/Maritimes Canada region?

A. Since the LNG market is a global market, the New England/Maritimes Canada region must compete with international markets for imported LNG supplies. The volume of LNG imported into the region is influenced by various factors, including the demand for LNG

[51] Source: National Energy Board of Canada, LNG - Shipment Details, accessed on October 25, 2017.

in alternative markets, and the need for the New England market to pull the supply by contracting for imported LNG volumes.

C. Summary of Regional Natural Gas Market Dynamics

Q. Please summarize the current regional natural gas demand and supply trends and the implications for LDCs in terms of natural gas supply strategy and planning.

A. The New England region is currently faced with increasing demand for natural gas by both the traditional LDC and power generation segments and significant natural gas supply and capacity challenges, particularly during the winter period. During the winter periods when the demand from the traditional LDC segment is generally higher due to the heat sensitive nature of the LDC load requirements, there may be competition from the power generation segment for winter gas supplies leading to higher and more volatile New England natural gas price indices.

With respect to natural gas supplies, there are three main challenges impacting the long-term availability and feasibility of natural gas resource options to serve the region. First, there will likely be limited to no natural gas supplies from off-shore Nova Scotia (i.e., SOEP and Deep Panuke) to the New England region by 2020. Second, the New England region will likely need to compete with alternative markets for imported LNG supplies. Finally, there is significant complexity and long lead times associated with the development of new incremental pipeline capacity projects into the region and, thus, regional LDCs may need to rely on existing infrastructure that require limited facilities for expansion, and invest in on-system resources that address each LDC's unique circumstances.

These market dynamics and regional supply challenges faced by the New England LDCs highlight the importance of the LDC's role in planning, procuring, and managing a portfolio of resources to meet customer requirements. The LDC's natural gas supply strategy and planning must account for the present and future market conditions, as well as its unique situation, to ensure reliable supplies at a reasonable cost for its customers.

IV. REVIEW OF ENERGYNORTH'S NATURAL GAS DEMAND

Q. Please discuss the Company's growth in natural gas customers since the acquisition of EnergyNorth by Liberty Energy (NH).

A. As discussed in the Fleck/DaFonte Testimony, since the transfer of ownership of EnergyNorth from National Grid USA to Liberty Energy (NH),[52] EnergyNorth has experienced growth in its number of natural gas customers as a result of an increased focus on sales and marketing. The number of EnergyNorth customers has increased by 8% from approximately 85,500 customers in 2012 to approximately 91,000 customers in 2017.[53] Notably, as a result of the Company's sales and marketing efforts, there was an increase of approximately 1,400 customers between 2014 and 2015 and an increase of approximately 1,800 customers between 2015 and 2016 as illustrated in Figure 16 below.

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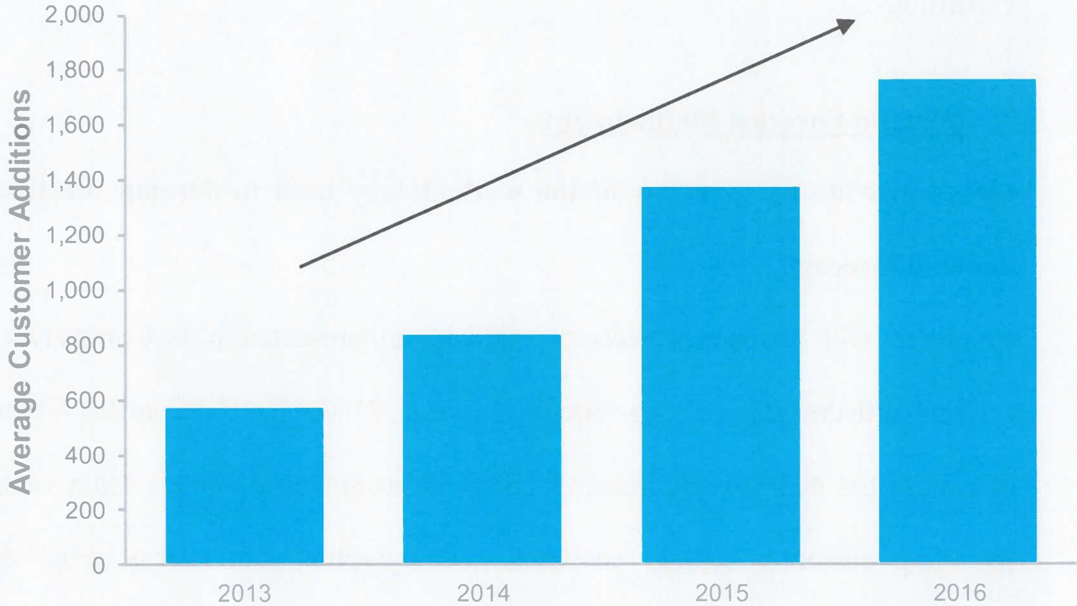
[52] The Commission approved the transfer of ownership as part of a settlement agreement between National Grid USA and Liberty Energy (NH). *See*, Order No. 25,370 (May 30, 2012).

[53] Represents the average number of sales and capacity assigned transportation customers for the fiscal year period from April to March.

Figure 16: EnergyNorth Growth in Customers[54]



The increase in EnergyNorth's natural gas customers has resulted in an overall increase in natural gas demand.

Q. Does EnergyNorth expect the demand for natural gas will continue to grow?

A. Yes, it does. The demand forecast developed by EnergyNorth for this filing shows a continued increase in the number of natural gas customers, as well as an increase in the overall demand for natural gas. The growth in demand for natural gas is supported by: (1) EnergyNorth's continued focus on customer growth in its existing service territories; (2) incremental load requirements for certain customers that are not captured by the

54 Represents the average number of sales and capacity assigned transportation customers for the fiscal year period from April to March.

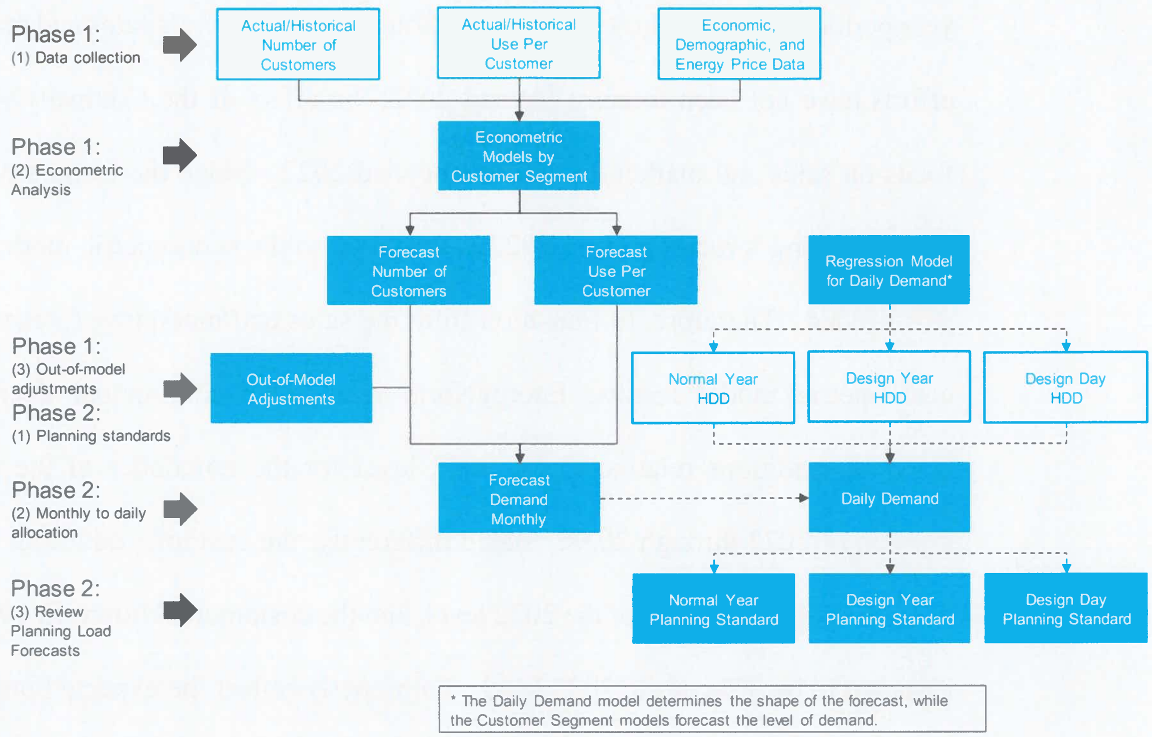
Company's econometric forecast models; and (3) additional growth from service area expansions.

A. <u>Demand Forecast Methodology</u>

Q. Please provide an overview of the methodology used to develop the EnergyNorth demand forecast.

A. Consistent with the demand forecast methodology presented in the Company's 2017 IRP, EnergyNorth developed a long-term forecast (i.e., 21-year period from 2017/18 to 2037/38) of natural gas demand requirements based on econometric models using various inputs, including customer billing, economic, demographic, and energy price data. The methodology used to develop the demand forecast in this instant filing is the same process used for the Company's 2017 IRP filing. A flow chart illustrating the overall demand forecast methodology is provided in Figure 17 below. More detailed information regarding the demand forecast methodology is provided in the Company's 2017 IRP filing.

Figure 17: EnergyNorth Demand Forecast Methodology



Q. How did the Company extend the demand forecast beyond the five-year period of 2017/18 to 2021/22 contained in the 2017 IRP?

A. For Phase 1 of the demand forecast process (see Figure 17 above), the Company used the same econometric (i.e., regression) models by customer segment developed in the 2017 IRP, and extended the forecast period through 2037/38 using the economic, demographic, and energy price data provided by Moody's and EIA. Next, the Company extended the out-of-model adjustments for its existing and new service territories using the approach outlined below:

- Existing Service Territory – As discussed in detail in the 2017 IRP, the out-of-model adjustment for growth within the Company's existing service territory is based on the sales and marketing group's planned customer additions for the six-year period from 2017 through 2022. Although the Company's sales and marketing efforts have not been forecast beyond 2022, the effect of the Company's current focus on sales and marketing will last beyond 2022. Since the Company's sales and marketing forecast ends in 2022, a transition to the econometric model results was needed. Therefore, to transition from the sales and marketing forecast to the econometric model results, EnergyNorth assumed a 5% annual decrease in customer additions relative to the 2022 level for the remainder of the forecast horizon of 2023 through 2038. Stated differently, the customer additions in 2023 were assumed to be 95% of the 2022 level, and the customer additions in 2024 were assumed to be 90% of the 2022 level. To properly reflect the expected increase in customer additions, the annual customer growth associated with the econometric forecast was compared to the calculated annual customer addition estimates during the transition period by customer segment. Where the annual transition period estimates for a customer segment were higher than the econometric forecast of customer additions, the customer additions of the econometric forecast were adjusted by the difference between the transition period estimates and the econometric forecast of annual customer additions. For years in which the econometric forecast of customer additions was equal to or above the estimated customer additions for a customer segment, the econometric forecast was relied on with no adjustment. The customer additions were then multiplied by the projected use per customer values from the Company's econometric models for the respective customer segment to determine the projected volumes.

- New Service Territories – As discussed in the 2017 IRP, the Company developed an out-of-model adjustment for its expansion plans to new service areas, which includes the Pelham and Windham communities,[55] and the communities along the proposed Granite Bridge Pipeline (Epping, Raymond, and Candia). Since these new service areas have no historical data on customer additions or usage pattern, the Company relied on the sales and marketing group's planned customer additions for these new service areas for the six-year period from 2017 through 2022, and assumed the number of customer additions for the remainder of the forecast (i.e., 2023 through 2038) would be equivalent to the 2022 level.[56] The customer additions were then multiplied by the projected use per customer values from the Company's econometric models for the respective customer segment to determine the projected volumes.

Figure 18 below summarizes the various out-of-model adjustments to the results of the econometric models in the Base Case demand forecast.

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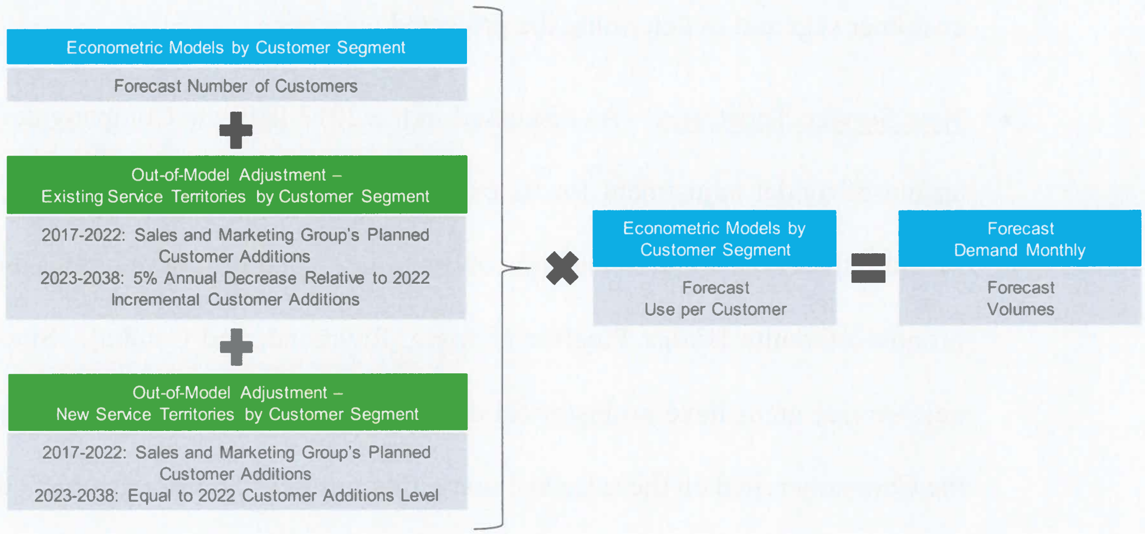
55 The Commission previously approved the Company's expansion plans to serve the towns of Windham and Pelham in Order No. 25,987 (Feb. 8, 2017).

56 As a result, the projected saturation level for the new service territories is estimated be approximately 40% by the end of the forecast horizon (i.e., 2037/38).

Figure 18: EnergyNorth Base Case Demand Forecast



Q. Did the Company develop various demand scenarios?

A. Yes, it did. EnergyNorth developed demand forecasts under a range of weather conditions. Specifically, the demand forecast reflects three weather planning periods: (1) Normal Year, or the demand that is likely to occur; (2) Design Day, or the highest single day demand levels that the Company is projected to supply; and (3) Design Year that represents demand under extended cold weather conditions.

Q. Please describe the process used to develop the Normal Year, Design Year, and Design Day planning standards.

A. The Company used the same analytical approaches described in the 2017 IRP to develop the weather planning periods. EnergyNorth's analyses resulted in a Normal Year of 6,325 heating degree days ("HDDs"), a Design Year of 6,869 HDDs, and a Design Day of 71 HDDs.

Q. Did the demand forecast include the effects of the Company's energy efficiency plan?

A. Yes, it did. The volumetric results of the demand forecast (i.e., econometric models plus out-of-model adjustments) were reduced by energy efficiency savings to determine the Company's net demand requirements. The energy efficiency savings were assumed to be equal to those estimated by the Company in the 2018-2020 New Hampshire Statewide Energy Efficiency Plan filed with the Commission in Docket No. DE 17-136. Using the same approach defined in the 2017 IRP for energy efficiency savings beyond 2020, the Company assumed the percentage of residential energy efficiency volumes relative to residential firm demand continued to be equivalent to the 2020 level through the end of the forecast horizon. The same assumption was made for energy efficiency savings for C&I customers for the 2021 to 2038 time period.

Q. Please describe the Company's process for allocating the net monthly demand requirements to daily demand requirements.

A. The Company allocated the net monthly demand forecast into daily requirements to model its resources and requirements with its SENDOUT® linear programming software modeling package. In addition, given that the contract and operational parameters of the gas supply portfolio (e.g., contractual maximum transportation quantities or maximum storage withdrawal volumes) are modeled as daily values in SENDOUT®, the monthly demand requirements also must be allocated into daily values. As detailed in the 2017 IRP, that monthly demand allocation was accomplished by using a daily demand model, which was developed by the Company using a regression model based on daily sendout and temperature. The daily demand model determines the daily shape of the demand forecast, while the customer segment models forecast the level of demand.

B. Results of the EnergyNorth Demand Forecast

Q. Please summarize the results of the Company's demand forecast.

A. Figures 19 and 20 below depict the results of EnergyNorth's Base Case demand forecast for Normal Year, Design Year, and Design Day over the 21-year forecast horizon.

Figure 19: EnergyNorth Normal Year and Design Year Demand Forecast

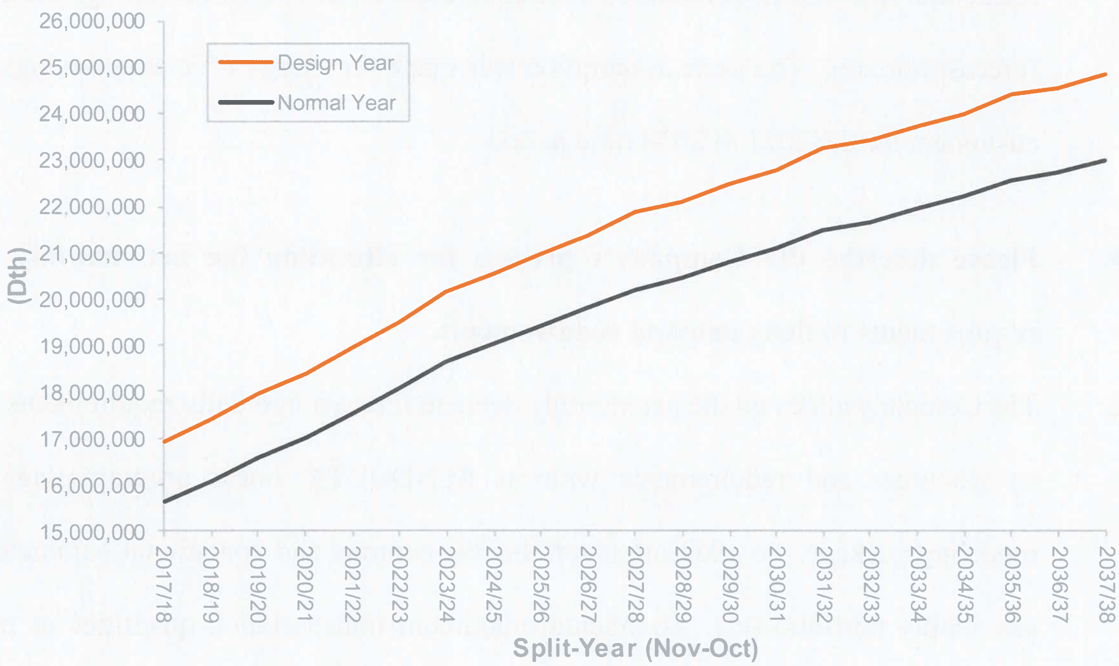
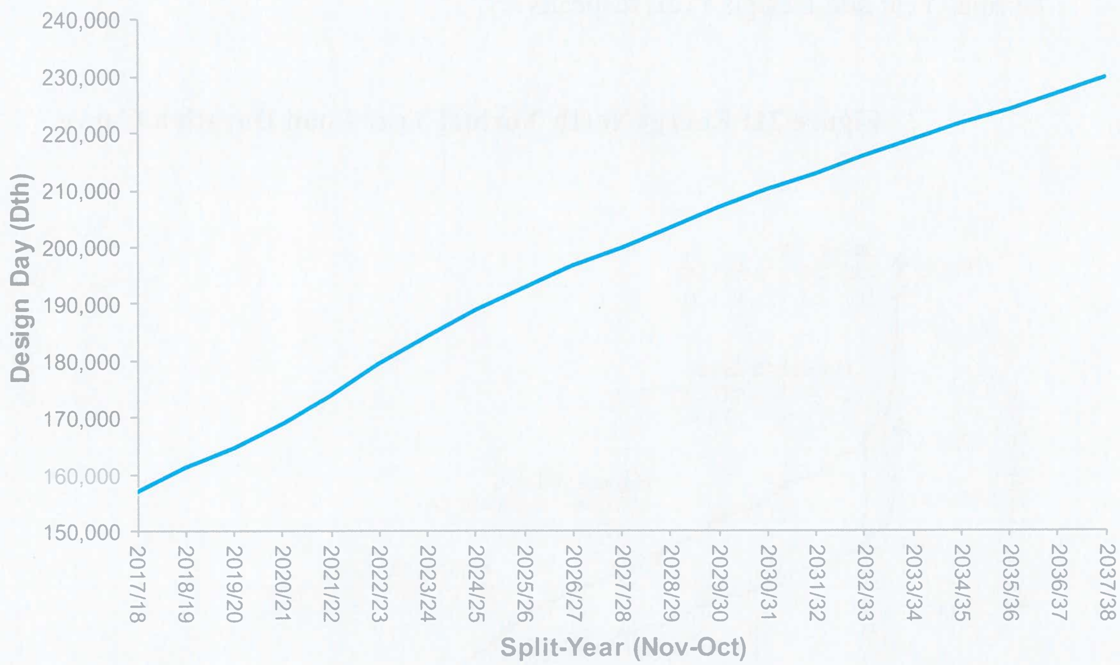


Figure 20: EnergyNorth Design Day Demand Forecast



The results of the Company's demand forecast show an increase in natural gas demand requirements over the forecast horizon. Specifically, over the 21-year forecast horizon from 2017/18 to 2037/38, the incremental demand requirement is approximately 7.4 million Dth for Normal Year and 7.9 million Dth for Design Year. With respect to Design Day, the incremental Design Day demand requirement is 72,768 Dth by 2037/38.

Q. Please discuss EnergyNorth's projected demand profile.

A. To analyze the Company's projected demand profile, EnergyNorth developed a load duration curve analysis. Load duration curves were developed by re-sorting the projected daily demand requirements by highest load day to lowest load day for certain years in the forecast horizon. Figures 21 and 22 below illustrate the load duration curve analysis for Normal Year and Design Year, respectively.

Figure 21: EnergyNorth Normal Year Load Duration Curve

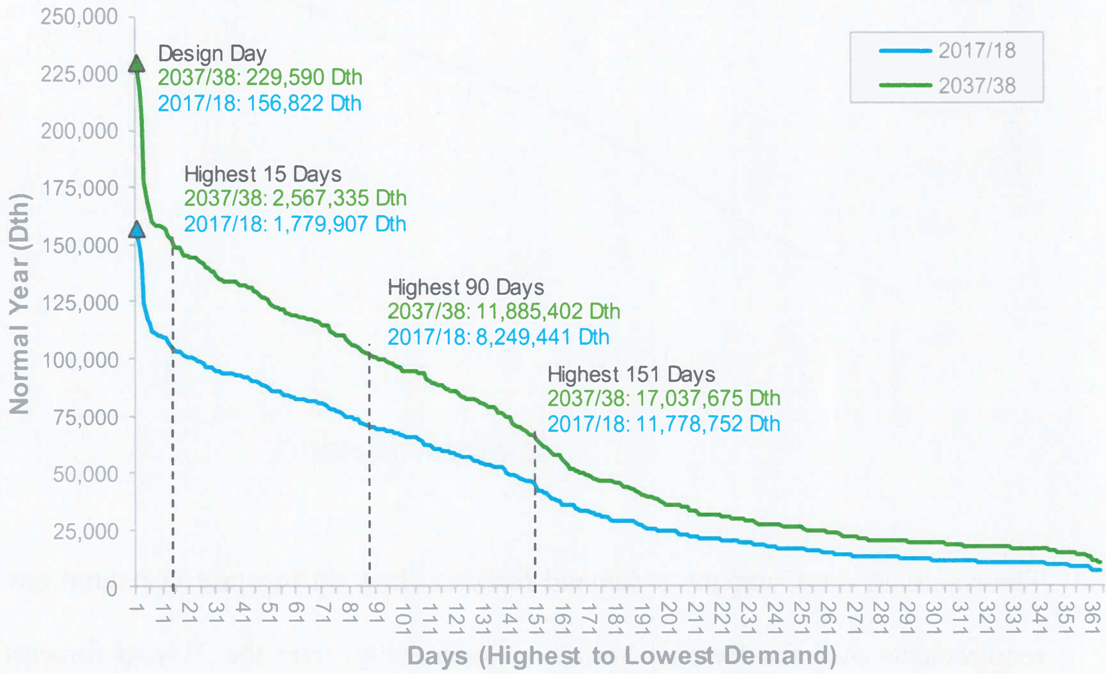
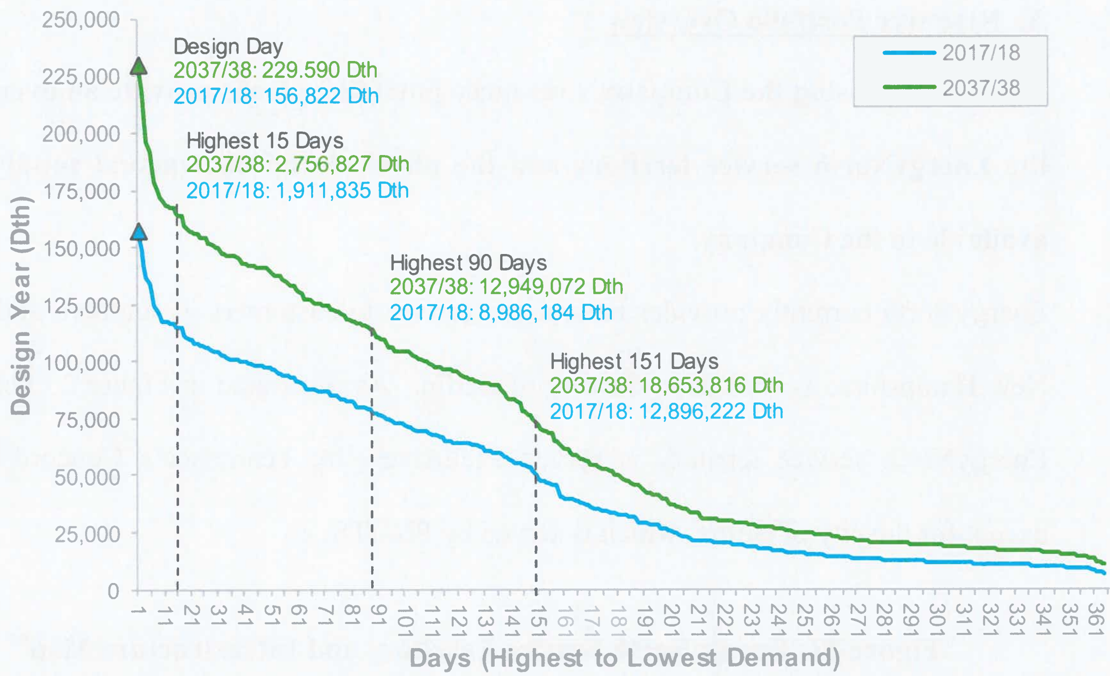


Figure 22: EnergyNorth Design Year Load Duration Curve



As depicted in Figures 21 and 22, EnergyNorth has significant peak day and winter period demand requirements. The Company's Design Day demand grows by 72,768 Dth over the 21-year forecast horizon to a total of 229,590 Dth by 2037/38. On the highest 15 demand days, the total demand requirement increases by nearly 800,000 Dth for Normal Year and 840,000 Dth for Design Year between 2017/18 and 2037/38. Focusing on the highest 90 demand days (the peak winter period), the total Normal Year and Design Year demand requirement increases by approximately 3.6 million Dth and 3.9 million Dth, respectively. Finally, the total demand for the highest 151 demand days (the winter period) increases by over 5.2 million Dth and 5.7 million Dth between 2017/18 and 2037/38 for Normal Year and Design Year, respectively.

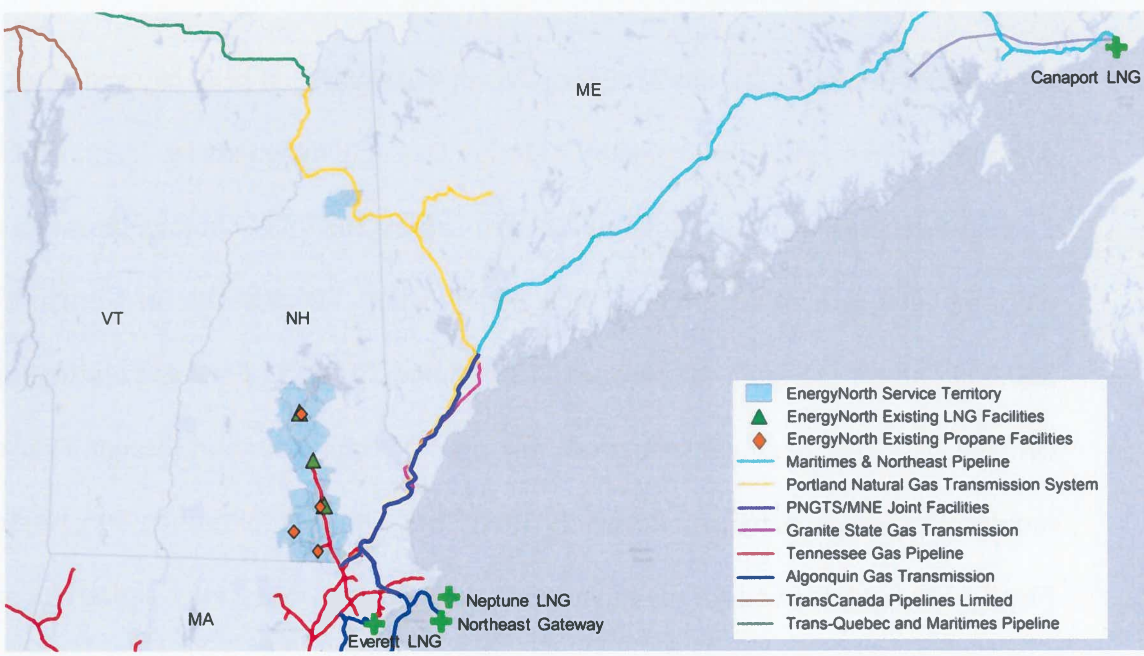
V. REVIEW OF ENERGYNORTH'S CURRENT NATURAL GAS PORTFOLIO

A. Resource Portfolio Overview

Q. Prior to discussing the Company's resource portfolio, please provide an overview of the EnergyNorth service territory and the physical and contractual supply assets available to the Company.

A. EnergyNorth currently provides natural gas service to customers in southern and central New Hampshire, as well as in the city of Berlin. As illustrated in Figure 23 below, the EnergyNorth service territory is served exclusively by Tennessee's Concord Lateral, except for the city of Berlin, which is served by PNGTS.

Figure 23: EnergyNorth Service Territory and Infrastructure Map[57]



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57 Source: S&P Global Market Intelligence [modified by ScottMadden].

As shown by Figure 23 above, the upstream natural gas supply options available to the Company are determined based on the ability of a particular resource to access Tennessee. Stated differently, since Tennessee is the only feed to almost all of the EnergyNorth service territory, it is currently determinative with respect to upstream supply decisions.

Q. Please summarize the current EnergyNorth natural gas supply portfolio.

A. To meet Design Day and Design Year sendout requirements, the Company's portfolio is comprised of the following resources: (1) long-haul and short-haul transportation capacity; (2) underground storage; and (3) on-system peak-shaving LNG and propane facilities. A summary of EnergyNorth's current resource portfolio, with associated contract expiration dates, is provided in Table 3 below.

Table 3: EnergyNorth Design Day Resources[58]

Gas Supply	Contract Entity	Contract Number	Contract End Date	Contract MDQ (Dth/day)	
Canadian Supply					
East Hereford	PNGTS	FT (#1999-001)	11/30/2032		1,000
Dawn	Union Gas	FT (#M12200)	10/31/2022	4,092	
	TCPL	FT (#41232)	10/31/2022	4,047	
	Iroquois	RTS (#470-01)	11/1/2022	4,047	
	Tennessee	FT-A (#95346)	11/30/2021		4,000
Niagara	Tennessee	FT-A (#2302)	10/31/2020		3,122
U.S. Domestic Supply					
Dracut	Tennessee	FT-A (#42076)	10/31/2020		20,000
Dracut	Tennessee	FT-A (#72694)	10/31/2029		30,000
Gulf (Zone-0 100 Leg)	Tennessee	FT-A (#8587)	10/31/2020	7,035	
Gulf (Zone-1 100 Leg)	Tennessee	FT-A (#8587)	10/31/2020	523	
Gulf (Zone-1 800 Leg)	Tennessee	FT-A (#8587)	10/31/2020	4,536	
Gulf (Zone-1 500 Leg)	Tennessee	FT-A (#8587)	10/31/2020	9,502	
Storage (Zone 4)	Tennessee	FT-A (#8587)	10/31/2020	3,811	
	Tennessee	FT-A (#8587)	10/31/2020		25,407
Storage	Tennessee	FS-MA (#523)	10/31/2020	21,844	
	Tennessee	FT-A (#632)	10/31/2020		15,265
Storage	Honeoye	SS-NY (#11234)	3/31/2020	1,957	
Storage	Dominion	GSS (#300076)	3/31/2021	934	
Storage	National Fuel	FSS (#O02357)	3/31/2019	6,098	
	National Fuel	FST (#N02358)	3/31/2019	6,098	
	Tennessee	FT-A (#11234)	10/31/2020		9,039
Total Firm Transportation					**107,833**
LNG Daily Operational Capacity (Concord/Manchester/Tilton)					12,600
Propane Daily Deliverability (Amherst/Manchester/Nashua/Tilton)					34,600
TOTAL DESIGN DAY RESOURCES					**155,033**

As illustrated in Table 3 above, EnergyNorth has firm transportation contracts on Tennessee (106,833 Dth per day) and PNGTS (1,000 Dth per day) to provide a total daily deliverability of 107,833 Dth per day to its city-gate stations from three natural gas supply sources (Canadian supply, domestic U.S. supply, and underground storage in Pennsylvania

58 Please note that certain contracts are organized by path, with only the contract that ultimately delivers to EnergyNorth included in the total resource calculation.

and New York). In addition, the Company owns three LNG facilities in Concord, Manchester, and Tilton with a combined daily operational vaporization and storage capacity of approximately 12,600 Dth. Finally, there are three propane facilities located in Manchester, Nashua, and Tilton that are directly connected to the Company's distribution system, and a fourth "satellite" propane facility in Amherst.[59] The propane facilities have a combined vaporization rate of approximately 34,600 Dth per day and storage capacity of approximately 108,397 Dth. In total, EnergyNorth has Design Day resources of approximately 155,033 Dth per day.

B. <u>Transportation Capacity</u>

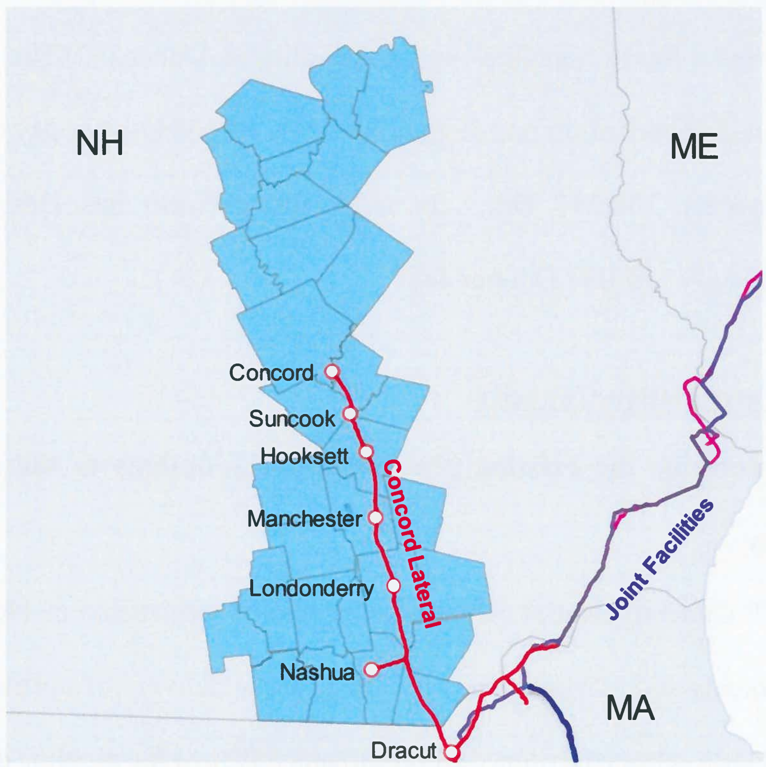
Q. Please describe the existing pipeline delivery options to the EnergyNorth service territory.

A. The TGP Concord Lateral, which was originally constructed in 1951, is the primary and, for all intents and purposes, the only feed for the delivery of upstream gas supplies to the EnergyNorth service territory. Approximately 99% of the pipeline deliveries (106,833 Dth per day of the 107,833 Dth per day of total firm transportation contract MDQ) to the EnergyNorth service territory are from the TGP Concord Lateral, while only 1% (1,000 Dth per day) of the pipeline deliveries are from PNGTS, which directly serves the city of Berlin. With respect to the physical path of the TGP Concord Lateral, it originates near Dracut, where Tennessee has interconnections with MNE-US and PNGTS, and traverses

[59] The propane facility in Amherst is used solely for storage.

north along Interstate 93 terminating near Concord, New Hampshire. Figure 24 is an illustrative map of the TGP Concord Lateral.

Figure 24: Illustrative TGP Concord Lateral Map[60]



Q. Please summarize the upstream resources in EnergyNorth's existing supply portfolio.

A. Table 4 below is a summary of the Company's existing firm transportation capacity (as provided in Table 3 above) by upstream supply source.

60 Source: S&P Global Market Intelligence [modified by ScottMadden and EnergyNorth].

Table 4: EnergyNorth Upstream Supply Sources

Gas Supply	Contract MDQ (Dth/day)	% of Total Resources
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 4, the combined long-line and storage resources provide 46% of the total firm pipeline capacity, while the transportation contracts from Dracut also provide 46% of the pipeline capacity. The capacity contracts associated with Canadian supply contribute the smallest percentage (i.e., 8%) of the pipeline capacity.

C. Supplemental Peaking Resources

Q. Please summarize the existing LNG and propane resources of the Company.

A. EnergyNorth has three existing LNG facilities with a combined daily operational and storage capacity of 12,600 Dth. The maximum daily design vaporization capacity of the three LNG facilities is 22,800 Dth, which may be achieved if the Company refills the storage tanks using additional LNG truck loads (i.e., the storage capacity of 12,600 Dth is cycled). The propane facilities of the Company have a daily vaporization capability of 34,600 Dth with a storage volume of approximately 108,397 Dth. Table 5 below is a summary of the LNG and propane facilities by location.

Table 5: EnergyNorth Supplemental Peaking Resources[61]

Location	LNG or Propane	Design Vaporization	Storage Capacity
Concord	LNG	4,800	4,200
Manchester	LNG	8,400	4,200
Tilton	LNG	9,600	4,200
Total LNG Facilities		**22,800**	**12,600**
Amherst	Propane	n/a	26,088
Manchester	Propane	21,600	51,219
Nashua	Propane	11,000	25,968
Tilton	Propane	2,000	5,122
Total Propane Facilities		**34,600**	**108,397**

Q. Please discuss the role of the LNG and propane facilities in meeting the Company's Design Day demand.

A. EnergyNorth's existing LNG capacity is minimal. The combined daily operational vaporization capacity of the three existing LNG facilities is approximately 12,600 Dth, which represents only 8% of the Company's total Design Day resources as shown in Table 6 below.

Table 6: EnergyNorth Design Day Resource Portfolio

Gas Supply	Contract MDQ (Dth/day)	% of Total Resources
Canadian Supply	8,122	5%
Dracut	50,000	32%
Long-line	21,596	14%
Storage	28,115	18%
Total Firm Transportation	**107,833**	**70%**
LNG Daily Operational Capacity	12,600	8%
Propane Daily Deliverability	34,600	22%
TOTAL DESIGN DAY RESOURCES	**155,033**	**100%**

61 EnergyNorth's share of the Amherst storage capacity is 26,088 Dth, which represents 50% of the total storage capacity of 52,176 Dth.

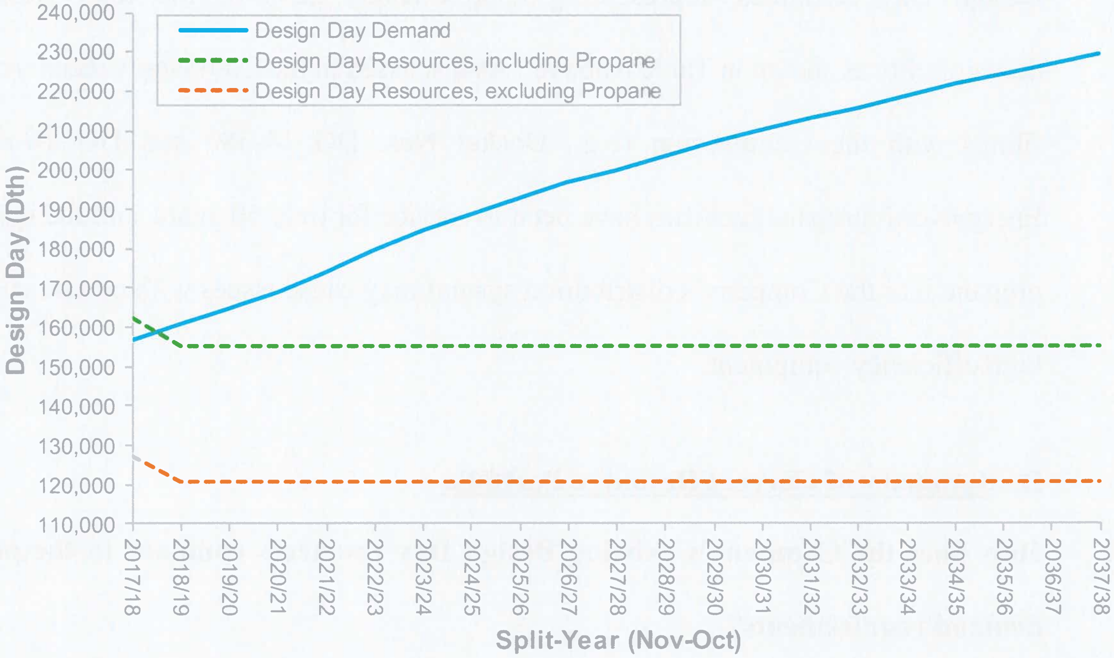
Finally, the deliverability of the propane facilities is a large component of EnergyNorth's Design Day resources, representing approximately 22% of the total Design Day deliverability as shown in Table 6 above. As discussed in the Company's recent regulatory filings with the Commission (e.g., Docket Nos. DG 14-380 and DG 16-814), the EnergyNorth propane facilities have been in service for over 50 years, and the injection of propane into the Company's distribution system may cause issues with certain customers' high efficiency equipment.

D. <u>Summary of Current Resource Portfolio</u>

Q. How does the Company's existing Design Day resources compare to the projected demand requirements?

A. As illustrated in Figure 25 and Table 7 below, the Company has a resource shortfall on Design Day beginning in 2018/19 of 5,956 Dth. Excluding the daily deliverability of the propane facilities of 34,600 Dth would increase the 2018/19 resource shortfall to 40,556 Dth. By the 2037/38 split-year, the resource shortfall on Design Day is approximately 75,000 Dth (or over 109,000 Dth excluding the propane facilities).

Figure 25: EnergyNorth Design Day Demand and Resources[62]



[62] As discussed previously, the 2017/18 Design Day resources include the contract with ENGIE for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018.

Table 7: EnergyNorth Design Day Resource Shortfall (Dth)[63]

Split-Year (Nov-Oct)	Design Day Demand	Design Day Resources, including Propane	Reserve / (Deficiency) including Propane	Reserve / (Deficiency) excluding Propane
2017/18	156,822	162,033	5,211	(29,389)
2018/19	160,989	155,033	(5,956)	(40,556)
2019/20	164,640	155,033	(9,607)	(44,207)
2020/21	168,934	155,033	(13,901)	(48,501)
2021/22	173,917	155,033	(18,884)	(53,484)
2022/23	179,382	155,033	(24,349)	(58,949)
2023/24	184,432	155,033	(29,399)	(63,999)
2024/25	188,856	155,033	(33,823)	(68,423)
2025/26	192,933	155,033	(37,900)	(72,500)
2026/27	196,785	155,033	(41,752)	(76,352)
2027/28	199,954	155,033	(44,921)	(79,521)
2028/29	203,491	155,033	(48,458)	(83,058)
2029/30	206,790	155,033	(51,757)	(86,357)
2030/31	210,016	155,033	(54,983)	(89,583)
2031/32	212,972	155,033	(57,939)	(92,539)
2032/33	215,843	155,033	(60,810)	(95,410)
2033/34	218,828	155,033	(63,795)	(98,395)
2034/35	221,631	155,033	(66,598)	(101,198)
2035/36	224,148	155,033	(69,115)	(103,715)
2036/37	226,863	155,033	(71,830)	(106,430)
2037/38	229,590	155,033	(74,557)	(109,157)

[63] As discussed previously, the 2017/18 Design Day resources include the contract with ENGIE for a combination liquid/vapor service for up to 7,000 Dth per day, which terminates on March 31, 2018.

VI. ENERGYNORTH'S RESOURCE EVALUATION APPROACH

A. Portfolio Planning Objectives

Q. What are the overall objectives of EnergyNorth's resource portfolio planning process?

A. The primary goal of the Company's resource planning process is to meet the expected demand requirements of its customers in a reliable manner at the best cost. The Company's resource plan maintains or enhances the reliability of the overall resource portfolio to meet the various forecasted planning scenarios. As market conditions continue to change and evolve, the Company's gas supply portfolio needs to have the flexibility and optionality to adapt to these new conditions while maintaining reliability. While the objectives of reliability, flexibility, diversity, and viability are paramount, it is important to achieve these objectives in a reasonable manner at the best cost.

Q. Are EnergyNorth's resource planning objectives consistent with other LDCs?

A. Yes. In our experience, EnergyNorth's gas supply portfolio objectives are consistent with the objectives of other LDCs.

B. Evaluation of Resource Alternatives

1. Deliveries to City-gates

Q. Please discuss the resource options evaluated by EnergyNorth as part of its long-term resource planning process to meet the projected demand requirements.

A. As part of EnergyNorth's evaluation of its long-term gas supply portfolio, the Company assessed not only the available gas supply options, but also the delivery options associated with those supplies. Since certain gas supplies may rely on, or be enabled by, delivery options, EnergyNorth's evaluation of these delivery options is discussed first.

Q. Please summarize the delivery options evaluated by the Company.

A. EnergyNorth evaluated two pipeline delivery options that could provide incremental gas supplies to its service territory. The first option evaluated was an expansion of the existing pipeline connection between Tennessee and EnergyNorth (i.e., the TGP Concord Lateral). The second option analyzed was the construction of the Granite Bridge Pipeline that would connect the Joint Facilities to the TGP Concord Lateral.

Q. Please describe the first option (i.e., the TGP Concord Lateral).

A. As discussed previously in Section V, the TGP Concord Lateral is the primary and, for all intents and purposes, the only feed for the delivery of pipeline gas supplies to EnergyNorth's service territory. The TGP Concord Lateral runs from Dracut, along Interstate 93 terminating near Concord.

Q. Is there available capacity on the TGP Concord Lateral?

A. No, there is not. The TGP Concord Lateral, which was last expanded in 2009 when the Company contracted for 30,000 Dth per day of capacity, is fully subscribed.[64] Therefore, any additional requests to increase capacity and deliverability will, at a minimum, require incremental facilities on the Tennessee system.

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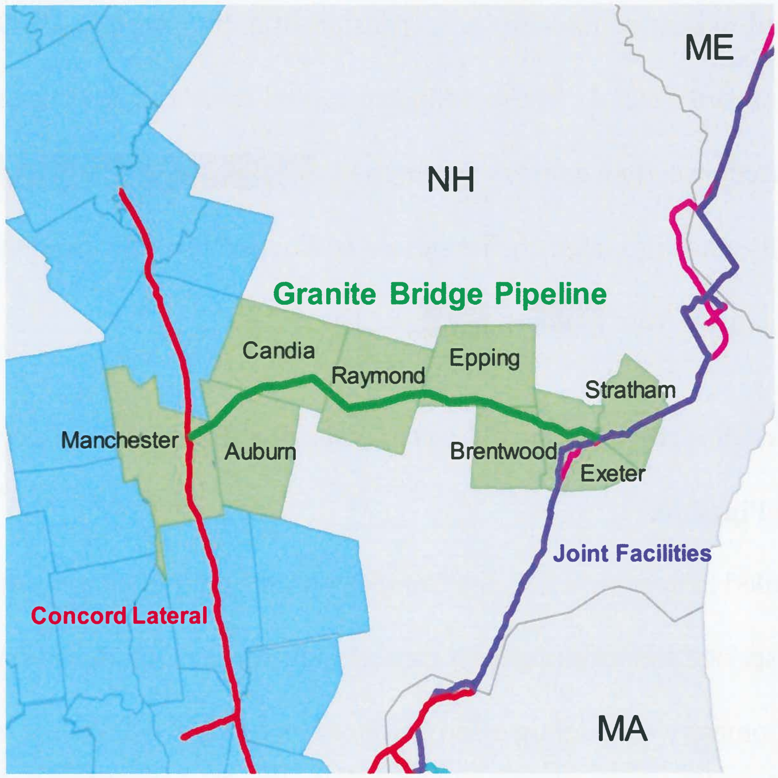
[64] The Commission issued an order approving the Settlement Agreement relating to the Company's transportation agreement on the TGP Concord Lateral expansion in Order No. 24,825 (Feb. 29, 2008). The TGP Concord Lateral expansion was approved for construction by the FERC in Docket No. CP 08-65-000.

Q. Please describe the second delivery option (i.e., the Granite Bridge Pipeline).

A. As discussed in the Fleck/DaFonte Testimony, the proposed Granite Bridge Pipeline would originate at the Joint Facilities in Stratham, and stay within the New Hampshire Department of Transportation ("NHDOT") right-of-way along Route 101[65] to connect to the TGP Concord Lateral in Manchester. The Granite Bridge Pipeline would add a second pipeline feed to EnergyNorth's existing service territory, and would enable upstream supplies on PNGTS and MNE-US to be delivered to the TGP Concord Lateral. In addition, re-gasified LNG from the proposed Granite Bridge LNG facility would connect to the Granite Bridge Pipeline for ultimate delivery to EnergyNorth. Figure 26 below is an illustrative map of the proposed Granite Bridge Pipeline.

65 In 2016, the New Hampshire Legislature passed a law (i.e., House Bill 626-FN-A) designating Route 101 as one of the state's Energy Infrastructure Corridors.

Figure 26: Illustrative Granite Bridge Pipeline Map[66]



Q. Did the Company conduct a quantitative and qualitative comparison of the two delivery options?

A. Yes, the Company developed both a quantitative (i.e., cost comparison) and a qualitative (i.e., other benefits) assessment of the two delivery options.

Q. Please summarize the cost for the first delivery option (i.e., an expansion of the TGP Concord Lateral).

A. In its evaluation of potential gas supply options, EnergyNorth had discussions with Tennessee regarding an expansion of the existing facilities on the Tennessee system.

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66 Source: S&P Global Market Intelligence [modified by ScottMadden and EnergyNorth].

Pursuant to those confidential discussions, the Company received an estimate of the capital costs and indicative rates for an expansion of approximately 75,000 Dth per day on the TGP Concord Lateral. These estimated capital costs and associated indicative daily rates were based on certain delivery assumptions [redacted] The daily rates provided by Tennessee to EnergyNorth for expanding the TGP Concord Lateral ranged from [redacted] to [redacted] per Dth.

Q. Please review the Company's cost analysis for the second delivery option, the Granite Bridge Pipeline.

A. As detailed in Section VII.C, the Company used a multi-step process to develop a levelized cost of service and resulting daily rate estimate for the Granite Bridge Pipeline. The results of the Company's modeling effort produced an estimated daily rate of approximately [redacted] per Dth based on the estimated levelized annual cost of [redacted] and capacity of 75,000 Dth per day for the Granite Bridge Pipeline. The daily rate for the Granite Bridge Pipeline was estimated based on a capacity of 75,000 Dth per day to provide an "apples-to-apple" unit cost comparison to the expansion of the TGP Concord Lateral. If the daily rate of the Granite Bridge Pipeline was estimated based on the operating capacity of approximately 150,000 Dth per day, the resulting unit cost would be cut in half. Please see the direct testimony of Timothy S. Lyons for a more detailed discussion of the levelized cost of service model and Granite Bridge Pipeline unit cost estimate.

Q. Please discuss the results of the Company's cost analysis of the two delivery options.

A. The estimated daily rate associated with the Granite Bridge Pipeline is significantly lower than the estimated daily rate for an expansion of the TGP Concord Lateral. The estimated daily rate to expand the TGP Concord Lateral ranged from [redacted] to [redacted] per Dth, whereas the estimated daily rate for constructing the Granite Bridge Pipeline was approximately [redacted] per Dth, which is approximately [redacted] and [redacted] lower than the low and high end of the daily rate for the expansion of the TGP Concord Lateral, respectively. Stated differently, the cost to construct the Granite Bridge Pipeline could increase by over [redacted] and the resulting rate would still be lower than the low end of the estimated daily rate to expand the TGP Concord Lateral.

Q. Please discuss your observations with respect to the Company's cost analysis for the two delivery options.

A. The methodologies used to develop the quantitative analysis for the two delivery options were reasonable and allowed the Company to review the options on a comparable basis, as each option had a daily rate for service that reflected a similar volume of delivery. With respect to the first delivery option (i.e., an expansion of the TGP Concord Lateral), the Company relied on the owner and operator of the Tennessee system to provide the estimated capital requirement and associated daily rate for the expansion project. The owner and operator of existing pipeline infrastructure is generally best positioned to provide an estimate of the capital costs and expected daily rate associated with an expansion of that infrastructure. Therefore, the Company's reliance on the capital cost and daily rate information from Tennessee regarding an expansion of the TGP Concord Lateral is appropriate and reasonable.

Regarding the second physical delivery option (i.e., the Granite Bridge Pipeline), the Company developed a levelized cost of service model to estimate the daily rate for the Granite Bridge Pipeline, which allowed the Company to compare it to the estimated daily rate for an expansion of the TGP Concord Lateral on an apples-to-apples basis. The levelized cost of service model included an estimate of the initial capital cost of the project supported by a conceptual engineering design provided by CHA Consulting, Inc. ("CHA"), which included detailed mapping of the proposed route and reflected several discussions with the NHDOT. In addition, the levelized cost of service model included estimates for various financial and operational assumptions or costs, which were developed by the Company. This detailed modeling approach to develop a daily rate for the Granite Bridge Pipeline is appropriate and reasonable.

Q. Did EnergyNorth consider the qualitative benefits provided by the Granite Bridge Pipeline?

A. Yes. The Company evaluated various qualitative benefits, including reliability, flexibility, diversity, and viability of the Granite Bridge Pipeline.

Q. Please review the qualitative benefits associated with the Granite Bridge Pipeline.

A. There are five primary qualitative benefits associated with the Granite Bridge Pipeline:

- First, an additional pipeline feed to the Company (i.e., the Granite Bridge Pipeline) increases the diversity of EnergyNorth's delivery infrastructure, which significantly increases the reliability and security of gas supply deliveries.

- Second, a new delivery connection increases delivery options as the Company could access natural gas supplies that are delivered or pathed on the Granite Bridge Pipeline, the TGP Concord Lateral, the proposed Granite Bridge LNG facility, or directly to the city-gates. This increase in gas supply diversity and options increases the reliability of the overall gas supply portfolio and provides more price stability for the customers of EnergyNorth.

- Third, the Granite Bridge Pipeline would provide pressure support to the TGP Concord Lateral as the Granite Bridge Pipeline will connect with the Tennessee system in Manchester, with the capability to deliver 750 pounds per square inch ("psi") into the TGP Concord Lateral, where pressures at times have dropped to 300 psi or less during the winter.

- Fourth, the Granite Bridge Pipeline would provide the Company with negotiation leverage. As discussed in Section V.B above, the Company's current resource portfolio has two Tennessee contracts that originate at Dracut and have a total MDQ of 50,000 Dth per day, which is nearly 50% of the Company's total pipeline capacity. When these two Tennessee contracts come up for renewal, the Granite Bridge Pipeline could provide a replacement option for EnergyNorth, thus providing leverage in the negotiation with Tennessee regarding these contracts.

- Finally, the Granite Bridge Pipeline would allow the Company the opportunity to provide natural gas as a fuel choice to communities along the construction path of the pipeline; specifically, the towns of Epping, Raymond, and Candia. As such, towns, businesses, and homes that currently do not have access to natural gas, given the absence of gas infrastructure, would now have choices with respect to their energy decisions.

Q. Please explain in detail the increase in diversity and reliability associated with the Granite Bridge Pipeline.

A. Although both delivery options (i.e., the Granite Bridge Pipeline and an expansion of the TGP Concord Lateral) increase the reliability of gas supply deliveries and reduce the reliance on the Company's aging propane facilities to meet Design Day and extreme cold weather demand, the Granite Bridge Pipeline significantly diversifies the physical infrastructure associated with supplying the Company and, importantly, provides additional pressure support to the existing TGP Concord Lateral, thus providing a higher level of reliability than an expansion of the TGP Concord Lateral. The Granite Bridge Pipeline will be connected on its east end to the Joint Facilities, which has a maximum allowable operating pressure ("MAOP") of 1,440 psi, as compared to Tennessee's MAOP of 750 psi. More importantly, Tennessee is only obligated to provide a minimum of 100 psi on the TGP Concord Lateral. Given the higher inlet pressure from the Joint Facilities, the Granite Bridge Pipeline will help bolster the TGP Concord Lateral pressures to the south and north during peak winter periods, which would significantly enhance the reliability of gas supply deliveries to the Company.

Further, EnergyNorth would no longer depend on one feed or line (i.e., the TGP Concord Lateral) for almost all of its pipeline supplies, and would now have access to the proposed Granite Bridge LNG facility and supplies on the Joint Facilities, enhancing the diversity and flexibility of supplies. Simply stated, a second feed would: (i) provide the Company with an alternative means of delivering gas supplies should the other line experience service disruption; and (ii) bolster the TGP Concord Lateral pressures in general. This increase in physical delivery reliability and supply security is achieved only with a second line and not with an expansion of the TGP Concord Lateral.

2. Upstream Gas Supplies

Q. Once EnergyNorth identified the Granite Bridge Pipeline as the preferred delivery option, what was the next step in the Company's analysis?

A. After establishing the Granite Bridge Pipeline as the preferred delivery option, the Company next focused on the evaluation of specific natural gas supply options within the context of the overall resource portfolio. The options evaluated for upstream gas supply covered a variety of supply and volume options, including: (1) pipeline supplies (e.g., PNGTS); (2) imported LNG (e.g., Repsol and ENGIE); and (3) on-system assets.

Q. Please describe the process used by the Company to analyze the gas supply options.

A. EnergyNorth utilized the following framework to evaluate the natural gas supply options. First, the Company identified gas supply options that were available in the marketplace or have certain development activity underway. Next, EnergyNorth determined which gas supply options should be considered for further quantitative analysis, modeled using the

SENDOUT® portfolio optimization software, and qualitative analysis (i.e., other benefits such as portfolio diversity). Stated differently, the Company identified the supply options that were viable for further analysis. Finally, based on the totality of the analysis, EnergyNorth identified the appropriate volumes and contract terms for certain gas supply options.

Q. Prior to discussing the Company's gas supply evaluation process, please describe the SENDOUT® model.

A. The SENDOUT® model is a proprietary linear programming model owned by ABB (formerly, Ventyx) and used by EnergyNorth since 1996 to: (1) determine the adequacy of the Company's existing and potential gas supply portfolio in meeting projected requirements; and (2) identify any supply or volume shortfalls during the analysis period. The results of the SENDOUT® model provide the Company with the least-cost, economic dispatch of its existing resources subject to the underlying assumptions (e.g., contractual and operating constraints), and assist with identifying the need for, and type of, additional resources required during the analysis period. The SENDOUT® model calculates the optimal portfolio based on certain Company-specific assumptions including, daily demand, weather patterns, pipeline and storage contract volumes, rates, and costs, gas supply prices for various indices, and contractual paths for the various supplies. Based on these operating and market assumptions, the SENDOUT® model can be used to determine the best use of a given portfolio of supply, capacity, and storage contracts to meet a specified demand. Please note that the SENDOUT® model dispatches the portfolio based on the resources with the lowest variable cost over the duration of the modeling period to meet demand since the demand charges are fixed and, therefore, unavoidable.

EnergyNorth has used the SENDOUT® model in several recent regulatory filings with the Commission, including the Company's cost of gas submissions, the NED Market and Supply Path filings, and IRP filings. For this proceeding, EnergyNorth also used the Resource Mix module of the SENDOUT® model, in which the appropriate mix of incremental resources and associated volumes or contract sizes are determined and optimized within the SENDOUT® model itself. Stated differently, the Resource Mix module allows the Company to input various gas supply resource options that the SENDOUT® model can include or exclude to determine the optimal portfolio. As such, the Company does not need to define scenarios that include certain resources and exclude others. Rather, the Resource Mix module of the SENDOUT® model will select the resource and the associated volume from the available options that achieves the optimal solution. To do this, the SENDOUT® model analyzes the available contracts and the size of each contract (e.g., MDQ) to determine the combination of resources that results in the lowest total cost over the duration of the modeling period, considering both variable and fixed costs.

Q. Please discuss the first step in the Company's analysis framework (i.e., identifying gas supply options).

A. The first step in the EnergyNorth framework was to identify the range of likely or viable natural gas supply resources that are currently under development, being marketed to the

Company, or have been identified as a potential supply option. The list of gas supply resource options was broad and based on the market insight and knowledge of the EnergyNorth Energy Procurement Group, who are active in industry organizations and trade groups as well as participants at energy conferences, pipeline customer groups, and regulatory proceedings. Based on the knowledge of the EnergyNorth personnel, the following gas supply resource options were identified:

- Pipeline transportation capacity from the Dawn Hub on the Union Gas, TCPL Canadian Mainline, and PNGTS pipeline systems;[67]
- Pipeline transportation capacity on Tennessee (i.e., service on the Tennessee Mainline from receipt points upstream of Dracut);
- Pipeline transportation capacity on Algonquin (i.e., Enbridge expansion of the Algonquin and MNE pipeline systems);
- Imported LNG supplies from Repsol;
- Imported LNG supplies from ENGIE delivered to the EnergyNorth city-gates; and
- An on-system LNG facility (i.e., the Granite Bridge LNG facility).

Q. Please review the gas supply options that were considered for further evaluation.

A. After reviewing the various gas supply alternatives, the following options were short-listed as viable options and considered for further evaluation:

[67] As discussed in Section VII.B, the Union Gas capacity is a component of the TCPL Canadian Mainline via a TBO.

- Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian Mainline and PNGTS pipeline systems;
- Imported LNG supplies from Repsol;
- Imported LNG supplies from ENGIE delivered to the EnergyNorth city-gates; and
- An on-system LNG facility (i.e., the Granite Bridge LNG facility).

These supply alternatives cover a wide breadth of gas supply options, including pipeline capacity, winter season services, and peaking supplies.

Q. Why were the pipeline transportation capacity paths on the Tennessee Mainline and Algonquin excluded from the short-listed options?

A. The Tennessee Mainline path was not included as a short-listed option for two primary reasons. First, the Tennessee Mainline is fully subscribed for capacity from west-to-east (e.g., from Wright, New York to Dracut, Massachusetts or EnergyNorth city-gates). Incremental capacity on the Tennessee Mainline associated with volumes originating at Wright or other points west of Dracut, would require incremental facilities on the Tennessee Mainline, which would be costly as evidenced by the estimated daily rate to expand the TGP Concord Lateral discussed above, or would require a greenfield expansion, such as the canceled TGP NED project.

Second, the PNGTS path provides access to the Dawn Hub, which is one of the more liquid natural gas trading points in North America, while the Tennessee Mainline path would originate at points west of Dracut, Massachusetts, such as Wright, New York. Although the Wright point may become more liquid if incremental gas pipeline capacity is constructed to Wright, it is considered a less liquid point today especially when compared to the Dawn Hub. As a result, the PNGTS path was the preferred pipeline option relative to a Tennessee Mainline option.

Finally, with respect to the Algonquin path, EnergyNorth did not identify an active Enbridge project on Algonquin and/or MNE to evaluate. As discussed in Section III.B, Algonquin has withdrawn its Access Northeast project from the pre-filing review process at the FERC and no other Enbridge sponsored project was identified by the Company for evaluation.

Q. Prior to discussing why EnergyNorth included an on-system LNG facility as a short-listed supply option, please describe the proposed Granite Bridge LNG facility.

A. As detailed in the Fleck/DaFonte Testimony, EnergyNorth is proposing to construct an on-system LNG facility, the Granite Bridge LNG facility, which would connect to the proposed Granite Bridge Pipeline. The Granite Bridge LNG facility would consist of 2 Bcf of storage capacity, 150,000 Mcf per day of vaporization, and 8,000 Mcf per day of liquefaction.

Q. Please discuss the inclusion of an on-system LNG facility as a short-listed option.

A. The Company used two distinct analyses to conclude that an on-system LNG facility should be evaluated as part of the quantitative analysis (i.e., the SENDOUT® modeling). First, as discussed previously in Section IV.B, the Company developed a load duration curve analysis to review the projected demand requirements as shown in Figures 27 and 28 below.

Figure 27: EnergyNorth Normal Year Load Duration Curve

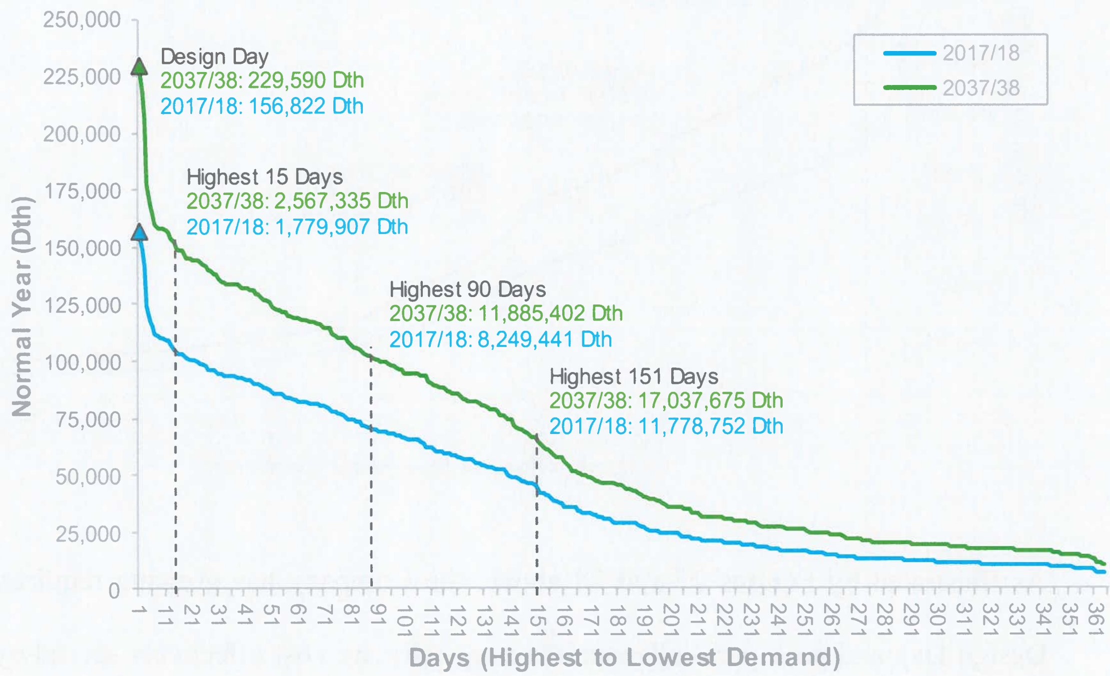
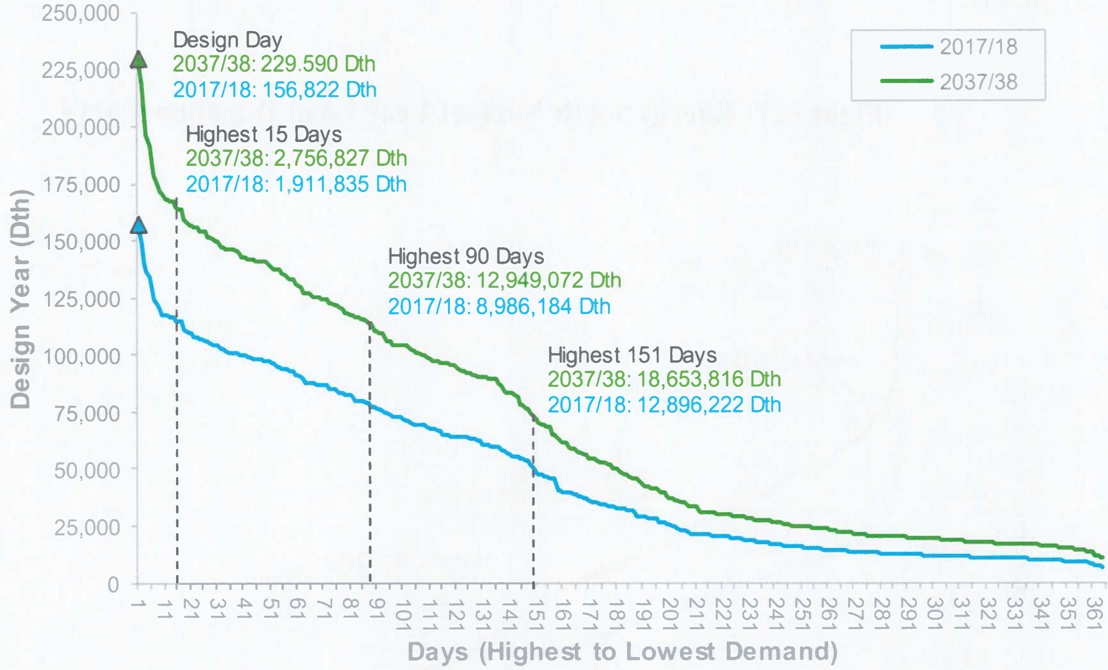


Figure 28: EnergyNorth Design Year Load Duration Curve



As illustrated by Figures 27 and 28 above, the Company has growing requirements in Design Day and peak period demand that typically are cost effectively served by a peak supply resource such as on-system LNG. Therefore, including an on-system LNG facility (i.e., the Granite Bridge LNG facility) as an option for consideration in the resource portfolio was reasonable and appropriate.

The second analysis undertaken by the Company regarding on-system LNG was to compare or benchmark the role of on-system LNG in the existing EnergyNorth portfolio relative to the level of on-system LNG in the supply portfolios of other LDCs in New England. Given the similarities in demand requirements (i.e., heating sensitive customers) and, therefore, winter demand requirements of New England LDCs, the LNG benchmarking analysis offers a good comparison of the role of on-system LNG in the various LDC portfolios. For the first benchmarking metric, the Company compared on-system LNG vaporization relative to expected Design Day demand and, for the second benchmarking metric, the Company compared LNG storage relative to LNG vaporization (i.e., days of LNG storage). The following table summarizes the results of the LNG benchmarking analysis.

Table 8: Summary of LNG Benchmarking Analysis[68]

LDC	LNG Storage Capacity (MMBtu)	LNG Vaporization (MMBtu)	Design Day Demand (MMBtu)	% LNG Vaporization of Design Day	Days of LNG Storage
Berkshire Gas Company	12,260	3,300	64,705	5%	3.7
Columbia Gas of Massachusetts (Bay State Gas Company)	1,810,004	112,500	502,152	22%	16.1
Eversource Energy (NSTAR Gas)	3,650,000	210,000	517,000	41%	17.4
Eversource Energy (Yankee Gas Services Company)	1,200,000	105,000	465,411	23%	11.4
Liberty Utilities (New England Gas Company)	164,000	18,500	77,260	24%	8.9
National Grid (Boston Gas/Colonial Gas)	4,934,319	507,641	1,403,000	36%	9.7
National Grid (Narragansett Electric Company)	802,000	113,000	354,000	32%	7.1
UIL (Connecticut Natural Gas Corporation)	1,200,000	97,500	347,137	28%	12.3
UIL (Southern Connecticut Gas Company)	1,200,000	82,500	318,950	26%	14.5
Unitil (Fitchburg Gas & Electric)	4,326	3,172	22,198	14%	1.4
Unitil (Northern Utilities)	13,335	10,000	162,759	6%	1.3
Total	14,990,244	1,263,113	4,234,572	30%	9.4

With respect to the first benchmarking metric (LNG vaporization relative to Design Day demand), the existing LNG vaporization for EnergyNorth represents about 8% of the Design Day demand.[69] Conversely, for the comparison group, the ratio of on-system LNG vaporization capability compared to Design Day demand averaged 30%, with Eversource Energy (NSTAR Gas) having the highest LNG vaporization to Design Day demand ratio at 41%. Regarding the second benchmarking metric (days of LNG storage), the Company

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68 Please note, the Design Day demand represents the projected demand for 2017/18. Sources: most recently filed Integrated Resource Plan for each respective LDC.

69 Please note, EnergyNorth's vaporization capacity is limited by the storage capacity.

has less than one day of storage, while the comparator group average is almost 10 days of LNG storage, with several LDCs having 12 to 16 days of LNG storage.

As shown by the above table and analysis, the Company does not have the LNG vaporization relative to Design Day demand as its peer group, nor does EnergyNorth have the days of LNG storage that is typical of New England LDCs. Therefore, including on-system LNG (i.e., the Granite Bridge LNG facility) as a resource option for further evaluation was reasonable and appropriate.

Q. Once the short-listed resource options were identified, how did the Company organize its SENDOUT® modeling?

A. The Company's SENDOUT® modeling was organized into two resource planning scenarios, which centered on the resources available to serve the projected Design Day and peak period demands (i.e., including or excluding the Granite Bridge LNG facility, and whether the existing propane facilities are retired). Specifically, the two resource planning scenarios used by EnergyNorth are summarized below:

- <u>Base Case</u>: includes the Granite Bridge LNG facility, and assumes the existing propane facilities are retired;
  - <u>Base Case Sensitivity</u>: includes the Granite Bridge LNG facility, and assumes the existing propane facilities remain in service;
- <u>Alternative Case</u>: excludes the Granite Bridge LNG facility, and assumes the existing propane facilities are retired; and

- o <u>Alternative Case Sensitivity</u>: excludes the Granite Bridge LNG facility, and assumes the existing propane facilities remain in service.

In addition, given the lead time required for infrastructure developments and the long-term nature of pipeline capacity contracts, EnergyNorth performed cost simulations using the SENDOUT® model for the 21-year period from November 1, 2017, through October 31, 2038, for each resource planning scenario.

Q. Please briefly review the SENDOUT® modeling assumptions that are common across the four resource planning scenarios.

A. The Company used the following key assumptions in the SENDOUT® modeling regardless of the resource planning scenario:

- All legacy contracts for pipeline capacity and storage service expiring during the forecast period would be renewed for the length of the analysis with no change in rates, quantities, or operating characteristics.
- The existing LNG facilities remain in service for the duration of the analysis and, as needed, liquid-only supply is available to refill the LNG storage inventory.
- The natural gas prices are based on monthly closing prices on August 18, 2017, from S&P Global Market Intelligence. The Company used the natural gas prices for the length of the time period provided by S&P Global Market Intelligence and, for the remaining years in the analysis, the natural gas prices are escalated at 1%.

- Gas supplies are available at Dracut, with the winter price for those supplies reflective of the daily weather pattern (i.e., colder weather days will have higher daily prices at the Dracut point), and the summer price for those supplies are based on monthly closing prices on August 18, 2017, from S&P Global Market Intelligence.

Q. How were the gas supply resource options analyzed by the Company in SENDOUT®?

A. First, EnergyNorth included the following resources in each resource planning scenario:

- The capacity contract with ENGIE for 90-day winter, combination (i.e., liquid and/or vapor) service with an MDQ of 7,000 Dth per day was included through March 31, 2022.
- Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian Mainline and PNGTS pipeline systems was phased-in over three-years, with an MDQ of 1,784 Dth per day starting on November 1, 2018, 4,432 Dth per day starting on November 1, 2019, and 5,000 Dth per day starting on November 1, 2020.
- The Granite Bridge Pipeline was placed in service on November 1, 2021, and there was no expansion of the TGP Concord Lateral.

Then the Company outlined the following gas supply options for the Resource Mix module:

- Repsol delivered service with an MDQ of up to 150,000 Dth per day and a seasonal maximum capacity of 6,000,000 Dth, beginning on November 1, 2021, through the end of the forecast horizon.

- Pipeline transportation capacity from the Dawn Hub on the TCPL Canadian Mainline and PNGTS pipeline systems with an MDQ of up to 150,000 Dth per day beginning on November 1, 2021, through the end of the forecast horizon.

- ENGIE 90-day winter, combination service with an MDQ of up to 7,000 Dth per day beginning on November 1, 2022, through the end of the forecast horizon.

As discussed above, the Resource Mix module of the SENDOUT® model selects the resource and the associated volume from the available options that achieves the optimal solution (i.e., lowest total cost over the duration of the forecast period, considering both variable and fixed costs) to meet the projected demand requirements.

Q. Please summarize the results of the SENDOUT® model runs.

A. The SENDOUT® results for the Base and Alternative Cases are summarized in Table 9 below and the detailed SENDOUT® reports are provided as Exhibits WRK/JMS-4 through WRK/JMS-7.

Table 9: EnergyNorth SENDOUT® Model Runs

Resource Planning Scenario	Exhibit No.	Granite Bridge LNG	Propane Facilities	Resource Mix Results Dawn (Dth/day)	Resource Mix Results Repsol (Dth/day)	Resource Mix Results ENGIE (Dth/day)	Total System Cost ($000)	Comparison to Base Case ($000)
Base Case	WRK/JMS-4	2.0 Bcf	No	9,470	0	0	$2,797,138	$ -
Base Case Sensitivity	WRK/JMS-5	2.0 Bcf	Yes	9,260	0	0	$2,797,226	$ 88
Alternative Case	WRK/JMS-6	No	No	6,840	105,360	1,150	$2,976,108	$ 178,970
Alternative Case Sensitivity	WRK/JMS-7	No	Yes	19,230	51,210	7,000	$2,800,530	$ 3,392

As shown in Table 9, under the Base Case resource planning scenario (which includes the Granite Bridge LNG facility and assumes retirement of the existing propane facilities), the Company would develop and construct the Granite Bridge LNG facility, which is expected to commence service on April 1, 2022, and would phase out the use of the existing propane facilities depending on the timing of the in-service date of the Granite Bridge LNG facility. In addition, the Resource Mix module results included capacity on the Dawn to PNGTS path of approximately 9,470 Dth per day and zero Repsol and ENGIE capacity. The total cost of the Base Case portfolio was approximately $2.797 billion over the analysis period, which was the lowest total cost of the four resource planning scenarios analyzed. Under the Base Case Sensitivity where the propane facilities remain in-service, the Resource Mix module results were essentially unchanged and the total portfolio cost was equivalent (i.e., approximately $2.797 billion). In other words, the inclusion of the Granite Bridge LNG facility provides the Company a low to no cost option with respect to including or retiring the aging propane facilities.

The Alternative Case resource planning scenario (which excludes the Granite Bridge LNG facility and assumes the retirement of the existing propane facilities) results in a total portfolio cost of $2.976 billion over the analysis period, which is nearly $180 million more than the Base Case scenario. Under the Alternative Case, the results of the Resource Mix module included a volume of approximately 6,840 Dth per day on the Dawn to TCPL Canadian Mainline to PNGTS path, a volume of over 105,000 Dth per day from Repsol, and 1,150 Dth per day of ENGIE supply. Under the Alternative Case Sensitivity (which excludes the Granite Bridge LNG facility and the propane facilities remain in service), the results of the Resource Mix module included a volume of approximately 19,230 Dth per day on the Dawn to TCPL Canadian Mainline to PNGTS path, a volume of approximately 51,000 Dth per day from Repsol, and 7,000 Dth per day of ENGIE supply. The cost associated with the Alternative Case Sensitivity was approximately $2.801 billion over the analysis period, which is approximately $3 million more than the Base Case and Base Case Sensitivity scenarios.

Q. Please review the cost implications for retiring the Company's propane facilities in the Base Case and Alternative Case.

A. In the Base Case, the decision to retire the propane facilities would result in a cost decrease of approximately $88,000. In other words, in the Base Case, the inclusion or retirement of the propane facilities is a "no cost" option as the Granite Bridge LNG facility provides the Company with significant flexibility. In the Alternative Case, the cost to retire the propane facilities is equal to approximately $176 million, as the Company does not have the flexibility and daily capability of the Granite Bridge LNG facility. It is interesting to note that the cost to retire the propane facilities in the Alternative Case is nearly as much as the estimated capital cost of the Granite Bridge LNG facility of approximately [redacted], which is discussed in Section VII.C below.

Q. Based on the results of the SENDOUT® analysis, did the Company further evaluate the natural gas supply from Repsol?

A. Yes, EnergyNorth was engaged in discussions with Repsol for winter peaking supply. However, the Company determined that the Repsol supply was not a viable long-term option for three reasons. First, the Resource Mix results for the Base Case resource planning scenarios indicated that the Repsol supply was not cost-effective compared to the alternative resource options. Second, the full MDQ of the Repsol service would commence on November 1, 2018, and, thus, would not provide EnergyNorth with incremental supply to meet its Design Day and peak season needs until the Granite Bridge Pipeline was placed into service. Third, the proposed contract terms would not provide the Company and its customers with [redacted]

Q. Did EnergyNorth consider the qualitative benefits provided by each of the preferred upstream gas supply options?

A. Yes, the Company evaluated each of the supply resource options on a qualitative basis (e.g., reliability, flexibility, and diversity) and as part of the Company's overall gas supply portfolio.

Q. What are the qualitative benefits associated with the ENGIE combination service contract?

A. The ENGIE combination service contract provides two unique benefits that will increase the flexibility and reliability of EnergyNorth's resource portfolio in the near-term. First, the ENGIE supply is the only resource option that can be delivered, on a firm basis, to the

EnergyNorth city-gates. Therefore, it is the only pipeline-based option that can provide incremental supply in the near-term to meet the Company's growing Design Day demand. Secondly, EnergyNorth has the option to receive the ENGIE volume as vapor or liquid. The ENGIE supply can be delivered as vapor to the Company's city-gate stations, as liquid via trucks to refill the Company's on-system LNG facilities, or as a combination of vapor and liquid. This option to receive the product as vapor or liquid enhances the reliability of the EnergyNorth portfolio and provides the Company with increased flexibility to meet various demand scenarios. In addition to these two unique benefits, the ENGIE price structure provides more cost stability to the EnergyNorth portfolio as the price is based on [redacted]. This price structure benefits the Company and its customers as [redacted]

Q. What are the qualitative benefits of the TCPL/PNGTS transportation capacity?

A. The TCPL/PNGTS capacity increases the reliability, flexibility, and supply diversity of the Company's resource portfolio by providing additional access to the Dawn Hub, which is one of the most liquid gas supply points in North America, with access to numerous suppliers and significant storage capacity. In addition, the TCPL/PNGTS capacity provides delivery flexibility. As currently structured, the Company's precedent agreement with PNGTS has Dracut as the primary delivery point for the capacity. Since Dracut is the interconnection point with Tennessee, EnergyNorth could use its existing capacity on Tennessee to transport the PNGTS supply to the Company's city-gates. However, it only becomes an incremental supply resource once the Granite Bridge Pipeline is placed into service, at which time EnergyNorth will have the option to move the primary delivery point to the interconnection between PNGTS and the Granite Bridge Pipeline, thus providing incremental volumes to meet projected demand.

As discussed in Section VII.B below, the PNGTS precedent agreement has a TBO component which provides for transportation capacity from the Dawn Hub on Union Gas and the TCPL Canadian Mainline, and PNGTS will assign the associated transportation capacity on each pipeline (i.e., Union Gas and the TCPL Canadian Mainline) to EnergyNorth upon the in-service date for each phase. With respect to rates, expansions on Union Gas and the TCPL Canadian Mainline are typically rolled into the overall cost of service for the respective pipeline system and the rates for service are set by the Ontario Energy Board (for Union Gas) or the National Energy Board of Canada (for the TCPL Canadian Mainline). This regulatory approach for toll setting is similar to the approach used by the FERC to set the rates for certain of the Company's transportation and storage contracts on Tennessee, National Fuel, Dominion, and Iroquois. Finally, the rate for the capacity on PNGTS is a negotiated rate with a cap on cost overruns, which not only limits the Company's exposure but provides cost and rate certainty to its customers.

Q. Please discuss the qualitative benefits of the Granite Bridge LNG facility.

A. There are four primary qualitative benefits associated with the proposed Granite Bridge LNG facility:

- First, the Granite Bridge LNG facility will increase the Company's on-system assets, which will increase the reliability of the Company's gas supply portfolio. As demonstrated in the LNG benchmarking analysis discussed above, EnergyNorth does not have the same level of LNG vaporization relative to Design Day demand as its peer group, nor does EnergyNorth have the days of LNG storage that is typical of New England LDCs. The Granite Bridge LNG facility will be a cost-effective addition to the Company's peaking resources, and will also ensure the continued flow of natural gas supply to the Company's customers should there be a restriction on the upstream pipelines.

- Second, the Granite Bridge LNG facility will provide for load following service, which greatly enhances the flexibility of the Company's resource portfolio. As demand within a day fluctuates, the Company can use the vaporization flexibility of the Granite Bridge LNG facility to meet that change in demand and reduce its exposure to volatile intraday spot gas purchase prices and pipeline imbalance charges.

- Third, the Granite Bridge LNG facility diversifies the Company's supply assets, reduces price volatility during peak periods, and is a peaking supply resource to meet the growing requirements for Design Day and peak period demand. The Granite Bridge LNG facility provides the Company with a physical hedge product that allows EnergyNorth to purchase supply during the off-peak season, when prices are generally lower, liquefy that supply, store it in its tank, and vaporize the liquid to meet demands during the peak period when natural gas prices are generally higher.

- Finally, the Granite Bridge LNG facility provides EnergyNorth with a cost-effective option with respect to maintaining or retiring the Company's aging propane facilities. As demonstrated by the results of the Company's SENDOUT analysis in Table 9 above, the Granite Bridge LNG facility provides the Company with a low to no cost option to retain or retiring the propane facilities.

Q. How did EnergyNorth determine the appropriate volumes for each of the resource options?

A. Given the projected Design Day and peak season demand requirements, and since the ENGIE contract is the only available resource option to provide incremental supply on a firm basis to EnergyNorth's city-gates in the interim period, the Company concluded that the full capacity of 7,000 Dth per day offered by ENGIE would be appropriate. As discussed above, the ENGIE contract would provide the Company with several unique qualitative benefits, and would allow the Company to transition to the long-term resource portfolio by providing incremental supply through March 2022.

As shown in Table 9 above, the SENDOUT® Resource Mix module selected the TCPL/PNGTS capacity from Dawn in all four resource planning scenarios. The resulting Resource Mix volume for the TCPL/PNGTS capacity ranged from 6,840 Dth per day in the Alternative Case to 9,470 Dth per day in the Base Case scenario, and from 9,260 Dth per day to 19,230 Dth per day in the Base Case Sensitivity and Alternative Case Sensitivity scenarios, respectively. Based on the Company's review of the analytical results, and taking into consideration the qualitative benefits associated with the TCPL/PNGTS capacity, EnergyNorth concluded that some volume on the TCPL/PNGTS transportation path from Dawn would be appropriate at this time.[70] Given the long-term capacity commitment associated with the TCPL/PNGTS contract (a 22-year contract term), the Company determined a volume level of 5,000 Dth per day allows the Company to meet its requirements, while maintaining near term portfolio flexibility, which best positions the Company to adjust to changing market conditions.

Q. Did the Company analyze different storage tank sizes for the Granite Bridge LNG facility?

A. Yes, it did. As discussed in Section VII.C, the Company conducted an assessment of engineering requirements and construction costs associated with an on-system LNG facility, which included initial capital cost estimates from Sanborn, Head & Associates ("Sanborn Head") for various storage tank sizes. With respect to the Granite Bridge LNG facility, the Company performed additional SENDOUT® analyses to determine the cost implications associated with various tank sizes. Based on the results of the SENDOUT® analyses, a facility with 2 Bcf of LNG storage capacity is the lowest cost option for its customers. Specifically, as shown in Table 10 below, the Base Case resource planning

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70 The Company also analyzed the Base Case scenario using the SENDOUT® Resource Mix module for the interim period (i.e., through 2021/22). The Resource Mix results for the interim period included a TCPL/PNGTS volume of 7,120 Dth per day and zero Repsol volumes, which aligns with the Company's conclusion that contracting on the TCPL/PNGTS path from Dawn would be appropriate.

scenario with a 2 Bcf LNG storage facility is approximately $12 million and $79 million lower in total system cost than a 1.2 Bcf or 2.5 Bcf tank size, respectively.

Table 10: EnergyNorth SENDOUT® Model Runs – LNG Tank Size Scenarios

Resource Planning Scenario	Exhibit No.	Granite Bridge LNG	Propane Facilities	Resource Mix Results			Total System Cost ($000)	Comparison to 2.0 Bcf Tank ($000)
				Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)		
Base Case	WRK/JMS-4	2.0 Bcf	No	9,470	0	0	$2,797,138	$ -
Base Case	WRK/JMS-8	1.2 Bcf	No	12,550	0	1,850	$2,809,145	$ 12,007
Base Case	WRK/JMS-9	2.5 Bcf	No	8,700	0	0	$2,876,272	$ 79,134

Q. How will the addition of each resource option impact the Company's Design Day resource shortfalls?

A. The ENGIE contract provides EnergyNorth with incremental supply of 7,000 Dth per day in the interim period from November 1, 2018, to March 31, 2022. As discussed previously, given the current deliverability to the Company's city-gates, the TCPL/PNGTS contract would not provide the Company with incremental capacity until the Granite Bridge Pipeline is placed in-service. Specifically, beginning on November 1, 2021, the TCPL/PNGTS contract would provide EnergyNorth with incremental capacity of 5,000 Dth per day through the end of the analysis period. Table 11 below summarizes the Company's Design Day demand and resources with the addition of the proposed ENGIE and TCPL/PNGTS contracts.

Table 11: EnergyNorth Design Day Resource Shortfall with Addition of Proposed Resource Options (Dth)

Split-Year (Nov-Oct)	Design Day Demand	Current Design Day Resources, including Propane	Reserve / (Deficiency) including Propane	Reserve / (Deficiency) including Propane and ENGIE	Reserve / (Deficiency) including Propane, ENGIE and TCPL/PNGTS
2017/18	156,822	162,033	5,211	5,211	5,211
2018/19	160,989	155,033	(5,956)	1,044	1,044
2019/20	164,640	155,033	(9,607)	(2,607)	(2,607)
2020/21	168,934	155,033	(13,901)	(6,901)	(6,901)
2021/22	173,917	155,033	(18,884)	(11,884)	(6,884)
2022/23	179,382	155,033	(24,349)	(24,349)	(19,349)
2023/24	184,432	155,033	(29,399)	(29,399)	(24,399)
2024/25	188,856	155,033	(33,823)	(33,823)	(28,823)
2025/26	192,933	155,033	(37,900)	(37,900)	(32,900)
2026/27	196,785	155,033	(41,752)	(41,752)	(36,752)
2027/28	199,954	155,033	(44,921)	(44,921)	(39,921)
2028/29	203,491	155,033	(48,458)	(48,458)	(43,458)
2029/30	206,790	155,033	(51,757)	(51,757)	(46,757)
2030/31	210,016	155,033	(54,983)	(54,983)	(49,983)
2031/32	212,972	155,033	(57,939)	(57,939)	(52,939)
2032/33	215,843	155,033	(60,810)	(60,810)	(55,810)
2033/34	218,828	155,033	(63,795)	(63,795)	(58,795)
2034/35	221,631	155,033	(66,598)	(66,598)	(61,598)
2035/36	224,148	155,033	(69,115)	(69,115)	(64,115)
2036/37	226,863	155,033	(71,830)	(71,830)	(66,830)
2037/38	229,590	155,033	(74,557)	(74,557)	(69,557)

Q. Please describe how the Company will manage any resource shortfall or reserve capacity shown in Table 11 above.

A. Prior to the proposed in-service date of the Granite Bridge LNG facility, the Company is projected to have a Design Day capacity deficiency of 2,607 Dth per day in 2019/20, 6,901 Dth per day in 2020/21, and 6,884 Dth per day in 2021/22. Once operational, the proposed Granite Bridge LNG facility would meet the Company's Design Day resource needs in the 2022/23 through 2037/38 time period. In addition, the Granite Bridge LNG facility provides the Company with the option to retire the aging propane facilities. If the existing propane facilities were retired, the Design Day resource shortfall shown in Table 11 above would increase from 69,557 Dth per day to 104,157 Dth per day in 2037/38, which can be met by the Granite Bridge LNG facility.

As a temporary solution to meet the Design Day resource shortfall in the interim period, EnergyNorth will likely need to increase the utilization of the Company's existing LNG facilities beyond the daily operational and storage capacity of 12,600 Dth and contract for additional winter liquid-only supply and LNG trucking service. By contracting for this winter refill arrangement, EnergyNorth would be able to cycle the LNG inventory and use the available daily vaporization capacity as a short-term solution to meet the Company's Design Day deficiency. At this time, the Company has not contracted for additional liquid-only supply or dedicated trucking service. If it is determined that there is still a capacity deficiency for those upcoming winters, the Company will issue an RFP for liquid refill in the preceding summers to meet the then-anticipated supply shortfall.

With regard to any reserve capacity, the Company will continue its efforts to mitigate the cost of underutilized capacity as it does today through various resource optimization strategies, including asset management agreements, capacity releases, and off-system sales. In addition, the Company will continue to review the feasibility of maintaining its propane facilities after the Granite Bridge LNG facility is placed in-service. Depending on the condition of the facilities and the market dynamics at the time, a combination of the facilities could be "mothballed" if that is deemed as being in the best interest of the customers.

Q. Please summarize the conclusions regarding the Company's long-term supply strategy (i.e., the Granite Bridge Project and TCPL/PNGTS pipeline capacity).

A. As demonstrated by the Company's quantitative and qualitative analyses, the Granite Bridge LNG facility and TCPL/PNGTS pipeline capacity when paired with the Granite Bridge Pipeline results in a best-cost portfolio for its customers over the long-term. The Granite Bridge LNG facility is a cost-effective resource that will also provide the Company with significant qualitative benefits, which increase the reliability and flexibility of the EnergyNorth resource portfolio and diversifies the Company's supply assets. In addition, the Granite Bridge LNG facility will provide the Company with flexibility to maintain or retire the Company's propane facilities. The TCPL/PNGTS capacity will access natural gas supplies at the Dawn Hub and, together with the Granite Bridge Project, provide the Company with several qualitative benefits (e.g., increased reliability, supply diversity, and delivery flexibility). The Granite Bridge Pipeline will be required to facilitate the delivery of each of these resource options and the associated benefits.

Q. Please summarize the Company's conclusion regarding the interim resource option, the ENGIE contract?

A. Prior to the implementation of the long-term resource strategy, the Company needed to develop an interim gas supply strategy to meet its growing incremental demand requirements and associated resource shortfall on Design Day and peak winter periods.

The incremental supply provided by the ENGIE contract helps to meet that near-term demand requirement, and is a cost-effective resource that provides unique qualitative benefits to the Company (e.g., firm deliveries to the Company's city-gates, and combination vapor and/or liquid service).

VII. SUMMARY OF ENERGYNORTH'S SUPPLY STRATEGY

Q. Please summarize the supply and capacity contracts and proposed infrastructure projects for which the Company seeks Commission approval.

A. As detailed in the Fleck/DaFonte Testimony, EnergyNorth is seeking approval from the Commission for its interim and long-term natural gas supply strategy, which includes: (1) the supply and capacity contract with ENGIE; (2) the precedent agreement with PNGTS that includes capacity on PNGTS, the TCPL Canadian Mainline, and Union Gas; (3) the development and construction of the proposed Granite Bridge Pipeline to facilitate the delivery of supplies from PNGTS and the Granite Bridge LNG facility; and (4) the development and construction of the Granite Bridge LNG facility. A review of the associated tolls/rates, operational parameters, key contract terms, and timing of resource availability for each of the gas supply and capacity resources is provided below.

A. ENGIE Capacity

Q. Please summarize the ENGIE service for which EnergyNorth has requested approval.

A. EnergyNorth entered into a Transaction Confirmation with ENGIE on July 19, 2017, which is subject to a Base Contract between the parties dated December 19, 2011. The four-year contract with ENGIE begins in November 2018 and terminates in March 2022; and provides EnergyNorth with up to 7,000 Dth per day of firm, delivered service to EnergyNorth city-gates. In addition, the total annual contract quantity ("ACQ") of 630,000 Dth can be delivered to EnergyNorth as vapor and/or liquid.

The price structure of the ENGIE contract includes a demand charge, or call payment, of [redacted] per year, and the commodity price is based on [redacted]. This price structure reflects the delivered nature of the ENGIE contract where supply and capacity are bundled for a city-gate product. In addition, the price structure reflects the option to receive the ENGIE volume as liquid.

Q. Please discuss the regulatory approval provision outlined in the Transaction Confirmation between EnergyNorth and ENGIE.

A. EnergyNorth has negotiated a provision with ENGIE that allows the Company to terminate the arrangement should the Commission not approve the service as outlined in the Transaction Confirmation. The deadline for the Commission's decision with respect to approval of this contract is [redacted] The regulatory approval provision provides the Company with the opportunity to seek and receive approval for the service outlined in the Transaction Confirmation prior to initiation of service, thus mitigating risk for the Company and its customers.

Q. Does the ENGIE service require expansion of existing pipeline facilities or any other construction requirements?

A. No, it does not. The ENGIE service as contracted by EnergyNorth can be provided by existing infrastructure so there is no need for facility expansion or construction. As a result, the ENGIE service is not subject to project development risk.

B. PNGTS Precedent Agreement

Q. Please summarize the precedent agreement with PNGTS for which EnergyNorth requests approval.

A. EnergyNorth has entered into a precedent agreement with PNGTS associated with the Portland XPress Project on October 4, 2017, for 5,000 Dth per day of firm transportation capacity from the Dawn Hub (the receipt point) to Dracut (the delivery point), which will be phased in over three years. Specifically, the Company will receive 1,784 Dth per day beginning November 2018, 4,432 Dth per day in November 2019, and 5,000 Dth per day in November 2020. As structured in the PNGTS precedent agreement, EnergyNorth has contracted for transportation capacity on the following pipelines:

- Union Gas: EnergyNorth has contracted with Union Gas via a TBO in the TCPL Canadian Mainline agreement from the Dawn Hub to an interconnection with the TCPL Canadian Mainline at Parkway, Ontario;
- TCPL Canadian Mainline: The Company has a contract with the TCPL Canadian Mainline from Parkway to East Hereford (i.e., the interconnection point between

the TCPL Canadian Mainline and PNGTS) via a TBO in the PNGTS precedent agreement; and

- PNGTS: EnergyNorth has contracted for transportation capacity from East Hereford to Dracut, which is the interconnection point between PNGTS and Tennessee.

As discussed, the PNGTS precedent agreement structure has a TBO component that allows EnergyNorth to contract with PNGTS for the entire path from the Dawn Hub to Dracut. PNGTS will assign the associated transportation capacity on each pipeline (i.e., Union Gas, TCPL Canadian Mainline) to EnergyNorth upon the in-service date for each phase. This structure enhances the regulatory approval requirement as discussed below.

Q. Does the PNGTS precedent agreement provide EnergyNorth with flexibility with respect to [redacted]?

A. Yes, the precedent agreement negotiated by the Company with PNGTS provides significant flexibility with respect to [redacted]

Q. Please discuss the negotiated rate and the associated cap on construction cost overruns.

A. As outlined in the PNGTS precedent agreement, EnergyNorth has negotiated a fixed daily rate of [redacted] per Dth on PNGTS for the initial term of the contract. [redacted]

Q. Please discuss the rates for transportation service on the TCPL Canadian Mainline and Union Gas.

A. The capacity service provided by the TCPL Canadian Mainline and Union Gas is regulated by the National Energy Board of Canada and the Ontario Energy Board, respectively. As such, the Company, similar to other shippers on these pipelines, will pay a cost of service rate as approved by the specific regulatory authority. This type of rate structure is also similar to the approach used by the FERC to regulate rates in certain of the legacy transportation and storage contracts in the Company's portfolio.

Q. Please discuss the regulatory approval provision outlined in the PNGTS Precedent Agreement.

A. EnergyNorth negotiated a provision with PNGTS that allows the Company to terminate the arrangement should the Commission not approve the contract as structured. The deadline for the Commission's decision with respect to approval of this precedent agreement is [redacted] The regulatory approval provision provides the Company with the opportunity to seek and receive approval for the terms and conditions of service as outlined in the precedent agreement prior to initiation of service, thus mitigating risk for the Company and its customers.

Q. Does the regulatory approval clause in the PNGTS precedent agreement include the transportation capacity on the TCPL Canadian Mainline and Union Gas?

A. Yes, it does. Since EnergyNorth executed one contract with PNGTS for all three service components (i.e., transportation on Union Gas, the TCPL Canadian Mainline, and PNGTS), the regulatory approval clause applies to all three components.

Q. Does the PNGTS service require expansion of existing pipeline facilities or any other construction requirements?

A. Yes, it does. As part of the approximately $80 million Portland XPress Project, PNGTS will need to develop and construct certain enhancements to existing infrastructure, including upstream capacity expansions.[71] These facility additions are relatively minor and, in the case of PNGTS, are upgrades at certain compressor stations. Given the relatively minimal construction required, the capacity associated with the PNGTS precedent agreement is likely subject to minimal development risk.

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71 *See*, TC PipeLines, LP Announces 2017 Third Quarter Financial Results, News Release, November 6, 2017.

C. **Granite Bridge Project**

Q. Please describe the project facilities associated with the Granite Bridge Project.

A. As detailed in the Fleck/DaFonte Testimony, the proposed Granite Bridge Project is comprised of (i) the Granite Bridge Pipeline, which provide a second delivery feed to the EnergyNorth service area by November 1, 2021; and (ii) the Granite Bridge LNG facility, which would connect to the proposed Granite Bridge Pipeline and be placed in service by April 1, 2022.

Q. Has the Company assessed the costs of the proposed Granite Bridge Pipeline and Granite Bridge LNG facility?

A. Yes, EnergyNorth has conducted a detailed assessment of the engineering, regulatory and permitting requirements, and expected costs. Specifically, an estimate of the initial capital cost of the Granite Bridge Lateral was developed based on a conceptual engineering design provided by CHA. For the Granite Bridge LNG facility, EnergyNorth has engaged Sanborn Head to provide a detailed evaluation of the engineering requirements and construction costs associated with an on-system LNG facility.

Q. What is the initial capital cost estimate for the proposed Granite Bridge Pipeline?

A. The initial capital cost estimate to construct the proposed Granite Bridge Pipeline is approximately $110.0 million as discussed in the direct testimony of Timothy S. Lyons.

Q. Please describe the estimated daily rate for the Granite Bridge Pipeline.

A. The Company used the following four-step process to develop a levelized cost of service and resulting daily rate estimate for the Granite Bridge Pipeline: (1) the likely path for the

Granite Bridge Pipeline was identified resulting in an approximate length of the pipeline; (2) a cost per mile to construct the pipeline was developed and applied to the estimated length of the pipeline based on conceptual engineering completed by CHA; (3) a cost estimate for two gate stations on either end of the pipeline in Manchester and Stratham, as well as a metering station connected to the Granite Bridge LNG facility in Epping, were also considered as part of the cost of the pipeline; (4) certain required assumptions for a levelized cost of service model were developed, including financial elements (e.g., cost of capital, income and property taxes, and depreciation) and operational costs (e.g., O&M expenses); and (5) the various inputs and assumptions were modeled in an Excel-based cost of service model. The results of this modeling effort produced an estimated daily rate of approximately [redacted] per Dth based on the estimated levelized annual cost of [redacted] and capacity of 75,000 Dth per day for the Granite Bridge Pipeline. Please see the direct testimony of Timothy S. Lyons for a more detailed discussion of the levelized cost of service model and Granite Bridge Pipeline cost estimate.

Q. Please outline the cost estimate for the proposed Granite Bridge LNG facility.

A. The initial capital cost estimate to construct the proposed Granite Bridge LNG facility is approximately $201.7 million as discussed in the direct testimony of Timothy S. Lyons.

Q. Has EnergyNorth estimated the annual levelized cost associated with the proposed Granite Bridge LNG facility?

A. Yes, it has. Specifically, the Company developed a levelized cost of service model that calculated the annual cost of service associated with the proposed Granite Bridge LNG facility under certain financial and operating assumptions (e.g., capital structure, income and property taxes, depreciation, and O&M expenses). The results of the levelized cost of service model is an annual cost of approximately [redacted]. Please see the direct testimony of Timothy S. Lyons for more detail regarding the levelized cost of service analysis for the proposed Granite Bridge LNG facility.

Q. How will EnergyNorth meet the projected increase in demand if the supply and capacity contracts and investment decisions are not approved by the Commission?

A. In the interim period, the ENGIE contract is the only incremental supply option available to the Company at this time. Should the Commission not approve the ENGIE contract, EnergyNorth would not be able to meet the resource deficiency in the near-term as there are no available alternatives to provide incremental supply to the Company's city-gates. Although EnergyNorth could increase its reliance on its existing supplemental peaking LNG and propane resources, that option would not be a viable long-term solution. The Company's propane facilities are more than 50 years old and require continued investment in maintenance, and the limited storage capacity of the existing LNG facilities would require frequent trucking of LNG to replenish the Company's inventory, which could pose significant reliability concerns. It is also important to note that even with the inclusion of the ENGIE contract, EnergyNorth would still need to increase its reliance on the existing peaking facilities to meet the Company's incremental demand requirements in the 2019/20 to 2021/22 time period (as discussed in Section VI.B).

EnergyNorth's quantitative and qualitative analyses demonstrate that a gas supply resource portfolio including pipeline transportation on TCPL/PNGTS from Dawn, in conjunction with investments in the Granite Bridge Pipeline and the Granite Bridge LNG facility, results in the best-cost portfolio to reliably meet the long-term requirements of its customers. Should the Commission not approve EnergyNorth's strategy regarding long-term supply resources, the Company would need to consider other available capacity alternatives in the marketplace at the time the Commission's decision is issued. An expansion of the TGP Concord Lateral, if it is viable at that time, would be an alternative for incremental capacity to the Company's city-gates. Other supply resource alternatives would be revised values for PNGTS, ENGIE, or Repsol should those options still be viable at that time. However, without incremental capacity to the EnergyNorth city-gates, those options alone would not provide incremental supply to meet the Company's projected demand requirements.

VIII. CONCLUSION

Q. Please summarize the conclusions with respect to the Company's natural gas supply strategy and associated infrastructure development and contract decisions to meet its projected long-term demand requirements.

A. As discussed herein, the Company is forecasting continued growth in natural gas demand, particularly in the Design Day and winter periods, from customers within its existing footprint and from customers in new service areas. To meet this forecasted demand and to increase the reliability, flexibility, and diversity of its natural gas supply portfolio, EnergyNorth has developed a comprehensive natural gas supply strategy based on extensive quantitative and qualitative analyses of reasonably available resource alternatives. As a result, the Company is requesting approval of its contract with ENGIE and the precedent agreement with PNGTS, in conjunction with the authority to develop the Granite Bridge Pipeline and Granite Bridge LNG facility.

The interim and long-term supply strategy positions the Company to: (i) serve natural gas demand requirements under various scenarios; (ii) provide energy choice to more New Hampshire communities, businesses, and residents; and (iii) significantly increase the reliability of the gas supply portfolio by adding a second feed (Granite Bridge Pipeline) and a flexible on-system asset (Granite Bridge LNG facility). Importantly, the Company's plan for a long-term natural gas portfolio results in the lowest total system cost for the customers of EnergyNorth as illustrated by the results of the SENDOUT® analysis, and provides EnergyNorth with a no cost option to retire some or all of the aging propane assets.

Q. Does this conclude your testimony?

A. Yes, it does.