Liberty Utilities

REDACTED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DG 17-198

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

SUPPLEMENTAL DIRECT TESTIMONY

OF

FRANCISCO C. DAFONTE

AND

WILLIAM R. KILLEEN

March 15, 2019

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I. INTRODUCTION AND EXECUTIVE SUMMARY

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

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

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

Q. On whose behalf are you submitting this Supplemental Direct Testimony?

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

Q. Are you the same Francisco C. DaFonte and William R. (Bill) Killeen that submitted direct testimony in this docket on December 22, 2017?

A. Yes, we are.

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

A. The Company's initial filing in Docket No. DG 17-198, which included three prefiled direct testimonies and detailed analyses supporting the Company's proposed natural gas supply strategy, was filed with the Commission on December 22, 2017. Subsequent to that filing, EnergyNorth has been engaged with the Commission Staff, the Office of Consumer Advocate ("OCA"), and other intervenors through the discovery process, intervenor discussions, and technical sessions on March 9, May 24, and November 5, 2018.

Through this engagement process with the various intervenors, EnergyNorth has: (i) updated the Company's levelized cost model to reflect certain changes, including the impact of the Tax Cuts and Jobs Act of 2017 ("TCJA") on the proposed Granite Bridge Project infrastructure revenue requirement (see the Company's response to OCA 1-30);[1] (ii) revised certain assumptions related to the out-of-model adjustments used to produce the Company's demand forecast (see the Company's response to CLF Tech 1-2); and (iii) outlined the benefits to the Company's customers associated with the commercial terms of a Memorandum of Understanding ("MOU") between the Company and Calpine Corporation ("Calpine") and together hereinafter referred to as the "Calpine MOU" (see the Company's supplemental responses to PLAN 1-3 and PLAN 2-6). EnergyNorth has also included updates to the SENDOUT® analyses to reflect the aforementioned changes (i.e., updated levelized cost modeling, revised demand forecast, and benefits of the mitigation/portfolio optimization value outlined in the Calpine MOU), as well as conducted a number of additional SENDOUT® runs and analyses to reflect certain sensitivities as requested by intervenors through the discovery process (see, for example, the Company's

[1] All responses to discovery referenced throughout our Supplemental Direct Testimony (excluding spreadsheets and voluminous attachments, such as detailed SENDOUT® reports) are provided collectively as Exhibit FCD/WRK-1, unless otherwise noted. For ease of reference, the discovery responses included in that exhibit are provided in numerical sequence by requesting party.

responses to Staff 5-15, Staff 5-17, Staff 5-18, OCA 4-6 through OCA 4-9, and OCA Set 6 through Set 9).[2]

Q. What is the purpose of your Supplemental Direct Testimony?

A. Since there have been several developments subsequent to the Company's initial filing over a year ago, EnergyNorth and the parties agreed that an update of certain aspects of the filing would facilitate the review and assessment of this application. Therefore, the purpose of our Supplemental Direct Testimony is to: (i) provide an update regarding the major natural gas market changes impacting the availability and pricing of natural gas supplies in New England; (ii) provide updated project designs and cost estimates for the proposed Granite Bridge Pipeline and Granite Bridge LNG facility (collectively, the Granite Bridge Project); (iii) reaffirm the mitigation value (i.e., portfolio optimization revenue) associated with the Granite Bridge Project, as evidenced by the negotiated commercial terms outlined in the Calpine MOU, and present the approach proposed by the Company to guarantee that benefit to our customers; and (iv) incorporate the various updates and changes since the initial filing in the Company's quantitative (i.e., SENDOUT®) and qualitative analyses.

Q. Please provide a high-level summary of your Supplemental Direct Testimony.

A. Since the Company's initial filing, there have been no additional infrastructure projects proposed that would deliver additional natural gas supply into EnergyNorth's service territory in New Hampshire. Due to capacity constraints and the loss of supply, the New

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2 Please note, these specific discovery responses are provided for illustrative purposes and are not included in Exhibit FCD/WRK-1.

England natural gas market continues to be high cost and volatile, which subjects EnergyNorth's customers to increased costs. The Company, working with outside consultants, has made significant progress on the design of the Granite Bridge Pipeline and Granite Bridge LNG facility. Refinement of the initial project designs and decisions to invest in certain infrastructure, which will lower operational costs, have led to overall increases in the capital costs of the project. These increases are reduced by the Company's guarantee of the value of its agreement with Calpine and reductions in the operational costs of the Granite Bridge Project. The Company's updated quantitative and qualitative analyses continue to demonstrate that the Company's Base Case Supplemental – Customer Benefit Guarantee portfolio is the lowest cost option to bring additional natural gas supply to serve EnergyNorth's customers. In fact, a historical analysis of the Company's natural gas purchases over the past five split-years demonstrates considerable gas purchase cost savings to customers from the Granite Bridge LNG facility.

Q. Please provide an overview of the major changes in the New England natural gas market since the Company's initial filing.

A. The natural gas market issues discussed in the Company's initial filing (see Bates 126R to 150R of the December 22, 2017, Direct Testimony of William R. Killeen and James M. Stephens) continue to pose significant natural gas supply and capacity challenges for the New England region in general, and for the Company in particular. As further detailed in Section II, one of the primary sources of natural gas supply to the New England region, the Sable Offshore Energy Project ("SOEP") and Deep Panuke Offshore Gas Development Project ("Deep Panuke"), has permanently shut down production, which not only reduces natural gas supply options, but also places price pressure on other natural gas supply sources. In addition, the primary source of imported LNG to the New England region, the Everett LNG facility, is undergoing commercial changes,[3] which may impact the future availability and pricing of natural gas supply from Constellation LNG, LLC ("CLNG"). Furthermore, other than the Portland XPress ("PXP") Project, which the Company has already contracted for pipeline transportation service as part of its long-term natural gas supply strategy in this docket, there have been no new announcements of pipeline projects that would provide service to EnergyNorth. Finally, natural gas prices in New England continue to experience significant volatility and reached record levels over the 2017/18 winter. In the face of these significant natural gas market challenges, the Company's natural gas supply plan, which includes the proposed Granite Bridge Project, continues to be the optimal strategy, which will provide significant reliability and security of natural gas supply to our customers in a cost-effective manner, as discussed in the Company's initial filing and further evidenced by the updated analyses herein.

Q. Prior to discussing the results of the Company's updated analyses, please summarize the updated project designs and cost estimates for the proposed Granite Bridge Project.

A. The data provided in the Company's initial filing with respect to cost estimates for the proposed Granite Bridge Pipeline and Granite Bridge LNG facility were based on the best

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

available information at that time. Specifically, those preliminary cost estimates were based on conceptual engineering and feasibility studies (see also, the Company's responses to OCA 1-9, OCA 1-34, OCA 1-38, and Staff 1-19). Subsequent to the initial filing in this docket, the Company has continued to work collaboratively with the New Hampshire Department of Transportation ("NHDOT"), municipal officials, environmental permitting consultants, and engineering firms to develop a more detailed and refined engineering design of the proposed Granite Bridge Pipeline and Granite Bridge LNG facility and, therefore, has updated cost estimates as discussed further in Section III.

With respect to the pipeline component of the Granite Bridge Project, the Company has completed the necessary environmental, surveying, and geotechnical work necessary to achieve a 30% engineering design of the proposed Granite Bridge Pipeline, which is a threshold requirement for a Preliminary Conceptual Feasibility Study needed by the NHDOT to initiate its review of the proposed pipeline route. In addition, the Company provided the 30% engineering design to four independent engineering, procurement, and construction ("EPC") companies to obtain detailed construction cost estimates for the proposed Granite Bridge Pipeline. Based on the capital cost estimates received from the four EPC companies, the revised cost of the proposed Granite Bridge Pipeline is approximately $168 million. The high and low EPC estimates were within [redacted] of each other, thus providing the Company with confidence that the responses represent consistent and independently-derived estimates, to use as a basis for the economic evaluation of Granite Bridge Pipeline. The updated Granite Bridge Pipeline cost estimates are discussed more fully in Section III.A.

Contemporaneously with the design review of the Granite Bridge Pipeline, the Company's outside engineering consultant, Sanborn, Head & Associates ("Sanborn Head"), also completed the preliminary design basis for the Granite Bridge LNG facility, which was provided to two independent EPC companies for updated construction cost estimates. Based on the detailed capital cost estimates received from the two EPC companies, the Company's revised estimate of the cost of the proposed Granite Bridge LNG facility is approximately $246 million. These estimates were within [redacted] of each other, thus providing the Company with confidence that the responses represent consistent and independently-derived bids to use as a basis for the economic evaluation of the Granite Bridge LNG facility. However, recognizing that a more detailed design basis and final EPC request for proposals ("RFP") is still to be developed, the Company, working with the intervening parties and as part of an overall settlement, would be open to discussing a potential cap on the capital costs associated with the Granite Bridge LNG facility. The updated Granite Bridge LNG Facility cost estimates are discussed more fully in Section III.B.

Q. Has the Company reflected the updated project designs and cost estimates for the proposed Granite Bridge Project in the levelized cost model and analyses discussed herein?

A. Yes, it has. The Company requested Mr. Timothy S. Lyons to update the levelized cost analysis to reflect the updated project designs and cost estimates for the Granite Bridge Project, as well as updates to certain financial assumptions, which are further detailed in Section III. Based on these revisions, the updated levelized cost for the Granite Bridge

Pipeline is approximately $17.6 million per year; and the updated levelized cost for the Granite Bridge LNG facility is approximately $28.8 million per year.

Q. Does the Company expect to mitigate the cost of the proposed Granite Bridge Project during the initial years of operation?

A. Yes, it does. First and foremost, it is important to remember that the proposed Granite Bridge Project is necessary to serve the natural gas demand of our customers in New Hampshire and the project has been designed for that sole purpose. Without additional capacity that can deliver incremental natural gas supply into EnergyNorth's service territory in southern and central New Hampshire, the Company will be forced to impose a moratorium. That is, absent the Granite Bridge Project, the Company would have to impose a prohibition on any new or expanded use of natural gas in its existing service territory given EnergyNorth's current infrastructure and resource levels. Further, the Company would have to continue to rely heavily on its aging propane facilities to meet existing customer demand. Should these facilities become inoperable or unreliable in the future, EnergyNorth's existing customers would be at risk of losing natural gas service during the peak winter periods.

With respect to cost mitigation, similar to other natural gas supply and infrastructure contracts and investments, the Company's natural gas supply portfolio is designed to meet current and planned demand requirements, resulting in the potential for available supply and capacity during the initial years after a resource (e.g., the Granite Bridge Project) has been added to the portfolio. As a strong market signal of capacity mitigation opportunity associated with the Granite Bridge Project, the Company obtained a third-party marker of value through discussions with Calpine that were memorialized in the Calpine MOU.

Q. Please summarize the Calpine MOU and the associated market price signal (i.e., mitigation opportunity) for a peaking service provided by the proposed Granite Bridge Project.

A. In October 2018, the Company entered into a MOU to provide Calpine with certain natural gas supply services for its Granite Ridge Energy Center ("GREC") in Londonderry, New Hampshire (see the Company's supplemental responses to PLAN 1-3 and PLAN 2-6). The natural gas supply service to Calpine, which is enabled by the Company's Base Case portfolio (the Granite Bridge Pipeline and 2.0 Bcf Granite Bridge LNG facility), provides the Company with a unique opportunity to receive up to [redacted][4] of annual capacity mitigation or portfolio optimization revenues as an additional benefit to EnergyNorth's customers. As discussed in Section IV, this negotiated marker of value provides the Company with insight and confidence regarding the capacity mitigation value for the Granite Bridge Project. Therefore, regardless of whether EnergyNorth executes a contract with Calpine or another third-party, the Company commits to providing its customers with the market value outlined in the Calpine MOU for the duration of the MOU's initial term (hereinafter the "Customer Benefit Guarantee"). Through the Customer Benefit Guarantee, the Company agrees it will not seek to recover from its customers the fixed cost

[4] The annual revenue outlined in the Calpine MOU reflects [redacted] types of fees [redacted]

and variable cost value of the Calpine MOU over the initial term of the agreement, irrespective of whether Calpine or any other party ultimately executes a binding Precedent Agreement. This reduces the cost of the Granite Bridge Project to customers and also places risk on the Company's shareholders if it is unable to execute the Calpine MOU, or a similar mitigation agreement with another third-party. The Calpine MOU and the Customer Benefit Guarantee are discussed more fully in Section IV.

Q. Please summarize the Company's updated quantitative and qualitative analyses.

A. As further detailed in Section V, the Company's updated quantitative SENDOUT® analysis incorporated: (i) the updated project designs and cost estimates for the proposed Granite Bridge Project; (ii) the value of the Customer Benefit Guarantee in the Base Case portfolio (hereinafter referred to as the "Base Case Supplemental – Customer Benefit Guarantee" scenario); and (iii) certain modifications to the assumptions and parameters in the SENDOUT® model including the Company's demand forecast, natural gas price assumptions, and assumptions regarding working capital requirements for certain supplemental/peaking assets and storage contracts as requested by intervenors in this docket. The results of the updated SENDOUT® analysis continue to demonstrate that the least-cost portfolio for our customers is the Company's Base Case Supplemental – Customer Benefit Guarantee portfolio, which includes the proposed Granite Bridge Pipeline and a 2.0 Bcf Granite Bridge LNG facility, the Company's delivered supply contract with CLNG for 7,000 Dth per day of combination (i.e., liquid and/or vapor) service,[5] the precedent agreement with Portland Natural Gas Transmission ("PNGTS") for 5,000 Dth per day of firm transportation capacity on the PXP Project,[6] the Company's existing gas supply portfolio, and the Company's commitment to provide the Customer Benefit Guarantee.[7] In fact, the total cost of the Base Case Supplemental – Customer Benefit Guarantee scenario is approximately $182 million lower than the Alternative Case Supplemental scenario (see Table 2 in Section V).

The same qualitative benefits discussed in the Company's initial filing apply to the Base Case Supplemental – Customer Benefit Guarantee portfolio. The unique value proposition of the Granite Bridge Project has never been more evident given the current state of the New England natural gas market. Specifically, the Granite Bridge Project provides the most natural gas supply and delivery reliability for our customers. In addition to providing a significant increase in reliability, the Granite Bridge Project would also increase the diversity, flexibility, and resiliency of the Company's overall natural gas supply portfolio, as well as provide more price stability for our customers. By way of example, and as discussed in Section VI, if the Granite Bridge LNG facility had been part of the EnergyNorth portfolio during the 2013/14 to 2017/18 period, our customers would have received a benefit of approximately $122 million in their gas purchase costs. This physical

[5] CLNG has taken assignment of ENGIE's interests in the contract with the Company. See, Motion of Constellation LNG, LLC for Leave to Intervene Out-of-Time, Docket No. DG 17-198, December 12, 2018.

[6] As described on Bates 208R of the Company's initial filing, the PXP Project is being implemented in three phases. The Company's volumes are phased-in over three years beginning on November 1, 2018. However, given the current deliverability limitations on the TGP Concord Lateral, the PNGTS contract does not provide incremental Design Day supply to the Company's city-gates until the proposed Granite Bridge Pipeline is on-line.

[7] Please note, the alternative cases exclude the Granite Bridge LNG facility and, as such, do not reflect the Customer Benefit Guarantee.

hedge attribute of the Granite Bridge LNG facility alone covers approximately 85% of the annual cost of service for the Granite Bridge LNG facility. In fact, assuming that the subsequent five-year period (i.e., 2018/19 to 2022/23) yielded a similar savings as the 2013/14 to 2017/18 period, the ten-year benefit associated with the physical hedge attribute is $244 million, which is comparable to the capital cost estimate for the Granite Bridge LNG facility.

Q. How is the remainder of your Supplemental Direct Testimony organized?

A. The remainder of our Supplemental Direct Testimony is organized as follows:

- <u>Section II – Regional Natural Gas Market Update</u>: This section provides an update and appropriate context regarding the New England natural gas market issues that the Company is currently facing.
- <u>Section III – Updated Granite Bridge Project Design and Cost Estimates</u>: This section provides details regarding the project status, updated project design and associated cost estimates for the proposed Granite Bridge Pipeline and Granite Bridge LNG facility, and summarizes the corresponding updates to the assumptions in the Company's levelized cost model and SENDOUT® model.
- <u>Section IV – Customer Benefit Guarantee Value</u>: This section provides details regarding the deal parameters and key commercial terms of the Calpine MOU, which demonstrate the market value for a peaking service provided by the proposed Granite Bridge Project and support the Company's commitment to provide the Customer Benefit Guarantee.

- Section V – Updated SENDOUT® Analysis: This section reviews the various assumption enhancements and updates to the SENDOUT® model runs and provides the results of the Company's updated SENDOUT® analyses.

- Section VI – Benefits of the Base Case Supplemental – Customer Benefit Guarantee Portfolio: This section summarizes the key benefits associated with the Company's proposed natural gas supply strategy, which includes the Granite Bridge Pipeline and 2.0 Bcf Granite Bridge LNG facility.

- Section VII – Conclusions: This section summarizes the results of the various updates to EnergyNorth's analyses, which continue to support the Company's conclusions in our initial filing that the Company's Base Case Supplemental – Customer Benefit Guarantee portfolio is the best cost gas supply strategy for our customers.

II. REGIONAL NATURAL GAS MARKET UPDATE

A. Offshore Nova Scotia Supplies

Q. In the December 22, 2017, Direct Testimony of William R. Killeen and James M. Stephens, the decline of offshore Nova Scotia natural gas production was reviewed in detail. Has the situation changed?

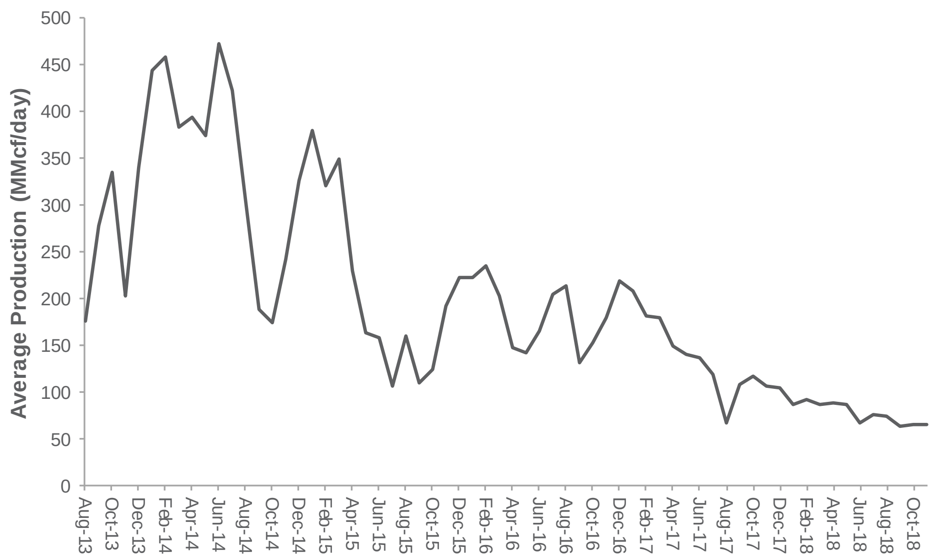
A. Yes, it has. Specifically, there is no longer any natural gas production from SOEP and Deep Panuke. The Canada-Nova Scotia Petroleum Board announced that production from

SOEP has been permanently shut down as of December 31, 2018,[8] and natural gas production from Deep Panuke has been permanently shut down since May 2018.[9]

Q. What is the level of natural gas supply that has been removed from the marketplace as a result of the shutdown of SOEP and Deep Panuke?

A. As illustrated in Figure 1 below, the combined average daily natural gas production from SOEP and Deep Panuke was as high as 470 MMcf per day in the 2013/14 split-year, and recently provided approximately 100 MMcf per day of gas supply to the New England and Maritime Canada regions.

Figure 1: Combined Average Daily SOEP and Deep Panuke Production[10]



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8 See, Canada-Nova Scotia Offshore Petroleum Board, Weekly Operations Report, January 3, 2019. https://www.cnsopb.ns.ca/sites/default/files/pdfs/Jan0319.pdf

9 Ibid.

10 Sources: Canada-Nova Scotia Offshore Petroleum Board, Sable and Deep Panuke Monthly Production Reports, access date January 3, 2019.

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

A. Given the permanent production shut down of SOEP and Deep Panuke, the New England and Maritime Canada regions no longer have access to natural gas supply flowing into the Maritimes & Northeast Pipeline ("MNE") system from offshore Nova Scotia, which is a supply loss ranging from 100 to 470 MMcf per day. The loss of offshore Nova Scotia natural gas production places pressure on other natural gas supply sources and leaves re-vaporized LNG from the Canaport LNG facility as the only gas supply source option available from Maritime Canada[11] for the New England market.

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

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

A. As discussed in the Company's initial filing, the Everett LNG facility is a primary source of imported LNG supplies to the New England region. The Everett LNG facility was recently acquired by Exelon[12] and is currently undergoing commercial changes. Specifically, a subsidiary of Exelon, Constellation Mystic Power, LLC ("Mystic"), filed a request with the Federal Energy Regulatory Commission ("FERC") in May 2018 for approval of a cost-of-service agreement between Mystic, Exelon, and ISO New England ("ISO-NE"), which would support the continued operation of the Mystic 8 and 9 natural

11 Excludes certain limited volume from Corridor Resources.

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

gas-fired generating units.[13] In its order issued on December 20, 2018, in Docket No. ER18-1639-000, the FERC approved the cost-of-service agreement, with certain conditions, to maintain the fuel security needs of the ISO-NE region through May 2024.[14] In addition, the FERC determined that Mystic can recover 91% of the cost of ownership and operation of the Everett LNG facility and ordered the implementation of an incentive mechanism to promote third-party sales of LNG from the Everett LNG facility.[15]

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

A. Exelon's filing with the FERC and associated commercial strategy for the Everett LNG facility may impact the future availability and pricing of LNG from the facility. While the Company's delivered service contracts with ENGIE that are part of this docket have been assigned to CLNG, a subsidiary of Exelon, there is uncertainty associated with the duration and pricing of service from the Everett LNG facility beyond the current term of the contracts. To that point, certain intervenors in FERC Docket No. ER18-1639-000 raised concerns related to incentives in the cost-of-service compensation agreement, which could cause Exelon to act in a way that may have the effect of raising or lowering the natural gas prices in the Northeast.[16] Because Exelon will be operating the Mystic and Everett LNG facilities under a new cost recovery framework, it is unclear: (i) if Exelon will change the

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

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

15 Ibid.

16 Ibid, Para. 213-216.

operations of the Everett LNG facility in response to the new incentives; (ii) how those changes will affect natural gas supply and prices in New England; or (iii) if CLNG will offer similar products and services (e.g., liquefied natural gas for refill). Regardless, the commercial changes at the Everett LNG facility will increase uncertainty associated with type and availability of service offerings and associated price signals.

C. Incremental Pipeline Capacity

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

A. In addition to the three incremental New England supply projects discussed in the Company's initial filing (the Algonquin Incremental Market, TGP Connecticut Expansion, and Atlantic Bridge projects), the PNGTS PXP Project, which is part of the Company's natural gas supply strategy in this docket, has initiated service. As detailed in the initial filing, EnergyNorth has executed a precedent agreement with PNGTS associated with the PXP Project. This agreement provides the Company with firm transportation capacity of up to 5,000 Dth per day from the Dawn Hub to Dracut, Massachusetts, the interconnection point between the Joint Facilities[17] and Tennessee. Phase I of the PNGTS PXP Project commenced service as of November 1, 2018, which provides the Company with supply diversity at Dracut, but not added capacity given that there is no additional capacity available on Tennessee's Concord Lateral. However, once the proposed Granite Bridge

[17] The "Joint Facilities" refers to the portion of the PNGTS system from Westbrook, Maine to Dracut, Massachusetts, which is owned jointly by PNGTS and MNE-US.

Pipeline is placed in-service, the contracted PXP Project capacity will be able to provide incremental Design Day supply to EnergyNorth's city-gates.

Q. Have there been any new pipeline projects for New England announced since the Company's initial filing in this docket?

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

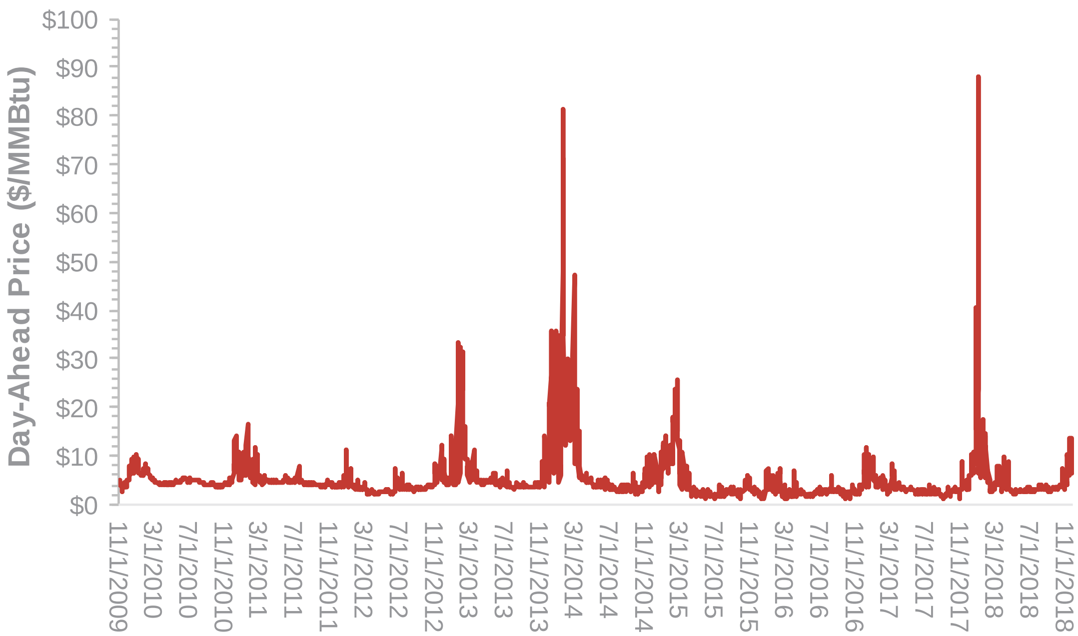
D. Regional Natural Gas Price Trends

Q. Please discuss the record natural gas price levels experienced in New England last winter.

A. Please see Figure 2 below for a chart of the daily New England natural gas prices, as represented by the TGP Dracut price index, over the November 2009 through November 2018 time period. As illustrated in Figure 2 and discussed in the Company's response to

Staff 2-53, the TGP Dracut price index has consistently exceeded $10 per MMBtu during each winter period and reached a record high of approximately $90 per MMBtu during the winter of 2017/18.

Figure 2: TGP Dracut Day-Ahead Prices (Nov. 1, 2009 – Nov. 30, 2018)[18]



Q. Please discuss the volatility of the New England natural gas prices.

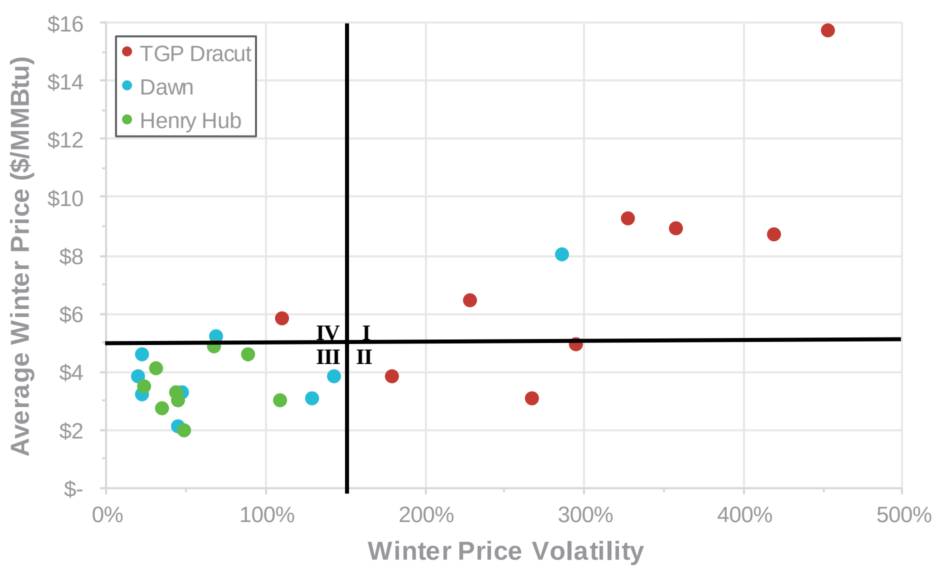
A. As discussed in the Company's response to Staff 2-53, the TGP Dracut price index has exhibited higher price levels and more volatility relative to the Dawn and Henry Hub price indices. Figure 3 below is a scatterplot showing the historical natural gas price volatility[19] (on the x-axis) and the average winter price (on the y-axis) for the TGP Dracut, Dawn, and

[18] Source: S&P Global Market Intelligence.

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

Henry Hub price indices over the winters of 2009/10 through 2017/18. The scatterplot is divided into four quadrants with a vertical line parallel to the x-axis, which separates observations with relatively lower volatility (less than 150%) in quadrants III and IV and higher volatility (greater than 150%) in quadrants I and II, and a horizontal line parallel to the y-axis, which separates observations with an average winter price level of less than $5 per MMBtu in quadrants II and III or greater than $5 per MMBtu in quadrants I and IV.

Figure 3: Average Winter Prices and Volatility (2009/10 – 2017/18)[20]



As shown in Figure 3 above, on a comparative basis, there are nine observations in quadrants I and II, which are the higher volatility quadrants, and eight of those nine observations are the TGP Dracut price index. Specifically, for the TGP Dracut price index, five of nine observations are in quadrant I, which reflect higher price and higher volatility;

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

three observations in quadrant II with higher volatility and average winter prices between $3 to $5 per MMBtu; and one observation in quadrant IV with an average winter price of nearly $6 per MMBtu and winter price volatility of over 110%.

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

A. Yes, there also are liquidity concerns associated with the TGP Dracut price index. There are limited gas supply options and counterparties at the TGP Dracut point. [redacted] the lack of liquidity at Dracut in general, and on the TGP Concord Lateral in particular. [redacted] the Company would be forced to rely solely on spot gas purchases at Dracut and would not be able to execute its basis hedging plan, exposing our customers to significant price volatility. Furthermore, S&P Global Platts has recently disaggregated the Tennessee Zone 6 pricing into four price points -- TGP Zone 6 delivered, TGP Zone 6 delivered North, TGP Zone 6 delivered South, and TGP Zone 6 (300 Leg) delivered.[21] This will not only negatively impact the price liquidity and volatility of the Tennessee Zone 6 pricing, but also the TGP Dracut index. Again, the lack of liquidity at Dracut will expose the Company's customers to higher commodity prices and more price volatility.

[21] See, S&P Global Platts, Methodology and specifications guide: North American natural gas, November 2018.

E. <u>Summary of Regional Natural Gas Market Dynamics</u>

Q. Please summarize how the recent changes in the New England natural gas market have impacted EnergyNorth and the Company's proposed natural gas supply strategy.

A. As discussed in the Company's initial filing, the EnergyNorth distribution system currently receives natural gas supply from the TGP Concord Lateral, which originates near Dracut, Massachusetts, where the Tennessee system has interconnections with MNE-US and PNGTS. Since the TGP Concord Lateral is the only pipeline that directly connects to the Company's service territory in New Hampshire, it is the sole source of pipeline supply for all the Company's service territories except for the City of Berlin, which is served exclusively by PNGTS. Given the delivery limitations on the TGP Concord Lateral, as well as expectations regarding the New England natural gas market at the time of the Company's initial filing, EnergyNorth developed and presented for Commission approval an interim and long-term natural gas supply strategy to provide reliable service to our customers at the lowest cost. Specifically, the Company's natural gas supply strategy is comprised of a contract with CLNG for service from the Everett LNG facility, a precedent agreement with PNGTS for firm transportation capacity on the PXP Project, and the construction of the Granite Bridge Pipeline and Granite Bridge LNG facility.

The changes in the New England natural gas market since the Company's initial filing continue to support the Company's contractual decisions regarding the Everett LNG facility and PXP Project, and demonstrate the critical need for the Granite Bridge Project, which will allow EnergyNorth to reliably meet forecasted demand requirements in a cost-effective manner. Specifically, the recent changes in the New England natural gas market bring into question the availability and long-term feasibility of certain natural gas supply options to serve the New England region, in general, and EnergyNorth, in particular.

As discussed above, with the loss of offshore Nova Scotia production, the Canaport LNG facility is now the only gas supply option into MNE from the north to serve the New England and Maritime Canada markets. There is uncertainty regarding the types and availability of service offerings and associated pricing from the Everett LNG facility and how that uncertainty may affect services offered to the Company beyond 2022. In addition, there have been no new pipeline capacity projects announced over the past year that could provide incremental deliverability and supply to the Company's service territory.

These natural gas supply challenges exacerbate the concerns regarding the availability of certain natural gas supply options, regional natural gas supply and transportation constraints, and associated price spikes and high volatility levels, particularly in the winter period. These market issues and commercial dynamics highlight the need for the Company to implement its natural gas supply strategy to ensure our customers receive reliable and cost-effective service going forward. Therefore, the Company is moving forward with its delivered liquid/vapor service contract with CLNG, the 20-year PXP contract for capacity on PNGTS, and the development of the Granite Bridge Project.

III. UPDATED GRANITE BRIDGE PROJECT DESIGNS AND COST ESTIMATES

A. Granite Bridge Pipeline

Q. Please discuss the project development status of the proposed Granite Bridge Pipeline since the Company's initial filing.

A. Subsequent to the initial filing, EnergyNorth conducted a solicitation for bids to develop a more detailed and refined engineering design for the proposed Granite Bridge Pipeline (see also, the Company's response to OCA 1-9). As part of that solicitation process, the Company retained the design engineering firm, CHI Engineering Services, Inc. ("CHI"), to refine and finalize the route design and, together with environmental permitting consultants Vanasse Hangen Brustlin, Inc. ("VHB"), obtain the necessary permitting and develop the construction requirements (see also, the Company's response to Staff Tech 1-3). The Company and its expert consultants have held numerous meetings with the NHDOT, the New Hampshire Division of Historical Resources, the New Hampshire Fish and Game Department, and other state agencies to comply with all state agency requirements for the route and construction design of the proposed Granite Bridge Pipeline. The Company continues to work collaboratively with all state agencies and local communities on the refinement of the pipeline route and construction design. The refined engineering and construction design of the proposed Granite Bridge Pipeline discussed herein is based upon environmental, surveying, archaeological, and geotechnical investigation of the proposed route within the NHDOT right-of-way.

The Company also negotiated an option to acquire an easement with the Town of Exeter, New Hampshire, for the siting of a meter station to be located on municipal property at the

Exeter wastewater treatment plant, which is adjacent to Route 101 East. An interconnection with the Joint Facilities at this location shortens the proposed Granite Bridge Pipeline by approximately half a mile and eliminates the need for a horizontal directional drill ("HDD") underneath the Squamscott River, as the pipeline will no longer need to extend into the Town of Stratham.

During the past twelve months, the Company has completed the necessary environmental, surveying, and geotechnical work necessary to achieve a 30% engineering design of the proposed Granite Bridge Pipeline, which is a threshold requirement for a Preliminary Conceptual Feasibility Study needed by the NHDOT to initiate its review of the proposed pipeline route. The refined engineering design has established a more precise pipeline route within the NHDOT right-of-way along Route 101, which includes the detailed location of wetlands, road crossings, work space requirements, and the location and number of HDDs for the Granite Bridge Pipeline. To facilitate the review of the 30% engineering design, the Company disaggregated the proposed pipeline route into five construction spreads, each of which has been discussed and initially reviewed with the NHDOT. All comments and recommended changes from the NHDOT discussions have been incorporated into the 30% engineering design constituting the final Preliminary Conceptual Feasibility Study required by the NHDOT as the first phase of its final approval of the proposed pipeline route within the NHDOT right-of-way. The Company expects to receive NHDOT approval of this Preliminary Conceptual Feasibility Study within 90 days of its filing with NHDOT, which the Company expects to make in March 2019.

Q. Please discuss the updated cost estimate for the proposed Granite Bridge Pipeline based on the refined engineering and construction design.

A. The major advancements and refinements to the pipeline route have resulted in certain revisions to the capital cost estimate for the Granite Bridge Pipeline. To develop the 30% engineering design for the pipeline route, EnergyNorth has worked with its environmental and engineering consultants to complete a detailed route survey, initial wetlands delineation, geotechnical review, and above ground historical resources review, as well as archaeological surveys for two-thirds of the proposed pipeline route. The Company provided the 30% engineering design to four independent EPC companies and requested that they submit construction cost estimates for the proposed Granite Bridge Pipeline. Each EPC also conducted a field inspection of the Route 101 right-of-way and met with the Company and its engineering, environmental, and geotechnical consultants to discuss the proposed route, various aspects of the pipe design, and potential construction methods. EnergyNorth received three full pipeline construction cost estimates and one response that focused solely on the HDD cost for the proposed Granite Bridge Pipeline. The HDD-only estimate was compared to the HDD cost estimates from the other three EPCs to verify and validate the responses that were received, again providing the Company with confidence in the estimates received by all EPCs. Based on these capital cost estimates, the revised cost of the proposed Granite Bridge Pipeline is approximately $168 million, which constitutes an average of the three submitted EPC estimates,[22] compared to the cost of approximately $110 million submitted in the initial filing. The estimates were all within

[22] The cost estimates ranged from approximately [redacted].

[redacted] of each other, thus providing the Company with confidence that the responses represent consistent and independently-derived information to use as a basis for the economic evaluation of Granite Bridge Pipeline. Further, at a 30% engineering design, this confidence allows for contingencies of less than 10% on the overall cost estimates provided by the EPCs and are reflected in the revised cost estimate above.

Q. Please discuss the reasons that the estimates for the proposed Granite Bridge Pipeline increased from the Company's initial filing in December 2017.

A. In its initial filing, EnergyNorth produced construction estimates for the Granite Bridge Pipeline based on three different data points. Those analyses were performed over several months in the summer and fall of 2017. First, the Company hired CHA Consulting Inc. to conduct an initial route conceptual design and develop an estimate based upon this work product. That conceptual design was reviewed with the NHDOT prior to announcement of the Granite Bridge Project and the submission of the Company's initial filing in this docket. Route changes requested by the NHDOT were incorporated in the final preliminary route (i.e. the requirement to move the pipe outside of on- and off-ramps, as opposed to placing the pipe on the side of the highway under overpasses). The Company then used actual construction costs from the recently completed upgrade to its high-pressure distribution line that brings natural gas supply from Concord to Tilton, New Hampshire ("High-Line Project"). The High-Line Project involved installing 5.5 miles of 12-inch coated steel pipe along Route 106, a state highway in Loudon, New Hampshire. This project, in terms of installation methods, is very similar to the proposed 16-inch, coated steel pipe that would be installed along Route 101 as part of the Granite Bridge

Pipeline. The High-Line Project was the largest ever completed by EnergyNorth, and was completed on-time and under-budget. Finally, the Company also reviewed the costs that were incurred in 2003 to construct 2.8 miles of transmission pipeline to serve the GREC in Londonderry. The Company used those actual construction costs for transmission pipeline installation in New Hampshire and applied the Handy Whitman Index of Public Utility Construction Costs to bring those costs up to present day value. The Company then took the highest value of these three estimates and used that as the basis for its initial filing to the Commission. The resulting cost per mile estimate was in line with a recent similar utility expansion project in Vermont.

As discussed previously, considerable effort has been spent by the Company and its outside consultants since the initial cost estimates were developed to refine the proposed Granite Bridge Pipeline route within the NHDOT right-of-way along Route 101. This field survey work, which the Company was unable to perform prior to the public announcement of the Granite Bridge Project, and the Company's detailed discussions with the NHDOT have led to changes in the proposed route and construction methods. These changes are reflected in the 30% engineering design, which is being finalized for submission to the NHDOT this month, and were discussed and provided to the four EPCs who reviewed the project and provided cost estimates to the Company. Other factors that contributed to the change in estimated costs for the Granite Bridge Pipeline include revised duties on imports of steel into the United States, which were announced in March 2018, and the increased number and length of the HDDs as a result of the more detailed survey, environmental, and geotechnical work performed under the 30% engineering design of the project.

Q. When will the Company have a final cost estimate for the proposed Granite Bridge Pipeline?

A. The Company will have a final cost estimate for the proposed Granite Bridge Pipeline when it solicits bids for final EPC services.[23] However, the 30% completed engineering and project design provides stakeholders with a refined and detailed cost estimate that is reasonable and appropriate for the analysis of cost implications discussed herein.

Q. Has the Company updated its levelized cost analysis to reflect the updated capital cost estimate for the proposed Granite Bridge Pipeline?

A. Yes, it has. The Company asked Mr. Timothy S. Lyons to update the levelized cost analysis that he sponsored in his prefiled direct testimony submitted on December 22, 2017, which was subsequently revised in the Company's response to OCA 1-30 to reflect the income tax changes detailed in the TCJA. Mr. Lyons has now made the following updates to the levelized cost analysis provided in response to OCA 1-30: (i) updates to reflect revised capital cost investments in the Granite Bridge Pipeline; (ii) updates to reflect the Commission's decision in EnergyNorth's most recent rate case (Docket No. DG 17-048), including capital structure, cost of equity and cost of debt; and (iii) updates to reflect recent financial information, including state income taxes, property insurance, and pipeline O&M costs. As a result of these updates, the levelized cost estimate for the proposed Granite

[23] As indicated in the Company's response to Staff Tech 1-3, the Company expects to conduct the solicitation for final EPC services following the submittal of the application for approval of the Granite Bridge Pipeline and Granite Bridge LNG facility with the New Hampshire Site Evaluation Committee ("NHSEC"), which is expected to occur in mid-2019. The Company's application to the NHSEC will contain a 70% engineering and construction design of the proposed Granite Bridge Pipeline route.

Bridge Pipeline is approximately $17.6 million per year, compared to the $12.4 million per year estimate provided in the response to OCA 1-30.

Q. Please discuss the updated cost estimate for the proposed Granite Bridge Pipeline relative to the alternative delivery option to the Company's city-gates.

A. It is first important to review the Company's current natural gas delivery situation. Since the EnergyNorth distribution system receives natural gas supply from the TGP Concord Lateral, which is fully subscribed, any additional requests to increase capacity and deliverability will, at a minimum, require incremental facilities on the TGP Concord Lateral. As discussed in the initial filing and detailed in the Company's responses to OCA 1-36 and OCA 2-46, the indicative daily rates provided by Tennessee for the expansion of approximately 75,000 Dth per day on the TGP Concord Lateral ranged from [redacted] to [redacted] per Dth. To provide an "apples-to-apples" unit cost comparison to the expansion of the TGP Concord Lateral, a unit cost estimate for the Granite Bridge Pipeline was calculated based on a capacity of 75,000 Dth per day.[24] Specifically, the updated levelized annual cost of $17.6 million divided by a capacity of 75,000 Dth per day resulted in an updated unit cost of $0.64 per Dth per day for the proposed Granite Bridge Pipeline,[25] which is still approximately [redacted] to [redacted] lower than the indicative rates for the expansion of the TGP Concord Lateral.

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24 See also, Bates 079R to 080R and 091R of the Direct Testimony of Timothy S. Lyons, Bates 177R to 178R of the Direct Testimony of William R. Killeen and James M. Stephens, and the Company's response to OCA 1-36.

25 Please note, using the full operating capacity of 150,000 Dth per day for the Granite Bridge Pipeline results in an updated unit cost value of $0.32 per Dth per day.

Q. In addition to the cost advantage, does the Granite Bridge Pipeline provide the Company and its customers with other benefits?

A. Yes, it does. As detailed in the December 22, 2017, Direct Testimony of William R. Killeen and James M. Stephens at Bates 178R to 180R, the Granite Bridge Pipeline provides the following qualitative benefits:

First, an additional pipeline feed to the EnergyNorth service territory increases the diversity of the Company's delivery infrastructure, which significantly increases the reliability and security of natural gas supply deliveries. Simply stated, a second source of supply offers increased reliability in the event of a service disruption on the TGP Concord Lateral.

Second, a new direct connection with the Joint Facilities increases delivery options as EnergyNorth could access additional natural gas supplies that are delivered or sited on the Granite Bridge Pipeline and Joint Facilities. These supply options include vaporized LNG from the proposed Granite Bridge LNG facility, Canadian supply via PNGTS, and imported LNG supplies via MNE-US. This increase in natural gas supply diversity and options increases the reliability of the overall gas supply portfolio and provides greater price stability for the Company's customers.

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

Fourth, the Granite Bridge Pipeline would provide EnergyNorth with negotiating leverage when evaluating its current resource portfolio. The Company's current resource portfolio has two TGP contracts that originate at Dracut, with total annual demand charges of approximately $5.5 million and a total maximum daily quantity ("MDQ") of 50,000 Dth, which is nearly 50% of EnergyNorth's current total pipeline capacity. As discussed previously, due to upstream pipeline constraints, Dracut has become one of the most expensive natural gas trading hubs in North America during colder months. When these two TGP contracts come up for renewal, a new pipeline could provide a replacement option for the Company, thus providing leverage in the negotiation with TGP regarding these contracts.

Finally, a new pipeline would allow EnergyNorth the opportunity to provide natural gas as a fuel choice to communities along the construction path of the Granite Bridge Pipeline. Towns, businesses, and homes that currently do not have access to natural gas, given the absence of natural gas infrastructure, would now have choices with respect to their energy decisions.

Therefore, the proposed Granite Bridge Pipeline continues to be the most cost-effective alternative for increasing deliverability to the Company's distribution system and is the option that provides more qualitative benefits (e.g., reliability). Given the quantitative and qualitative benefits of the Granite Bridge Pipeline relative to the alternative (expansion of the TGP Concord Lateral), the Company has included the Granite Bridge Pipeline in all the SENDOUT® model runs, and the SENDOUT® results are detailed in Section V below.

B. <u>Granite Bridge LNG Facility</u>

Q. What is the current project development status of the proposed Granite Bridge LNG facility?

A. Similar to the Granite Bridge Pipeline discussion in Section III.A above, the Company has conducted a solicitation of bids for Owner's Engineering Services for the proposed Granite Bridge LNG facility to further refine and finalize the Granite Bridge LNG facility design. The Company retained Sanborn Head to refine the Granite Bridge LNG facility design and, together with VHB, finalize the necessary permitting for the proposed site of the Granite Bridge LNG facility (see also, the Company's response to Staff Tech 1-3).

As part of the refined engineering design of the proposed Granite Bridge LNG facility, the LNG storage tank and appurtenant facilities were further defined based on environmental, geotechnical, and surveying considerations. This field work has allowed the Company to establish a preliminary design basis for the Granite Bridge LNG facility which details the type and location of the LNG facility equipment, and an overall plot plan for the proposed Granite Bridge LNG site. This preliminary design basis includes several changes to the initial plant design, including on-site generation to serve the facility's electrical needs, increased liquefaction capacity, and appropriate technology for the pretreatment and liquefaction system.

Q. Please provide more detail regarding the identified plant design changes for the proposed Granite Bridge LNG facility.

A. With respect to the first design change (on-site generation), the Company in conjunction with its engineering consultants determined that on-site electricity generation is the most cost-effective manner in which to meet the electricity requirements of the liquefaction process of the proposed Granite Bridge LNG facility. Using on-site generation would allow the Company to avoid significant fixed electricity transmission and distribution charges and higher priced electricity commodity purchases. Second, the design of the liquefaction capacity of the proposed Granite Bridge LNG facility was increased from 8,000 Mcf per day to 10,000 Mcf per day to reduce the number of days of required liquefaction to refill tank inventory. The increased liquefaction capacity will reduce the number of days required to refill the capacity in the LNG tank from approximately 250 to 200 days, thus allowing the Company to optimally purchase and liquefy during the lowest cost months of the off-peak period. Lastly, EnergyNorth selected a pretreatment and liquefaction technology which is operationally required to maximize the efficiency of the liquefaction process.

Q. Please discuss the updated cost estimate for the proposed Granite Bridge LNG facility based on the refined engineering and LNG design work conducted to date.

A. The refinements to the Granite Bridge LNG facility design have resulted in certain revisions to the capital cost estimate for the proposed Granite Bridge LNG facility. The Company provided the previously discussed preliminary design for the Granite Bridge LNG facility to two independent EPC companies and requested that they submit construction costs estimates. Both EPCs conducted field inspections of the proposed facility location in Epping, reviewing the site and evaluating any geotechnical and civil engineering work that may be needed. The EPC companies provided estimates for the LNG tank, balance of plant, and civil engineering work necessary for the construction of the proposed Granite Bridge LNG facility at the proposed site. Based on these estimates, which reflect the design and equipment refinements discussed above, the Company estimates the cost of the proposed Granite Bridge LNG project to bet approximately $246 million,[26] compared to the estimate of approximately $202 million submitted in the initial filing. Please note, the two estimates received by the Company for the Granite Bridge LNG facility were within [redacted] of each other. As with the EPC estimates provided for the Granite Bridge Pipeline, having multiple, consistent, independent contractor estimates for the Granite Bridge LNG facility provides the Company with confidence in the accuracy of the responses. Given the proximity of the EPC cost estimates and the current preliminary design basis, the Company incorporated contingencies of less than 15% in the overall cost estimates provided by the EPCs.

The increased cost of the Granite Bridge LNG facility can be attributed to several key factors, including the aforementioned revised duties on imports of steel into the United States, which were announced in March 2018, the addition of on-site generation to reduce electrical operating expenses, and the increase in liquefaction capacity to provide flexibility in refilling the LNG tank during the off-peak period.

[26] The cost estimates ranged from approximately [redacted].

Q. When will the Company have a final cost estimate for the proposed Granite Bridge LNG facility?

A. The Company will have a final cost estimate for the proposed Granite Bridge LNG facility when it solicits bids for final EPC services, which is expected to occur later this year. However, the preliminary design basis for the Granite Bridge LNG facility, outlined above, provides intervenors with a refined and detailed cost estimate that is reasonable and appropriate for the analysis of cost implications discussed herein. That stated, recognizing that a more detailed design basis and final EPC RFP is still to be developed, the Company, working with the intervening parties and as part of an overall settlement, would be open to discussing a potential cap on the capital cost associated with the Granite Bridge LNG facility.

Q. Has the Company updated its levelized cost analysis to reflect the updated capital cost estimate for the proposed Granite Bridge LNG facility?

A. Yes, it has. Similar to the discussion above with respect to the Granite Bridge Pipeline, the Company asked Mr. Lyons to update the levelized cost analysis for the Granite Bridge LNG facility. Mr. Lyons made the following updates to the levelized cost analysis provided in response to OCA 1-30, which reflected the income tax changes detailed in the TCJA: (i) updates to reflect the revised project design and capital cost investment in the Granite Bridge LNG facility; (ii) updates to reflect the Commission's decision in EnergyNorth's most recent rate case (Docket No. DG 17-048), including capital structure, cost of equity and cost of debt; and (iii) updates to reflect recent financial information, including state income taxes, property insurance, and LNG facility O&M expenses. As a result of these assumption changes, the updated levelized cost for the proposed Granite Bridge LNG facility with a 2.0 Bcf storage tank is approximately $28.8 million per year, as compared to the $26.6 million estimate provided in the response to OCA 1-30.

As detailed in Section V below, the updated project design assumptions and levelized annual cost value for the Granite Bridge LNG facility were included in certain scenarios of the Company's updated SENDOUT® analyses to evaluate the proposed Granite Bridge LNG facility relative to other upstream natural gas supply options. Specifically, in addition to the updated levelized annual cost value and the updated liquefaction capacity of 10,000 Mcf per day, the variable liquefaction and vaporization costs and fuel retention associated with the updated project design for the Granite Bridge LNG facility were included in certain of the Company's updated SENDOUT® analyses (e.g., the Base Case Supplemental – Customer Benefit Guarantee scenario).

IV. COMPANY DETERMINATION OF CUSTOMER BENEFIT GUARANTEE

A. Discussions with Calpine

Q. Please summarize the discussions between the Company and Calpine.

A. As discussed in the Company's supplemental responses to PLAN 1-3 and PLAN 2-6, the Company had initial discussions with Calpine as far back as 2016 regarding the potential for Calpine to provide a peaking service to the Company utilizing its capacity on the TGP Concord Lateral. As part of those discussions, Calpine indicated that it could not provide EnergyNorth with a peaking service, but did indicate that it may be interested in receiving or contracting for a service from the Company.

Q. Please provide background regarding Calpine and their assets in New England.

A. Calpine is one of the largest owners, operators, and developers of natural gas-fired power generation facilities in the U.S., with approximately 80 power plants in operation or under construction that can generate approximately 26,000 megawatts ("MW").[27] In the New England region, Calpine owns and operates over 2,000 MW of power generation facilities, including the GREC, the Fore River Energy Center located in Massachusetts, and the Westbrook Energy Center in Maine. Given the national and regional natural gas-fired generation assets owned by Calpine, it is a significant participant in the natural gas market.

Q. Please describe Calpine's GREC facility.

A. The GREC commenced operations in March 2003 and was acquired by Calpine in February 2016. The GREC facility, which is owned in full by Calpine, can generate up to 745 MW of power utilizing two natural gas-fired combined cycle turbines.[28] The GREC is connected to the TGP Concord Lateral, which would allow Calpine to utilize a natural gas supply service provided by the Company, as the volumes from the proposed Granite Bridge LNG facility would be delivered into the TGP Concord Lateral via the proposed Granite Bridge Pipeline.

Q. Please review the process used to negotiate an arrangement with Calpine.

A. As with any commercial negotiation, the Company and Calpine participated in various discussions that culminated with an MOU, executed on October 3, 2018. The Calpine

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27 Source: Calpine website, http://www.calpine.com/, accessed September 2018.
28 Ibid.

MOU, which was provided as Confidential Attachment PLAN 1-3.2 to the Company's supplemental response to PLAN 1-3, summarizes the major deal parameters and commercial aspects mutually agreeable to the parties. Importantly, the MOU between Calpine and the Company provides a third-party market view of the value of a peaking service that can be provided by the Granite Bridge Project. This negotiated marker of value for a peaking service to a power generator provides the Company with insight to the capacity mitigation value (i.e., portfolio optimization) of the Granite Bridge Project, regardless of whether Calpine is the ultimate customer or another entity executes a contract for service.

Q. What is the status of the commercial arrangement with Calpine?

A. Subsequent to the execution of the Calpine MOU, the Company and Calpine have continued discussions with respect to a potential transaction. While Calpine has indicated strong interest in the winter peaking service from the proposed Granite Bridge Project as outlined in the MOU, Calpine indicated that it was not yet willing to further commit itself to a service that would not be available until 2023. Calpine indicated that a precedent agreement for winter peaking service at this time would be premature given the projected in-service date of the Granite Bridge LNG project and the uncertainty of future New England power market changes. That said, Calpine is continuing to stand by its MOU with the Company and sees value in a peaking service from the proposed Granite Bridge LNG facility.

B. Determination of the Customer Benefit Guarantee Based on the Calpine MOU

Q. How did the Company determine the Customer Benefit Guarantee used in the updated SENDOUT® analysis?

A. The commercial arrangement summarized in the Calpine MOU provided the Company with an appropriate market value for a peaking service associated with the Granite Bridge Project. The Company is confident that the value outlined in the Calpine MOU can also be achieved in a negotiation with other third-party market participants. Therefore, EnergyNorth will not seek recovery from its customers an amount equal to the value outlined in the Calpine MOU for the initial term of [redacted] regardless of whether the Company is successful in executing an agreement with Calpine or another third-party.

Q. Please provide the specific service attributes of the proposed peaking service as outlined in the Calpine MOU, which will either be provided to Calpine as part of a contractual arrangement or used by the Company to offset the Customer Benefit Guarantee.

A. As contemplated in the Calpine MOU, the Company will provide to Calpine a service that is available [redacted]. The initial term of the service is for [redacted] and will commence with the in-service date of the proposed Granite Bridge LNG facility, which is estimated to be in 2023. The parameters of the firm winter service to be provided to Calpine by the Company include LNG storage capacity (i.e., inventory space) of [redacted] and daily vaporization volume of [redacted].

By committing to the Customer Benefit Guarantee, the Company would use these parameters in the Calpine MOU to achieve an optimization value, which it would retain for taking the upfront risk of providing the Customer Benefit Guarantee. Stated differently, by committing to the Customer Benefit Guarantee, the Company would use the same parameters offered to Calpine for the Company's optimization opportunity and would keep any benefit to offset its commitment to provide the Customer Benefit Guarantee. In this way, regardless of the approach, our customers receive the Customer Benefit Guarantee, and Calpine, another third-party, or the Company has the right to optimize and keep any value earned.

Q. Is the compensation for the service defined in the Calpine MOU?

A. Yes, it is. As outlined in the Calpine MOU, there are certain options with respect to price structure. However, regardless of the service option the expected revenue from the Calpine MOU is approximately [redacted]. Therefore, the Company is proposing to provide a Customer Benefit Guarantee [redacted].[29]

[29] The annual revenue outlined in the Calpine MOU reflects [redacted] types of fees: [redacted].

Q. Please review the economies of scale benefit associated with an arrangement with Calpine, another third-party, or by the Company's Customer Benefit Guarantee.

A. Regardless of the contractual approach, the Calpine MOU or the Customer Benefit Guarantee will provide EnergyNorth customers with the long-term benefit of a 2.0 Bcf capacity storage tank, while initially paying less than the cost of a [redacted] storage tank. To better illustrate this point, the total system costs in the Base Case Supplemental – Customer Benefit Guarantee scenario, which includes the 2.0 Bcf storage tank coupled with the Customer Benefit Guarantee, are approximately $65 million lower than the 1.2 Bcf storage tank scenario and approximately $41 million lower than the 1.5 Bcf storage tank scenario (see Table 2 in Section V).

V. UPDATED SENDOUT® ANALYSIS

A. Enhancements and Updates to the SENDOUT® Modeling Approach

Q. As a preliminary matter, please outline the resource planning scenarios used in the Company's updated SENDOUT® analyses.

A. Similar to the approach discussed in the Company's initial filing, the Company's SENDOUT® modeling was organized into the following 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):

- Base Case Supplemental – Customer Benefit Guarantee: includes the Granite Bridge LNG facility with a tank size of 2.0 Bcf, assumes the Company's existing propane facilities are retired, and reflects the Customer Benefit Guarantee;[30]

- Alternative Case Supplemental: excludes the Granite Bridge LNG facility, and assumes the existing propane facilities are retired; and

    - Alternative Case Sensitivity Supplemental: excludes the Granite Bridge LNG facility, and assumes the existing propane facilities remain in service.[31]

In addition, with respect to the Granite Bridge LNG facility, the Company has analyzed the alternative tank sizes of 1.2 Bcf and 1.5 Bcf (i.e., the "1.2 Bcf Base Case Supplemental" and "1.5 Bcf Base Case Supplemental" scenarios).[32]

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[30] In this docket, the Company has also conducted numerous Base Case Sensitivity scenarios (i.e., includes the 2.0 Bcf Granite Bridge LNG facility and assumes the propane facilities are not retired) and the total portfolio cost of these scenarios has not been materially different than the results of the Base Case scenarios. Therefore, for ease of presentation and discussion in our Supplemental Direct Testimony, the Company is not running the Base Case Sensitivity scenario in SENDOUT®.

[31] Please note that the Alternative Case and Alternative Case Sensitivity scenarios exclude the Granite Bridge LNG facility and, as such, do not reflect the Customer Benefit Guarantee. The Company is presenting the results for the Alternative Case Sensitivity scenario as these results differ significantly from the Alternative Case. Stated differently, the decision to rely or not rely on the existing propane facilities to serve customer demand for the analysis period (i.e., through 2038/39) has a material impact on the Alternative Case and Alternative Case Sensitivity results.

[32] While the Company's initial filing also analyzed an alternative tank size of 2.5 Bcf for the Granite Bridge LNG facility, the Company did not update the analyses for the 2.5 Bcf tank size in this Supplemental Direct Testimony, as the Company is not proposing such a scenario.

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

A. The Company relied on the same key assumptions discussed on Bates 191R to 192R of the December 22, 2017, Direct Testimony of William R. Killeen and James M. Stephens regardless of the resource planning scenario. Specifically, the following assumptions were used in the SENDOUT® modeling:

- All legacy contracts for pipeline capacity and storage service expiring during the forecast period are 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 inventory at the existing LNG storage facilities; and
- Natural gas supplies are available at Dracut, Massachusetts.

In addition, the Company has incorporated the following modeling enhancements and updates to the Company's SENDOUT® model runs, which are discussed further below:

- Updated cost estimates for the proposed Granite Bridge Pipeline as discussed in Section III.A above and operational parameters (e.g., in-service date);
- Updated cost estimates for the proposed Granite Bridge LNG facility as discussed in Section III.B above and operational parameters (e.g., in-service date);

- Included cost estimates for working capital requirements;
- Updated natural gas prices based on monthly closing prices on October 29, 2018 from S&P Global Market Intelligence; and
- Updated winter prices at the Dracut point reflective of the daily weather pattern, and updated summer prices at the Dracut point based on the monthly closing prices on October 29, 2018 from S&P Global Market Intelligence.

Q. What assumptions did the Company include regarding working capital requirements in the updated SENDOUT® model runs?

A. In response to discussions at the technical sessions and through the discovery process in this docket, the Company has included certain assumptions in the updated SENDOUT® model runs regarding working capital requirements for the existing underground storage contracts, existing LNG and propane facilities, and the proposed Granite Bridge LNG facility. Specifically, a carrying cost of 9.36% per year (or 0.78% per month)[33] was applied to the identified supplemental/peaking assets and storage contracts.

Q. Please describe the updated natural gas prices used in the Company's SENDOUT® model runs.

A. The Company has updated the natural gas prices used in the SENDOUT® analyses to reflect the monthly closing prices on October 29, 2018, from S&P Global Market Intelligence, which reflects the last available monthly closing prices prior to the November

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[33] The carrying cost is consistent with the Company's most recent cost-of-gas filing in Docket No. DG 18-137.

1, 2018, start date of the Company's SENDOUT® analyses.[34] Using the same approach described in the initial filing, the Company used the natural gas prices for the length of the time period provided by S&P Global Market Intelligence (i.e., data through November 2028) and, for the remaining years in the analysis, the monthly natural gas prices are escalated at 1% annually.

Q. Please discuss the updated natural gas prices for the Dracut point.

A. Using the same methodology for the Dracut price point as discussed on Bates 192R of the Direct Testimony of William R. Killeen and James M. Stephens, and detailed in the Company's revised response to OCA 2-79, the updated winter prices at the Dracut point were reflective of the daily weather pattern (i.e., colder weather days will have higher daily prices at the Dracut point),[35] and the updated summer prices at the Dracut point are based on the monthly closing prices on October 29, 2018, from S&P Global Market Intelligence, which reflects the last available monthly closing prices prior to the November 1, 2018, start date of the Company's SENDOUT® analyses.[36] Finally, similar to the other natural gas price points, the Company used the data for the length of the time period provided by S&P

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[34] Please note, the initial filing relied on monthly closing prices on August 18, 2017, from S&P Global Market Intelligence.

[35] Using the same methodology described in the Company's revised response to OCA 2-79, the updated daily price string for the Dracut point was developed for the winter period using the Palisades @Risk software based on the Company's analysis of: (1) actual daily winter weather using heating degree days for EnergyNorth's service territory; (2) daily winter basis differentials between the TGP Dracut and Henry Hub price indices using proprietary data from S&P Global Market Intelligence over the eight winters from 2010/11 through 2017/18 (excluding weekends and holidays); (3) daily weather conditions (i.e., Normal Year heating degree days as defined in the Company's demand forecast model; and (4) average monthly forward TGP Dracut basis values for the 10 forward years as of October 29, 2018, from S&P Global Market Intelligence.

[36] Please note, the initial filing relied on monthly closing prices on August 18, 2017, from S&P Global Market Intelligence.

Global Market Intelligence and, for the remaining years of the analysis, the Dracut natural gas prices are escalated by 1% annually.

Q. Has the Company updated its demand forecast?

A. Yes, it has. There were three adjustments made to the revised demand forecast provided in the Company's response to CLF Tech 1-2 to reflect more recent information. First, on February 8, 2019, the Commission granted Northern Utilities, Inc. ("Northern Utilities") the authority to provide natural gas service in certain parts of the Town of Epping.[37] As discussed on Bates 155R of the Direct Testimony of William R. Killeen and James M. Stephens, the Company had developed an out-of-model adjustment for its expansion plans to new service areas, which included customers in the communities along the proposed Granite Bridge Pipeline (Epping, Raymond, and Candia). Because Northern Utilities was granted franchise rights to a portion of the Town of Epping, the number of potential customers that EnergyNorth can serve via the proposed Granite Bridge Pipeline has decreased. The Company thus decreased the number of expected customer additions in the new service territories.

Second, because the proposed Granite Bridge Pipeline is now expected to be placed into service in late 2022, the forecasted customer additions in the new service territories served

[37] See, State of New Hampshire Public Utilities Commission, Petition for Authority to Operate in the Town of Epping, Order Granting Franchise Authority and Motion for Confidential Treatment, Order No. 26,220, Docket No. DG 18-094, at 1. On March 7, 2019, the Company filed a Motion for Clarification and, Alternatively, Rehearing of Order No. 26,220 seeking clarification of the specific authority granted to Northern Utilities. The motion is currently pending consideration by the Commission.

by the pipeline (Epping, Raymond, and Candia) are assumed to commence in 2023, instead of 2022.

Finally, given the revised in-service date for the proposed Granite Bridge Pipeline, the Company has extended the demand forecast by one year to 2038/39. Table 1 below shows that by the end of the Forecast Period, the updated demand forecast is approximately 0.5% lower than the revised demand forecast provided in CLF Tech 1-2.[38]

[38] The same is true for the Normal Year, Design Year, and Design Day.

Table 1: Updated Demand Forecast Results (Dth)

	Revised Demand Forecast (CLF Tech 1-2)			Updated Demand Forecast		
Split-Year (Nov-Oct)	Normal Year	Design Year	Design Day	Normal Year	Design Year	Design Day
2017/2018	14,640,845	15,833,870	157,848	14,640,845	15,833,870	157,848
2018/2019	15,235,354	16,449,392	164,571	15,235,354	16,449,392	164,571
2019/2020	15,648,467	16,923,283	167,643	15,648,467	16,923,283	167,643
2020/2021	16,150,273	17,414,989	168,942	16,150,273	17,414,989	168,942
2021/2022	16,585,278	17,881,953	174,618	16,565,963	17,862,082	174,618
2022/2023	17,864,174	19,198,013	184,000	17,796,053	19,125,038	183,409
2023/2024	18,354,074	19,760,680	188,352	18,283,321	19,684,202	187,625
2024/2025	18,660,183	20,055,937	192,033	18,605,265	19,997,027	191,536
2025/2026	19,008,442	20,431,417	195,542	18,947,408	20,365,918	194,985
2026/2027	19,318,284	20,765,901	198,777	19,251,633	20,694,363	198,167
2027/2028	19,659,031	21,169,792	201,364	19,586,567	21,091,874	200,701
2028/2029	19,872,063	21,362,731	204,235	19,794,259	21,279,200	203,518
2029/2030	20,136,752	21,648,299	206,906	20,053,370	21,558,771	206,136
2030/2031	20,392,048	21,924,085	209,593	20,303,075	21,828,547	208,770
2031/2032	20,701,897	22,297,494	212,031	20,607,024	22,195,443	211,155
2032/2033	20,858,981	22,428,427	214,448	20,758,838	22,320,882	213,519
2033/2034	21,075,945	22,663,122	216,822	20,970,193	22,549,549	215,841
2034/2035	21,269,443	22,872,418	218,944	21,158,054	22,752,788	217,910
2035/2036	21,516,836	23,180,235	220,704	21,399,423	23,053,924	219,616
2036/2037	21,618,013	23,249,243	222,599	21,495,356	23,117,511	221,459
2037/2038	21,798,963	23,444,867	224,511	21,670,676	23,307,088	223,318
2038/2039	21,988,962	23,650,321	226,551	21,855,035	23,506,485	225,306
CAGR (18/19 - 38/39)	1.9%	1.8%	1.6%	1.8%	1.8%	1.6%

As shown in Table 1, the updated demand for Normal Year and Design Year increases at a compound annual growth rate ("CAGR") of approximately 1.8%, and Design Day demand increases at a CAGR of 1.6% over the 2018/19 to 2038/39 time period, which is similar to the growth submitted by the Company in its response to CLF Tech 1-2, and well within the estimates of natural gas demand growth of other local distribution companies ("LDCs") in the New England region.

Q. Please review the natural gas supply resource options analyzed by the Company in SENDOUT®.

A. While EnergyNorth has generally relied on the same approach (i.e., using the Resource Mix module of the SENDOUT® model) that was discussed on Bates 192R to 193R of the Direct Testimony of William R. Killeen and James M. Stephens with respect to the gas supply alternatives, the Company has updated certain assumptions regarding the available resource options. First, the Company has included the following natural gas supplies and/or pipeline capacity contracts in each resource planning scenario:

- The delivered supply contract with CLNG for 90-day winter, combination (i.e., liquid and/or vapor) service from the Everett LNG facility with an MDQ of 7,000 Dth per day was included through March 31, 2022.
- The pipeline capacity on the PXP Project (i.e., transportation from the Dawn Hub to Dracut)[39] was included with a three-year phase-in, 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, through the end of the forecast horizon as contemplated in the precedent agreement with PNGTS.[40]

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[39] As discussed in the Company's initial filing, the structure of the PNGTS precedent agreement has a transportation-by-others ("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 Limited ("Union Gas"), TransCanada PipeLines Limited ("TCPL") Canadian Mainline, and PNGTS). See, Bates 208R to 209R of the Direct Testimony of William R. Killeen and James M. Stephens.

[40] Since the PNGTS PXP volumes are now flowing, the Company has added this contract to its existing resource portfolio and included the pipeline capacity on the PXP Project in every resource planning scenario. However, given the current deliverability limitations on the TGP Concord Lateral, the PNGTS contract does not provide incremental Design Day supply to the Company's city-gates until the proposed Granite Bridge Pipeline is on-line.

- The Granite Bridge Pipeline is placed into service on November 1, 2022.

Next, 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, 2022, through the end of the forecast horizon (i.e., 2038/39).
- Pipeline transportation capacity from the Dawn Hub on the Union Gas, TCPL Canadian Mainline, and PNGTS pipeline systems with an MDQ of up to 150,000 Dth per day beginning on November 1, 2022, through the end of the forecast horizon.[41]
- 90-day winter, combination service from the Everett LNG facility 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 in the Company's initial filing, 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.

[41] Please note, based on discussions with PNGTS, the Company used an updated estimate for the daily demand rate regarding an incremental expansion of PNGTS to Dracut, Massachusetts.

B. Updated SENDOUT® Modeling Results

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

A. The results of the Company's updated SENDOUT® analyses, which incorporate the various assumption enhancements and updates discussed above are summarized in Table 2 below; and the detailed SENDOUT® reports are provided as Exhibit FCD/WRK-2 through Exhibit FCD/WRK-6.

Table 2: Updated SENDOUT® Model Results

Resource Planning Scenario	Reference - Confidential Exhibit	Granite Bridge LNG	Propane Facilities	Resource Mix Results			Total System Cost ($000)	Comparison to Base Case - Customer Benefit Guarantee ($000)
				Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)		
Base Case Supplemental - Customer Benefit Guarantee	FCD/WRK-2	2 0 Bcf	No	0.00	0.00	0.00	$2,796,648	$ -
Alternative Case Supplemental	FCD/WRK-3	No	No	0.00	100.28	0.51	$2,978,425	$ 181,777
Alternative Case Sensitivity Supplemental	FCD/WRK-4	No	Yes	0.00	60.94	7.00	$2,820,168	$ 23,520
Base Case Supplemental	FCD/WRK-5	1 2 Bcf	No	0.00	0.00	4.19	$2,861,181	$ 64,533
Base Case Supplemental	FCD/WRK-6	1 5 Bcf	No	0.00	0.00	1.97	$2,838,078	$ 41,430

As illustrated in Table 2, the Company's Base Case Supplemental – Customer Benefit Guarantee natural gas supply portfolio, which includes the Granite Bridge Pipeline, the 2.0 Bcf Granite Bridge LNG facility, the retirement of the propane facilities, and the Customer Benefit Guarantee, continues to be the optimal supply portfolio for our customers and allows the Company to meet long-term forecasted demand requirements at the lowest cost. The total cost of the Base Case Supplemental – Customer Benefit Guarantee scenario is approximately $182 million lower than the Alternative Case Supplemental scenario and almost $24 million lower than the Alternative Case Sensitivity Supplemental scenario, which has a significant reliance on the performance of the Company's aging propane assets. In addition, the Alternative Case Supplemental and the Alternative Case Sensitivity

Supplemental scenarios have a significant concentration risk as between 60,000 to over 103,000 Dth per day of gas supply and delivery is reliant on the availability and performance of a single entity. Lastly, the Base Case Supplemental – Customer Benefit Guarantee scenario, with a 2.0 Bcf tank is approximately $65 million and $41 million lower in total cost as compared to the 1.2 Bcf tank and 1.5 Bcf tank, respectively.

Q. In addition to the SENDOUT® analyses discussed above, did the Company conduct any other analysis regarding natural gas supply costs?

A. Yes, it has. In response to certain data requests issued by Commission Staff,[42] the Company has also calculated the unit cost of natural gas under various resource planning scenarios and compared that unit cost to the weighted average cost-of-gas rate for 2017/18 of approximately $6.86 per Dth. For ease of reference, this analysis is defined as the "Unit Cost Analysis."

Q. Please describe the assumptions used by the Company in the Unit Cost Analysis.

A. For each scenario (e.g., Base Case Supplemental – Customer Benefit Guarantee) reviewed in the Unit Cost Analysis, the Company used a two-step process to calculate the cost of natural gas for each split-year in the analysis period. First, the Company used the total cost of natural gas for each year as calculated by the SENDOUT® model. Next, that total supply cost was divided by the annual demand for natural gas resulting in a unit cost of

[42] See, for example, the Company's response to Staff 5-17.

natural gas supply by split-year. A summary of the Unit Cost Analysis is provided in Table 3 below, while the detailed calculations are included as Exhibit FCD/WRK-7.

Table 3: Unit Cost Analysis Results

($/Dth)	Base Case Supplemental – Customer Benefit Guarantee	Alternative Case Supplemental	Alternative Case Sensitivity Supplemental	1.2 Bcf Base Case Supplemental	1.5 Bcf Base Case Supplemental
Average (2022/23 – 2038/39)	$7.14	$7.68	$7.21	$7.33	$7.27

As illustrated by Table 3 above and Exhibit FCD/WRK-7, the unit cost of gas under the Base Case Supplemental – Customer Benefit Guarantee scenario is the lowest of the various scenarios analyzed. Specifically, the Base Case Supplemental – Customer Benefit Guarantee scenario is almost $0.55 per Dth lower than the Alternative Case Supplemental. For context, the Base Case Supplemental – Customer Benefit Guarantee scenario average unit cost of gas over the analysis period, which includes escalating commodity prices and new infrastructure is comparable to the 2017/18 weighted average cost of gas rate of $6.86 per Dth. In fact, over the 2022/23 to 2027/28 period, the Base Case Supplemental – Customer Benefit Guarantee scenario averages $6.88 per Dth, which is equivalent to the 2017/18 value.

Q. Did the Company calculate the annual gas supply cost for a typical residential customer under the Unit Cost Analysis calculations?

A. Yes, it did. As provided in Exhibit FCD/WRK-7, the Company applied the calculated unit gas cost values to the typical residential customer annual usage of 78 Dth to calculate an annual gas supply cost for each split-year in the analysis period. While the annual gas supply cost will vary each year depending on the unit gas supply cost for that year, the change relative to current year's results in an additional cost of approximately $1.82 per month for a typical residential customer using 78 Dth per year. This increase is inclusive of the costs of the Granite Bridge Pipeline and Granite Bridge LNG facility. It should be noted that the unit costs reflected in the SENDOUT® model take into account the forward pricing curve and include a commodity escalator of 1% in the latter years, which would also be reflected in the forward-looking projects for the annual gas supply cost, with or without the Granite Bridge Project. Moreover, without the Granite Bridge Project, the Company will be unable to offer natural gas service to additional customers, which will result in cost increases to EnergyNorth's existing customers, as increasing operational and capital costs will be spread over the current customer pool, as opposed to a greater number of customers.

VI. <u>BENEFITS OF THE BASE CASE SUPPLEMENTAL – CUSTOMER BENEFIT GUARANTEE PORTFOLIO</u>

Q. The Company's initial filing discussed in detail the qualitative benefits of the Company's proposed natural gas supply strategy. Do these same benefits apply to the Base Case Supplemental – Customer Benefit Guarantee portfolio?

A. Yes, the same qualitative benefits with respect to the Company's proposed natural gas supply strategy discussed in the initial filing apply to the Base Case Supplemental – Customer Benefit Guarantee portfolio. Specifically, the reliability of the Company's natural gas supply portfolio is significantly enhanced by the proposed Granite Bridge

Pipeline and 2.0 Bcf Granite Bridge LNG facility. Together, the components of the Company's proposed natural gas supply strategy (the Base Case Supplemental – Customer Benefit Guarantee portfolio) produce the least cost portfolio and provide the most reliability for EnergyNorth's customers. The Granite Bridge Project also provides our customers with supply diversity and price stability, and as a significant increase in the flexibility and resiliency of the overall gas supply portfolio.

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

A. Prior to discussing the qualitative benefits of the Granite Bridge Pipeline, it is important to review the current natural gas delivery situation for the Company. As discussed previously, the Company is literally at the end of the line as it is the furthest downstream customer on the TGP Concord Lateral. Because the Company is currently completely reliant[43] on the TGP Concord Lateral for the delivery of pipeline supplies, should there be any type of interruption or restriction along TGP's pipeline system, the Company's customers would be at risk of service interruption. For example, TGP could experience an unplanned outage at a compressor station, or need to replace a section of pipeline, that may affect or curtail service or reduce pressures to the Company.

As such, the primary benefit of the proposed Granite Bridge Pipeline is reliability. As a second feed from a completely independent pipeline system (the Granite Bridge Pipeline connects to the Joint Facilities), the Granite Bridge Pipeline diversifies the Company's

[43] Since the TGP Concord Lateral is the only pipeline that directly connects to the Company, it is the sole source of pipeline supply for all the Company's service territories, except for the City of Berlin, which is served exclusively by PNGTS.

delivery options, thus significantly mitigating the risk associated with the current reliance on the TGP Concord Lateral for pipeline supply deliveries. By way of example, with approximately 150,000 Mcf per day of capacity, the Granite Bridge Pipeline, together with the Granite Bridge LNG facility, would be capable of insulating nearly all of EnergyNorth's customers from a major curtailment on the TGP Concord Lateral.

Second, the proposed Granite Bridge Pipeline, as a new pipeline delivery path, increases natural gas supply options for the Company. Once the Granite Bridge Pipeline is placed into service, the Company can contract and schedule natural gas supplies to be delivered on the Granite Bridge Pipeline, the TGP Concord Lateral, or directly to the city-gates. This increase in supply diversity and contract pathing options increases the reliability of the Company's overall natural gas supply portfolio.

Third, the Granite Bridge Pipeline provides incremental capacity to serve growth in the Company's existing service territory. As discussed in the Company's initial filing and the response to CLF Tech 1-2, EnergyNorth has experienced an increasing trend in customer growth over the past few years and continues to focus on growth in New Hampshire and providing more customers with the option to choose natural gas as their fuel. Presently, growth in EnergyNorth's existing service territory is limited by the current deliverability on the TGP Concord Lateral. Absent any change to EnergyNorth's existing infrastructure and gas supply portfolio, the Company will not be able to meet the growing demand requirements of new and existing customers over the medium and long-term. That is, the Company would have to impose a moratorium prohibiting any new or expanded use of natural gas in the existing service territory.[44] Further, the Company would have to continue to rely on its aging propane facilities to meet existing customer demand. Should these facilities become inoperable or unreliable in the future, EnergyNorth's existing customers would be at risk of losing natural gas service during the peak winter periods. The Granite Bridge Pipeline will provide incremental capacity, which will allow the Company to reliably serve growing demand requirements in the existing service territory and in the new service territories; and provide a reliable supply alternative to its aging propane facilities for all our customers.

Lastly, the Granite Bridge Pipeline would provide pressure support to the TGP Concord Lateral as the Granite Bridge Pipeline will provide up to 750 psi of pressure support to the TGP Concord Lateral, where pressures at times, and with growing frequency, have dropped well below 300 psi or less during the winter. This pressure support from the Granite Bridge Pipeline improves the reliability of service to all customers.

Q. Please summarize the qualitative benefits to the natural gas supply portfolio associated with the Granite Bridge LNG facility.

A. Similar to the discussion of the Granite Bridge Pipeline in Section III.A, the primary qualitative benefit associated with the Granite Bridge LNG facility is the increase in overall reliability of the EnergyNorth natural gas supply portfolio. First, as proposed, the Granite

[44] As a result of continued growth in customer requests for natural gas coupled with the lead time required to develop new natural gas infrastructure, several LDCs have placed a moratorium on growth from either existing or new customers. For example, LDCs that have implemented moratoriums include: Berkshire Gas Company, Columbia Gas of Massachusetts, Holyoke Gas and Electric, Middleborough Gas and Electric, and Consolidated Edison Company of New York.

Bridge LNG facility as an on-system asset provides the Company with full control and management of the resource (e.g., dispatching of re-vaporized LNG), thus increasing the reliability of the overall natural gas supply portfolio. In addition, the Granite Bridge LNG facility reduces the Company's exposure to its aging peaking assets (e.g., propane facilities). The development of the Granite Bridge LNG facility will position the Company's portfolio in a manner similar to other New England LDCs that use on-system LNG for Design Day, cold snap, and Design Year needs.

Second, the Granite Bridge LNG facility provides for significant dispatch flexibility allowing the Company to dispatch re-vaporized LNG at a moment's notice to meet hourly, or weather-related, fluctuations in load. Since there is no third-party nomination required, the Granite Bridge LNG facility will be the most flexible resource in the Company's portfolio, thus enhancing the overall reliability of the natural gas supply portfolio.

Third, the Granite Bridge LNG facility provides the Company with a physical hedge that not only provides more price stability, but also provides natural gas supply replacement. Specifically, the Granite Bridge LNG facility reduces exposure to spot supply availability and volatility, and increases price stability since the Company will purchase supply during the off-peak season, when prices are generally lower, liquefy that supply, store it in the tank, and re-vaporize the liquid to meet demands during the peak period when natural gas prices are generally higher. In addition, the location of the LNG tank (i.e., connected to the Granite Bridge Pipeline in Epping) provides the Company with access to a supply source should one of its upstream natural gas supplies experience production or transmission curtailments.

Lastly, the proposed Granite Bridge LNG facility provides the Company with additional options to manage uncertainty and market changes (i.e., a more resilient natural gas supply portfolio). Specifically, with the inclusion of the Granite Bridge LNG facility in the Company's portfolio, EnergyNorth has more options and levers to manage a variety of circumstances, including (i) the potential retirement of some or all its existing propane assets, (ii) changing load profiles and demand curves, and (iii) more stringent pipeline balancing tolerances and requirements.

Q. One of the qualitative benefits just discussed for the proposed Granite Bridge LNG facility is its ability to provide a physical hedge. Please elaborate on this benefit and its relationship to the Company's existing hedging program.

A. The Granite Bridge LNG facility provides a physical hedge in that the Company can: (i) purchase natural gas in the off-peak period (i.e., summer) at prices that are typically much lower and with significantly less volatility compared to peak winter prices; (ii) liquefy and store that purchased quantity of natural in the LNG tank; and (iii) dispatch or re-vaporize the stored LNG during the highest demand days (or hours) that also have the highest potential price exposure for our customers. This physical hedge attribute of the Granite Bridge LNG facility allows the Company to dispatch a Design Day or peak period supply at a fixed and known price reflecting lower cost off-peak purchases, thus providing price stability for our customers.

The physical hedge aspect of the Granite Bridge LNG facility also provides the Company with more options and levers to manage price volatility. Specifically, the physical hedge attribute of the Granite Bridge LNG facility allows the Company to adjust or modify the volumes hedged to match the actual demand of our customers and, thereby, reduce or lower the cost incurred by the Company to provide price stability for our customers.

Over the past five years, the Company's hedging program (the purchasing of month specific transportation or basis contracts at fixed prices to increase price stability) has resulted in a cost or insurance premium of approximately $13 million. With the inclusion of the Granite Bridge LNG facility in the EnergyNorth natural gas supply portfolio, the Company can avoid this insurance premium by adjusting its approach to purchasing fixed basis contracts (e.g., lower or eliminate the transaction volume for December, January, and February, which are the months with the most price exposure and, therefore, highest cost for hedging products), yet still provide our customers with the same contribution to price stability.

Lastly, it is important to note that the physical hedge aspect of the Granite Bridge LNG facility also allows the Company to not dispatch or re-vaporize the volume in the LNG tank should the weather during a particular month of a winter season be warmer than normal. This option to not dispatch is in stark contrast to the current hedging program where the Company is obligated to purchase the hedged volumes in the specific month (i.e., January volume hedges become baseload purchases) regardless of weather conditions. By way of example, during a warm winter day or month when there is lower demand from our customers, EnergyNorth must still purchase its hedged supplies, which results in the Company scaling back on its lower cost underground storage purchases and Gulf Coast/Zone 4 purchases, resulting in a higher cost for price stability. Conversely, the proposed Granite Bridge LNG facility would simply not dispatch vapor on a warm day or lower demand month, which would allow the Company to optimize its use of low-cost underground storage and Gulf Coast/Zone 4 supplies, resulting in a lower cost physical hedging option. The flexibility to dispatch or not dispatch the physical inventory in the Granite Bridge LNG tank provides the Company with significant flexibility to more cost-effectively manage price exposure (i.e., increasing price stability) than the Company's current hedging program.

Q. Since the proposed Granite Bridge LNG facility provides the Company with a physical hedge (i.e., allows summer-priced natural gas to be purchased, liquefied, and stored in the LNG tank and dispatched in the peak winter period, thus avoiding winter prices), has the Company quantified this benefit?

A. Yes, it has. For the five most recent split-years, 2013/14 through 2017/18, the Company compared its actual cost of purchasing peak period natural gas supplies at Dracut or delivered to the Company's city-gates to a calculated physical hedge cost assuming the Granite Bridge LNG facility had been a component of the Company's gas supply portfolio during that 2013/14 to 2017/18 period.

Q. Please describe how the Company determined the actual cost of its Dracut and city-gate purchases over the 2013/14 to 2017/18 split-years.

A. For each split-year, the Company identified the vendor, volume, and cost for winter peaking natural gas supplies purchased at Dracut or the Company's city-gates. By way of example, in the 2013/14 winter period, the Company purchased approximately 2,313,000 MMBtu of natural gas at Dracut or delivered to the Company's city-gates under 11 gas supply contracts from seven vendors. The total cost for these peak period natural gas purchases was approximately $54.29 million, or a unit price of $23.47 per MMBtu.

Q. If the Granite Bridge LNG facility had been available to the Company in the summer of 2013 (the off-peak period prior to the winter of 2013/14), what would have been the cost to purchase off-peak natural gas supplies, transport that supply to the LNG facility, and liquefy those volumes for dispatch in the peak winter period?

A. Using a 7-month off-peak period from April 2013 through October 2013 and assuming that the Company purchased an equivalent amount of natural gas in each month (adjusted for the number of calendar days per month), the total cost for purchasing, transporting, liquefying and storing approximately 2,070,000 MMBtu of natural gas in the Granite Bridge LNG facility was estimated to be approximately $8.95 million, or a unit rate of $4.32 per MMBtu.

Q. Please summarize the cost savings for the EnergyNorth customers if the Granite Bridge LNG facility was available to the Company in the winter of 2013/14.

A. Based on the avoided cost of $23.47 per MMBtu (the average unit rate of the actual peak period natural gas purchased at Dracut or delivered to the Company's city-gates) compared to the Granite Bridge LNG facility physical hedge unit cost of inventory of $4.32 per MMBtu, our customers would have experienced a benefit of approximately $19.15 per MMBtu resulting in a total cost savings of approximately $40 million, assuming a 2.0 Bcf storage tank.

Q. Based on the Company's analysis over the 2013/14 to 2017/18 period, what are the total estimated savings for the physical hedge attribute of the Granite Bridge LNG facility?

A. The Company has estimated that the physical hedge provided by the 2.0 Bcf Granite Bridge LNG facility would have resulted in a total benefit of approximately $116 million over the 2013/14 to 2017/18 period for our customers. While the annual benefit ranged from approximately $12 million to $40 million, each year reviewed produced a savings or benefit associated with the physical hedge aspect of the Granite Bridge LNG facility. Please see Exhibit FCD/WRK-8, which provides the estimated cost savings for each of the split-years in the analysis, as well as a summary of the results. Also, please note that if the analysis period was focused on the December through February period of its current hedging plan (i.e., the coldest months with high price levels and volatility), the total savings increases from $116 million to $122 million. Stated differently, the physical hedge benefit alone covers approximately 85% of the annual cost of service for the Granite Bridge LNG facility. In fact, assuming that the subsequent five-year period (i.e., 2018/19 to 2022/23) yielded a similar savings as the 2013/14 to 2017/18 period, the ten-year benefit associated with the physical hedge attribute is $244 million, which is comparable to the capital cost estimate for the Granite Bridge LNG facility.

VII. CONCLUSIONS

Q. Please summarize the Company's conclusions based on the various updates and analyses discussed in your Supplemental Direct Testimony.

A. Our Supplemental Direct Testimony updates the Company's initial filing and provides more refined detail and confidence in the design and cost estimates for the proposed Granite Bridge Project. The inclusion of the Granite Bridge Project in the Company's gas supply portfolio not only significantly increases the reliability of our portfolio, it also increases the overall reliability of service to our customers in a least cost fashion. In addition, customers that do not have natural gas as an energy choice for their business or home will now have that choice.

Based on the information and analysis provided herein, the Company has the following summary conclusions:

- New England Natural Gas Supply Market
  - The natural gas supply options in the New England market are becoming more limited with the cessation of natural gas production from off-shore Nova Scotia and the likely commercial changes associated with CLNG.

- There have not been any announcements of pipeline projects that would add incremental pipeline capacity to New Hampshire.
- The Company has significant exposure to natural gas prices at the Dracut supply point, which is a New England regional natural gas pricing index. It is important to note that the New England region in general, and the Dracut supply point in particular, have some of the highest natural gas price signals in North America with considerable volatility, thus reducing the ability of the Company to provide price stability to our customers.

- EnergyNorth's Specific Situation
  - Natural gas demand in the existing EnergyNorth service territory is growing.
  - There are homeowners, businesses, and entire communities in New Hampshire that do not have access to natural gas and are precluded from having more choice in energy options.
  - The Company is currently reliant on a single feed for the delivery of gas supply to its service territory (the TGP Concord Lateral), which results in significant concentration risk should Tennessee experience an operational incident that reduces flows.
  - Since the Company is at the end of the line with respect to the TGP Concord Lateral, any reduction in pipeline pressure can result in significant operational issues for the Company's customers.

- The Company's existing customers are uniquely reliant on aging propane assets to meet Design Day, Design Year, and Cold Snap winter events.
- The Company's existing LNG assets are not on par with other New England LDCs that have significant on-system LNG peaking resources with respect to storage, liquefaction, and vaporization.

- <u>EnergyNorth's Proposed Natural Gas Supply Strategy</u>
  - To address the regional natural gas market dynamics and the Company's specific gas supply portfolio issues, EnergyNorth has developed a natural gas supply strategy that diversifies the current contracts and assets in our resource portfolio; increases the overall reliability of service to our customers and of the gas supply portfolio, creates more resiliency in our portfolio to meet changing demand and operational conditions, provides more control of the assets and, therefore, the prices paid by our customers (i.e., increases price stability); and is cost effective.
  - The Granite Bridge Project provides the Company with a measure of energy independence from the volatile New England market via an incremental gas supply source located in New Hampshire for service to New Hampshire customers. The Granite Bridge Project is under the control of the Company so it provides significant operational flexibility to meet hourly load changes and local access to address upstream supply or pipeline issues. The physical hedge associated with the Granite Bridge LNG storage tank will increase

price stability for all customers and lower commodity costs. The footprint of the Granite Bridge Pipeline will provide a second feed to the EnergyNorth service territory while providing natural gas as a fuel choice to more New Hampshire businesses and homes. And the facility is a cost-of-service asset subject to regulation by the Commission, thus providing more transparency than other third-party commercial arrangements.

- The alternatives to developing the Granite Bridge Project are severely limited and would place the Company in the unenviable position of having to negotiate with a supplier that has significant leverage. In addition, the Company would have a significant concentration risk as between 60,000 and 103,000 Dth per day of supply would be contracted with one entity that is already the major supply source at Dracut.
- The contract with PNGTS for 5,000 Dth per day of capacity on the PXP Project provides near-term diversity with respect to Dracut natural gas purchases, and will increase deliverability once the Granite Bridge Pipeline is placed in service.
- The contract with CLNG not only provides deliverability to the Company's service territory, but has a unique attribute as the gas supply can be purchased as liquid or as vapor.

Q. Does this conclude your Supplemental Direct Testimony?

A. Yes, it does.