STATE OF NEW HAMPSHIRE
BEFORE THE
NEW HAMPSHIRE PUBLIC UTILITIES COMMISSION

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

Docket No. DG 17-198

Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

DIRECT TESTIMONY OF JOHN A. ROSENKRANZ
ON BEHALF OF
PIPE LINE AWARENESS NETWORK FOR THE NORTHEAST, INC.

September 13, 2019

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

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

A. My name is John A. Rosenkranz. I am Principal with North Side Energy, LLC. My business address is 56 Washington Drive, Acton, MA 01720.

Q. Please describe your professional background and experience.

A. I have more than 30 years of experience in the areas of natural gas supply planning, gas utility regulation, and pipeline and storage project development. I have worked as a consultant to natural gas distribution companies, helping to evaluate gas supply options and document these decisions. I have negotiated and managed long-term gas supply and transportation contracts, and have done market and rate analysis for interstate pipeline and gas storage projects. I have submitted testimony and appeared as a witness in proceedings before the Federal Energy Regulatory Commission, the Maine Public Utilities Commission, the New Jersey Board of Public Utilities, and the Ontario Energy Board. I received a BA degree in economics from George Washington University, and completed all course and examination requirements for a doctorate in economics at Northwestern University. My Experience Statement can be found in Exhibit JAR-1.

Q. Have you previously testified before the New Hampshire Public Utilities Commission?

A. Yes, I have. I testified in Docket No. DG 14-380, in which Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities ("EnergyNorth") requested Commission approval for a long term gas transportation agreement.

Q. On whose behalf are you sponsoring testimony in this proceeding?

A. I am testifying on behalf of the Pipe Line Awareness Network for the Northeast, Inc.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to review the resource planning process that EnergyNorth used to support its proposal to build the Granite Bridge Project, and to assess whether the Granite Bridge Project would be the best way for EnergyNorth to meet the projected growth in customer requirements.

Q. Please summarize your conclusions.

A. EnergyNorth's proposal to build the Granite Bridge Project should be not be approved. The proposed project has two parts: a new high-pressure pipeline and a large liquefied natural gas ("LNG") peaking facility. While the idea of building a new on-system LNG facility to increase EnergyNorth's design day delivery capacity and reduce customers' dependence on propane for winter gas supply has merit, the proposed Granite Bridge LNG facility is too large for the expected need.

The Granite Bridge Pipeline should be rejected because it is more costly than other available options, and because building a new high-pressure pipeline and an on-system peaking facility at the same time would cause a wasteful duplication of capacity. EnergyNorth's dispatch modeling shows that the Granite Bridge Pipeline would not be needed to provide additional delivery capacity and gas supply after a new on-system peaking facility is brought on line.

Instead of building the Granite Bridge Project, EnergyNorth should adopt a more flexible supply strategy that adds new gas supply resources as they are needed. One such strategy would be to contract for a smaller amount of new gas transportation service from Tennessee Gas Pipeline ("TGP") to meet customers' near-term requirements, and defer the consideration of a new on-system LNG facility to a later date, with the size and timing of the facility tied to the actual growth in customer requirements.

Q. Please explain how your testimony organized.

A. Section II describes the Granite Bridge Project proposal. Section III considers the long-term demand forecast that EnergyNorth used for its gas resource evaluation, while Section IV looks specifically at EnergyNorth's gas sales obligations under the special contract with iNATGAS. Section V reviews EnergyNorth's gas resource evaluation methodology, and explains the problems with the Company's approach. Section VI addresses the non-cost factors that EnergyNorth considered in its assessment of the Granite Bridge Project. Section VII recommends a modified gas supply strategy as an alternative to the Granite Bridge Project.

II. ENERGYNORTH'S PROPOSAL

Q. What approvals is EnergyNorth requesting?

A. EnergyNorth has asked the Commission to:

1. Approve a delivered supply contract with ENGIE Gas & LNG, LLC ("ENGIE");
2. Approve a precedent agreement with PNGTS for firm transportation capacity;
3. Find to be prudent the Company's decision to build the Granite Bridge Pipeline;
4. Find to be prudent the Company's decision to build the Granite Bridge LNG facility.[1]

Q. What is the status of the ENGIE contract?

A. Constellation LNG, LLC ("CLNG") took over the ENGIE winter peaking contract in 2018. The CLNG contract provides up to 7,000 dekatherms ("Dth") per day and up to 630,000 Dth each winter season, delivered at EnergyNorth city gates. The CLNG contract extends through March 31, 2022.

Q. What is the status of the PNGTS precedent agreement?

A Under the terms of the PNGTS precedent agreement, EnergyNorth executed agreements for 5,000 Dth/day of firm transportation service from the Dawn Hub in Ontario, Canada to Dracut, MA. Partial service began in November 2018, and the full contract quantity is scheduled to be available in 2020.

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[1] Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project, December 22, 2017 ("December 2017 Petition"), page 1.

Q. Please describe the Granite Bridge Pipeline.

A. The Granite Bridge Pipeline is a proposed 26.5-mile gas transmission pipeline that would extend from Exeter, NH to Manchester, NH. The new high pressure pipe would receive up to 150,000 thousand cubic feet of gas per day ("Mcf/day") from the Joint Facilities pipeline at Exeter, and would connect to the TGP pipeline system at Manchester.[2] EnergyNorth estimates that the Granite Bridge Pipeline will cost $179 million, based on a planned in-service date of November 1, 2022.[3]

Q. Please describe the Granite Bridge LNG facility.

A. The Granite Bridge LNG storage and peaking facility would connect to the Granite Bridge Pipeline in Epping, NH. The proposed facility includes a tank capable of storing the liquid equivalent of 2.0 billion cubic feet ("Bcf") of gas, three vaporizers with a combined maximum withdrawal rate of 150,000 thousand cubic feet per day ("Mcf/day"), and liquefiers with the capacity to inject up to 10,000 Mcf/day.[4] The current cost estimate for the Granite Bridge LNG facility is $260 million.[5] EnergyNorth expects that the facility could begin operating in mid-2023 and be available for withdrawals during the 2023-24 winter season.

III. NEED ASSESSMENT

Q. Why does EnergyNorth say that the Granite Bridge Project is needed?

A. The main purpose of the Granite Bridge Project is to increase EnergyNorth's gas delivery capacity to keep up with projected growth in customer requirements. Without additional

[2] The Joint Facilities is a gas transmission pipeline that is jointly owned by Maritimes & Northeast Pipeline ("M&N") and Portland Natural Gas Transmission System ("PNGTS"). The Joint Facilities pipeline, completed in 2000, extends from Westbrook, ME to a connection with TGP at Dracut, MA.
[3] *See* attached Exhibit JAR-2, EnergyNorth's response to Data Request PLAN 8-9.1. This includes the capital costs of $168 million and $11 million for AFUDC.
[4] Because one vaporizer would be kept in reserve, the design capacity for planning purposes is 100,000 Mcf/day (*see* attached Exhibit JAR-3, EnergyNorth's response to Data Request PLAN 4-3). Based on the energy value of 1.035 Dth per Mcf used by EnergyNorth, this is equal to 103,500 Dth/day.
[5] *See* attached Exhibit JAR-4, EnergyNorth's response to Data Request PLAN 8-9.2.

gas supply resources, the Company says that it would have to impose a moratorium prohibiting any new or expanded use of natural gas.[6]

Q. How much gas delivery capacity does EnergyNorth have today?

A. EnergyNorth currently has at least 162,033 Dth of gas delivery capacity on a peak winter day (Table 1). This includes 107,833 Dth/day that is delivered to city gates using EnergyNorth's firm transportation contracts on TGP and PNGTS, 7,000 Dth/day delivered to EnergyNorth city gates by the supplier (in this case, CLNG), and 47,200 Dth/day that can be injected directly into the distribution system from EnergyNorth's on-system peaking facilities. The on-system peaking facilities include three LNG vaporization facilities and three facilities that inject propane into the natural gas stream.

Table 1: EnergyNorth's Design Day Portfolio (Dth)[7]

	Supply Resource	2019-20
1	TGP	106,833
2	PNGTS (Berlin, NH)	1,000
3	Pipeline Contracts	107,833
4	Delivered Supply (CLNG)	7,000
5	LNG Peaking	12,600
6	Propane Peaking	34,600
7	Total Delivery Capacity	162,033

Q. How did EnergyNorth estimate the amount of gas delivery capacity that customers will need?

A. EnergyNorth prepared a long-term gas demand forecast through the 2038-39 planning year, using the 2017 Least Cost Integrated Resource Plan ("2017 LCIRP") forecast as the starting point.[8] The 2017 LCIRP forecast, which is still under review by the Commission, is based on econometric modelling, but also includes significant out-of-

[6] Direct Testimony of Susan L. Fleck and Francisco C. DaFonte ("Fleck-DaFonte Testimony"), Bates page 23.
[7] Killeen-Stephens Testimony, Bates page 168R.
[8] Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, Least Cost Integrated Resource Plan, Docket No. DG 17-152.

model adjustments. The adjustments include: (a) higher customer additions in existing market areas from increased marketing and sales activity, (b) gas use projections for the towns of Windham and Pelham, (c) projected requirements under EnergyNorth's special contract with Innovative Natural Gas, LLC ("iNATGAS"), and (d) potential gas use in the towns of Candia, Raymond, and Epping, which are outside EnergyNorth's franchise area. Because the 2017 LCIRP forecast ends in 2021-22, EnergyNorth extended the forecast for another 17 years.[9]

Q. How much additional delivery capacity is needed with the Base Case forecast?

A. EnergyNorth's Base Case forecast projects a 38,947 Dth (24 percent) increase in design day gas requirements from 2018-19 to 2028-29, and a 60,735 Dth (37 percent) increase from 2018-19 to 2038-39 (Table 2). With EnergyNorth's existing gas supply resources, the projected design day shortfall is approximately 41,500 Dth in 2028-29 and just over 63,000 Dth in 2038-39.

Table 2: EnergyNorth Design Day Forecast – Base Case (Dth)[10]

		2018-19	2023-24	2028-29	2033-34	2038-39
1	Econometric	157,306	164,055	169,885	177,489	185,282
2	Marketing Adjustment	2,903	13,682	22,147	25,542	25,896
3	Windham, Pelham	111	644	1,176	1,705	2,232
4	Candia, Raymond, Epping	0	443	1,511	2,304	3,095
5	iNATGAS	4,251	8,800	8,800	8,800	8,800
6	Total Requirement	164,571	187,625	203,518	215,841	225,306
7	Supply Resources	162,033	162,033	162,033	162,033	162,033
8	Shortfall	(2,538)	(25,592)	(41,485)	(53,804)	(63,273)
9	Existing Franchise Area	(2,548)	(25,149)	(39,974)	(51,504)	(60,178)

Q: Has EnergyNorth shown that these out-of-model adjustments are reasonable?

A: No. There are several questionable aspects to EnergyNorth's Base Case forecast. First, EnergyNorth's firm requirements forecast should not include towns that are outside the

[9] Direct Testimony of William R. Killeen and James M. Stephens ("Killeen-Stephens Testimony"), Bates pages 153R to 155R.
[10] *See* attached Exhibit JAR-5, EnergyNorth's response to Data Request PLAN 8-11.

Company's existing franchise area, where gas service from EnergyNorth would depend on the construction of the Granite Bridge Pipeline. Removing these requirements lowers the projected 2038-39 design day shortfall by 3,095 Dth/day. Second, the marketing adjustment is based on customer additions projected by EnergyNorth's Sales and Marketing Group that may be overly-optimistic. Finally, there is uncertainty about EnergyNorth's future gas delivery obligations to iNATGAS, which is discussed below.

Q: Did EnergyNorth also develop a Low Case forecast?

A: Yes. In response to discovery requests, EnergyNorth also prepared a Low Case forecast that excludes the out-of-model marketing adjustment. With the Low Case, the design day requirement is projected to increase by 19,682 Dth (12 percent) from 2018-19 to 2028-29, and by 37,707 Dth (23 percent) from 2018-19 to 2028-29 (Table 3). With EnergyNorth's existing gas supply resources, the design day shortfall remains below 40,000 Dth through 2038-39.

Table 3: EnergyNorth Design Day Forecast – Low Case (Dth)[11]

		2018-19	2023-24	2028-29	2033-34	2038-39
1	Low Case	162,668	174,926	182,350	191,269	200,375
2	Supply Resources	162,033	162,033	162,033	162,033	162,033
3	Surplus/(Shortfall)	(635)	(12,893)	(20,317)	(29,236)	(38,342)

Q. How do EnergyNorth's forecasts compare to forecasts of other New England LDCs?

A. Table 4 compares the EnergyNorth forecasts to the recent forecasts of other New England LDCs over similar five-year periods. The average annual growth rate for EnergyNorth's Base Case forecast is the highest of all of the forecasts shown, while the Low Case forecast is more consistent with the base forecasts of the other LDCs.

[11] *See* attached Exhibit JAR-6, EnergyNorth's response to Data Request OCA 12-18.a.

Table 4: Projected Demand Growth Rates for New England LDCs[12]

	Company	Annual Demand	Design Day	Forecast Period
1	Berkshire Gas	0.3%	0.3%	2018-19 – 2022-23
2	Bay State Gas	0.8%	0.6%	2017-18 – 2021-22
3	Boston Gas/Colonial Gas	1.4%	1.5%	2018-19 – 2022-23
4	Fitchburg Gas & Electric	0.4%	0.5%	2018-19 – 2022-23
5	Liberty Utilities – MA	-0.1%	-0.1%	2018-19 – 2022-23
6	NSTAR Gas	2.4%	2.0%	2017-18 – 2021-22
7	Narragansett Electric	0.8%	0.9%	2018-19 – 2022-23
8	Connecticut Natural	1.6%	1.5%	2018-19 – 2022-23
9	Southern Connecticut	1.9%	1.6%	2018-19 – 2022-23
10	Yankee Gas	2.1%	1.5%	2018-19 – 2022-23
11	Vermont Gas	0.7%	0.7%	2018-19 – 2022-23
12	Northern Utilities	1.5%	1.5%	2019-20 – 2023-24
13	EnergyNorth – Base Case	4.0%	2.8%	2018-19 – 2022-23
14	EnergyNorth – Low Case	2.6%	1.5%	2018-19 – 2022-23

Q. Could EnergyNorth demand growth be lower than the Low Case?

A. Yes. Although EnergyNorth believes that the Low Case provides "a reasonable lower bound" for future load growth, it still includes the Base Case econometric forecast, the large out-of-model increase for the iNATGAS contract, and estimated demand in new towns that EnergyNorth would only serve if the Granite Bridge Pipeline is built.[13] It is very possible that new technology, such as high-efficiency electric heat pumps, and further increases in gas use efficiency will cause gas requirements to be lower.

IV. THE iNATGAS SPECIAL CONTRACT

Q. Why is the iNATGAS special contract important?

A. iNATGAS is a potentially large gas sales load that EnergyNorth has found difficult to predict. EnergyNorth assumes that iNATGAS' design day gas use will more than double

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[12] The sources for the LDC planning load forecasts are listed in Exhibit JAR-7.
[13] *See* attached Exhibit JAR-8, EnergyNorth's response to Data Request Staff 5-17 (Revised).

from 2021-22 to 2022-23, which significantly increases the projected design day supply shortfall.[14]

Q. Please explain.

A. iNATGAS is a compressed natural gas ("CNG") reseller that began operating in Concord in late 2016. Under the terms of the special contract that the Commission approved in Docket No. DG 14-091, EnergyNorth is obligated to deliver gas to iNATGAS up to a maximum hourly quantity of 720 Dth.[15] The contract puts no other maximum or minimum limits on iNATGAS' daily or annual gas use during the 15-year term.

When EnergyNorth developed the forecast for the 2017 LCIRP, the Company initially assumed that the iNATGAS requirement would not be significant.[16] EnergyNorth subsequently filed a revised forecast with much higher iNATGAS gas use.[17] For the years 2018-19 through 2021-22 EnergyNorth set the design day requirement at 4,251 Dth, which was iNATGAS' highest actual daily gas use during the 2017-18 winter. Beginning in 2022-23, EnergyNorth projects that the iNATGAS design day requirement will increase to 8,800 Dth.[18]

Q. How well has EnergyNorth been able to predict iNATGAS gas use?

A. Not well at all. Table 5 shows the large difference between the EnergyNorth forecasts and actual iNATGAS gas use during the first three years of operation. EnergyNorth concedes that it cannot predict when iNATGAS will take additional amounts of gas, and

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[14] Supplemental Testimony, Bates pages 129-137. Table 2 shows that iNATGAS accounts for 35 percent of EnergyNorth's projected design day shortfall for 2023-24.
[15] Order No. 25,694 (July 15, 2014).
[16] 2017 LCIRP, Bates page 26, footnote 25 ("…the demand from iNATGAS is not currently expected to have a significant effect on the demand forecast.")
[17] Supplemental Testimony, Bates page 65.
[18] *See* attached Exhibit JAR-9, EnergyNorth's response to Data Request PLAN 8-14. EnergyNorth assumes that iNATGAS can fill up to 22 truck trailers per day at the Concord terminal, and that the trailers used by iNATGAS will increase in size from 355 Dth to 400 Dth.

in what quantities.[19] The Company has not shown that an increase in iNATGAS' assumed design day gas use above the historical peak of 4,251 Dth is reasonable.

Table 5: EnergyNorth Forecasts and Actual iNATGAS Gas Use (Dth)[20]

	Maximum Daily Use		Annual Gas Use	
	Forecast	Actual	Forecast	Actual
2015-16	3,965	0		0
2016-17	5,619	[redacted]		[redacted]
2017-18	20	[redacted]	[redacted]	[redacted]
2018-19	4,251	[redacted]	[redacted]	[redacted]
2019-20	4,251		[redacted]	
2020-21	4,251		[redacted]	
2021-22	4,251		[redacted]	
2022-23	8,800		[redacted]	

Q. How could EnergyNorth reduce the uncertainty caused by the iNATGAS contract?

A. EnergyNorth should try to amend the existing iNATGAS agreement to define, and possibly reduce, the Company's obligation to supply gas to iNATGAS during periods of high gas demand. EnergyNorth should not extend the iNATGAS arrangement on the same terms when the Special Contract for Transportation Service expires in 2031.

V. ENERGYNORTH'S GAS RESOURCE EVALUATION

Q. After finding that additional gas supply resources will be needed, how did EnergyNorth evaluate the alternatives for meeting this need?

A. EnergyNorth says that it "conducted a rigorous evaluation of all reasonably available resource options in the marketplace to meet the needs of our customers using the resource planning standards and decisions-making process" defined in the 2017 LCIRP.[21] The

[19] *See* attached Exhibit JAR-10, EnergyNorth's response to Data Request Staff 8-6 (Exh. 10 a) ("...Liberty is not privy to the business plans of iNATGAS so it does not know the reason iNATGAS used minimal amounts of gas throughout the 2018-2019 winter season.") and PLAN 8-15 (Exh. 10 b).
[20] Forecast: Supplemental Testimony, Bates page 65. *See* also attached Exhibits JAR-11 and JAR-12, EnergyNorth's response to Data Request Actual use: PLAN 5-7 and PLAN 8-13 (through March 31, 2019).
[21] Fleck-DaFonte Testimony, Bates page 9.

2017 LCIRP states that the Company considers both price and non-price factors when evaluating resource options. Non-price factors include reliability, flexibility, viability, and diversity of supply sources.[22]

Q. How did EnergyNorth conduct its resource evaluation?

A. EnergyNorth evaluated the alternatives for expanding gas delivery capacity and increasing gas supply in two separate steps. In Step 1, EnergyNorth considered two capacity options: (1) contracting with TGP to expand the Concord Lateral, or (2) building the Granite Bridge Pipeline.[23] In Step 2, EnergyNorth considered the gas supply sources that could be obtained using the capacity resource selected in Step 1.[24]

<u>Step 1: Gas Delivery Capacity</u>

Q. Please explain the TGP Concord Lateral expansion option.

A. The Concord Lateral is the portion TGP's pipeline system that supplies gas to central New Hampshire, and is the backbone for EnergyNorth's gas distribution system. The lateral consists of two parallel pipes that extend for 38 miles from Dracut to Concord, NH. A 12-inch diameter pipe extends for the full length of the lateral. The second line is a 20-inch pipe from Dracut to Londonderry, NH, and 8-inch and 6-inch pipe between Londonderry and Concord. The design capacity of the Concord Lateral is approximately 245,000 Dth/day.[25]

Q. How much capacity does EnergyNorth currently hold on the Concord Lateral?

A. EnergyNorth has long-term contracts for 106,833 Dth/day of TGP gas transportation service to its city gates on the Concord Lateral. This includes 56,833 Dth/day of "long-

[22] 2017 LCIRP, Bates page 43.
[23] Killeen-Stephens Testimony, Bates pages 172R to 178R.
[24] Killeen-Stephens Testimony, Bates page 181R.
[25] This is the sum of EnergyNorth contract capacity of 106,833 Dth/day, the Calpine capacity of 130,000 Dth/day, and the CLNG capacity of 7,000 Dth/day.

haul" transportation service from receipt points outside of New England, and 50,000 Dth/day of transportation service with the primary receipt point at Dracut.[26]

Q. Why would TGP have to expand the Concord Lateral?

A Because all of the design capacity of the Concord Lateral is currently committed to shippers under long term contracts, EnergyNorth assumes that TGP would need to physically expand the Concord Lateral in order to provide additional gas transportation service to EnergyNorth city gates.

Q. How would TGP increase delivery capacity on the lateral?

A. TGP has indicated that it would increase the capacity of the Concord Lateral by [redacted][27] [redacted].

Q. Has TGP previously expanded the Concord Lateral?

A. Yes. The Concord Lateral has been expanded twice within the last twenty years:

1. In 2001 TGP expanded the Concord Lateral to provide the 130,000 Dth/day of service for Calpine's Granite Ridge generating facility. TGP replaced 19 miles of 8-inch pipeline with 20-inch pipeline at a cost of $33.4 million.[28]
2. In 2009 TGP installed a 6,130 horsepower gas compressor at a new station in Pelham, NH to provide 30,000 Dth/day of additional transportation service from Dracut to Concord/Laconia for EnergyNorth. The project cost was $22.5 million. EnergyNorth entered into a 20-year service agreement with TGP with a negotiated reservation rate of $0.40 per Dth.[29]

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[26] Killeen-Stephens Testimony, Bates page 164R.
[27] Supplemental Testimony, Exhibit FCD/WRK-1, Bates page 102.
[28] Federal Energy Regulatory Commission, Docket No. CP00-48.
[29] Federal Energy Regulatory Commission, Docket No. CP08-65.

Q. How did EnergyNorth estimate the Concord Lateral expansion costs?

A. EnergyNorth asked TGP to provide cost estimates for Concord Lateral expansions of 50,000 Dth/day and 75,000 Dth/day. TGP gave EnergyNorth a range of estimates, based on where on the Concord Lateral the additional gas would be delivered. The "Case 1" estimates shown in Tables 6 and 7 assume that firm delivery capacity to each EnergyNorth city gate is increased pro rata based on historical flows. The other cases assume that the Concord Lateral is expanded to better balance the contracted capacity at each city gate with the actual use. This means that more of the expansion capacity would go to city gates where the contracted capacity is currently tight, and the contracted capacity at city gates where EnergyNorth currently has a surplus would either stay the same, or be reduced.

Table 6: TGP Cost Estimates for a 75,000 Dth/day Concord Lateral Expansion[30]

			Incremental Delivery Capacity		
	City Gate	Units	Case 1	Case 2	Case 3
1	Concord/Laconia	Dth/day	[redacted]	[redacted]	[redacted]
2	Suncook	Dth/day	[redacted]	[redacted]	[redacted]
3	Hooksett	Dth/day	[redacted]	[redacted]	[redacted]
4	Manchester	Dth/day	[redacted]	[redacted]	[redacted]
5	Londonderry	Dth/day	[redacted]	[redacted]	[redacted]
6	Nashua	Dth/day	[redacted]	[redacted]	[redacted]
7	Total	Dth/day	[redacted]	[redacted]	[redacted]
8	Capital Cost	$ Million	[redacted]	[redacted]	[redacted]
9	Implied Rate	$/Dth	[redacted]	[redacted]	[redacted]

Q. What expansion costs did EnergyNorth use for its resource evaluation?

A. EnergyNorth used an estimated capital cost of $[redacted] for an expansion of 75,000 Dth/day. This cost is the average of two of the three expansion cost estimates provided by TGP (Case 1 and Case 2 in Table 6). EnergyNorth then used TGP's implied rate

[30] Supplemental Testimony, Exhibit FCD/WRK-1, Bates page 102.

estimates to calculate a reservation cost of $[redacted] per year for 75,000 Dth/day of additional transportation service from Dracut.[31]

Q. Is EnergyNorth's cost estimate for expanding the Concord Lateral reasonable?

A. No. EnergyNorth overstates the cost of the Concord Lateral expansion alternative.

Q. Please explain.

A. The first reason that EnergyNorth's Concord Lateral expansion cost is too high is that the Company does not need 75,000 Dth/day of additional gas delivery capacity. Even if a single resource option is used to meet all of EnergyNorth's projected increase in design day requirements, an increase in gas delivery capacity of 40,000 Dth/day would cover the projected supply shortfall over a 10-year planning horizon for the Base Case (Table 2), and a 20-year planning horizon for the Low Case (Table 3).

Q. What is the second reason that EnergyNorth's cost estimate is too high?

A: The second reason that the Concord Lateral expansion cost is too high is that it includes costs to increase delivery capacity to city gates at the northern end of the lateral, where EnergyNorth does not need additional capacity. TGP's cost estimates show that as gas is transported farther from Dracut, the expansion costs become significantly higher. For example, Table 7 shows that for a 50,000 Dth/day expansion, shifting [redacted].

[31] *See* attached Exhibit JAR-13, EnergyNorth's response to Data Request Staff 6-7.

Table 7: TGP Cost Estimates for a 50,000 Dth/day Concord Lateral Expansion[32]

	City Gate	Units	Case 1	Case 2
1	Concord/Laconia	Dth/day	[redacted]	0
2	Suncook	Dth/day	[redacted]	1,768
3	Hooksett	Dth/day	[redacted]	0
4	Manchester	Dth/day	[redacted]	8,696
5	Londonderry	Dth/day	[redacted]	10,220
6	Nashua	Dth/day	[redacted]	29,317
7	Total	Dth/day	[redacted]	50,001
8	Capital Cost	$ Million	[redacted]	101.9
9	Implied Rate	$/Dth	[redacted]	1.28

Q. Why would the Concord Lateral only need to be expanded to Nashua or Londonderry?

A. Under its existing contracts with TGP, EnergyNorth has more contracted capacity to Concord/Laconia than it is currently using, but the Company could use additional transportation service to Nashua or Londonderry. This is shown by Table 8, which lists EnergyNorth's seven Concord Lateral city gates, ordered from south to north. The table shows the contracted capacity to each city gate, and the peak day quantities delivered at each city gate from all sources for the last three winters. The contract capacity is higher than the actual deliveries at Concord/Laconia, but lower than the actual deliveries at Nashua.

[32] Supplemental Testimony, Exhibit FCD/WRK-1, Bates pages 112 and 120.

Table 8: TGP City Gate Quantities (Dth)[33]

	EnergyNorth City Gates	Contract Quantity	Actual Peak Day Receipts		
			2016-17	2017-18	2018-19
1	Pelham	0	0	0	135
2	Nashua	49,534	45,954	50,893	50,815
3	Londonderry	3,200	8,904	12,053	12,351
4	Manchester	50,320	33,107	33,686	35,107
5	Hooksett	4,694	1,710	2,055	2,140
6	Suncook	2,000	1,809	2,230	2,371
7	Concord/Laconia	63,500	25,856	31,513	26,968
8	Total	106,833	117,340	132,430	129,887

Q. What is the third reason that the cost to expand the Concord Lateral is overstated?

A. The expansion cost is overstated because TGP cost estimates include costs to upgrade the 3.6-mile lateral that connects the Concord Lateral to EnergyNorth's Nashua-area distribution system (the "Hudson Lateral"). However, EnergyNorth has determined that because the Company plans to integrate the Nashua and Londonderry distribution systems, less gas will need to be delivered at Nashua, making upgrades to the Hudson Lateral unnecessary. [34]

Q. Why did TGP include Hudson Lateral upgrade costs in its estimates?

A. TGP estimates that primary deliveries to Nashua through the Hudson Lateral could be increased by up to 27,000 Dth/day with the existing facilities, and that a larger increase would require modifications to these facilities.[35] Because all of the expansion cases that TGP examined assume that Nashua deliveries increase by at least [redacted] Dth/day (see Tables 6 and 7, line 6), TGP included approximately [redacted].[36]

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[33] *See* attached Exhibits JAR-14 and JAR-15, EnergyNorth's responses to Data Requests PLAN 4-4 and PLAN 8-1 respectively. Note that the sum of the contract capacities exceeds the total because some TGP contracts allow the same gas quantities to be delivered on a primary firm basis at multiple points.

[34] *See* attached Exhibits JAR-16 and JAR-17, EnergyNorth's response to Data Request PLAN 1-4 and PLAN 8-18, respectively.

[35] *See* attached Exhibit JAR-18, EnergyNorth's response to Data Request PLAN 6-5.

[36] *See* attached Exhibit JAR-19, EnergyNorth's response to Data Request PLAN 3-1.

Redacted

Q. How do the capital cost estimates for the Concord Lateral expansion option compare to the Granite Bridge Pipeline cost?

A. If the Hudson Lateral upgrade costs are removed, the TGP cost estimates for a 50,000 Dth/day Concord Lateral expansion in Table 7 would range from $[redacted] to $[redacted]. While 50,000 Dth/day is still a larger expansion amount than EnergyNorth is likely to need, this cost is considerably lower than the current capital cost estimate of $168 million for the Granite Bridge Pipeline.

Q. If the capital cost to expand the Concord Lateral is less than the Granite Bridge Pipeline cost, why did EnergyNorth conclude that the Granite Bridge Pipeline is the lower-cost option?

A. EnergyNorth did not compare the capital costs of the two capacity options. Instead, EnergyNorth calculated the estimated annual cost for the Granite Bridge Pipeline, and converted this to a daily cost using an assumed quantity of 75,000 Dth/day. Based on an estimated annual cost of $17.6 million, the daily Granite Bridge Pipeline cost is $0.64/Dth.[37] The Company then compared the daily Granite Bridge Pipeline cost to the implied reservation costs for a 75,000 Dth/day expansion (Table 6, line 9).

Q. How did EnergyNorth calculate the annual cost of the Granite Bridge Pipeline?

A. EnergyNorth used cost levelization to spread the capital costs and fixed operating expenses of the Granite Bridge Pipeline evenly over the economic life of the facilities, which was assumed to be 55 years. EnergyNorth says that it levelized costs in order to achieve an "apples-to-apples" comparison between a company investment and a pipeline company proposal.[38]

Q. Do you agree?

A. No. EnergyNorth's use of levelized costs is inappropriate for several reasons:

[37] Supplemental Testimony, Bates page 34.
[38] Direct Testimony of Timothy S. Lyons, Bates page 80R.

First, when compared to a standard cost of service rate calculation, levelization lowers costs in the early years of operation, and causes more of the costs to build and finance the project to be pushed out beyond the end of the planning horizon. In this case, the Granite Bridge Pipeline is assumed to begin operations in November 2022 and the modeling period extends through October 2039. EnergyNorth's analysis includes the levelized Granite Bridge Pipeline cost of $17.6 million per year for a period of 17 years, or about $300 million. However, because the assumed life of the pipeline is 55 years, the same annual costs would continue for another 38 years after the modeling period ends. In other words, approximately $669 million of Granite Bridge Pipeline costs ($17.6 million per year times 38 years) is excluded from EnergyNorth's analysis.

Second, EnergyNorth does not propose to use levelized costs to set customer rates. EnergyNorth says that it plans to include Granite Bridge Pipeline costs in distribution rates, and recover Granite Bridge LNG costs through the cost of gas.[39] In both cases, the rates charged to EnergyNorth customers would be calculated using a standard cost of service rate methodology, with higher initial costs that decline as assets are depreciated. The Granite Bridge Project should be evaluated using the costs that would actually be paid by EnergyNorth's customers.

Finally, EnergyNorth's levelized costs are not comparable to interstate pipeline negotiated rates. The "implied" or "indicative" rate quotes that EnergyNorth obtained from TGP are [redacted].

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[39] December 2017 Petition, pages 3-4.
[40] *See* attached Exhibit JAR-19, EnergyNorth's response to Data Request PLAN 3-1.

<u>**Step 2: Gas Supply**</u>

Q: After EnergyNorth selected Granite Bridge Pipeline as the preferred capacity resource, how did the Company evaluate options for additional gas supply?

A. Step 2 of EnergyNorth's resource evaluation considered three sources of gas supply: (1) pipeline transportation service from the Dawn Hub, (2) winter peaking supplies, and (3) the Granite Bridge LNG facility. The pipeline option is similar to the PNGTS expansion service that EnergyNorth recently added to its resource portfolio. The winter peaking options include an extension of the CLNG city gate service, and a winter peaking supply that would be delivered into Granite Bridge Pipeline or at Dracut from M&N. EnergyNorth entered these pipeline and winter peaking options into its gas supply planning model and solved for the contract quantities that minimize total costs over the period ending October 2039.

Q. How did EnergyNorth evaluate the Granite Bridge LNG option?

A. EnergyNorth evaluated the Granite Bridge LNG option by running the gas supply planning model with only the Granite Bridge Pipeline, and with both the Granite Bridge Pipeline and Granite Bridge LNG. The Company found that with the Base Case demand forecast, including Granite Bridge LNG in the resource portfolio resulted in a lower total cost over the 21-year modeling period (Table 9).

Table 9: Total Gas Supply Costs (Millions)

		Base Case[41]	Low Case[42]
1	With Granite Bridge LNG	$2,796.6	2,535.4
2	Without Granite Bridge LNG	$2,820.2	2,498.1
3	Difference	($23.6)	37.3

Q. Did EnergyNorth get the same result with Low Case demand forecast?

[41] Supplemental Testimony, Bates page 56.
[42] *See* attached Exhibits JAR-20 and JAR-21, EnergyNorth's response to Data Request OCA 12-18.b.1 (with LNG) and OCA 12-18.b.2 (without LNG), respectively.

A. No, with lower growth in gas requirements, the total cost was higher when the Granite Bridge LNG facility was included. EnergyNorth's analysis shows that without a large increase in gas demand, particularly during peak winter periods when gas prices are high, the fixed costs for the Granite Bridge LNG facility overwhelm the savings in gas purchase costs.

Q. Did EnergyNorth make any other adjustments to the Granite Bridge LNG costs?

A. Yes. In addition to using levelized costs, the modeling analysis presented in the Supplemental Testimony includes the Customer Benefit Guarantee. EnergyNorth acknowledges that, as proposed, the Granite Bridge LNG facility is larger than is needed during the initial years that the facility would be in service, but the Company assumes that it would be able to mitigate the high fixed costs by selling peaking services in the off-system market. With the Company's Customer Benefit Guarantee proposal, EnergyNorth would reserve a portion of the storage and withdrawal capacity of the Granite Bridge LNG for off-system transactions, and guarantee that customers would receive a minimum credit amount each year.[43]

Q. Did EnergyNorth consider any supply strategies that included new on-system LNG, but did not include the Granite Bridge Pipeline?

A. No. EnergyNorth only evaluated Granite Bridge LNG as a gas supply option tied to the Granite Bridge Pipeline. The Company did not consider on-system LNG as an independent source of gas delivery capacity. Given that EnergyNorth's existing on-system peaking resources currently account for 29 percent of the Company's design day delivery capacity, it is not clear why EnergyNorth failed to consider new on-system LNG peaking as a capacity resource option.[44]

Q. If Granite Bridge LNG is built, would the Granite Bridge Pipeline be needed?

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[43] Supplemental Testimony, Bates pages 44 and 45.
[44] See Table 1.

A. No, it would not. EnergyNorth's modeling analysis shows that once the Granite Bridge LNG facility comes on line in 2023, there is enough delivery capacity and gas supply to meet customer requirements through 2038 without using the Granite Bridge Pipeline to receive additional gas supplies. The only gas that would be received into the Granite Bridge Pipeline on the design day is gas flowing through the PNGTS transportation service from the Dawn Hub (Table 10, line 3). However, because EnergyNorth could also transport this gas to Dracut, and use existing TGP capacity to deliver the gas to its city gates, the Company would still be able to obtain this supply without the Granite Bridge Pipeline. Under EnergyNorth's recommended supply strategy, the Granite Bridge Pipeline segment between Epping and Manchester would be used to move gas into and out of the Granite Bridge LNG facility, but the 10-mile pipeline segment between Exeter and Epping would essentially remain empty.

Table 10: Design Day Dispatch – EnergyNorth Base Case (MDth)[45]

		2018-19	2023-24	2028-29	2033-34	2038-39
1	Pipeline (Long Haul)	57.8	57.8	57.8	57.8	57.8
2	Pipeline (Dracut)	45.6	0	0	0	0
3	Pipeline (Dawn)	-	5.0	5.0	5.0	5.0
4	Existing LNG	19.6	11.3	0.1	0.1	9.6
5	Granite Bridge LNG	-	[redacted]	[redacted]	[redacted]	[redacted]
6	Propane Peaking	34.6	-	-	-	-
7	Constellation	7.0	-	-	-	-
8	Total	164.5	[redacted]	[redacted]	[redacted]	[redacted]

Q. Could EnergyNorth connect a new LNG facility to the Concord Lateral without building the Granite Bridge Pipeline?

A. Yes. EnergyNorth could truncate the Granite Bridge Pipeline and just build the 16.5 miles of pipeline from Epping to the Concord Lateral. This would reduce the estimated pipeline cost from $179 million to approximately $115 million.[46] However, EnergyNorth

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[45] *See* attached Exhibit JAR-22, EnergyNorth's response to Data Request PLAN 8-16.
[46] *See* attached Exhibit JAR-23, EnergyNorth's response to Data Request Staff 7-28.

would achieve greater cost savings by locating the new LNG facility at a site within its existing service area, closer to the TGP Concord Lateral.

Q. Did EnergyNorth consider any new LNG sites within its existing service area?

A. No. EnergyNorth commissioned a study of potential LNG sites along the proposed Granite Bridge Pipeline route, but did not consider any new sites within its existing franchise area.[47] The Company would need to conduct additional investigations to identify potential sites.

Q. Please summarize your findings concerning EnergyNorth's resource evaluation.

A. EnergyNorth identified a need for additional gas delivery capacity and supply to meet projected growth in customer requirements, but failed to conduct a reasonable evaluation of the alternatives for addressing this need. EnergyNorth's resource evaluation has several major flaws:

1. EnergyNorth considered just two capacity options: a large one-time expansion of the TGP Concord Lateral and the Granite Bridge Pipeline. EnergyNorth failed to recognize that on-system LNG is also a capacity resource, and that a new on-system LNG facility could be built without building the Granite Bridge Pipeline.

2. EnergyNorth evaluated the Concord Lateral option based on a one-time expansion of 75,000 Dth/day, which is much larger than the projected need. The Company did not consider the option of expanding the Concord Lateral by a smaller amount, or expanding the Concord Lateral first and adding a new on-system LNG facility at a later date.

3. EnergyNorth's use of levelized costs is inconsistent with the way that Granite Bridge Project costs would be charged to customers. Levelization biased the cost comparisons to favor capital expenditures on company-owned facilities, like the

[47] *See* attached Exhibits JAR-24 and JAR-25, EnergyNorth's response to Data Request PLAN 1-7 and PLAN 5-1, respectively ("For the reasons stated in the Company's response to PLAN 1-7, no other LNG sites, other than its own Concord site, were considered within the Company's existing service territory.")

Granite Bridge Pipeline, over contracted resources, such as new gas transportation service from TGP, by shifting more costs past the end of the modeling period.

VI. NON-COST FACTORS

Q. What non-cost benefits does EnergyNorth attribute to the Granite Bridge Project?

A. EnergyNorth identifies several non-cost benefits from building the Granite Bridge Project:

1. Increase supply diversity by adding a new source of gas supply.

   The Granite Bridge Project would add an independent source of gas supply that would reduce EnergyNorth's dependence on gas supplies delivered into the Concord Lateral from the TGP mainline at Dracut.[48]

2. Increase reliability by supporting gas pressures on the Concord Lateral.

   The Granite Bridge Project would increase operating pressures on the Concord Lateral by injecting high-pressure gas into the lateral downstream of Dracut.[49]

3. Reduce gas purchase costs by limiting exposure to winter price spikes.

   The Granite Bridge Project would create a physical price hedge by allowing the lower-priced gas to be injected into the LNG storage tank during off-peak periods, and withdrawn during the winter on days when prices in the New England market are relatively high.[50]

4. Reduce dependence on existing propane peaking plants.

   The Granite Bridge Project would allow EnergyNorth to meet design day requirements without relying on propane peaking facilities.[51] EnergyNorth does not

[48] Supplemental Testimony, Bates pages 60-61.
[49] Supplemental Testimony, Bates page 35.
[50] Supplemental Testimony, Bates page 64.
[51] Supplemental Testimony, Bates page 59.

identify an immediate need close its existing propane plants, but points to high maintenance costs and operating issues caused by injecting propane into the natural gas stream as reasons for retiring these facilities.

Q. Would these non-cost benefits be lost without the Granite Bridge Pipeline?

A. No. Because the nearly all of the non-cost benefits associated with the Granite Bridge Project would come from the on-system LNG peaking facility, not the pipeline, eliminating the Granite Bridge Pipeline would not significantly affect the supply reliability, pressure support, or price hedging benefits of the proposed project.

Q. Please explain why eliminating the Granite Bridge Pipeline would not reduce reliability.

A. EnergyNorth overstates the reliability benefits of the Granite Bridge Pipeline for several reasons.

First, because the Granite Bridge Pipeline would connect to the Joint Facilities just north of the TGP interconnection at Dracut, the pipeline, by itself, would not increase supply diversity. As EnergyNorth points out, the same gas supplies that would be available to EnergyNorth through the Granite Bridge Pipeline would also be available to EnergyNorth through the TGP Concord Lateral.[52]

Second, because the Granite Bridge Pipeline would not connect to EnergyNorth's existing gas distribution network, EnergyNorth would still rely on TGP transportation services to deliver gas to its city gates on the Concord Lateral.[53] Moreover, because capacity constraints on the Concord Lateral would limit TGP's ability to transport gas from the proposed Granite Bridge Pipeline interconnect in Manchester to the EnergyNorth city gates located south of Londonderry, customers supplied from the Nashua and Pelham city gates, which currently account for more than one-third of

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[52] *See* attached Exhibit JAR-26, EnergyNorth's response to Data Request OCA 2-72 ("…the supplies available at the Dracut point are the same supplies that are available to the Company using the proposed Granite Bridge Pipeline.").
[53] *See* attached Exhibit JAR-27, EnergyNorth's response to Data Request PLAN 1-5.

EnergyNorth's peak day receipts from TGP, would still depend on gas flowing into the Concord Lateral at Dracut.[54]

Finally, it is unlikely that Granite Bridge Pipeline would be a reliable source of backstop gas supplies in the event of a disruption on TGP. PNGTS' capacity to deliver gas into the Joint Facilities from Quebec is expected to be fully-committed under long-term contracts, and will be needed to supply markets in Maine, New Brunswick, Nova Scotia, and coastal New Hampshire. On M&N, the only significant source of gas is the Canaport LNG terminal, which operates as a winter season supply resource and has a limited amount of available supply. This means that unless EnergyNorth contracts for firm gas supply, there is no guarantee that the Company would be able to acquire significant amounts of gas from the Joint Facilities to fill the Granite Bridge Pipeline on short notice.

VI. A MODIFIED SUPPLY STRATEGY

Q. Based on your review, how should EnergyNorth modify its gas supply strategy?

A. Given the uncertainty about EnergyNorth's future gas requirements, the Company should modify its gas supply strategy to add new capacity and supply resources in smaller increments. A strategy that includes multiple decision points over a long-term planning horizon would allow the Company to take reasonable steps to meet its near-term requirements without over-building.

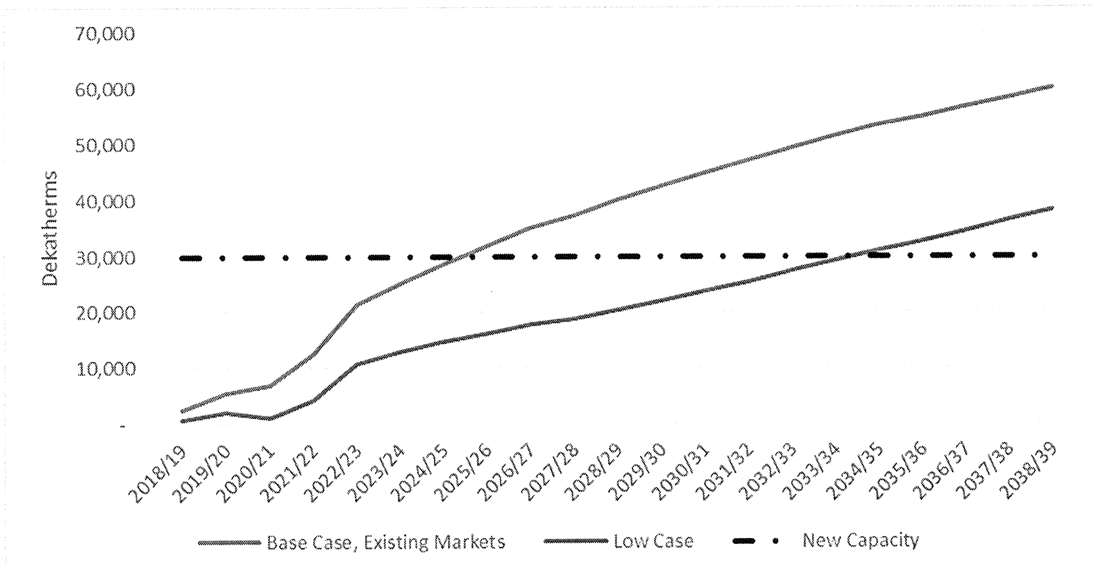
Q. How much capacity should EnergyNorth obtain to meet its near-term needs?

A. Based on the Base Case and Low Case demand forecasts, EnergyNorth's need for additional gas delivery capacity appears to be in the range of 20,000 to 30,000 Dth/day. For example, Figure 1 shows that 30,000 Dth/day of additional delivery capacity would meet the Company's projected design day requirement through 2024-25 with the Base Case forecast, and through 2033-34 with the Low Case forecast. For this amount of additional capacity, the cost to obtain additional TGP transportation service on the

[54] *See* attached Exhibit JAR-18, EnergyNorth's response to Data Request PLAN 6-5.

Concord Lateral, backed by firm winter supply at Dracut, would be less than the cost of building the Granite Bridge Pipeline and contracting for firm winter supply from the Joint Facilities.

Figure 1: EnergyNorth's Projected Design Day Shortfall



Q. How should EnergyNorth meet its long-term needs?

A. EnergyNorth does not need to make any additional commitments to gas delivery capacity or supply resources at this time. Going forward, a new on-system LNG facility connected to the TGP Concord Lateral is one option that the Company should consider. An on-system LNG facility would increase design day capacity and supply, and could replace peaking supplies that are currently provided by EnergyNorth's propane facilities, if one or more of these plants is retired for operational or economic reasons. However, if demand growth is lower than EnergyNorth projects, and the propane facilities remain viable, EnergyNorth may not need any additional gas capacity resources over a ten or twenty year planning horizon.

Q. Would the modified strategy result in lower costs for EnergyNorth's customers?

A. Yes. This is illustrated by Table 11, which uses gas supply model results that EnergyNorth provided in response to PLAN 12-2 and PLAN 12-3. This example shows that eliminating the Granite Bridge Project, contracting for 30,000 Dth/day of TGP transportation service, and timing construction of a new on-system LNG peaking facility based upon the actual growth in requirements would reduce total gas supply costs with both the Base Case and Low Case demand growth scenarios. The timing of costs is also very different. The Granite Bridge Project would commit EnergyNorth customers to large up-front capital expenditures, and cause a sudden jump in gas costs when the new facilities are put into service in 2022 and 2023 (Figures 2 and 3). With the modified supply strategy, costs are much lower in the early years of the modeling period, and comparable to the costs of EnergyNorth's preferred supply strategy after the first ten years.

Table 11: Total Gas Supply Costs, 2018-19 through 2038-39[55]

		Base Case Demand		Low Demand	
		LNG In Service	Total Cost (Millions)	LNG In Service	Total Cost (Millions)
1	Granite Bridge Proposal	2023	$2,835.0	2023	$2,571.3
2	Modified Strategy	2025	$2,756.0	2028	$2,506.1
3	Difference		($79.0)		($65.2)

[55] *See,* attached Exhibit 28, Modified Gas Supply Strategy Example. The assumptions and cost calculations for this example are provided in Exhibits JAR-28 and in JAR-28(a) (EnergyNorth's response to PLAN 10-1 (revised), JAR-28(b)(EnergyNorth's response to OCA 12.2.a), JAR-28(c), JAR-20, JAR-28(c)(EnergyNorth's response to OCA 12-2), and JAR-28(d)(EnergyNorth's response to OCA 13-5).

Figure 2: Granite Bridge Project vs. Modified Supply Strategy – Base Demand

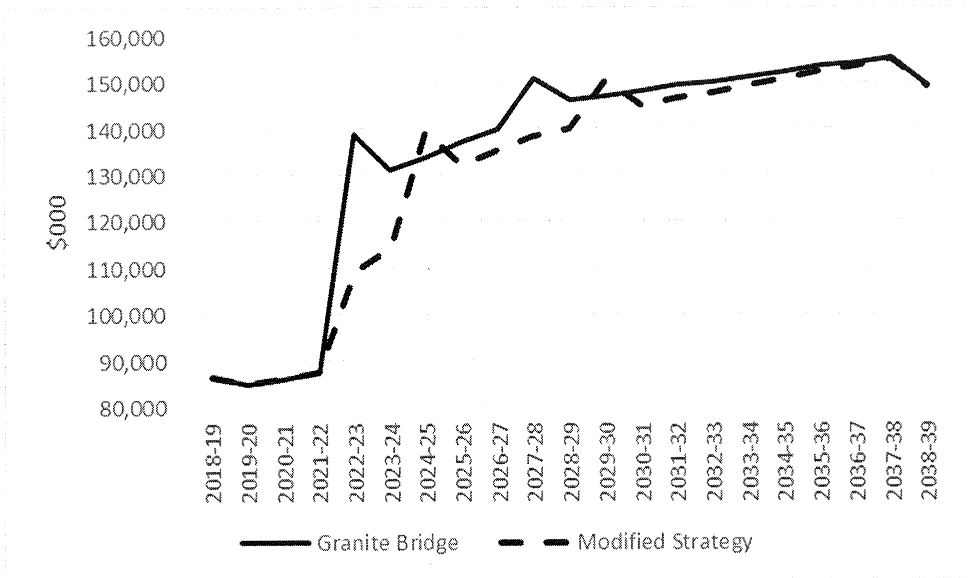
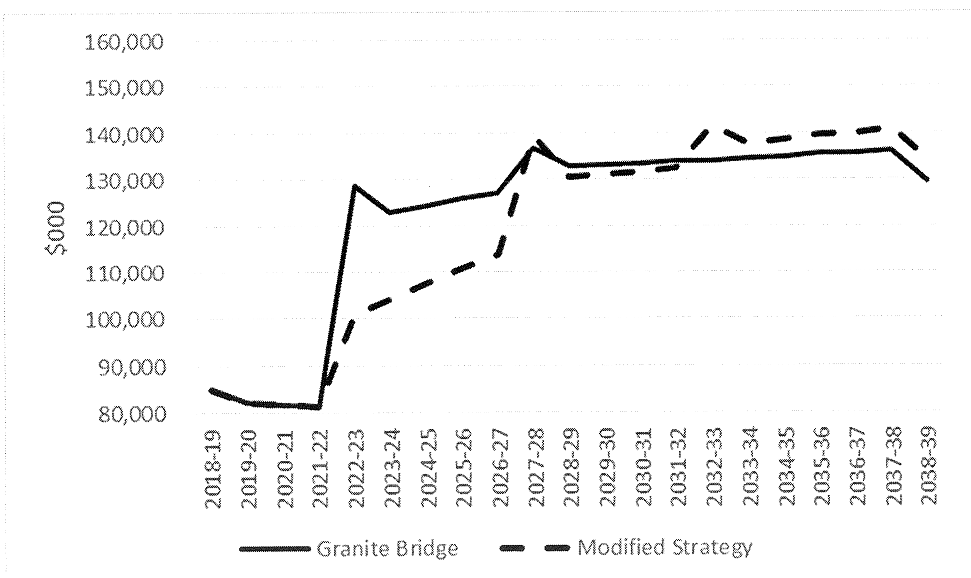


Figure 3: Granite Bridge Project vs. Modified Supply Strategy – Low Demand



Q. Are the cost savings likely to be greater than this example shows?

A. Yes. This example is conservative because the costs are based on EnergyNorth's Granite Bridge LNG proposal with 150,000 Mcf/day of delivery capacity, 10,000 Mcf/day of liquefaction, and 2.0 Bcf of storage. Because EnergyNorth's capacity on the Concord

Lateral would be expanded before an LNG facility is built, and demand growth is likely to be lower than is shown in the Company's Base Case forecast, the size of a new LNG peaking facility, if it is needed, would be smaller.

Q. Please summarize your findings.

A. The main findings from my review of the proposed Granite Bridge Project are as follows:

1. Future growth in gas requirements is uncertain. EnergyNorth's Base Case forecast shows a potential design day supply shortfall that grows to 60,000 Dth/day over the next 20 years. With the Low Case forecast, the projected shortfall in 2038-39 is less than 40,000 Dth/day. However, EnergyNorth's gas supply strategy should also allow for the possibility that demand growth will be lower.

2. EnergyNorth proposes to simultaneously construct a new high-pressure pipeline and a large LNG peaking facility, each having gas delivery capacity of at least 150,000 Dth/day. Because the gas pipeline would not be needed to provide additional gas supplies once the on-system LNG facility is completed, the Granite Bridge Project would cause a wasteful duplication of gas delivery capacity.

3. A gas supply strategy that includes a smaller amount of new TGP gas transportation service to meet near-term requirements, and defers construction of a new on-system LNG peaking facility connected to the Concord Lateral until additional delivery capacity is actually needed, would be a lower-cost and more flexible alternative to the EnergyNorth proposal.

Q. Does this complete your testimony?

A. Yes, it does.