STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

DOCKET NO. DG 17-152

IN THE MATTER OF:

LIBERTY UTILITIES (ENERGYNORTH NATURAL GAS) CORP. d/b/a LIBERTY UTILITIES

LEAST COST INTEGRATED RESOURCE PLAN

DIRECT TESTIMONY OF

JOHN ANTONUK AND JOHN ADGER
OF
THE LIBERTY CONSULTING GROUP

SEPTEMBER 6, 2019

<u>Introduction</u>

Q. Please state your names and addresses.

A. My name is John Antonuk. I am President of The Liberty Consulting Group, and Engagement Director for our work in support of the Commission Staff in this matter.

My name is John Adger. I am a Senior Consultant for The Liberty Consulting Group.

Our business address is c/o The Liberty Consulting Group, 1451 Quentin Road, Suite 400 #343, Lebanon, PA 17042.

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

A. In October 2017, Liberty Utilities (EnergyNorth Natural Gas) Corp., d/b/a Liberty Utilities (EnergyNorth or the Company) filed a Least Cost Integrated Resource Plan (LCIRP or Plan). The Plan addresses EnergyNorth's demand forecast for the next five years (2017/2018 through 2021/2022), the planning standards for determining its resource requirements for that period, and an assessment of its gas-supply resource portfolio. EnergyNorth requested approval of its Plan. EnergyNorth reported its "conclusion"[1] that replacing its aging propane-based peaking facilities "is necessary and appropriate to maintain reliable service and achieve a best-cost portfolio."[2] Our testimony in Docket No. DG 17-198 addresses later statements by management describing such retirement in terms of a possibility, as opposed to a firm plan.

[1] See Liberty Utilities, "Least Cost Integrated Resource Plan," filed in Docket No. DG 17-152 on October 2, 2017, at page 48.
[2] *Ibid.*

In March of this year, the Commission directed EnergyNorth to make a supplemental filing to address certain statutory requirements not covered in its original filing.[3] Those requirements allow the Commission to assess "potential environmental, economic and health-related impacts" of the LCIRP. That filing was made on April 30, 2019. After a Technical Session held at the Commission's offices on June 20, the Company further supplemented its Plan with expert testimony regarding those impacts.[4]

We have reviewed the Company's filings and its responses to data requests, and we have participated in all of the Technical Sessions in this matter.

This testimony, however, addresses the subjects addressed by the original LCIRP; *i.e.*, demand forecasting, planning standards, and EnergyNorth's assessment of its resource portfolio. The particular questions that we address are as follows:

1. Is EnergyNorth's demand forecast reasonable, and does it provide an appropriate basis for assessing its supply requirements for the IRP forecast period?
2. Are EnergyNorth's planning standards (normal year, design year and design day) reasonable, and do they provide an appropriate basis for assessing its supply requirements for the IRP forecast period?
3. Is EnergyNorth's assessment of its resource portfolio reasonable?

[3] New Hampshire Public Utilities Commission, Order No. 26,225, "2017 Least Cost Integrated Resource Plan, Order Denying Motion to Dismiss," issued in Docket No. DG 17-152 on March 13, 2019

[4] "Direct Testimony of Paul J. Hibbard", "Direct Testimony of Sherrie Trefry" and "Direct Testimony of Eric M. Stanley", all filed in Docket No. DG 17-152 on June 28, 2019.

Our evaluation of these aspects of the LCIRP as filed has been informed by responses to many data requests and presentations from the Company, and discussions at Technical Sessions in this matter.

With respect to the statutory requirements that electric and gas LCIRPs must address, we have not addressed potential environmental, health-related, and broad socio-economic impacts of proposed aspects of the LCIRP, but we note that the Company has provided supplemental filings that discuss the Plan's integration of and impact on the State of New Hampshire. We do not address the adequacy of the Company's assertions made about those issues in its supplemental filings.

Q. Please provide summaries of your qualifications in this matter.

A. John Antonuk is a founder of The Liberty Consulting Group (Liberty Consulting), which has served more than 40 utility regulatory authorities and a similar number of energy utilities across more than thirty years of service. He has served as the firm's president for many years, managing over 200 Liberty Consulting projects. Most of those projects have examined utility management and operations, and dozens have addressed the areas of natural gas and electricity supply planning and energy acquisition. His work on behalf of this Commission and its Staff extends across more than two decades. It includes directing and testifying about the results of a recent examination of a range of Liberty Utilities and affiliate functions and activities, including program and project planning and execution.[5]

[5] See The Liberty Consulting Group, "Final Report on a Management and Operations Audit of the Customer Service and Accounting Functions of Liberty Utilities," presented to the New Hampshire Public Utility Commission, August 12, 2016. The Liberty Consulting team that produced that report filed testimony about its investigations on December 16, 2016, in Docket No. DE 16-383.

Mr. Adger has led the firm's Natural Gas Practice Area for two decades. Since leaving government service as an Office Director at the U. S. Federal Energy Regulatory Commission, he has served clients in all segments of the natural gas industry in the United States (U.S.) and Canada. He began his association with Liberty Consulting in 1991, joining the firm full-time in 1994.

He has extensive experience with natural gas in the Northeast U.S. and Maritimes Canada. From late 1999 through 2004, he served as an adjunct to the Staff of Connecticut's Department of Public Utility Control, predecessor to today's Public Utilities Regulatory Authority. He participated in a number of proceedings during that period, including that agency's consideration of an LNG facility proposed to be constructed by Yankee Gas Services Company in Waterbury, Connecticut. The facility was authorized, and Mr. Adger returned in 2007 to assist with the Staff's evaluation of its costs. In 2013, he returned as a member of a Liberty Consulting team to assist the Staff in evaluating the Connecticut gas distribution companies' Natural Gas Infrastructure Expansion Plans, which envisioned increasing the number of gas customers in Connecticut by almost 50 percent over 10 years.

Mr. Adger was also a member of Liberty Consulting's team that served Nova Scotia's Utility and Review Board for 14 years (2004-2018), examining Nova Scotia Power's fuel-supply

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Members of that team conducted a review in 2017 to assess management's progress in implementing the audit's recommendations. See The Liberty Consulting Group, "Recommendations Verification of Liberty Utilities", presented to the New Hampshire Public Utility Commission on November 1, 2017, filed as attachment SPF-8 in the Direct Testimony of Steven P. Frink on November 30, 2017, in Docket No. DG-17-O48.

planning and management. His responsibilities included fuel-requirements forecasting and natural-gas supply planning, contracting, and management.

In New Hampshire, Mr. Adger led a Liberty Consulting team that evaluated EnergyNorth's supply planning and asset-management agreements in 2004 and 2005. That assignment included a review of EnergyNorth's then-current Integrated Resource Plan. The team returned in 2007 to assist the Commission Staff in its evaluation of EnergyNorth's proposal to enter a contract with the Tennessee Gas Pipeline Company (TGP) to expand the Concord Lateral. In early 2008, Mr. Adger and a colleague filed testimony in Docket No. DG 07-101 supporting the Company's proposal, which this Commission accepted. That expansion is covered by what EnergyNorth now refers to as its "Dracut 30" transportation contract with TGP.

Mr. Adger is currently serving as Lead Consultant for a comprehensive examination by Liberty Consulting of the natural gas supply procurement and management practices of the Maine Division of Northern Utilities, Inc. (Northern) for the Maine Public Utilities Commission. Northern also provides natural gas service in parts of New Hampshire. The personnel and processes used in Maine also support Northern's gas operations in New Hampshire.

Attachments 1 and 2 to this testimony present more complete descriptions of our backgrounds and experience.

Q. Please summarize your firm's experience in reviewing gas utility integrated resource plans.

A. We have reviewed gas-supply planning, management, and operations at many gas distribution companies and combination electric and gas utility companies over the firm's more than three decades of operation. A Liberty Consulting team evaluated EnergyNorth's 2004 LCIRP.

Demand Forecasts

Q. How does EnergyNorth forecast the demand that it needs to plan for?

A. The Company uses econometric models for forecasting, and then adjusts the results for factors that the models do not capture. The LCIRP modeled use-per-customer and numbers of customers. EnergyNorth calculated out-of-model adjustments for: (a) the effect of increased sales and marketing efforts, and (b) new customers resulting from expansion into new service territories. Management then reduced the adjusted volumetric results of its modeling for expected energy efficiency savings. These reductions and adjustments produced a forecast of net demand requirements.

The 2017 LCIRP filing combined EnergyNorth's 17 rate classes into four segments for sales and capacity-assigned transportation customers, and two segments for capacity-exempt customers. Monthly billing data for August 2010 through April 2017 then drove its models, which used regression analysis. For each segment, regression of a number of economic and demographic factors against numbers of customers produced the forecast equation for numbers of customers in that segment. Regression of customer use in each segment against weather data produced the use-per-customer equation.

EnergyNorth based its out-of-model adjustments on annual customer addition estimates for each segment. Its Sales & Marketing Group provided those estimates. Where the estimates from the Sales & Marketing Group exceeded those of the econometric forecast for portions of the existing service territory, management adjusted customer additions by the difference between the two. EnergyNorth did not employ an econometric forecast for prospective new service territories. It instead employed annual estimates of customer additions by rate class, as provided by the Sales & Marketing Group and based on market survey data provided by a contractor. EnergyNorth then aggregated those estimates into the six customer segments and added them to the respective forecasts. EnergyNorth assumed use per customer for each segment in the prospective new service territories to equal the value applied for the existing service territory.[6]

Q. What is your opinion of EnergyNorth's forecast methods?

A. We found the methods and results of the numbers-of-customers and use-per-customer models reasonable. We found the form of the customer-number models similar to those of neighboring utilities, and the diagnostics for the regression equations satisfactory. All six segments showed slight to moderate declines in use per customer, which generally matches results in comparable areas. The reductions for energy-efficiency savings also appeared reasonable.

[6] LCRIP filing page 22 describes the Company's explanation of these methods.

However, we found the out-of-model adjustments for EnergyNorth's increased sales and marketing efforts aggressive. Those adjustments increased the demand forecasts for the IRP forecast period from a compound annual growth rate (CAGR) of 0.9 percent per year[7] to 2.7 percent per year.[8]

Q. Describe the Sales & Marketing adjustments in EnergyNorth's original filing.

A. The following table[9] shows the original forecast for customer additions across the IRP forecast period. The Sales & Marketing adjustments account for 19 percent more new customers than do the econometric models.

Forecasted Customer Additions

Year	*Econometric Forecast*	*Sales & Marketing Adjustment*	*Total Additions*
2018/19	1,253	1,183	2,436
2019/20	1,197	1,212	2,408
2020/21	1,122	1,600	2,722
2021/22	1,182	1,652	2,834

Q. Did EnergyNorth adjust its the Sales & Marketing **Group's forecasts of customer additions following the original filing?**

A. EnergyNorth has twice revised its forecasts for customer additions. The first revision followed the May 2018 Technical Session, in which it made several Sales & Marketing adjustment revisions, including the following:

- Moving Concord Steam Corporation forecasted customers additions in the existing service territory to an out-of-model adjustment

[7] From Table 20 at page 21
[8] From Table 23 at page 24
[9] Source: Attachment Staff 1-9.xlsx

- Moving customer additions in the new service territories of Windham and Pelham from forecasted additions in the existing service territory to an out-of-model adjustment
- Reducing several other customer-addition forecasts to reflect more recent information.[10]

The table below[11] shows the effect of those revisions.

First Revised Sales & Marketing Adjustment

Year	*Original Sales & Marketing Adjustment*	*Revised Sales & Marketing Adjustment*	*Revised Total Customer Additions*[12]
2018/19	1,183	707	1,961
2019/20	1,212	885	2,081
2020/21	1,600	1,060	2,182
2021/22	1,652	1,202	2,384

The revised forecast still adds substantially to the Econometric Forecast, yielding a CAGR of 2.1 percent in the number of customers.

The Supplemental Direct Testimony in Docket No. 17-198 of Messrs. DaFonte and Killeen identified the second revision. That testimony reported three adjustments to the revised demand forecast provided in Attachment Staff Tech 1-7.1.[13] Only one of those changes affected Sales & Marketing's out-of-model adjustments, however. That effect occurs after the LCIRP forecast period. The revisions did not affect the Normal Year, Design Year or Design Day estimates of required gas-supply capacity for the IRP forecast period.

[10] A report on these changes was provided in Attachment Staff Tech 1-7.1, "Detailed Review of EnergyNorth's Demand Forecast, Docket Nos. DG 17-152 and DG 17-198."
[11] Source of the revised adjustment: Attachment Staff 4-5.c.1.xlsx
[12] Includes Econometric Forecast of customer additions
[13] Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen, filed in Docket No. DG 17-198 on March 15, 2019. See pages 47-49 (Bates 051-053)

Q. How do the Company's actual customer additions compare to its forecasts?

A. EnergyNorth has reported limited overlap between forecast and actual customer additions. The table below presents the available data, taken from responses to data requests in this proceeding and in Docket No. DG 17-198.

Forecasted versus Actual Customer Additions

Year	Forecasted[14]	Actual[15]
2014/15	1,750	1,483
2015/16	1,835	1,778
2016/17	2,110	1,790
2017/18		1,586
2018/19	1,961	1,501*
2019/20	2,081	
2020/21	2,182	
2021/22	2,384	

* Year-to-date and committed

Q. What do you conclude about likely customer additions across the forecast period?

A. The data show that EnergyNorth is adding customers, and doing so at a higher rate than it did before Liberty Utilities acquired the Company. Recent experience, however, suggests that EnergyNorth's Sales & Marketing Group is overly optimistic about the rate of customer additions. The rate is likely to be higher than the econometric forecast, but not as high as the forecasts suggest. Considering recent experience, we consider more appropriate a plan for adding about 1,600 to 1,800 customers per year for the balance of the IRP forecast period. A rate of 1,700 would produce a CAGR of 1.7 percent per year in number of customers for the

[14] Sources: response to DR No. Staff 4-10.d in Docket No. 17-152 for 2014/2015 through 2016/2017. The data in that response is for calendar years, rather than for the Forecast Years in the table, so we used the estimate with the most overlap with the Forecast Years in this table. For example, the entry for 2014/2015 is the number for 2015 in the DR response. The numbers for 2018/2019 through 2021/2022 are from Attachment Staff 4-5.c.1.xlsx in Docket No. DG 17-152.
[15] Source: response to DR No. Staff 8-2 in Docket No. DG 17-198

forecast period, down from the 2.1 percent per year that resulted from the Company's June 2018 revision.[16]

Q. Do you have any other observation about EnergyNorth's demand forecasts?

A. Yes; EnergyNorth adjusted its aggregate demand forecast for unaccounted-for gas and unbilled sales, and used regression analysis to develop forecasts of daily requirements. We found these typical and appropriate. EnergyNorth's application of them to the Net Demand numbers, however, produced a CAGR for the Normal Year Total Planning Load of 3.2 percent per year.[17] We view this rate as too high, because the forecast number of customers is too high, as discussed above. We do not have access to the necessary inputs for recalculating the Normal Year Total Planning Load, but we recommend that EnergyNorth recalculate it using the lower numbers for customer additions.

Q. How do EnergyNorth's forecasts compare with those of neighboring utilities?

A. Northern Utilities, Inc. (Northern) recently filed its IRP for the period 2019/2020 through 2023/2024.[18] That company's New Hampshire service territory is close geographically to EnergyNorth's. We looked at Northern's forecasts for its New Hampshire territory to see how they compare with EnergyNorth's.

Northern's New Hampshire Division (NUI-NH) has a smaller customer base than does EnergyNorth -- 32,990 customers in 2018[19] versus 99,466.[20] Its mix of customers parallels

[16] This is the revision reported in Attachment Staff Tech 1-7.1 in Docket No. DG 17-152.
[17] Source: Attachment Staff Tech 1-7.1 in Docket No. DG 17-152, at Table 1 on page 2
[18] Northern Utilities, Inc., 2019 Integrated Resource Plan, submitted jointly to the Maine Public Utilities Commission and the New Hampshire Public Utilities Commission, July 19, 2019
[19] Sum of Residential Customers for the 2017/2018 Gas Year from Table IV-19 on page IV-59 of Northern's IRP, plus C&I LLF from Table IV-23 on page IV-62, plus C&I HLF from Table IV-24 on page IV-63.
[20] Liberty Utilities (EnergyNorth Natural Gas) Inc., 2018 Annual Report to the New Hampshire Public Utilities Commission. See Page 31.

that of EnergyNorth -- 79.3 per cent residential/20.7 percent commercial and industrial (C&I) versus 86.3 percent residential/13.7 percent C&I for EnergyNorth. NUI-NH combines its Residential Heating and Non-Heating customers, producing use per customer of about 72 Dth/year. EnergyNorth calculates about 77 Dth/year for Residential Heating customers and about 23 Dth/year for Residential Non-Heating. Part of C&I use per customer is also similar: NUI-NH's use per customer for low-load-factor (LLF) customers is about 540 Dth per year, whereas EnergyNorth's for C&I heating customers falls just under 600. NUI-NH's use per customer in its high-load-factor C&I segment is higher than EnergyNorth's in its Non-Heating segment - - about 3,200 Dth/year compared to EnergyNorth's 1,200.

NUI-NH experienced a CAGR of 2.1 percent per year in its numbers of customers for years 2014/2015 through 2018/2019, but forecasts a slowing to 2.0 percent per year over the next five years. It forecasts net demand, after adjustment for energy efficiency savings, to grow by a CAGR of 1.4 percent per year,[21] considerably less than EnergyNorth's forecast rate of 2.7 percent per year.[22] NUI-NH's Net Demand is adjusted for Company Use, Lost and Unaccounted-For Gas and Energy Efficiency Savings to yield Normal Year Throughput, which appears to be roughly equivalent to EnergyNorth's Total Planning Load. NUI-NH's Normal Year Throughput is forecast to grow at a CAGR of 1.4 percent per year,[23] considerably less than EnergyNorth's 3.2 percent per year.

[21] NUI IRP, Table IV-28 at page IV-66
[22] EnergyNorth IRP, Table 24 at page 25
[23] NUI IRP, Table IV-35 at page IV-70

We attribute the difference in large part to the two companies' differing expectations for growth in their respective numbers of customers. NUI-NH's forecasts produce customer additions predicted by econometrics; EnergyNorth adds to its econometric forecasts out-of-model adjustments provided by its Sales & Marketing Group.

Planning Standards

Q. How did EnergyNorth develop its Normal Year planning standard?

A. EnergyNorth calculated the average annual number of heating degree-days (HDDs) using 30 years of HDD data for the Manchester weather station. It then replaced the 30-year average months with data-set actual months similar to the average HDD and standard deviation for each month. The results produced Normal Year HDD of 6,325, distributed through the year as shown in Table 27 of the LCIRP, at page 28 (Bates Page 32).

Q. How did the Company select a Design Year and a Design Day?

A. Management selected values of 71.4 HDD for the Design Day, and 6,869 HDD for the Design Year. The Company used a Monte Carlo analysis of 38 years of temperature data from the Manchester weather station (January 1, 1979 through December 31, 2016) to select its Design Year and Design Day. The Design Day calculation employed statistical analyses of the coldest day of each year; the Design Year calculation employed statistical analyses of the total HDDs in each calendar year. In both cases, management selected as its planning basis the average plus two standard deviations, which results in a probability of only about 2.5 percent that the selected value would be exceeded. EnergyNorth used monthly HDDs and standard deviations to distribute the HDDs through the year in a manner that would reflect daily and monthly variation.

Q. What is your opinion of this approach?

A. We found it acceptable. Use of Monte Carlo simulation to select these parameters is now industry best practice. Companies' methods for distributing the Design Year HDDs through the year can vary somewhat, but we found the EnergyNorth methods appropriate.

Q. So what do you conclude about EnergyNorth's planning standards?

A. We found no concerns with the methods that EnergyNorth used to determine its planning standards, neither the methods that the Company used nor the results that it obtained.

However, we did find the demand forecasts produced by applying the Company's choice of standards too high, because the numbers of customers used to produce those numbers are too high, as explained above. We do not have access to all of the inputs necessary to produce alternative values for Normal Year Demand, Design Year Demand and Design Day Demand, but we recommend that the Company recalculate those parameters using our lower estimates of customer additions.

Q. Do you have any other comments about EnergyNorth's discussion of its Planning Standards?

A. At the end of the LCIRP's discussion of Planning Standards, EnergyNorth added High Growth and Low Growth Scenarios. The High Growth Scenario adds 1.0 percent per year to the Base Case growth rate, which would yield a CAGR of 4.2 percent per year for the Normal Year Demand Forecast for the IRP forecast period, 4.1 percent per year for the Design Year Demand Forecast, and 3.6 percent per year for the Design Day Demand Forecast. The Low Growth Scenario subtracts 1.0 percent per year from the Base Case growth rate, yielding a CAGR of 2.2 percent per year for Normal Year Demand for the IRP forecast period, 2.1 percent per year for Design Year Demand, and 1.6 percent per year for Design Day Demand. Again, we do not have access to the inputs necessary to recalculate these parameters for the lower rate of customer growth that we envision, but the Company's Low Growth Scenario would seem closer to our expectations than the Base Case and High Growth Scenarios.

Assessment of Resource Portfolio

Q. What do you understand to comprise EnergyNorth's Design-Day gas-supply resources?

A. The Company has 107,833 Dth/day of deliverability to its city-gate stations, via capacity on the Tennessee Gas Pipeline (TGP) and the Portland Natural Gas Transportation System (PNGTS). The PNGTS capacity brings supply from Canada; the TGP capacity brings supply from production and market areas in the U. S. and Canada and storage gas from facilities in Pennsylvania.

A number of other facilities complement these sources of upstream capacity. They include three LNG facilities, with a combined operational storage and vaporization capacity of 12,600 Dth/day[24] and three propane-air plants, with a combined design vaporization rate of 34,600 Dth/day.

EnergyNorth's pipeline, LNG, and propane-air facilities provide a combined available supply capacity of 155,033 Dth/day.

[24] The binding constraint for these plants is storage capacity. Vaporization capacity is about twice the storage capacity.

Q. What is EnergyNorth seeking as part of the LCIRP filing?

A. EnergyNorth notes that almost all of its legacy pipeline and storage capacity contracts will expire during this LCIRP's forecast period. The Company proposes renewal of those contracts, given its continuing need to provide reasonable assurances of its ability to deliver volumes required to serve its customers. The next table lists the contracts proposed by EnergyNorth for renewal.

Contracts Proposed for Renewal

Contract Entity	Rate Schedule	Contract Number	MDQ/MDWQ (Dth)	StorageMSQ (Dth)	Expiration Date
Pipeline Transportation					
Union Gas System	M12	M12200	4,092	-	10/31/2022
TCPL	FT	41232	4,047	-	10/31/2022
Iroquois	RTS	470-01	4,047	-	11/1/2022
PNGTS	FT	1999-001	1,000	-	10/31/2019
TGP	FT-A (one 5 to Zone 6	95346	4,000	-	11/30/2021
TGP	FT-A Zone 5 to Zone 6	2302	3,122	-	10/31/2020
TGP	FT-A Zones 0,1 to Zone 6	8587	25,407	-	10/31/2020
Underground Storage and Associated Pipeline Transportation					
TGP	FS-MA	523	21,844	1,560,391	10/31/2020
TGP	FT-A Zone 4 to Zone 6	632	15,265	-	10/31/2020
Honeoye	SS-NY	11234	1,957	245,280	3/31/2020
TGP	FT-A Zone 5 to Zone 6	11234	1,957	-	10/31/2020
Dominion	GSS	300076	934	102,700	3/31/2021
TGP	FT-A Zone 4 to Zone 6	11234	932	-	10/31/2020
National Fuel	FSS	O02357	6,098	670,800	3/31/2019
National Fuel	FST	N02358	6,098	-	3/31/2019
TGP	FT-A Zone 4 to Zone 6	11234	6,150	-	10/31/2020

Q. Describe further EnergyNorth's position with respect to its propane facilities.

A. The Company noted concern about its "aging propane facilities and the continued reliance on them to perform at peak capacity during the coldest days of the year."[25] Its LCIRP Report states that "that the replacement of these propane facilities is necessary and appropriate to maintain reliable service and achieve a best-cost portfolio."[26]

Statements in the related proceeding (Docket No. DG 17-198) frame the Company position somewhat differently. That proceeding addresses EnergyNorth's proposals for a liquefied natural gas (LNG) manufacturing and storage facility and a high-pressure pipeline to connect that facility to the Company's service territory.[27] Those statements describe retirement of the facilities as more an option than a necessity.[28] As we will describe in our testimony in that proceeding, we believe that the information available supports continuing value for the Company and customers in continuing operation of its existing facilities.

Q. What conclusions did EnergyNorth reach with respect to Resource Assessment, as addressed in LCIRP?

A. The Company notes that its demand forecast shows an increase in requirements over the LCIRP forecast horizon. Its filing presents the results of its consideration of gas supply options that it identified, which include:

- Supply delivered by ENGIE[29] to the Company's LNG facilities and city gates

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[25] LCIRP Report, at page 48
[26] *Ibid.*
[27] NH PUC Docket No. DG 17-198, *In the Matter of: Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities, Petition to Approve Firm Supply, Transportation Agreements, and the Granite Bridge Project*
[28] See, *e.g.*, the Direct Testimony of Susan L. Fleck and Francisco C. DaFonte, filed on December 22, 2017, in Docket No. DG 17-198, at page 17 (Bates Page 021), lines 19-21.
[29] At the time that the LCIRP was prepared, ENGIE LLC owned the Everett, MA LNG receiving terminal, and provided gas-supply services out of that terminal. As a result of the acquisition of the Everett Facility, which transaction closed on October 1, 2018, Constellation became the assignee of the contract between ENGIE Gas &

- Supply delivered by Repsol to Dracut, MA
- Pipeline capacity from the Dawn Hub on the TransCanada PipeLines (TCPL) and PNGTS to Dracut, MA
- Increasing on-system LNG storage and vaporization capacity.

EnergyNorth presented the results of employing SENDOUT modeling to analyze its resource portfolio, incorporating the effects its alternatives would produce. The analysis showed that the addition of available resources (including the ENGIE supply, possible supply from Repsol, and potential pipeline-capacity contracts with TCPL/PNGTS) to its existing ones would sufficiently meet its requirements under Normal, Design Year and Design Day conditions. This result applied to both High- and Low-Growth Scenarios throughout the LCIRP forecast period.

Q. Has EnergyNorth acted on any of these options since preparation of the LCIRP?

At the time of LCIRP preparation, the Company reported that it had contracted with ENGIE for a combination liquid/vapor service for up to 7,000 Dth/day. Management considers this service useful in some combination of refilling its LNG storage tanks and delivering incremental supply to its city gates. EnergyNorth included this contract in its cost-of-gas filing in Docket No. DG 17-135, so we assume that it has started taking deliveries under the contract.

Q. What is your opinion of the Resource Assessment segment of the LCIRP?

LNG, LLC (ENGIE) and Liberty Utilities that is among the items under review by the Commission in Docket No. DG 17-198. Motion of Constellation LNG, LLC for Leave to Intervene Out-of-Time (12/13/18) at 1.

A. We found EnergyNorth's use of SENDOUT modeling to support its analysis and to justify its conclusions appropriate. This tool finds very widespread industry use for similar purposes. ABB licenses this proprietary model for use in natural gas supply-planning initiatives. SENDOUT works by using linear programming algorithms to simulate gas operations and optimize results. Linear programming forms the core of many commercial software models used to perform simulations and optimizations. SENDOUT considers demand forecasts, available supply and delivery options, and the costs associated with them to produce projections of costs for meeting demand with various combinations of supply options. It solves for the least-cost option to meet demand. Ultimately, SENDOUT provides users with an estimate of annual delivered supply cost that considers all costs.

We also found EnergyNorth's selection of the ENGIE, Repsol and TCPL/PNGTS supply options appropriate. Their specification to the SENDOUT modeling was based on actual contract parameters or offers of supply, which allowed for proper cost comparisons.

Our concern rests with the demand forecasts that Liberty relies on. As noted earlier, we consider them to be too high. However, we expect that EnergyNorth will continue to add customers during the LCIRP forecast period, and thus some amount of additional supply capacity will be required during that period.

EnergyNorth's SENDOUT analysis tested the Base Case, High Growth, and Low Growth Scenarios defined in the Planning Standards section of the LCIRP. The ENGIE contract that has already begun is required in all scenarios throughout the LCIRP forecast period, making it an appropriate portfolio element for planning purposes.

The SENDOUT analysis suggests that all other supply options require "an extension of [the Company's] system … capable of accessing incremental deliveries of natural gas supplies to serve incremental demand requirements."[30] Such an extension is not required for the ENGIE contract -- ENGIE can deliver to EnergyNorth's city gates. The Company has proposed an extension of its distribution system and a large on-system LNG facility in Docket No. DG 17-198. Those facility additions, along with the other alternatives identified in the LCIRP, are being considered in that proceeding. The analysis presented in the Resource Assessment section of the LCIRP assumes the extension of EnergyNorth's distribution system to access those other supply options. Whether such an extension will be required during the LCIRP forecast period remains to be examined with better demand estimates.

Q. Please summarize your conclusions and recommendations about the supply alternatives considered and those proposed by EnergyNorth.

A. The Company has projected across the LCIRP forecast period a continuing need for the legacy pipeline and storage capacity contracts set to expire. Our first conclusion is that it is appropriate to include them on an EnergyNorth planning basis. The U. S. Federal Energy Regulatory Commission's (FERC's) incremental-pricing policy makes this supply capacity lower in price than alternatives for replacing it.

[30] LCIRP Report, at page 52

Second, we conclude that the ENGIE contract also comprises an appropriate portfolio element in Liberty Utilities' plans. We agree that there exists a need for some addition to gas supplies, both capacity and commodity, during the LCIRP forecast period. We found EnergyNorth's identification of available supply options sufficient, and its analysis of them sound and comprehensive. Consideration of any other additions, including any system extensions necessary to access them, should be deferred to the Granite Bridge proceeding, Docket No. DG 17-198.

<u>Overall Recommendation</u>

Q. Do you have an overall recommendation regarding the LCIRP?

A. We have addressed the original LCIRP filing's treatment of demand forecasting, planning standards, and assessment of the resource portfolio. The demand forecast has been revised, as noted above, but is still too high in our view. We find that the processes for developing the Planning Standards to be satisfactory, but they have been applied to demand estimates that are too high. We recommend revision of those parameters to correspond with our lower demand estimates.

Regarding the resource portfolio, we find that the Company's identification of potential supply options reasonable, including the proposed ENGIE contract. Any further assessment of extensions to the Company's distribution system or additional supply options should be deferred to the Granite Bridge proceeding.

Q. Does that complete your testimony?

A. Yes.