APPENDIX A

Table A-1: Calendar Year Energy Efficiency

Year	Residential		C&I		Total	
	Energy Efficiency / Demand	Energy Efficiency (Dth)	Energy Efficiency / Demand	Energy Efficiency (Dth)	Energy Efficiency / Demand	Energy Efficiency (Dth)
2017	0.58%	34,584	0.83%	88,970	0.74%	123,554
2018	0.63%	39,079	0.81%	90,993	0.75%	130,072
2019	0.63%	39,586	0.87%	98,494	0.78%	138,080
2020	0.67%	42,664	0.90%	104,266	0.82%	146,929
2021	0.67%	43,493	0.90%	106,513	0.82%	150,009
2022	0.67%	44,395	0.90%	109,058	0.82%	153,453

Table A-2: Demand Forecast Results (Dth)[1]

Split-Year	Econometric Forecast Including Out-of-Model Adjustments	Energy Efficiency	Demand Net of Energy Efficiency
2017/18	14,582,686	106,785	14,475,900
2018/19	14,872,185	113,258	14,758,927
2019/20	15,228,065	121,480	15,106,585
2020/21	15,587,463	125,408	15,462,056
2021/22	15,985,398	128,686	15,856,712
CAGR	2.3%	4.8%	2.3%

[1] Results are prior to unaccounted for gas and unbilled sales, and the out-of-model adjustment for iNATGAS. Differences due to rounding.

Resume & Testimony Listing of:
James M. Stephens
Partner

scottmadden
MANAGEMENT CONSULTANTS

Summary

Mr. Stephens has 30 years of experience in the energy industry and has held senior management positions at economic consulting firms, a retail energy marketer, and local distribution companies prior to joining ScottMadden. Mr. Stephens has assisted numerous clients in the United States and Canada with natural gas supply analysis, portfolio assessment and optimization, demand forecasting and risk management, energy infrastructure evaluation, and regulatory strategy development and implementation. He has also provided expert testimony in numerous proceedings at various jurisdictions, including federal, state, and provincial regulatory agencies.

In addition, Mr. Stephens has commercial experience through his leadership positions at a retail energy marketing company, where he was responsible for all aspects of business unit management, including front, mid and back-office functions. He was also responsible for gas supply procurement and portfolio optimization for a local distribution company. Mr. Stephens holds a Bachelor of Science degree in management and a Masters in Business Administration with a concentration in operations management from Bentley College.

REPRESENTATIVE PROJECT EXPERIENCE

Energy Market Assessment

Retained by numerous companies to develop regional energy market assessments which included: market impacts associated with new energy infrastructure, assessment of the implications associated with natural gas infrastructure, market structure and regulatory situational analysis, and assessment of competitive position. Market assessment engagements typically have been used as required elements of business unit or asset-specific strategic plans or valuation analyses. In addition, certain market assessments have been submitted to various federal, state, and provincial regulatory agencies.

Representative engagements have included:

- Submitted expert testimony on behalf of Eversource to the Massachusetts Department of Public Utilities and the New Hampshire Public Utility Commission regarding pipeline capacity and LNG service precedent agreements on the Access Northeast project.
- Submitted an expert report on behalf of Union Gas and Enbridge Gas Distribution to the Ontario Energy Board with respect to pipeline precedent agreements on the NEXUS Pipeline project.
- For two Canadian LDCs, developed a review of certain mid-Atlantic natural gas supply basins.
- For the State of Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas and power markets; and analyzed the potential benefits and costs associated with natural gas pipeline expansions. The independent report was filed at the Maine Public Utility Commission.
- On behalf of Spectra Corporation, developed a market assessment evaluating the impact of new pipeline infrastructure into the New York City, New Jersey and New England markets. The independent reports were filed at the Federal Energy Regulatory Commission and/or presented to state public utility commissions.
- For a Canadian utility developed a detailed review of the U.S. Northeast energy market and presented findings to their senior management.
- For an international energy company, prepared an assessment of the market potential for distributed LNG, with a particular focus on the commercial and industrial sectors.
- For a project developer, prepared a natural gas demand analysis of the Southeast U.S. The independent report, which was filed at the Federal Energy Regulatory Commission, addressed the demand for natural gas in both the electric generation and traditional LDC markets.
- For an international energy company, prepared an analysis regarding LNG peaking facilities.
- Conducted due diligence for commercial banks regarding investments in natural gas pipelines, natural gas storage projects, and LNG facilities.

- For a project developer, assisted with the evaluation of the market opportunity for an LNG importation terminal in the northeastern United States.
- For numerous clients, provided regional natural gas demand assessments to assist with the evaluation of energy infrastructure.
- For a natural gas producer, reviewed energy contracting practices and pricing mechanisms to support a contract arbitration process.

Business Strategy and Operations

Retained by numerous North American energy companies to support the development of strategic plans and planning processes for both regulated and non-regulated entities. Specific services provided include: developing market entry strategies for the retail and wholesale energy sectors; review of management practices and procedures; and business process redesign initiatives.

Representative engagements have included:

- For Columbia Gas of Massachusetts, developed expert testimony analyzing a contract for natural gas pipeline capacity. The testimony was submitted to the Massachusetts Department of Public Utilities.
- For Union Gas, developed expert testimony regarding the gas supply planning process and associated activities. The testimony was submitted to the Ontario Energy Board.
- For Gaz Métro, developed expert testimony regarding the utilization of natural gas storage. The testimony was submitted to the Régie de l'énergie.
- For an LDC, reviewed its current retail choice program, certain proposed changes, and the potential impacts on the gas supply portfolio.
- For an LDC, reviewed the cost and benefits of expanding into new service territories.
- Reviewed natural gas supply alternatives (i.e., supply basin cost, transport basis and regulatory issues) for an integrated energy company.
- Developed regional market assessments and associated market entry strategies for a wholesale energy marketing company.
- Reviewed certain risk management practices and procedures for a wholesale energy marketing company.
- For a retail energy marketer, conducted due diligence including a review of risk management policies and procedures.
- Prepared a competitive position analysis (i.e., SWOT analysis) for an interstate gas pipeline.
- On behalf of a wholesale energy marketing company, reviewed federal and state requirements associated with entering certain natural gas markets.
- For an LDC, assessed the economic viability of gas distribution utility service expansion.
- Developed new service offerings, including firm transportation and stand-by service, for a mid-Atlantic utility.
- Managed the re-engineering of a large Midwest LDC's gas supply procurement process.
- Managed the re-engineering of a mid-Atlantic wholesale energy marketing company's gas operations including certain risk management areas.
- On behalf of an interstate pipeline, conducted a customer outreach/survey program.

Regulatory Analysis and Support

On behalf of energy market participants, supported the development of regulatory and ratemaking strategies, energy supply obligations, stranded cost assessment and recovery, rate design, and management procedures and decisions. Specific projects include: design and implementation of pipeline capacity open season processes; review utility contracting approaches with respect to gas supplies; assess compliance requirements of the FERC standard of conduct regarding affiliate transactions; analysis of provider of last resort obligations in both electric and gas markets; review the process to procure and hedge default service supplies; and develop new service offerings.

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Resume & Testimony Listing of:
James M. Stephens
Partner

Representative engagements have included:

- Retained by EPCOR Energy Alberta to review procurement and pricing of energy for their supplier of last resort obligation, including identifying and quantifying economic risks of providing the service. Expert report and testimony were submitted to the Alberta Utilities Commission.
- Retained by a utility for regulatory support with respect to energy storage and electric vehicle infrastructure.
- On behalf of an LDC, developed an integrated resource plan including demand forecasting and gas supply portfolios analysis. The final work product was submitted to the state utility commission.
- Retained by the Alaska Gasline Development Corporation to assist with a market review and assessment; open season process development, implementation, and third party contracting; and associated activities (e.g., tariff and service development).
- Retained by various LDCs and electricity utilities to evaluate interstate pipeline capacity and storage open seasons including an analysis of the quantitative and qualitative aspects of the various projects.
- Retained by an LDC to develop regulatory strategy associated with the funding of distribution expansion.
- Retained by a Midwest U.S. interstate gas pipeline to assist with an open season including drafting of tariffs and precedent agreements.
- Retained by a Northeast energy company to review the FERC reporting requirements and standards of conduct for an interstate pipeline business unit.
- Provided regulatory and litigation support to a natural gas pipeline regarding rate impacts of new infrastructure development.
- Provided litigation support to a mid-west utility regarding proposed gas purchase disallowances for storage utilization, hedging activity, and pipeline capacity decisions.
- On behalf of a Midwest utility, developed and implemented a third party transportation program.
- Developed a demand forecast to support the AES Sparrows Point LNG FERC application.
- Provided support to a Canadian LNG supplier regarding their NEB export license application.

Energy Procurement

Directed and participated in the review of various energy procurement projects including demand modeling, portfolio review/optimization, risk management, procurement strategies and associated cost structures.

Representative experience has included:

- Retained by a utility to review the financial concepts of risk and risk aversion with respect to the provision of regulated energy service and the associated compensation for the service obligation.
- Retained by New Brunswick Power to document and assess fuel procurement and associated processes. Expert report was submitted to New Brunswick Energy and Utilities Board.
- For a municipal utility, evaluated its current gas supply portfolio and associated purchasing strategies.
- For a municipal utility, evaluated the benefits and costs associated with quick-start generation.
- Retained by a utility to review the value achieved under an asset management agreement, including the use of storage.
- Provided a market participant with a review of natural gas supply and storage options, associated prices, and risk mitigation opportunities.
- On behalf of a natural gas distribution company, evaluated the benefit associated with asset management opportunities.
- On behalf of a regional combination utility, reviewed the appropriate jurisdiction for a natural gas pipeline asset.
- On behalf of a natural gas utility, conducted a detailed audit of the gas supply, marketing, risk management, and accounting functions.
- On behalf of several gas utilities, developed demand forecasts and supported those forecasts in regulatory proceedings.
- For a multi-state utility, reviewed the demand forecast planning process and procedures and recommended certain process changes.

- On behalf of a financial institution, reviewed the competitiveness of a storage project investment and quantified the impact of various new projects on the storage project financial performance.
- As President of a retail energy marketing firm directed all aspects of the business unit and was responsible for marketing, origination, operations, accounting, and billing. In addition, was responsible for the physical and financial commodity books; developed and implemented risk management strategy and objectives; implemented risk management policies and procedures; negotiated counterparty contracts; and reviewed and reported on financial performance to the Board of Directors.

Financial and Economic Advisory Services

Involved in the sale or evaluation of several regulated and non-regulated energy companies including wholesale and retail energy marketing companies, on-line energy brokers, and energy services' companies. Assisted clients with market strategy and the identification of partnership opportunities. Specific services provided include: business unit evaluation, development of marketing and sale materials, marketing of transaction, bid evaluation and negotiation support.

Representative engagements have included:

- For an energy broker, developed and executed an acquisition strategy.
- For Eversource, assisted with the sale of its retail services business unit.
- For an international integrated utility, supported its due diligence team with respect to an evaluation of a multi-state utility.
- For a private equity firm, evaluated natural gas procurement and energy sales in support of an investment in generation.
- For a utility, supported its due diligence with respect to a potential acquisition of a natural gas distribution company.
- For a municipal utility, evaluated and negotiated an asset management agreement.
- Assisted an LDC with gas supply due diligence regarding a potential asset acquisition.
- For a third-party investor, performed an independent review of a retail energy marketer including existing physical and financial books, risk management protocols and exposures, and growth strategy.
- Supported the sale of Niagara Mohawk Power Corporation's non-regulated energy marketing affiliate.
- Directed the sale of a non-regulated marketing affiliate.
- Performed an independent valuation of an on-line energy broker on behalf of an investor.

PROFESSIONAL HISTORY

ScottMadden, Inc. (2012 – Present)
Partner

Concentric Energy Advisors, Inc. (2002 – 2012)
Executive Advisor
Senior Vice President
Vice President

Navigant Consulting, Inc. (2000 – 2001)
Director, Energy Market Assessment Practice Area

Providence Energy Services (1997 – 2000)
President (1998 – 2000)
President, Providence-Southern (1997 – 1998)

REED Consulting Group (1994 – 1997)
Assistant Vice President

Colonial Gas Company (1991 – 1994)
Director, Gas Supply Planning and Acquisition (1993 – 1994)
Manager, Gas Supply (1991 – 1993)

Boston Gas Company (1987 – 1991)
Senior Gas Supply Analyst (1990 – 1991)
Transportation and Exchange Analyst (1988 – 1990)
Business Analyst (1987 – 1988)

EDUCATION

Masters in Business Administration with a concentration in Operations Management, Bentley College, 1991
Bachelor of Science in Management, Bentley College, 1987

DESIGNATIONS AND PROFESSIONAL AFFILIATIONS

Member of the American Gas Association
Member of the New England Gas Association
Member of the Society of Gas Lighting
Member of the New England-Canada Business Council
Member of the Northeast Energy and Commerce Association
Member of the Guild of Gas Managers

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Resume & Testimony Listing of:
James M. Stephens
Partner

Recent Expert Witness Appearances of James M. Stephens

SPONSOR	DATE	JURISDICTION	DOCKET NO.	SUBJECT
Union Gas Limited	April, 2013	Ontario	Docket No. 2013-0109	Gas Supply Planning
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-158	Pre-Approval of a Long-Term Capacity Contract
Columbia Gas of Massachusetts	September, 2013	Massachusetts	Docket No. 13-161	Integrated Resource Plan
Gaz Métro	October, 2013	Québec	Cause tarifaire 2014, R-3837-2013	Storage Utilization
Maine Public Utility Commission	February, 2014	Maine	Docket No. 2014-00071	Pipeline Open Season
Gaz Métro	January, 2015	Québec	Cause tarifaire 2015, R-3879-2014	Storage Utilization
UIL Holdings Corporation d/b/a Total Peaking Services, LLC	September, 2015	Federal Energy Regulatory Commission	Docket No. CP15-557-000	Market Power Study
Union Gas Limited	May, 2015	Ontario	Docket No. EB-2015-0166	Pre-Approval of a Long-Term Pipeline Capacity Contract
Enbridge Gas Distribution	June, 2015	Ontario	Docket No. EB-2015-0175	Pre-Approval of a Long-Term Pipeline Capacity Contract
Northern Utilities, Inc.	November, 2015	Maine	Docket No. 2014-00132	Retail Choice Transportation Program
Eversource Energy	December, 2015	Massachusetts	Docket No. 15-181	Pre-Approval of Long-Term Pipeline Capacity Contract
Eversource Energy	February, 2016	New Hampshire	Docket No. DE 16-241	Pre-Approval of Long-Term Pipeline Capacity Contract
New Brunswick Power	October, 2016	New Brunswick	Matter No. 336	Commodity Procurement / Risk Management
EPCOR Energy Alberta	January, 2017	Alberta	Proceeding ID 22357	Energy Procurement and Risk Assessment
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a Liberty Utilities	December, 2017	New Hampshire	Docket No. DG 17-198	Approval of Natural Gas Supply Strategy

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Resume & Testimony Listing of:
James M. Stephens
Partner

SPONSOR	DATE	JURISDICTION	DOCKET NO.	SUBJECT
Heritage Gas Limited	January, 2018	Nova Scotia	Matter No. M08473	Approval of Long-Term Natural Gas Transportation Contract; Cost Recovery Mechanism; and Capacity Assignment Principles
ENSTAR Natural Gas Company	June, 2018	Alaska	Docket No. U-18-004	Reply Testimony in Support of ENSTAR's Design Day and Gas Supply Contracting Practices
Southwestern Public Service Company	June, 2019	Texas	Docket No. 48973	Direct and Reply Testimony in Support of two Solar PPA's and Associated Cost Recovery in a Fuel Reconciliation Proceeding
Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a/ Liberty Utilities	October, 2019	New Hampshire	Docket No. DG 17-152	Approval of Least-Cost Integrated Resource Plan

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Resume of:

Adam J. Perry
Director

Summary

Adam Perry has 12 years of experience in the energy industry. Adam's experience in the energy industry includes work related to demand forecasting, cost of capital, regulatory proceedings, and market analyses. His work has included econometric modeling, modeling and analyzing financial data, researching regulatory issues, and developing and writing reports and testimony.

Adam has testified before the Massachusetts Department of Public Utilities. Adam holds a B.S. from Northeastern University.

Areas of Specialization

- Utilities
- Demand Forecasting
- Rates and Regulation
- Natural Gas
- Regulatory Strategy and Rate Case Support

Recent Assignments

- Developed econometric analyses, researched Department precedent and market information, developed filing, and testified in support of the demand forecast in the Liberty Utilities (New England Natural Gas Company) three most recent Forecast and Supply Plans filed with the Massachusetts Department of Public Utilities.
- Developed Design Day demand forecasts using econometric analysis for a natural gas utility covering four jurisdictions and 20 service territories.
- Evaluated an electric utility's sales, revenue, supply and peak load forecast modeling processes and provided recommendations regarding methods to improve the forecasts.
- For numerous electric and natural gas utilities, and natural gas pipelines, supported ROE testimony through research, testimony development, and the creation of analytical models and supporting analyses.
- Performed benchmarking analyses of North American utilities to review a utility's gas supply planning practices and the appropriateness of the weather normalization methodology used in its demand forecasting process.
- Developed benchmarking analyses and assisted with the preparation of testimony and a report supporting Total Peaking Services' Market Power Study filed with the Federal Energy Regulatory Commission for approval of market-based rates.

Professional History

ScottMadden, Inc. (2016 – Present)
Director
Manager

Sussex Economic Advisors, LLC (2012 – 2016)
Managing Consultant

Concentric Energy Advisors, Inc. (2007 – 2012)
Consultant
Assistant Consultant
Analyst
Associate

Education

Bachelor of Science, Economics, Northeastern University, magna cum laude, 2008

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

DG 17-152
Least Cost Integrated Resource Plan

Staff Data Requests - Set 2

Date Request Received: 4/10/18
Request No. Staff 2-4

Date of Response: 4/27/18
Respondent: William R. Killeen
James M. Stephens

<u>REQUEST</u>:

Re: the Company's *Least Cost Integrated Resource Plan*, as filed in Docket No. DG 17-152, please provide details of the Company's out-of-model adjustments to its econometric forecasts of gas requirements. Specifically:

a. Provide a quantitative justification for the adjustment made for the Company's recently-expanded sales and marketing efforts.

b. Provide a quantitative justification for the adjustment made for the Company's new service territories in New Hampshire.

c. For the new service territories, provide a comparison of expected customer additions with those for Maine, Massachusetts and Connecticut gas distribution companies' customer additions off of existing mains for each of the last five years.

    i. For the Maine, Massachusetts and Connecticut companies, provide the types of customers added in categories matching as closely as possible EnergyNorth's customer categories.

    ii. For each of the Maine, Massachusetts and Connecticut companies, also provide the total numbers of each type of customers.

<u>RESPONSE:</u>

a. The expansion of the sales and marketing efforts has resulted in 6,322 new customer additions and $7,297,998 in incremental margin since 2014. The Company expanded the sales and marketing organization in 2014 and added six FTEs to sales and marketing staff. The Company plans to continue its focus and support of the sales and marketing efforts. Please also see the response to Staff 1-7.

b. The sales and marketing forecast of customer additions in new service territories is consistent with, and supported by the Company's operating budget and capital expansion plans. These plans are reviewed within the Company's franchise approval applications or rate cases submitted to the New Hampshire Public Utility Commission. Please also see the response to Staff 1-7. The data with respect to customer prospect information from ICF International for each of the relevant service territories is provided below.

Location	Type of Prospect	Total Prospect Count
Windham	Residential	4,730
Windham	Commercial	985
Pelham	Residential	4,233
Pelham	Commercial	789
Epping	Residential	2,456
Epping	Commercial	403
Candia	Residential	1,382
Candia	Commercial	280
Raymond	Residential	3,499
Raymond	Commercial	515

c. The Company is not in possession of the requested information. However, the projected demand growth of the Company is consistent with other local natural gas distribution company (LDC) growth expectations in the New England region, which ranges between 1% and 3% annually based on recent forecast filings.

SUPPLEMENTAL

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

DG 17-152
Least Cost Integrated Resource Plan

Staff Data Requests - Set 4

Date Request Received: 7/9/18
Request No. Staff 4-8

Date of Response: 10/25/19
Respondent: William R. Killeen

REQUEST:

For each of 2015, 2016 and 2017, please provide the following measures of the Company's experience with capacity-exempt customers, for customers who changed from services of that type, please provide:

a. How many customers
b. Representing what volume
c. To what service classifications they changed.

RESPONSE:

a. Since 2015, six customers migrated from capacity-exempt to capacity-eligible service. Please see the table below.

Year	Number of Customers
2015	2
2016	3
2017	1

b. The transportation contract quantity for the customers that migrated from capacity-exempt to capacity-eligible service each year is summarized below.

Year	Transportation Contract Quantity (Dth)
2015	300
2016	78
2017	80

c. The service classification changes of the capacity-exempt customers leaving this status each year were as follows:

- In 2015, two customers switched from capacity-exempt to capacity-eligible status, with one from each of rate classes G-43 and G-53;
- In 2016, three customers switched from capacity-exempt to capacity-eligible status, with one from each of rate classes G-52, G-42, and G-41;
- In 2017, one customer switched from capacity-exempt to capacity-eligible status, with a rate classes G-53.

SUPPLEMENTAL RESPONSE:

The Company submits this supplemental response to provide an update to the capacity-exempt data previously provided.

a. Since 2015, nine customers migrated from capacity-exempt to capacity-eligible service, as shown in the table below.

Year	Number of Customers
2015	2
2016	3
2017	1
2018	2
2019	1

In addition to the customers identified in the table above, in each of 2018 and 2019, one capacity exempt customer left this service and their business location has remained vacant. It is expected that, at some future date, these locations will resume natural gas service. Further details are discussed in part c below.

b. The transportation contract quantity for the customers that migrated from capacity-exempt to capacity-eligible service each year is summarized below.

Year	Transportation Contract Quantity (Dth/day)
2015	300
2016	78
2017	80
2018	100
2019	30

c. The service classification changes of the capacity-exempt customers leaving this status each year were as follows:

- In 2015, two customers switched from capacity-exempt to capacity-eligible status, with one from each of rate classes G-43 and G-53;
- In 2016, three customers switched from capacity-exempt to capacity-eligible status, with one from each of rate classes G-52, G-42, and G-41;
- In 2017, one customer switched from capacity-exempt to capacity-eligible status, from rate class G-53;
- In 2018, three customers dropped from capacity-exempt status. Two of these customers switched from capacity-exempt to capacity eligible status. These customers were in rate class G-42 (with a TCQ of 70 Dth/day). The third customer dropped from capacity-exempt eligible status in 2018 and the location remains inactive as the building is vacant. That customer was also G-42. If a new customer moves into this location, they are eligible to retain company capacity (approximately 30 Dth/day); and
- In 2019 (to date), two customers have dropped from capacity-exempt status. Both customers were in rate class G-41. Both customers moved out. One has been replaced with a new customer who now retains Company capacity (15 Dth/day). The other building is vacant. If a new customer moves into this location, they are eligible to retain Company capacity (approximately 15 Dth/day).

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

DG 17-152
Least Cost Integrated Resource Plan

Staff Technical Session Data Requests - Set 1

Date Request Received: 5/30/18
Request No. Staff Tech 1-7

Date of Response: 6/27/18
Respondent: William R. Killeen
James M. Stephens
Adam Perry

REQUEST:

The previous questions focus on the work provided by ICF and its use. The Company at Technical Session Day 2 offered a more complete discussion, addressing all methods, analyses, and data inputs used to forecast customer and demand growth. Please, as offered by the Company, provide a description of all efforts and analyses undertaken to make those forecasts, and address how management combined those efforts and analyses into consolidated forecasts of customer and demand growth.

RESPONSE:

Please see Attachment Staff Tech 1-7.1, which contains the "Comprehensive Response" referred to in the responses to several other requests in this docket, and Attachment Staff Tech 1-7.2.

Detailed Review of EnergyNorth's Demand Forecast
Docket Nos. DG 17-152 and DG 17-198

I. Executive Summary

Pursuant to the May 23, 2018, technical session in Docket No. DG 17-152 and the May 24, 2018, technical session in Docket No. DG 17-198, the Company has undertaken a detailed review of its forecasted customer additions and how those estimated customer additions are integrated into the results of the econometric models (together defined herein as the Demand Forecast). The Company's detailed review resulted in the modification of certain assumptions related to the out-of-model adjustments used to produce the Demand Forecast, including:

- The customers of Concord Steam Corporation ("Concord Steam") were included in the estimate of customer additions for the existing service territory and have now been removed from the forecasted additions for the existing service territory. These customer additions are included as an out-of-model adjustment.
- The forecasted customer additions in Windham and Pelham were included in the estimate of customer additions in the existing service territory and have now been removed from the forecasted additions for the existing service territory. These customer additions are included as an out-of-model adjustment.
- The overall number of customer additions has been reduced to reflect more recent information, specifically:
    - In the initial filing, the Company included a 400-unit development in Windham; however, subsequent to the filing, the project has been reduced and is currently indefinitely delayed. As such, the project and the 400 units were removed from the forecasted customer additions for Windham and Pelham.
    - The forecasted customer additions for the potential franchise areas (i.e., Epping, Candia, and Raymond) were determined to be too high and have been lowered. Specifically, the initial filing assumed a total of 244 customers per year from the potential franchise areas, which was reduced to a total of 120 customers per year.
    - The forecasted customer composition for the potential franchise areas (i.e., the allocation between residential and commercial and industrial ("C&I") customers) resulted in a disproportionate number of commercial customer additions; specifically, the C&I customer allocation of 60% was corrected to be consistent with the Company's actual recent experience where 20% of the customer additions are C&I customers (as reflected in the residential and C&I customer additions data for 2016 and 2017 provided in the response to Staff 3-13 in Docket No. DG 17-152).[1] In addition, the 20% is consistent with the assumed C&I customer allocation for customers added in the existing service territory and in Windham and Pelham.
    - The Company also addressed a timing issue with respect to the start date for the initial customers from the potential franchise areas. The start date for these customers was delayed to better reflect the timing of the Granite Bridge Pipeline.

- For modeling purposes, certain formulas and calculations were simplified. For example, the approach to allocate the annual customer additions from the Sales and Marketing forecast to

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[1] For ease of reference, all Company responses referred to in this detailed review are provided as Attachment Staff Tech 1-7.2.

monthly customer additions was simplified, which also corrected an error regarding monthly customer additions.

- The assumption regarding natural gas consumption for Innovative Natural Gas, LLC ("iNATGAS") has been updated to reflect the actual usage information from this past winter.

As a result of these modifications to the Demand Forecast, the Company's forecast of natural gas demand has been slightly reduced as illustrated in Table 1 below.

Table 1: Updated Demand Forecast Results (Dth)

	Original Demand Forecast			Updated Demand Forecast		
Split-Year	Normal Year	Design Year	Design Day	Normal Year	Design Year	Design Day
2017/2018	15,634,082	16,901,795	156,822	14,640,845	15,833,870	157,848
2018/2019	16,075,247	17,376,013	160,989	15,235,354	16,449,392	164,571
2019/2020	16,575,525	17,944,792	164,640	15,648,467	16,923,283	167,643
2020/2021	17,000,558	18,367,180	168,934	16,150,273	17,414,989	168,942
2021/2022	17,527,589	18,933,736	173,917	16,585,278	17,881,953	174,618
2022/2023	18,071,614	19,519,884	179,382	17,864,174	19,198,013	184,000
2023/2024	18,638,472	20,168,391	184,432	18,354,074	19,760,680	188,352
2024/2025	19,009,173	20,530,513	188,856	18,660,183	20,055,937	192,033
2025/2026	19,416,449	20,969,502	192,933	19,008,442	20,431,417	195,542
2026/2027	19,788,597	21,371,088	196,785	19,318,284	20,765,901	198,777
2027/2028	20,198,023	21,852,258	199,954	19,659,031	21,169,792	201,364
2028/2029	20,471,958	22,107,358	203,491	19,872,063	21,362,731	204,235
2029/2030	20,798,293	22,459,424	206,790	20,136,752	21,648,299	206,906
2030/2031	21,108,206	22,794,033	210,016	20,392,048	21,924,085	209,593
2031/2032	21,476,694	23,234,556	212,972	20,701,897	22,297,494	212,031
2032/2033	21,678,072	23,409,030	215,843	20,858,981	22,428,427	214,448
2033/2034	21,960,444	23,713,995	218,828	21,075,945	22,663,122	216,822
2034/2035	22,227,307	24,002,078	221,631	21,269,443	22,872,418	218,944
2035/2036	22,564,042	24,410,287	224,148	21,516,836	23,180,235	220,704
2036/2037	22,742,621	24,558,141	226,863	21,618,013	23,249,243	222,599
2037/2038	23,007,564	24,844,142	229,590	21,798,963	23,444,867	224,511
CAGR (17/18 - 21/22)	2.9%	2.9%	2.6%	3.2%	3.1%	2.6%
CAGR (17/18 - 37/38)	2.0%	1.9%	1.9%	2.0%	2.0%	1.8%

As shown in Table 1, based on the changes to the Demand Forecast discussed above, the Company is forecasting Normal Year and Design Year demand to increase at a compound annual growth rate ("CAGR") of approximately 2.0% and Design Day demand to increase at a CAGR of 1.8% over the 2017/18 to 2037/38 time period, which is similar to the growth in the Company's initial filing, the pace of growth in recent years, and well within the estimates of natural gas demand growth of other local distribution companies in the New England region (as provided in the responses to Staff 3-2 in Docket No. DG 17-152 and Staff 2-30 in Docket No. DG 17-198).

The inclusion of changes to the Demand Forecast, although slightly lowering the expected demand, does not alter the primary conclusions documented by the Company in Docket Nos. DG 17-152 and DG 17-198, specifically:

- The customer additions and associated volume from the econometric model do not capture the Company's focus on customer growth in New Hampshire;
- An adjustment to the results of the econometric model is warranted and supported by the recent level of customer additions, access to new and potential franchise areas, and the regulatory programs approved by the Commission, none of which are captured in the historical data; and
- An adjustment based on information developed by the Sales and Marketing team, as well as the experience and judgment of that team, is a reasonable approach to estimate the level of adjustment to the results of the econometric model.

In addition, the Company reviewed the implications of changes to the forecasted customer additions on its SENDOUT® resource portfolio optimization analysis, as initially filed in Docket No. DG 17-198 and in the responses to OCA 2-86 and OCA 2-106R in Docket No. DG 17-198. Specifically, the revised Demand Forecast was uploaded into the SENDOUT® model for an assessment of the Company's gas supply portfolio; and, based on the results of that analysis, coupled with the non-price factors discussed in the various Company submissions in Docket Nos. DG 17-152 and DG 17-198, the Company concludes that the Granite Bridge Project, as outlined in Docket No. DG 17-198, continues to be the best cost option for the customers of EnergyNorth. As shown by Tables 2 and 3 below, the results of the SENDOUT® model continue to support the Granite Bridge Project as the best cost option to meet the demand requirements of EnergyNorth's customers.

Table 2: EnergyNorth SENDOUT® Model Runs - "Prime Revised"[2]

Resource Planning Scenario	Granite Bridge LNG	Propane Facilities	Resource Mix Results			Total System Cost ($000)	Comparison to Base Case Prime
			Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)		
Base Case Prime	2.0 Bcf	No	7,920	0	0	$2,645,295	$ -
Base Case Prime Sensitivity	2.0 Bcf	Yes	7,920	0	0	$2,645,925	$ 630
Alternative Case Prime	No	No	3,080	104,920	360	$2,850,073	$ 204,778
Alternative Case Prime Sensitivity	No	Yes	15,040	50,370	7,000	$2,667,144	$ 21,849

Table 3: EnergyNorth SENDOUT® Model Runs - LNG Tank Size Scenarios - "Prime Revised"

Resource Planning Scenario	Granite Bridge LNG	Propane Facilities	Resource Mix Results			Total System Cost ($000)	Comparison to 2.0 Bcf Tank ($000)
			Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)		
Base Case Prime	2.0 Bcf	No	7,920	0	0	$2,645,295	$ -
Base Case Prime	1.2 Bcf	No	7,920	0	470	$2,651,792	$ 6,497
Base Case Prime	1.5 Bcf	No	7,920	0	0	$2,653,873	$ 8,578
Base Case Prime	2.5 Bcf	No	7,920	0	0	$2,724,443	$ 79,148

As shown in Tables 2 and 3, the Resource Mix results (i.e., volumes for the various resources) and the Total System Costs across all scenarios are slightly lower than the results shown in the initial filing in Docket No. DG 17-198 and in the responses to OCA 2-86 and OCA 2-106R in Docket No. DG 17-198. However, the Total System Cost of the Base Case Prime (which includes the 2.0 Bcf Granite Bridge LNG facility) is

2 The SENDOUT® model runs denoted as "Prime" reflect the impact of the Tax Cuts and Jobs Act on the proposed Granite Bridge Project infrastructure revenue requirement.

approximately $2.645 billion over the analysis period and continues to be the lowest total cost of the resource planning scenarios and LNG tank size scenarios analyzed. The Alternative Case Prime resource planning scenario, which excludes the Granite Bridge LNG facility, results in a total system cost of approximately $2.850 billion over the analysis period, which is nearly $205 million more than the Base Case Prime scenario. The results shown in Tables 2 and 3 are consistent with the Company's prior analysis, and continue to support the conclusions regarding the Granite Bridge Pipeline and 2.0 Bcf Granite Bridge LNG facility.

II. Historical Customer Additions

In response to certain data requests in Docket Nos. DG 17-152 (e.g., CLF 1-9, Staff 2-4, and Staff 3-13) and DG 17-198 (e.g., Attachment OCA 1-12.b and CLF 1-8), the Company provided information with respect to historical customer additions. To be as responsive as possible to the specific data requests, the information provided by the Company was derived from several different internal data sources, each of which used different time periods, which best responded to the specific request. However, the use of various data sources and time periods in response to specific data requests has resulted in the need to reconcile the historical customer additions information submitted in Docket Nos. DG 17-152 and DG 17-198.

First, to be as consistent as possible with past submissions of long-term demand forecasts, the Company relied on an analytical framework and approach that has been used, vetted, and approved in several regulatory filings at the Commission. The use of a consistent framework across proceedings facilitates the comparison of results across those proceedings (e.g., please see Staff 1-11 in Docket No. DG 17-152, which asked the Company to compare the demand estimate for 2017 as produced in Docket Nos. DG 13-313 and DG 17-152). As such, for the development of the econometric models used by the Company in Docket Nos. DG 17-152 and DG 17-198, the Company used Customer Equivalent Bill data for the August 2010 to April 2017 period as the metric to represent customer numbers by segment (e.g., residential and C&I).[3] Customer Equivalent Bill data is the same customer metric used in the 2013 LCIRP in Docket No. DG 13-313, EnergyNorth's cost of gas submissions, and the Northeast Energy Direct ("NED") contract filing in Docket No. DG 14-380. Second, in response to certain data requests for historical customer additions, the Company relied on a new customer relationship management system (i.e., the ZOHO system)[4] used by its Sales and Marketing team, rather than the Customer Equivalent Bill data. Lastly, Company responses to certain data requests provided information for calendar years, while other responses provided information for different 12-month periods (e.g., April to March or November to October).

To reconcile the various information provided in the numerous data requests received by the Company with respect to historical customer additions, please find in Table 4 below a comparison of historical customer additions using the Customer Equivalent Bill metric and the annual customer additions from the ZOHO system.

[3] Please see Bates 014 of the Company's 2017 LCIRP filed in Docket No. DG 17-152.
[4] The ZOHO system was implemented by the Company on May 30, 2014.

Table 4: Historical Customer Additions Comparison

Year	Customer Equivalent Bill[5]	ZOHO Customer Additions[6]	Difference	Percent Difference
2014	1,178	1,199	(21)	(1.8%)
2015	1,770	1,784	(14)	(0.8%)
2016	1,531	1,588	(57)	(3.6%)
2017	1,733	1,708	25	1.5%
Total	6,212	6,279	(67)	(1.1%)
Average	1,553	1,570	(17)	(1.1%)
Average (excluding 2014)	1,678	1,693	(15)	(0.9%)

As shown in Table 4 above, the use of Customer Equivalent Bill data results in a total of 6,212 customer additions over the 2014[7] to 2017 period, which compares to the total of 6,279 customer additions using the ZOHO system. The difference between the two data sources is 67 customer additions, or approximately 1.1%. Using the average customer additions over the 2014 to 2017 period results in 1,553 annual additions based on Customer Equivalent Bill data and 1,570 customer additions from the ZOHO system, or a difference of 17 customers. Therefore, a comparison of the calendar year customer additions using the Customer Equivalent Bill data (i.e., the dependent variable in the customer equations of the econometric models) is for all intents and purposes equivalent to the annual customer additions data from the ZOHO system used by the Sales and Marketing team.

III. Need for a Sales and Marketing Adjustment

During the May 23, 2018, and May 24, 2018, technical sessions, there were discussions regarding the need for an adjustment to the customer additions results from the Company's econometric model. Although the Company has provided support in its responses to various data requests in both Docket No. DG 17-152 and DG 17-198, a summary of the rationale supporting an adjustment to the econometric model results is warranted. The Company has provided the following primary reasons in support of an adjustment to the customer additions forecasted by the econometric model: (i) the actual customer additions in the existing service territory, particularly the recent trends; (ii) the customer opportunity in the new and potential

5 To accurately compare Equivalent Bill data to the data from the ZOHO system, the Company used calendarized values and selected an appropriate reference month (i.e., December) for the Equivalent Bill data and compared that to the year-end customer count from the ZOHO system. There is a slight difference between the reported ZOHO customer count and the number of such customers from the Equivalent Bill data due to certain issues including duplication and a mis-recording of the service start date. Please note that the customer additions data provided in Figure 16 of the Direct Testimony of William R. Killeen and James M. Stephens in Docket No. DG 17-198 (see Bates 151R) were based on annual Customer Equivalent Bill data for the year-ending in March and not calendar year data.

6 Please note, in preparation of this response, the Company noted a discrepancy in the information provided in the responses to CLF 1-9, Staff 2-4, and Staff 3-13 in Docket No. DG 17-152 compared to the information provided in the responses to OCA 1-12 and CLF 1-8 in Docket No. DG 17-198. Although the ZOHO system was used to develop all these responses, the extraction parameters were not consistent thus resulting in a different number of historical customer additions. The historical customer additions data as provided in the responses to OCA 1-12 and CLF 1-8 in Docket No. DG 17-198 uses the appropriate extraction parameters and should replace the historical customer additions information provided in the responses to CLF 1-9, Staff 2-4, and Staff 3-13 in Docket No. DG 17-152.

7 Please note that the ZOHO system was placed on-line in late May 2014 so the information for that year reflects a partial year and, as such, the Customer Equivalent Bill data was presented on a similar basis.

franchise areas; (iii) the expansion of the Sales and Marketing team; (iv) innovative growth programs; and (v) past Commission precedent.

As a preliminary matter, there is academic support for adjusting econometric models to reflect information that is not otherwise captured in the historical data but is relevant to the accuracy of the forecast. For example, Michael Intriligator discusses the use of "add factors" (out-of-model adjustments) in *Econometric Models, Techniques, & Applications*:

> The add factors are based on judgments of factors not explicitly included in the model. For example, in a macroeconometric model there may be no explicit account taken of strike activity, but if major union contracts are expiring and a strike appears likely in the forecast period, the forecasts of production should be appropriately revised downward. Many other factors may not have been included in the model because their occurrence is rare or because data are difficult to obtain, but this does not mean that they must be overlooked in formulating a forecast. Indeed, it would be inappropriate to ignore relevant considerations simply because they were omitted from the model. In this sense forecasting with an econometric model is not simply a mechanical exercise but rather a blending of objective and subjective considerations. The subjective considerations embodied in the add factors, general improve significantly on the accuracy of the forecasts made with an econometric model.[8]

The factors discussed below show that the Company's recent activities and new programs will continue to promote customer growth above that found in the historical data, which supports the use of an out-of-model adjustment to appropriately reflect that information.

First, for the existing service territory, the actual or historical customer additions using Customer Equivalent Bill data is greater than the forecasted customer additions from the econometric model. Specifically, the forecast of customer additions from the econometric model results in approximately 1,180 customer additions per year for the existing service territory. However, as shown by Table 4 above, using the Customer Equivalent Bill data over the 2014 to 2017 period results in approximately 1,550 customer additions per year; and, if the partial customer additions results from 2014 are excluded, the annual customer additions over the 2015 to 2017 period for the existing service territory average approximately 1,700 customers per year.[9] Therefore, the actual customer additions information and experience in the existing service territory supports an adjustment to the customer addition results from the econometric model.

Second, in addition to the customer numbers shown in Table 4, Concord Steam has discontinued service and the Company received franchise approval for the towns of Windham and Pelham; and plans to file for approval of the potential franchise areas that would include the towns of Epping, Raymond, and Candia. None of the customers associated with the Concord Steam conversion and potential customers in the new or potential franchise areas are included in the results of the econometric model and should be considered as exogenous to the econometric model and, therefore, support the use of an adjustment to customer additions.

Third, the Company has continued to focus on growth and providing more customers with the option to choose natural gas as their fuel. As discussed in the responses to Staff 2-4 and Staff 3-13 in Docket No. DG 17-152, the Company has expanded its Sales and Marketing team by six full time equivalents ("FTEs"). These employees reside and are active in their local communities and provide "feet on the ground" with

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8 Michael D. Intriligator, Econometric Models, Techniques, & Applications, at 516-517.

9 An analysis of the information from the ZOHO system produces similar historical customer additions over the 2014 to 2017 and 2015 to 2017 time periods.

respect to participating in business organizations and town activities. This increase in number of Sales and Marketing employees and the local presence of those employees supports an adjustment to the results of the econometric models.

Fourth, the Company has proposed and received approval from the Commission for innovative expansion plans, such as revisions to the contribution-in-aid-of-construction policy (e.g., including the assumption that 60% of customers located along a main extension will take service) and the Managed Expansion Program ("MEP") approved by the Commission in August 2016. The MEP not only provides a mechanism to unitize expansion costs and collect those expenses over time, but also provides the Company an opportunity to install service lines for any end use application during the construction of a main, thus positioning the Company to add load from an existing customer. Stated differently, the Company, under MEP, can provide a service line to a customer for an end use application, such as water heating, and thus natural gas is a fuel choice for that customer when their existing heating equipment fails or needs to be replaced. Please see the response to Staff Tech 1-3 in Docket No. DG 17-152, which discusses the customer additions associated with MEP. In addition, the Company (1) eliminated the $900 flat fee for a new residential customer, (2) allowed for no-cost service connections of heating customers within 100 feet of an existing natural gas main, (3) allowed for no-cost service connections of non-heating customers within 100 feet if they commit to taking service prior to a main extension or replacement, and (4) lowered the level of revenue justification required for main and service extensions.

Fifth, the use of adjustments to improve the results of an econometric model have been presented to, and approved by, the Commission. By way of example, in the NED proceeding (i.e., Docket No. DG 14-380), the Company adjusted the results of the econometric model to reflect three markets that were exogenous to the results of the econometric model; specifically, the Company included adjustments for: (i) potential volumes to Keene, NH, as an incremental market; (ii) reverse migration of capacity exempt customers, reflecting recent market trends; and (iii) incremental volumes for iNATGAS, a new, large customer in the existing service territory. Similar to the NED proceeding, the Company in Docket Nos. DG 17-152 and DG 17-198 has adjusted the results of the econometric model to reflect incremental markets (e.g., the new and potential franchise areas), recent market trends (e.g., actual level of customer additions), and incremental volume (e.g., iNATGAS).

IV. <u>Out-of-Model Adjustments</u>

As discussed above, the Company has provided support for certain adjustments to the results of the econometric models. The calculated values and expected saturation levels for each of those adjustments (i.e., incremental customer additions in the existing service territory, incremental customers from new or potential franchise areas, and iNATGAS) are provided below.

First, with respect to the existing service territory, the Company has adjusted the results of the econometric models to reflect the recent historical customer additions, the investment by the Company in growth (i.e., incremental Sales and Marketing staff), and the approval of innovative programs (e.g., MEP). As such, the econometric models forecast of approximately 1,180 customers per year has been adjusted to approximately 1,625 customers per year,[10] which is aligned with the average customer additions over the 2015 to 2017 period (see Table 4 above). In addition, the Company has relied on the same transition schedule to the results of the econometric model for the period from 2023 to 2038 as originally filed.[11] As shown by Table

[10] Represents an average of the customer additions for the existing service territory over the forecast period.
[11] The transition period is discussed on Bates 154R of the Direct Testimony of William R. Killeen and James M. Stephens in Docket No. DG 17-198, and further detailed in the response to Staff 2-62 in Docket No. DG 17-198.

5 below, the Company's forecast of new residential and C&I customers in the existing service territory results in saturation levels in 2038 that are reasonable.

Second, regarding the new franchise areas (i.e., Windham and Pelham) and the potential franchise areas (i.e., Epping, Candia, and Raymond), the Company has adjusted the results of the econometric models to reflect customer additions in these areas as these towns were exogenous to the econometric model results. The Company will leverage its larger Sales and Marketing team and the approved, innovative regulatory programs to achieve the forecasted customer additions. As shown by Table 5 below, the Company's forecast of new residential and C&I customers in the new and potential franchise areas results in saturation levels in 2038 that are reasonable.

Table 5: Saturation Levels in 2038

	Residential[12]	**C&I**[13]	**Total**
Existing Service Territory	51%	84%	54%
New Franchise Areas (Windham/Pelham)	10%	20%	11%
Potential Franchise Areas (Epping /Candia/Raymond)	18%	40%	21%

Lastly, the Company adjusted the results of the econometric models to reflect the recent actual usage and contractual arrangements associated with iNATGAS, which were approved by the Commission in Docket No. DG 14-091 and reaffirmed by the Commission in the NED proceeding in Docket No. DG 14-380. At the time of the Company's initial filing in Docket Nos. DG 17-152 and DG 17-198, the Company understood the natural gas usage of iNATGAS to be minimal. Specifically, the Company in its initial filing assumed iNATGAS would consume 20 Dth on design day and approximately 1 Dth on every other day. However, this past winter iNATGAS consumed 4,251 Dth on its peak day, which supports an adjustment to the volumes used in the Company's initial filing. The Company's revised assumption for iNATGAS volumes based on the contractual arrangements and actual usage by iNATGAS is summarized in Table 6.

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[12] To calculate the residential saturation levels, the Company increased the number of residential customer prospects from ICF using certain information from Moody's (i.e., increased by the growth rate of the Total Households variable). Please see the response to Staff 2-4 in Docket No. DG 17-152 and the responses to Staff 1-8 and Staff 1-9 in Docket No. DG 17-198 for certain ICF customer prospect data.

[13] To calculate the C&I saturation levels, the Company increased the number of commercial customer prospects from ICF using certain information from Moody's (i.e., increased by the growth rate of the Total Employment variable). Please see the response to Staff 2-4 in Docket No. DG 17-152 and the responses to Staff 1-8 and Staff 1-9 in Docket No. DG 17-198 for certain ICF customer prospect data. Please note that the total number of commercial customer prospects from ICF is conservative when compared to data from the U.S. Census Bureau, thus resulting in C&I saturation rates that are higher than rates based on data from the U.S. Census Bureau.

Table 6: iNATGAS Volumes (Dth)

Split Year	Annual Volume	Design Day
2017/18	266	20
2018/19	300,000	4,251
2019/20	300,000	4,251
2020/21	500,000	4,251
2021/22	500,000	4,251
2022/23	1,300,000	8,800
2023/24	1,300,000	8,800
2024/25	1,300,000	8,800
2025/26	1,300,000	8,800
2026/27	1,300,000	8,800
2027/28	1,300,000	8,800
2028/29	1,300,000	8,800
2029/30	1,300,000	8,800
2030/31	1,300,000	8,800
2031/32	1,300,000	8,800
2032/33	1,300,000	8,800
2033/34	1,300,000	8,800
2034/35	1,300,000	8,800
2035/36	1,300,000	8,800
2036/37	1,300,000	8,800
2037/38	1,300,000	8,800

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

DG 17-152
Least Cost Integrated Resource Plan

Conservation Law Foundation Data Requests - Set 1

Date Request Received: 4/9/18
Request No. CLF 1-9

Date of Response: 4/23/18
Respondent: William R. Killeen

REQUEST:

Please see Liberty Utilities 2017 LCIRP p.22: "The Company recently expanded its sales and marketing efforts and expects to continue to do so through the Forecast Period. Because the Company's sales and marketing programs are expected to continue to expand throughout the Forecast Period, the effect of those programs is not fully captured in the historical billing data, and, as, such is not reflected in the econometric forecast."

a. In what month and year did the Company expand its sales and marketing efforts?
b. Please provide a quantification of these expanded efforts in person-hours, FTE, or another relevant metric.
c. Using that same metric, please provide a measure of the Company's total effort expended on sales and marketing for each historical year for which data exist.

RESPONSE:

a. The Company expanded the sales and marketing organization over the course of 2014.
b. The Company added six FTEs to the sales and marketing staff in 2014.
c. The sales and marketing staff's focus on customer outreach has resulted in customer additions in residential conversions, commercial conversions, new construction markets, and other opportunities. Since 2014, the expansion of sales and marketing has resulted in 6,322 new customer additions and $7,297,998 in incremental margin. The incremental margin added each year is as follows:

2017	$2,293,513
2016	$1,694,574
2015	$1,624,853
2014	$1,685,058

REVISED

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

DG 17-198
Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project

Staff Data Requests - Set 8

Date Request Received: 5/3/19	Date of Response: 10/25/19
Request No. Staff 8-2	Respondent: William R. Killeen William J. Clark

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REQUEST:

Using the same format and the same categories as in the previous request, and the same months in each of the split years as in the previous request, please report the actual numbers of customers added in each of the following years:

a. 2014/15
b. 2015/16
c. 2016/17
d. 2017/18
e. 2018/19 to date
f. 2018/19 currently committed but not yet installed.

RESPONSE:

For responses to subparts a. through f., see Attachment Staff 8-2.xlsx.

Please note, in 2016/17 the volumes associated with new C&I customers are higher than other years due to a number of large C&I customers that were added within the Company's existing service territory.

REVISED RESPONSE:

For responses to subparts a. through f., see Attachment Staff 8-2 (Revised).xlsx.

Please note, in 2016/17 the volumes associated with new C&I customers are higher than other years due to a number of large C&I customers that were added within the Company's existing service territory.

In the original attachment to this response, iNATGAS volumes in 2016/17 were inadvertently included in the "C&I – existing areas" row. This has been corrected in Attachment Staff 8-2 (Revised).xlsx.

Docket No. DG 17-198
Attachment Staff 8-2 (Revised) xlsx

Service Terri ory	201 /15						2015/16					
	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load
Former Concord Steam	0	0	3	3,221			0	0	8	3,276		
Residential - existing areas	1,2	98, 92					1, 99	11 ,828				
C&I - existing areas			236	225,1 6					271	200,078		
Windham, Pelham												
Hanover and Lebanon	0		0				0	0	0	0		
Epping, Raymond, and Cand a	0		0				0	0	0	0		
iNATGAS												
Total	1 2	98 92	239	228 367	1 83	326 859	1 99	11 828	279	203 35	1 778	318 182

Service Terri ory	2016 17						2017/18					
	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load
Former Concord Steam	0	0	59	80,67			0	0	27	59,016		
Residential - existing areas	1,327	105,109					1,260	92,691				
C&I - existing areas			03	3 3,380					292	208,618		
Windham, Pelham							1	80	6	2 ,9 8		
Hanover and Lebanon	0	0	0	0								
Epping, Raymond, and Cand a	0	0	0	0								
iNATGAS			1	300 000								
Total	1 327	105 109	63	72 05	1 790	829 163	1 261	92 771	325	292 582	1 586	385 353

Service Terri ory	2018/19 YTD						2018 19 Committed					
	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load
Former Concord Steam			1	3			0	0	0	0		
Residential - existing areas	638	9,152					610	8372				
C&I - existing areas			128	59,683					97	171, 36		
Windham, Pelham	20	1,600	1	360			1	80	5	16,605		
Hanover and Lebanon												
Epping, Raymond, and Cand a												
iNATGAS												
Total	658	50 752	130	60 077	788	110 829	611	8 52	102	188 0 1	713	236 93

Service Terri ory	2018/19 To al YTD and Committed					
	Resi	ADTH	C&I	ADTH	Tot Cust Addns	Est Tot Ann Load
Former Concord Steam	0	0	1	3		
Residential - existing areas	1,2 8	97,52	0	0		
C&I - existing areas	0	0	225	231,119		
Windham, Pelham	21	1,680	6	16,965		
Hanover and Lebanon						
Epping, Raymond, and Cand a						
iNATGAS						
Total	1 269	99 20	232	2 8 118	1 501	3 7 322

1-9 Reference Pages 8, 9, 24, and 26. Is Mr. Chernick aware that the Company provided an updated demand forecast reflecting more recent data in the response to Staff Tech 1-7?

Response:

Yes. That response elaborates on Liberty's efforts to increase sales and changes both some inputs to the econometric model and the out-of-model adjustments for sales and marketing. The response does not appear to address the error in the treatment of energy efficiency.

Normal Year Demand (Dth)

LDC	CAGR	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	Data Source(s)
Connecticut									
Eversource Energy (Yankee Gas Services Company)	2.1%		54,216,952	55,489,545	56,244,024	57,530,869	58,976,319		2018 Demand & Supply Forecast, Exhibit IV-6
UIL (Connecticut Natural Gas Corporation)	1.6%		37,130,123	37,749,722	38,339,131	38,933,703	39,544,148		2018 Demand & Supply Forecast, Exhibit S-1
UIL (Southern Connecticut Gas Company)	1.6%		34,303,038	34,903,270	35,465,714	36,030,125	36,589,736		2018 Demand & Supply Forecast, Exhibit S-1
Massachusetts									
Berkshire Gas Company	0.3%		6,475,839	6,512,826	6,521,058	6,540,414	6,554,604		2018 IRP, Attachment A, pg. 33
Columbia Gas of Massachusetts (Bay State Gas Company)	0.8%	46,336,728	46,722,503	47,023,591	47,351,948	47,874,160			2017 IRP, pg. 79
Eversource Energy (NSTAR Gas)	2.4%	48,299,821	49,932,911	51,951,667	52,421,804	53,187,532			2018 IRP, pg. 16
Without Special Contracts [1]	1.3%	45,988,677	46,526,767	47,148,102	47,628,810	48,394,538			2018 IRP, pg. 16
Liberty Utilities (New England Gas Company)	-0.3%	6,493,119	6,451,255	6,446,599	6,423,892	6,420,053	6,400,322		2018 IRP, pg. 45
National Grid (Boston Gas/Colonial Gas)	1.4%		126,548,155	128,522,675	130,148,177	131,654,619	133,531,509		2018 IRP, pg. 75
Unitil (Fitchburg Gas & Electric)	0.4%		2,215,437	2,220,884	2,215,091	2,226,716	2,250,068		2019 IRP, pg. 7
Maine									
Unitil (Northern Utilities)	1.6%			11,554,979	11,730,231	11,926,464	12,114,577	12,309,135	2019 IRP, pg. IV-69
New Hampshire									
Unitil (Northern Utilities)	1.4%			9,106,127	9,238,468	9,371,594	9,505,494	9,639,921	2019 IRP, pg. IV-69
Rhode Island									
National Grid (Narragansett Electric Company)	0.9%			36,838,000	36,868,000	37,180,000	37,540,000	38,142,000	2019 IRP, Table IV-A
Liberty Utilities (EnergyNorth Natural Gas) - Excl. iNATGAS	**2.3%**	**14,640,578**	**14,935,354**	**15,348,467**	**15,650,273**	**16,065,963**			
Minimum CAGR	**-0.3%**								
Maximum CAGR	**2.4%**								

Notes:
[1] NSTAR Gas has two special contracts. One of those contracts is with an MIT Cogeneration facility, which was expected to increase its operational capacity in November 2019, which would increase demand from the customer.
The other special contract is with iNATGAS. NSTAR Gas forecast usage for iNATGAS to begin in November 2018.

Design Year Demand (Dth)

LDC	CAGR	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	Data Source(s)
Connecticut									
Eversource Energy (Yankee Gas Services Company)	2.1%		57,202,999	58,542,267	59,287,158	60,611,657	62,220,712		2018 Demand & Supply Forecast, Exhibit IV-6
UIL (Connecticut Natural Gas Corporation)	1.6%		39,942,770	40,632,730	41,258,910	41,904,391	42,568,834		2018 Demand & Supply Forecast, Exhibit S-2
UIL (Southern Connecticut Gas Company)	1.7%		37,196,344	37,888,823	38,504,370	39,136,183	39,762,042		2018 Demand & Supply Forecast, Exhibit S-2
Massachusetts									
Berkshire Gas Company	0.3%		7,244,983	7,286,622	7,298,015	7,321,526	7,336,278		2018 IRP, Attachment A, pg. 40
Columbia Gas of Massachusetts (Bay State Gas Company)	0.8%	50,245,054	50,624,892	50,918,919	51,250,542	51,792,720			2018 IRP, pg. 80
Eversource Energy (NSTAR Gas)	2.4%	53,337,000	55,064,000	57,457,000	57,719,000	58,587,000			2018 IRP, Table G-22D
Without Special Contracts [1]	1.3%	51,025,856	51,657,856	52,653,435	52,926,006	53,794,006			2018 IRP, Table G-22D, pg. 16
Liberty Utilities (New England Gas Company)	0.0%	6,936,973	6,964,654	6,964,334	6,945,373	6,945,769	6,930,652		2018 IRP, pg. 45
National Grid (Boston Gas/Colonial Gas)	1.4%		142,395,261	144,616,011	146,450,900	148,138,086	150,245,148		2018 IRP, pg. 77
Unitil (Fitchburg Gas & Electric)	0.5%		2,416,985	2,424,982	2,421,473	2,435,437	2,461,270		2019 IRP, pg. 36
Maine									
Unitil (Northern Utilities)	1.5%			9,433,818	9,571,900	9,725,720	9,873,040	10,025,830	2019 IRP, pg. V-85
New Hampshire									
Unitil (Northern Utilities)	1.4%			6,863,948	6,961,683	7,059,962	7,158,788	7,257,977	2019 IRP, pg. V-80
Rhode Island									
National Grid (Narragansett Electric Company)	0.9%			41,624,000	41,648,000	42,004,000	42,411,000	43,110,000	2019 IRP, Table IV-A
Liberty Utilities (EnergyNorth Natural Gas) - Excl. iNATGAS	**2.3%**	**14,640,578**	**14,935,354**	**15,348,467**	**15,650,273**	**16,065,963**			
Minimum CAGR	**0.0%**								
Maximum CAGR	**2.4%**								

Notes:
[1] NSTAR Gas has two special contracts. One of those contracts is with an MIT Cogeneration facility, which was expected to increase its operational capacity in November 2019, which would increase demand from the customer.
The other special contract is with iNATGAS. NSTAR Gas forecast usage for iNATGAS to begin in November 2018.

Design Day Demand (Dth)

LDC	CAGR	2017/2018	2018/2019	2019/2020	2020/2021	2021/2022	2022/2023	2023/2024	Data Source(s)
Connecticut									
Eversource Energy (Yankee Gas Services Company)	1.5%		457,753	464,999	470,278	477,745	486,378		2018 Demand & Supply Forecast, Exhibit IV-5
UIL (Connecticut Natural Gas Corporation)	1.5%		351,063	356,683	362,028	367,388	372,932		2018 Demand & Supply Forecast, Exhibit S-4
UIL (Southern Connecticut Gas Company)	1.6%		322,286	327,621	332,688	337,764	342,857		2018 Demand & Supply Forecast, Exhibit S-4
Massachusetts									
Berkshire Gas Company	0.3%		66,424	66,808	66,915	67,133	67,272		2018 IRP, Attachment A, Page 43
Columbia Gas of Massachusetts (Bay State Gas Company)	0.6%	481,155	483,737	485,370	489,425	493,420			2017 IRP, pg. 78
Eversource Energy (NSTAR Gas)	2.0%	506,000	518,000	532,000	538,000	548,000			2018 IRP, Table G-23
Without Special Contracts [1]	1.7%	495,000	504,000	514,000	520,000	530,000			2018 IRP, Appendix-13C, pgs. 2,6,10,14,18; DPU 1-5
Liberty Utilities (New England Gas Company)	0.0%	77,156	77,464	77,110	77,249	77,253	77,085		2018 IRP, pg. 45
National Grid (Boston Gas/Colonial Gas)	1.5%		1,372,000	1,393,000	1,418,000	1,434,000	1,456,000		2018 IRP, Table G23-D
Unitil (Fitchburg Gas & Electric)	0.5%		21,938	22,011	21,982	22129	22,363		2019 IRP, pg. 37
Maine									
Unitil (Northern Utilities)	1.5%		76,727	77,631	78,772	80,045	81,266	82,530	2019 IRP, pg. IV-82, 88
New Hampshire									
Unitil (Northern Utilities)	1.4%		62,677	63,662	64,568	65,481	66,398	67,319	2019 IRP, pg. IV-82, 88
Rhode Island									
National Grid (Narragansett Electric Company)	1.0%			389,000	392,000	395,000	399,000	404,000	2019 IRP, Chart IV-A
Liberty Utilities (EnergyNorth Natural Gas) - Excl. iNATGAS	**1.9%**	**157,828**	**160,320**	**163,392**	**164,691**	**170,367**			
Minimum CAGR	**0.0%**								
Maximum CAGR	**2.0%**								

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