F. Chico DaFonte

WORK EXPERIENCE

Liberty Utilities, Salem, NH	(2011-Present)
Vice President, Regulated Infrastructure Development – Gas	(2017 – Present)
Vice President, Energy Procurement	(2014 – 2017)
Senior Director, Energy Procurement	(2011-2014)
NiSource, Inc, Westborough, MA	(1994 – 2011)
Director, Gas Management Services	(2007 – 2011)
Director, Energy Supply Services	(1996 – 2007)
Gas Resource Marketing Analyst	(1994 – 1996)
Commonwealth Gas Company (Eversource), Southborough, MA	(1985 – 1994)
Senior Forecast Analyst	(1993 –1994)
Gas Control Supervisor	(1988 – 1993)
Gas Load Dispatcher	(1985 – 1988)

EDUCATION

University of Massachusetts, Amherst, MA	(1981-1985)
Mathematics and Computer Science	

PROFFESSIONAL ORGANIZATIONS

Northeast Gas Association
New England – Canada Business Council
American Gas Association
Northeast Energy and Commerce Association

TESTIMONY

Various proceedings before the New Hampshire Public Utilities Commission
Various proceedings before the Massachusetts Department of Public Utilities
Various proceedings before the Missouri Public Service Commission
Various proceedings before the Georgia Public Service Commission
Various proceedings before the Maine Public Utilities Commission
Various proceedings before the Indiana Utility Regulatory Commission
Various proceedings before the Federal Energy Regulatory Commission

Resume & Testimony Listing of:

James M. Stephens

Partner

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.

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

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

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

Resume of:

Kim N. Dao
Director

scottmadden
MANAGEMENT CONSULTANTS

Summary

Ms. Dao has 15 years of experience in the energy and utility industries. She has contributed to engagements involving regulatory strategy and market analyses, including the evaluation of open seasons, regional energy market demand/supply dynamics, energy pricing and basis implications, and the associated drivers for new natural gas infrastructure; the development and evaluation of natural gas demand forecasts; and natural gas supply portfolio evaluation and optimization. Ms. Dao has also provided analytical support for expert witness testimony on a variety of issues, including gas supply planning, demand forecasting, cost of capital and capital structure, cost of service and rate design, marginal costs studies, and expense and operating performance benchmarking. She has extensive experience in data analysis, development of customized spreadsheet models (e.g., dispatch, storage optimization, gas pricing, landed costs), Monte Carlo simulation models, database development, researching regulatory and energy market issues, risk identification/assessment, performing statistical analysis, and financial analysis and modeling. Ms. Dao holds a B.A. in economics from Clark University, where she graduated summa cum laude and was a member of the Omicron Delta Epsilon Society.

Areas of Specialization

- Utilities
- Market assessment
- Regulatory strategy and rate case support
- Natural gas
- Demand forecast and supply portfolio evaluation
- Strategic and business planning

Recent Assignments

- Retained by an integrated utility company to support their analysis of new energy infrastructure and upstream pipeline capacity contracts; used @Risk software to develop a Monte Carlo simulation model of daily natural gas pricing estimates that were used in a portfolio optimization software; supported the levelized cost modeling of the utility's proposed infrastructure development projects; developed a qualitative assessment of the proposed projects relative to alternatives; supported the development of expert testimony and sponsored data requests regarding the utility's natural gas supply strategy
- Supported expert testimony filed before and subsequently approved by the Nova Scotia Utility and Review Board regarding a pipeline capacity contract, which included a review of natural gas market dynamics, and the development of several analytical models (e.g., landed cost and resource dispatch models) to review the need for and costs associated with the pipeline capacity contract under various weather and market conditions
- Assisted several New England LDCs with the development of integrated resource plans, including demand forecast model development using various statistical and econometric approaches and supply portfolio analysis and evaluation
- Provided analyses to support expert testimony filed before and subsequently approved by the Massachusetts DPU regarding the utility's capacity decisions associated with the Algonquin Incremental Market open season
- Developed several regression models to estimate peak day demand in support of a potential capacity decision as part of an evaluation of the Tennessee Gas Pipeline Northeast Expansion open season
- Conducted an assessment of the responses to a request for proposal and supported expert testimony that was submitted to the Massachusetts Department of Public Utilities (DPU), which included an overview of current energy market conditions, a summary of natural gas supply options submitted in response to the RFP, and a quantitative and qualitative evaluation of the submissions
- Provided research and analytical support for expert testimony submitted to the Maine Public Utility Commission regarding the retail choice program and the benefits of program changes to the LDC planning function
- Provided support for expert testimony submitted to the Régie de l'énergie regarding the utilization of natural gas storage, which included the development of a natural gas storage dispatch and optimization model
- Supported expert testimony submitted to the Ontario Energy Board, which included an overview of existing market conditions and a quantitative and qualitative assessment of a natural gas transmission project
- For the Maine Public Utility Commission, prepared a report that summarized the Northeast and Atlantic Canada natural gas and power markets, reviewed the current open seasons for incremental pipeline capacity, and analyzed the potential benefits and costs associated with incremental natural gas deliverability
- Supported the evaluation of natural gas storage for an electric utility, which included a review of the open season documentation and offers, the development of a model to evaluate various levels of storage service, and benchmarking analysis of the parameters of the proposed natural gas storage contract to similar services offered by other storage providers
- Supported expert testimony on the cost of capital for ratemaking purposes before numerous state utility regulatory agencies for electric and natural gas utilities through state and company-specific research and analysis, financial analysis and modeling, and testimony development

Resume of:

Kim N. Dao
Director

Professional History

ScottMadden, Inc. (2016 – Present)
Director
Manager

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

Concentric Energy Advisors, Inc. (2004 – 2012)
Consultant

Education

Bachelor of Arts, Economics, Clark University, summa cum laude, 2004

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 Date of Response: 4/27/18
Request No. Staff 2-12 Respondent: Francisco C. DaFonte

REQUEST:

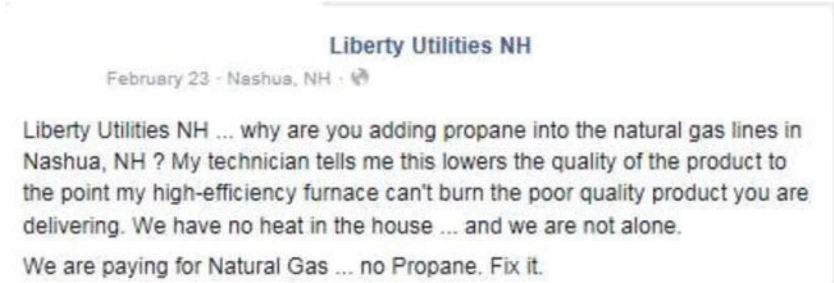
Re: the Company's *Least Cost Integrated Resource Plan*, as filed in Docket No. DG 17-152, at page 48 the Company reports "the Company's customers have experienced problems with their high efficiency furnaces at various times when these propane facilities are used extensively." Please provide details of these problems, including:

a. How many customers have experienced problems?
b. What has(ve) been the nature(s) of the problems?
c. Where have the problems been relative to the locations of the propane facilities?

RESPONSE:

a. The Company has received customer complaints at various times over the past few years. The exact number is not known as many of the calls are simply "no heat" calls and the customer is generally unaware of what has caused their furnace to stop working. However, the Company has previously discussed this issue at length in Docket No. DG 14-380 in the Rebuttal Testimony of Mr. DaFonte at Bates 051:

> "…In addition, from a system operations perspective, the Company has received multiple complaints from customers with new high-efficiency heating equipment as a result of EnergyNorth's use of the propane facilities. These complaints are generally attributable to the limited tolerance of more modern equipment to varying natural gas heating values, and at times has led to "no heat" calls by customers. As an example, the Company received the following complaint from a customer via Facebook in February 2015:



Liberty Utilities NH

February 23 · Nashua, NH ·

Liberty Utilities NH ... why are you adding propane into the natural gas lines in Nashua, NH ? My technician tells me this lowers the quality of the product to the point my high-efficiency furnace can't burn the poor quality product you are delivering. We have no heat in the house ... and we are not alone.

We are paying for Natural Gas ... no Propane. Fix it.

> Additionally, the Company has received reports from HVAC contractors that service accounts near to one of EnergyNorth's propane facilities who indicated they had received numerous customer calls due to noise from their high-efficiency boilers, including certain customers that were uncomfortable remaining in their homes while this was occurring. One of the HVAC contractors noted that it was "selling more and more" of the high efficiency boilers "due to rebates that incent their installation."

Just this past winter, the Company received calls from St. Anslem's College in Manchester, which lost heat to five buildings, and the City of Manchester, which also lost heat to several buildings including City Hall and one of the city schools. All of the affected equipment was high-efficiency.

With the incentives for customers to replace older, less efficient furnaces, the conversion of oil and propane customers to higher efficiency natural gas heating equipment, and simply the phasing out of the manufacturing of low efficiency heating equipment, this issue will only get worse unless propane can be phased out of the Company's resource portfolio. Further, it may act as a deterrent for customers who want to be more energy efficient and, quite frankly, take advantage of the Company's award winning energy efficiency programs.

b. Please see the Company's response to part (a) above.

c. The problems have occurred in Nashua and Manchester where the Company has two of its three propane facilities.

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 | Date of Response: 4/27/18
Request No. Staff 2-14 | Respondent: William R. Killeen

REQUEST:

Re: the Company's *Least Cost Integrated Resource Plan*, as filed in Docket No. DG 17-152, at page 48 the Company states "When these opportunities arise, the Company uses an appropriate decision-making process to determine whether modifications to the current resource plan are appropriate." Please describe the "appropriate decision-making process".

RESPONSE:

First, the Company evaluates the need to maintain the contract, or resource, as part of the overall supply portfolio in the context of current and expected future market conditions.

Second, depending on the type of resource needed, the Company will canvas the marketplace, including evaluating on-system investments, to determine the availability of a replacement or new resource and, where appropriate, the Company will solicit competitive bids to determine the least-cost available resource.

Finally, the Company evaluates non-price factors associated with the available replacement, or new resource option, to determine the best-cost resource. The Company will consider the reliability, diversity, flexibility and viability to determine the best-cost, most reliable option to meet the Company's resource need. In all cases, EnergyNorth will renew existing contracts on a cost-effective basis in order to assure that there is sufficient deliverability to meet customer requirements over the forecast horizon.

In the third step of EnergyNorth's resource planning process, the Company evaluates the ability of its resource portfolio to meet the projected demand requirements in each year of the forecast. As part of this evaluation, the Company reviews possible strategies for meeting customer requirements under a variety of circumstances using the SENDOUT® model.

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

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	Date of Response: 4/27/18
Request No. Staff 2-16	Respondent: William R. Killeen

REQUEST:

Re: the Company's *Least Cost Integrated Resource Plan*, as filed in Docket No. DG 17-152, at page 49 the Company lists five gas-supply options that have been identified:

a. Please identify the criteria on which those options have been identified.

b. None of those options involve the Algonquin pipeline system. Please explain why not.

RESPONSE:

a. The process and criteria used by the Company to select the five options identified is discussed in the response to Staff 2-14. The primary goal of the Company's resource planning process is to meet the expected demand requirements of its customers in a reliable manner, at the best cost. Further, the gas supply portfolio objectives include reliability, flexibility, diversity, and viability in order to achieve the best cost. The options listed at page 49 (Bates 053) were identified as being capable of meeting the planning objectives, in particular, viability, within the LCIRP timeframe.

b. The Company did not identify an active Enbridge project on Algonquin and/or Maritimes and Northeast Pipeline to evaluate. Algonquin has withdrawn its Access Northeast project from the pre-filing review process at the Federal Energy Regulatory Commission and no other Enbridge-sponsored project was identified by the Company for evaluation.

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	Date of Response: 4/27/18
Request No. Staff 2-19	Respondent: William R. Killeen

REQUEST:

Please:

a. State whether there have been any changes to the Company's resource plans since the filing of the IRP?
b. If so, please describe the changes?
c. If so, please described the reasons for making the changes.

RESPONSE:

Since the filing of the Least Cost Integrated Resource Plan ("LCIRP"), EnergyNorth has filed a Petition to Approve Firm Supply and Transportation Agreements and the Granite Bridge Project in Docket No. DG 17-198. The Company's gas supply plans as filed in Docket No. DG 17-198 are consistent with the approach outlined in the LCIRP in this docket (i.e., Docket No. DG 17-152). Specifically, in the LCIRP the Company's gas supply portfolio analysis assumed that EnergyNorth would add a new delivery option to connect to the Joint Facilities. The rationale for this new delivery option was provided in the LCIRP at Bates 054:

> "With respect to deliveries to its city-gates, the Company is, for all intents and purposes, limited to one feed (i.e., TGP Concord Lateral) for delivery of gas supplies to its service territory and that feed has no additional capacity to meet the Company's growing demand. Therefore, the Company has also evaluated the option to enhance its distribution system reliability, diversity and flexibility through an extension of its system. A system extension would provide access to incremental gas supply and capacity options."

This "system extension" has been more fully evaluated and the Company has determined that it is the most appropriate delivery option and submitted this option to the New Hampshire Public Utilities Commission ("Commission") for its approval as part of the Granite Bridge Project in Docket No. DG 17-198.

In addition to the "system extension," the Company in the LCIRP discussed the value of incremental LNG storage to meet forecasted demand at Bates 054, specifically:

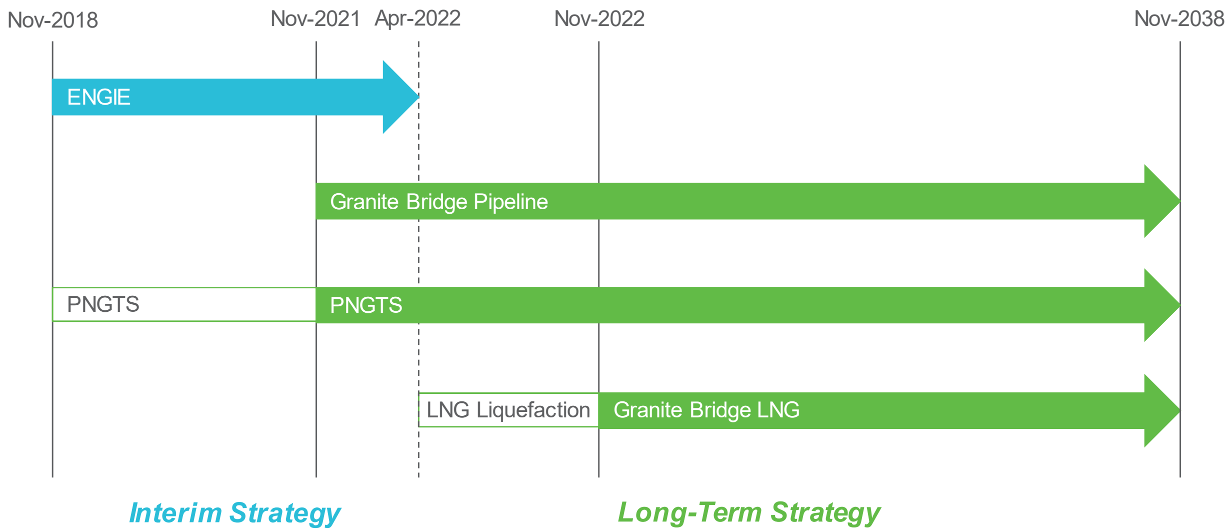
> "Finally, the Company has evaluated the option of increasing its on-system LNG storage and vaporization capacity to serve its long-term resource needs. As discussed in the 2013 IRP, and demonstrated in this filing, the Company has significant demand requirements in the winter period. LNG facilities are specifically designed to provide natural gas supply during the peak periods when customers require it most. In this way incremental LNG storage and vaporization capacity would be able to serve the Company's growing requirements for Design Day and peak period demand. Given EnergyNorth's existing resource portfolio structure, incremental LNG would increase the Company's existing on-system assets and diversify its supplies, which will increase the reliability of the overall portfolio."

This incremental LNG storage and vaporization option has been more fully evaluated and the Company has determined that an LNG facility would increase the reliability, diversity, and flexibility of the gas supply portfolio and provide cost-effective service to its customers. As such, the Granite Bridge Project includes such an LNG facility and was submitted to the Commission for its approval as part of Docket No. DG 17-198.

Finally, the Company's interim and long-term supply resource plans include contracts with ENGIE Gas & LNG LLC ("ENGIE") for a combination liquid/vapor service and Portland Natural Gas Transmission Company ("PNGTS") for transportation capacity on the proposed Portland XPress ("PXP") Project. As such, the interim and long-term strategies for the gas supply portfolio as detailed in Docket No. DG 17-198 represent the Company's plan for its gas supply portfolio and are consistent with the submission in this docket (i.e., Docket No. DG 17-152). Figure 3 from the Direct Testimony of William R. Killeen and James M. Stephens in Docket No. DG 17-198 is replicated below for convenience as it is a summary of the Company's interim and long-term gas supply strategy.

Docket No. DG 17-152 Request No. Staff 2-19

Figure Staff 2-19



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 2-21

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

REQUEST:

Please explain why a 1% adder above the base growth rate for the high scenario was chosen.

RESPONSE:

The high and low case demand scenarios add/subtract 1% from the annual Base Case growth rate, respectively. This methodology was maintained in this filing as it was consistent with the high and low demand scenario methodology in prior Least Cost Integrated Resource Plans developed by the Company and approved by the Commission (see Docket Nos. DG 13-313 and DG 10-041).

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	Date of Response: 4/27/18
Request No. Staff 2-23	Respondent: Francisco C. DaFonte

REQUEST:

Please explain how non-price factors such as reliability, flexibility, viability, and supply diversity relative to economics are weighed.

RESPONSE:

The primary goal of Liberty's planning process is to acquire and manage all available resources in a manner that achieves a best-cost resource portfolio for its customers. A best-cost portfolio appropriately balances lower costs with other important non-cost criteria such as reliability and diversity, flexibility, and viability. Pursuit of a best-cost portfolio allows the Company to provide its customers with reliable service at a reasonable cost.

The Company values portfolio security/reliability (which includes enhancing diversity across pipelines, supply basins, and suppliers) above all else when evaluating any resource. The economics of a particular resource are nearly on par with security/reliability and are a critical aspect of any resource evaluation process. Contract and supply flexibility is another key non-price factor in the determination of a best-cost portfolio. Lastly, the Company must ensure that a resource is viable in the long-term.

With respect to assessing the non-price factors, the Company primarily relies on the expertise and judgment of its gas supply staff augmented, on an as needed basis, by outside consultants.

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

[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 Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)	Total System Cost ($000)	Comparison to Base Case Prime
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 Dawn (Dth/day)	Repsol (Dth/day)	ENGIE (Dth/day)	Total System Cost ($000)	Comparison to 2.0 Bcf Tank ($000)
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

[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.

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 Technical Session Data Requests - Set 1

Date Request Received: 6/1/18	Date of Response: 6/15/18
Request No. CLF Tech 1-4	Respondent: William R. Killeen

REQUEST:

Please see:
Liberty Responses to Staff Data Requests - Set 2: Request No. Staff 2-21
Liberty Responses to Staff Data Requests - Set 2: Request No. Staff 2-22
Liberty Utilities 2017 LCIRP, page 31

Please answer the question on why the high/low case demand scenarios add/subtract 1% from the base case growth rate. Specifically:

a. Please explain the reasoning behind defining a high (low) growth scenario by adding (subtracting) 1 percent to the annual growth in the base case growth.

b. Please identify the source of the 1 percent value for this adjustment and provide all background materials related to this assumption.

RESPONSE:

a. To generate the High Growth demand forecast, the Company added 1.0 percent per annum growth to its Base Case growth rate. That is, the growth rate in the High Growth forecast in each year is 1.0 percent above the growth rate of the Base Case forecast.

   To generate the Low Growth demand forecast, the Company subtracted 1.0 percent per annum growth from its Base Case growth rate. That is, the growth rate in the Low Growth forecast in each year is 1.0 percent below the growth rate of the Base Case forecast.

   In the response to Staff 2-21, the Company explained that the high and low case demand scenarios add/subtract 1.0 percent from the annual Base Case growth rate, respectively. This methodology was maintained in this filing as it was consistent with the high and low demand scenario methodology in the prior Least Cost Integrated Resource Plans ("LCIRP") filings developed by the Company and approved by the Commission (see Docket Nos. DG 13-313 and DG 10-041).

   The LCIRP is to include reasonable high and low growth planning scenarios. The Company retained the growth rate adjustment methodology for the high/low cases based on the prior practice of the Company. This methodology has produced reasonable high and low growth planning scenarios in the past two LCIRP filings, and the Commission has approved the previous two LCIRPs and therefore accepted the high and low load growth assumptions as reasonable.

For this response, the Company also reviewed the filing in Docket No. DG 06-105 (EnergyNorth was under the ownership of Keyspan at that time). The high and low growth methodology was different at that time. The Company has no opinion on the method used under Keyspan ownership. However, of note, the methods used at that time produced a very narrow range of possible demand outlooks. The load additions by the fifth year of the Plan that were approximately 550,000 Dth higher/lower than the Base Case scenario. In contrast, the High Growth and Low Growth Normal Year load additions are higher/lower by approximately 2,500,000 Dth by the fifth year of the Plan in this filing. This provides a much broader range of possible demand scenarios.

b. The Company reviewed the last three LCIRP filings to understand the source of the 1 percent adjustment. The method changed in Docket No. DG 10-041, at which time the Company was under the ownership of National Grid.

In Docket No. DG 10-041, the following discussion was included in the LCIRP:

> *National Grid NH's resource portfolio must be designed to have adequate and reliable resources available to meet forecasted demand at the lowest possible cost. Because the future cannot be predicted with precision, the Company evaluates whether the portfolio resources will be adequate and reliable when actual experience departs from the forecast. Specifically, the Company considered the levels of uncertainty in the demand and sendout forecasts and developed high- and low-demand scenarios relative to the base case forecast to determine the impact a range of alternatives would have on its resource portfolio. A comparison of the average annual load additions for the base case, high- and low-demand scenarios is presented in Chart III-B-2.*
>
> *National Grid NH used the results of the econometric models to develop the high and low demand scenarios. The growth rates of the combined results of econometric model for customers, use per customer and sales, for the residential heating and non-heating and C&I heating and non-heating classes were adjusted up and down by 1 percentage point. For the high case, the Company increased the growth rates on the resulting forecast by 1 percentage point to calculate the high demand values. Similarly, for the low case, the Company decreased the growth rates on the resulting forecast by 1 percentage point to calculate the low demand values.*

One can only conclude that the Company deemed the high/low scenarios to be reasonable for planning purposes. The approval of the LCIRP implies that the Commission agreed with those assumptions.

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

OCA Technical Session Data Requests - Set 1

Date Request Received: 6/21/19
Request No. OCA TS 1-1

Date of Response: 7/10/19
Respondent: Francisco C. DaFonte
William R. Killeen

REQUEST:

Reference Supplemental Testimony of DaFonte and Killeen, Attachment FCD/WRK-4, Bates pages 286-352:

a. Please describe the assumed propane facility usage during the design day for the above-cited SENDOUT run.

b. Is there any day within the last six years when the Company has used the entire capacity of its propane facilities for an entire 24 hour period? If so, please provide documentation of those instances and the Company's resource mix during those instances, preferably in live EXCEL format. Please also provide a narrative describing why the Company utilized its entire capacity of its propane storage facilities during each of those days.

c. If the response to TS 1-1(b) is negative, is there any single hour within the last six years when the Company has used the entire capacity of its propane facilities? If so, please provide documentation of those instances and the Company's resource mix during those instances, preferably in live EXCEL format. Please also provide a narrative describing why the Company utilized its entire capacity of its propane storage facilities during each of those hours.

RESPONSE:

a. For the Alternative Case Sensitivity Supplemental ("ACS") scenario, which was provided in the Supplemental Direct Testimony of Francisco C. DaFonte and William R. Killeen as Attachment FCD/WRK-4, the Company assumes that up to 34,600 Dth/day of supply can be provided by the propane facilities on the Design Day. Please see Confidential Attachment OCA TS 1-1.a for the SENDOUT® report showing that the model uses the maximum available supply from the propane facilities on the Design Day, which occurs on January 19 of each winter, in this ACS scenario.

b. No.

c. Yes. There have been four days within the last six years during which the Company's three propane facilities at Manchester, Tilton, and Nashua operated on the same day: on

December 28 and 29, 2015, and on March 4 and 5, 2014. Operational records indicate that for five hours on March 5, 2014, from 0400 to 0800, all three facilities were operating at full propane production capacity. The resource mix on the day is provided below:

Date	March 5, 2014
EDDs (Effective Degree Days)	53
Sendout	106,070
Resources:	
LNG	4,507 (incl. boiloff of 63)
LPG	4,089
Via Transport (Transportation)	27,988
Via Transport (Sales)	66,850
Operating Balance Agreement	2,636

The propane facilities are used as peaking supply, for short durations, and typically during cold weather periods to ensure customer demand and operational needs are met. This day provides an excellent example of how the propane (and LNG) facilities provide supply flexibility. Over the span of approximately 36 hours leading up to and during March 5, 2014, the weather forecast trended 6 HDDs colder, and the demand forecast increased by over 15% (or more than 15,000 Dths). Once pipeline and supply nominations were set, the weather during the gas day continued to get colder, demand trended much higher than expected, and the propane and LNG facilities were required late in the gas day to ensure customer needs were satisfied.

Confidential Attachment OCA TS 1-1.a contains third party pricing information that is "confidential, commercial, or financial information" which is protected from disclosure by RSA 91-A:5, IV, and for which the Commission granted confidential treatment of similar information in Order No. 26,166 (Aug. 1, 2018). Therefore, pursuant to that order, statute, and Puc 203.08(d), the Company has a good faith basis to seek confidential treatment of this information and will submit a motion confirming confidential treatment prior to the final hearing in this docket.
Note that the entire document has been marked confidential at this time because the personnel best suited to identify the confidential material are not available given the upcoming holiday weekend. The Company will supplement this response with a more narrowly redacted version as soon as possible.

REVISED RESPONSE:

The Company has determined there is no confidential information in the document previously provided as Confidential Attachment OCA TS 1-1.a. Therefore, the Company is revising the above response to withdraw its claim of confidentiality and is providing the same document, with no redactions, now identified as Attachment OCA TS 1-1.a.

1-28 Reference Page 20, lines 8 to 9 and lines 11 to 13. "There is a significant risk that the resources will not remain economic through their expected terms of service [] Liberty is unlikely to need the delivery capacity for very long, leaving its customers vulnerable to having to pay for stranded assets."

a) Please provide all source documentation, data, and analysis relied upon by Mr. Chernick to support these two assertions. If there are none, please state as such.

Response:

See Mr. Chernick's testimony at pages 20-29. The analysis relied on is identified in Mr. Chernick's testimony.

1-32 Reference Page 28, lines 15 to 16. "While the LCIRP may be painting the lack of demand for LNG in the New England market as some sort of problem, it is in fact an advantage for gas buyers, since import (and associated storage) capacity is readily available."

a) Please provide a list of all the imported LNG supply contracts negotiated by Mr. Chernick.
b) Please provide all testimony and work product developed by Mr. Chernick with respect to imported LNG supplies over the past 10 years.
c) Please provide all testimony and work product developed by Mr. Chernick with respect to interstate pipeline capacity over the past 10 years.

Objection:

CLF objects to this data request because it is overly broad, unduly burdensome, seeks to have the witness provide information that is publicly available or additional analysis beyond his testimony, and is not reasonably calculated to lead to the discovery of admissible evidence.

Notwithstanding this objection, CLF provides the following response:

Response:

a. None.

b. See http://resourceinsight.com/wp-content/uploads/2019/08/PLC-346_ME_PUC_2019_00105_Direct_8-2019.pdf and http://resourceinsight.com/wp-content/uploads/2019/08/PLC-345_ME_PUC_2019-00101_Direct_8-2019.pdf. Mr. Chernick's work for Boston Gas Company in the late 1980s and early 1990s also involved imports of LNG through Distrigas, but this was outside the date range of the request.

c. See http://resourceinsight.com/wp-content/uploads/2015/01/PLC-286_ON_OEB_2012-0451_0433_0074_Direct_6-2014.pdf, http://resourceinsight.com/wp-content/uploads/2019/09/PLC-304_GEC_INTRV_EVIDENCE2_CORRECTED_7-2015.pdf, http://resourceinsight.com/wp-content/uploads/2015/01/PLC-245_PA_PUC_R-2009-2139884_Direct_12-2009.pdf, http://resourceinsight.com/wp-content/uploads/2019/09/PLC-303_PA_PUC_P-2014-2459362_Direct_5-2015.pdf, http://resourceinsight.com/wp-content/uploads/2019/09/PLC-303_PA_PUC_P-2014-2459362_Rebuttal_7-2015.pdf. Mr. Chernick has developed avoided gas costs for other Philadelphia Gas Works proceedings, Peoples Gas (Pennsylvania) and various UGI gas subsidiaries, reflecting pipeline and storage supplies, but this work did not result in any free-standing public reports.

Chico DaFonte

From:	William Clark
Sent:	Thursday, October 17, 2019 1:37 PM
To:	Chico DaFonte
Subject:	FW: Contact Information
Follow Up Flag:	Follow up
Flag Status:	Flagged

William Clark | **Liberty Utilities** (East Region) | Senior Director, Business Development
P: 603-724-2124 | C: 603-475-8107 | E: William.Clark@libertyutilities.com

From: Lisa DeGregory
Sent: Thursday, October 17, 2019 1:34 PM
To: Huck Montgomery <Huck.Montgomery@libertyutilities.com>
Cc: William Clark <William.Clark@libertyutilities.com>
Subject: FW: Contact Information

Please see below from Joyce P&H.

Lisa DeGregory | **Liberty Utilities** (East Region) | Senior Regional Manager, Business and Community Development
P: 603-782-2374 | C: 603-401-6512 | E: Lisa.DeGregory@libertyutilities.com

From: Ryan Lagasse
Sent: Thursday, October 17, 2019 1:21 PM
To: Lisa DeGregory <Lisa.DeGregory@libertyutilities.com>
Subject: FW: Contact Information

Joyce Heating/Cooling provided the email below describing their issues with the propane air injection.

Ryan Lagasse | **Liberty Utilities** (New Hampshire) | Territory Manager, Business and Community Development
P: 603-782-2338 | C: 603-327-7151 | E: Ryan.Lagasse@libertyutilities.com

From: Suzanne Pacheco
Sent: Thursday, October 17, 2019 1:16 PM
To: Ryan Lagasse <Ryan.Lagasse@libertyutilities.com>
Subject: FW: Contact Information

FYI

Suzanne Pacheco | **Liberty Utilities** (New Hampshire) | Residential Territory Manager, Business and Community Development
P: 603-782-2334 | C: 603-231-6299 | E: Suzanne.Pacheco@libertyutilities.com

From: Shaun Dougherty [mailto:sd@joycecool.com]
Sent: Thursday, October 17, 2019 1:12 PM
To: Suzanne Pacheco <Suzanne.Pacheco@libertyutilities.com>

Cc: Lisa DeGregory <Lisa.DeGregory@libertyutilities.com>
Subject: Re: Contact Information

Hi Suzanne,

I apologize for the delay on getting this to you.

Please see below In regards to the issues we experience when propane is added into the natural gas lines.

1. Customers with high end heating units, mostly modulating gas boiler, will have a very loud rumbling noise. The boiler sounds terrible and actually shakes in some cases when it happens.
2. Once the customer hears the sound they call us to set up a service call. After we receive several calls from the same neighborhood we now that there has been propane added into the gas lines. We've been told that it is due to usage and needing to increase the volume delivered to the customers.
3. We do our best to tell customers over the phone that we can't do anything to correct the issue but a lot of them want us to come out anyways and typically these systems are under warranty so we can't charge for the visit.
4. Usually this happens on extreme cold mornings when a lot of systems are running after set back from the night. We've found that after 2 or 3 hours whatever

Shaun Dougherty

Joyce Cooling & Heating Inc.

603-882-4244

Shaun Dougherty
Joyce Cooling & Heating Inc.
603-882-4244
www.joycecool.com

On Oct 17, 2019, at 10:51 AM, sd@joycecool.com wrote:

I sent an email right after we spoke last week in regards to this.

Shaun Dougherty
Joyce Cooling & Heating Inc.
603-882-4244
www.joycecool.com

On Oct 17, 2019, at 10:05 AM, Suzanne Pacheco
<Suzanne.Pacheco@libertyutilities.com> wrote:

Hi Shaun,

My apologies for not spelling your first name correctly in my last email!

I just wanted to follow up and see if you would have a free moment to document the effects of what happens when propane is fed into the system during the winter.

Thanks so much!

Suzanne

Suzanne Pacheco | Liberty Utilities (New Hampshire**) |** Residential Territory Manager, Business and Community Development
P: 603-782-2334 | C: 603-231-6299 | E: Suzanne.Pacheco@libertyutilities.com

From: Suzanne Pacheco
Sent: Friday, October 04, 2019 12:26 PM
To: 'sd@joycecool.com' <sd@joycecool.com>
Subject: Contact Information
Importance: High

Hi Shawn,

Thank you for returning my call and agreeing to document the issues that are encountered when propane is fed in to the system in the winter.

Please find my direct contact information below.

Best Regards,
Suzanne

Suzanne Pacheco | Liberty Utilities (New Hampshire**) |** Residential Territory Manager, Business and Community Development
P: 603-782-2334 | C: 603-231-6299 | E: Suzanne.Pacheco@libertyutilities.com
130 Elm Street, Manchester, NH 03101

Chico DaFonte

From: Chico DaFonte
Sent: Thursday, October 24, 2019 8:32 AM
To: Chico DaFonte
Subject: FW: Gas issues

Begin forwarded message:

From: Paul Renaud [mailto:PRenaud@Anselm.Edu]
Sent: Tuesday, October 22, 2019 8:54 AM
To: Andrew Morgan <Andrew.Morgan@libertyutilities.com>
Subject: FW: Gas issues

Hi Andrew,

In preparation for this winter I am wondering if there is anything I can do. During almost every winter we have had critical boilers for buildings trip out during really cold storms. We have some buildings here that require 100% outside air so you can imagine when the boilers trip. Luckily our freeze stats are working to shut units off. I am resending you this e-mail to refresh your memory of last year. I do not have correspondence from before that time. I am looking into getting alarm histories put together to show when the boilers tripped.

-Goulet Science has labs and animals and has 100% outside air

-Gadbois Hall is an old brick and block Nursing building which gets cold quick when no heat is available

-Alumni Hall which is our administration building and has many offices as well as some classrooms is also an old building and gets cold quick.

-Stoutenburgh Gymnasium which is where our basketball, volleyball games are and has an expensive floor. There are also gang showers.

-Dana Center is our theater building which holds upwards of 300 people and needs the temperature to be maintained

There is also the issue with costs for call-ins to reset the boilers. We are probably around 100 man hours and half of that is overtime call-ins with a 3 hour minimum.

Thank you,

Paul Renaud

Plumbing and HVAC Supervisor

603.641.7358

Saint Anselm College
FACILITIES AND
PHYSICAL PLANT

From: Andrew Morgan [mailto:Andrew.Morgan@libertyutilities.com]
Sent: Monday, March 12, 2018 8:38 AM
To: Paul Renaud <PRenaud@Anselm.Edu>
Subject: RE: Gas issues

Paul,

Good morning. Our gas control department did inject propane into the system last week for demand support. This may have caused the boilers to trip. We did not have any pressure related issues with the system. I have not heard anything from gas control saying that we will be doing this again. If I hear anything, I'll be sure to let you know.

Thank you,

Andrew Morgan | Liberty Utilities (New Hampshire) | Manager III-Gas, Business and Community Development
P: 603-782-2321 | C: 603-327-5357 | E: Andrew.Morgan@libertyutilities.com

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From: Paul Renaud [mailto:PRenaud@Anselm.Edu]
Sent: Monday, March 12, 2018 7:30 AM
To: Andrew Morgan <Andrew.Morgan@libertyutilities.com>
Subject: Gas issues

Hi Andy,

In advance of this next storm I was wondering if I have to do anything? Last week's storm tripped out 5 buildings of gas boilers and 1 building I had to increase the gas pressure on the boilers gas valve to get them to fire. Do you know of anything that happened last week during the storm?

Thanks

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