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Liberty Utilities

(EnergyNorth Natural Gas) Corp.

d/b/a Liberty Utilities

Least Cost Integrated Resource Plan

DG 17-___

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I. INTRODUCTION

This filing presents the 2017 Least Cost Integrated Resource Plan ("2017 IRP," "LCIRP," or "Plan") for Liberty Utilities (EnergyNorth Natural Gas) Corp. d/b/a/ Liberty Utilities (hereinafter referred to as "EnergyNorth" or the "Company"), for the planning years 2017/2018 through 2021/2022 (the "Forecast Period").[1] The Plan details EnergyNorth's resource planning process and presents the Company's resource strategies based on its current forecast of customer requirements and expected market conditions. The Company submits this LCIRP for review by the New Hampshire Public Utilities Commission (the "Commission") pursuant to Order No. 25,762 (Feb. 9, 2015) (the "2013 IRP Order") and the requirements of RSA 378:38 and 378:39. EnergyNorth requests the Commission's approval of its LCIRP that sets forth a resource plan to meet its expected customer requirements using currently accepted planning processes, standards, and methods.

A. Company Background

EnergyNorth is a local distribution company ("LDC") that provides natural gas service to approximately 91,000 residential, commercial, and industrial customers in thirty-three cities and towns in New Hampshire. In Order No. 25,370 (May 30, 2012), the Commission approved the transfer of ownership of EnergyNorth to Liberty Energy Utilities (New Hampshire) Corp. The majority of EnergyNorth's customer base is comprised of residential heating customers having heat-sensitive demand. The remainder of EnergyNorth's customers are small and medium-size commercial and industrial ("C&I") loads, as well as some larger industrial customers.

In general, there are two categories of customers with respect to portfolio planning: those customers for whom EnergyNorth must plan and acquire capacity (i.e., sales and capacity-assigned), and those who receive delivered supplies from competitive suppliers (i.e., capacity-exempt transportation). EnergyNorth's C&I customers have the option of purchasing supply from a competitive supplier and receiving transportation-only service from EnergyNorth pursuant to the Company's unbundled tariff options. The terms and conditions applicable to transportation-only service specify EnergyNorth's obligation to assign capacity to portions of the transportation customer loads. EnergyNorth's resource planning process appropriately reflects its obligation to assign capacity and maintain reliability in conjunction with its unbundled service offerings. Certain transportation-only customers have capacity-exempt status for whom the Company is not responsible for obtaining supply or capacity resources to meet their demand.

To provide capacity for its sales service and capacity-assigned transportation customers, the Company has developed a gas supply portfolio with various assets and contracts. EnergyNorth's current resource portfolio is comprised of long- and short-haul transportation capacity, storage capacity and associated transportation capacity, and on-system peak-shaving facilities. Nearly all of EnergyNorth's upstream long- and short-haul transportation capacity and underground storage is ultimately delivered to the Company via Tennessee Gas Pipeline ("Tennessee" or "TGP") with the exception of 1,000 dekatherms ("Dth")/day of pipeline capacity which is delivered via the Portland Natural Gas Transmission System ("PNGTS") to serve the city of Berlin. EnergyNorth's peaking supplies include on-system liquid propane

[1] A gas supply planning year or "split-year" is defined as the twelve-month period beginning November 1 and ending October 31.

gas and liquefied natural gas ("LNG") facilities located in Manchester, Concord, Nashua, and Tilton, New Hampshire, and an additional "satellite" propane facility in Amherst.[2]

B. Organization of the 2017 IRP Filing

The 2017 IRP filing is organized as follows:

- Section II provides a summary of the Company's resource planning process and an overview of the results;
- Section III discusses the Company's econometric demand forecasting methodology and provides detailed results for each customer segment, summarizes the adjustments for the Company's energy efficiency programs and other out-of-model adjustments, and discusses the allocation of the monthly forecast to a daily basis, which facilitates supply and capacity analysis. This section also provides a comparison of the 2017 IRP forecast results to the 2013 IRP results;
- Section IV provides details on the Company's approach to developing the various planning standards;
- Section V discusses the Company's supply resource portfolio and the adequacy of the portfolio in terms of meeting forecast requirements under the Base Case and various growth and weather scenarios; and
- Section VI provides a summary of the Commission's directives outlined in the 2013 IRP Order and the actions taken by the Company to ensure compliance with those directives, consistent with the requirements of RSA 378:38 and 378:39.

Additional information to support the 2017 IRP is provided in the following Appendices:

Appendix 1. Detailed Regression Results

Appendix 2. Energy Efficiency

Appendix 3. Description of the Daily Regression Analysis

Appendix 4. Description of the Monte Carlo Analysis

Appendix 5. Existing Supply Resource Portfolio

Appendix 6. SENDOUT® Results

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[2] The satellite propane facility in Amherst is used solely for storage.

II. OVERVIEW OF RESOURCE REQUIREMENTS

EnergyNorth's resource planning process begins with the establishment of appropriate goals and objectives. The primary goal of EnergyNorth's planning process is to acquire and manage resources that provide reliable service under various demand scenarios while focusing on a best-cost resource portfolio for its customers. A best-cost portfolio appropriately balances costs with EnergyNorth's planning objectives, which are to maintain reliability and supply security, provide contract flexibility, and promote the acquisition of viable resources. Pursuit of a best-cost portfolio allows EnergyNorth to provide its customers with reliable service at the lowest reasonable cost.

As discussed in detail in Section III, the first step of the resource planning process is the development of a five-year demand forecast for the Company's service territory for which the Company must plan ("Planning Load"). The Company's Planning Load includes demand from firm sales customers and capacity-assigned transportation customers (i.e., firm transportation customers that are not exempt from capacity assignment requirements, as specified in the Company's Terms and Conditions, Section 11.0). The Planning Load requirements are derived from econometric demand forecast models developed for four customer segments: residential heating; residential non-heating; C&I heating; and C&I non-heating. In addition, certain out-of-model adjustments were included in the forecast to reflect the Company's increasing sales and marketing efforts, and its expansion into new service territories.[3] The Company's Planning Load requirements are adjusted to account for demand reductions expected to be achieved through the implementation of its energy efficiency programs.

Over the Forecast Period, the Company's Planning Load is expected to increase in demand. The Planning Load forecast is driven by increases in the residential heating and C&I heating and non-heating demand. As discussed in Section III.A.13 below, residential heating volumes are forecast to increase at a compound annual growth rate ("CAGR")[4] of 2.3 percent between 2017/2018 and 2021/2022, and the C&I heating and non-heating volumes are forecast to increase at a CAGR of 3.5 percent and 1.5 percent, respectively, over the same period.[5] Residential non-heating volumes are forecast to decline at a CAGR of 3.2 percent.

As discussed in Section IV, the Company has prepared forecasts of Planning Load requirements under a Base Case scenario and under a range of weather and growth scenarios. The weather scenarios analyzed include (1) Normal Year, (2) Design Year, and (3) Design Day. The growth scenarios include (1) Base Case, (2) Low Growth, and (3) High Growth.

The final step of the planning process is the review and evaluation of the Company's current supply resource portfolio using the SENDOUT® portfolio optimization model. As discussed in Section V, the Company outlines its strategy for a long-term resource portfolio that enhances the reliability, diversity, and flexibility of the portfolio, which better positions the Company to meet expected demand at the best cost for its customers.

EnergyNorth's LCIRP provides a complete description of the Company's planning processes which it has employed, and continues to employ, enabling the Commission to adequately review the Plan and to come

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[3] Forecast demand associated with Innovative Natural Gas, LLC ("iNATGAS"), a reseller of compressed natural gas, was also included as an out-of-model adjustment. However, the demand from iNATGAS is currently expected to be minimal and does not have a significant effect on the demand forecast.

[4] The CAGR is calculated as $((\text{Value}_{\text{Yearn}} / \text{Value}_{\text{Year1}})$ ^ $(1 / n)) – 1$.

[5] Including out-of-model adjustments.

to a full understanding of the methods used in practice and the results reached by applying those methods to current circumstances. The Plan also demonstrates that EnergyNorth's planning standards are appropriate and that the resource strategies described herein are in the best interests of its customers and result in a reliable, best-cost, long-range supply and capacity portfolio to meet the Company's forecasted Planning Load.

Important aspects of EnergyNorth's Plan are that it incorporates flexibility and reflects expected future conditions. Thus, it is a dynamic document in the sense that it continues to be refined as needed to reasonably respond to the changing requirements of EnergyNorth's customers and market conditions.

A. Current Resource Planning Environment

Market and regulatory restructuring of wholesale and retail natural gas markets over the last few decades have increased the complexity associated with acquiring and managing a best-cost resource portfolio. Virtually every aspect of LDC portfolio management has been transformed by regulatory and market changes. In the broadest of terms, the very markets in which LDCs such as EnergyNorth participate, the types of products and services that are bought and sold, and the manner in which these transactions are completed are vastly different today than 30 years ago. Market transformation has brought about many new opportunities and risks for all market participants, including LDCs, which must continue to reliably meet the supply requirements of their customers.

Natural gas markets continue on a course of broad restructuring that began with the initial deregulation of most wellhead supply prices in 1978 by an act of Congress. Through a series of physical infrastructure, financial market, regulatory, and technological advances, the manner in which gas supplies are traded and delivered to end-use customers has changed entirely. The result is a dynamic and competitive marketplace that is capable of delivering greater value to customers, but also increases the complexity of resource planning.

Today, wholesale natural gas commodity markets are no longer price-regulated and the delivery of supplies to LDC city-gate stations is unbundled from supply and storage services. Large volumes of gas are traded at many different pooling points along the interstate pipeline transmission system at transparent prices. LDCs and many end-users purchase supplies directly from marketing entities under flexible contract terms.

Prior to these changes, LDCs purchased all supplies from a limited number of pipelines serving their market area. To a large degree, LDCs relied on Federal Energy Regulatory Commission ("FERC") oversight to ensure that the bundled supplies were reliable and reasonably-priced. During that period, LDC markets demonstrated remarkable stability from year-to-year, minimizing the market risks associated with the long-term contracts required by pipeline providers.

Restructuring of retail markets significantly impacted EnergyNorth's planning process as C&I customers availed themselves of opportunities to purchase supply from competitive suppliers pursuant to firm transportation options available under EnergyNorth's tariff. As of July 31, 2017, approximately 2,600 C&I customers purchased supply from competitive suppliers.

These changes in natural gas markets have brought greater competition and customer choice, but they have also introduced considerable uncertainty in the resource planning process. In particular, the LDC's continuing role to plan for and acquire firm capacity resources for C&I customers complicates the manner in which it forecasts customer demand and designs its resource portfolio. Even with the introduction of competition from marketers, the LDC remains responsible for ensuring overall reliability on its distribution system, and must be prepared to address any situation whereby one or more of its firm customers may be without gas supply for any reason.

EnergyNorth must continue to plan in a manner that ensures adequate and reliable supply so that its distribution system is not impaired by, or the Company can mitigate the effects of, an upstream disruption or a failure to deliver natural gas on a critical day. Natural gas flows on EnergyNorth's system and through the meters of every customer on its system, regardless of whether that customer buys its commodity from EnergyNorth or someone else.

There are several recent gas supply and market trends that will affect the New England market in general, and New Hampshire in particular. The dwindling off-shore natural gas supplies from Nova Scotia reduce the supply options available to the Company, whereas the significant increase in domestic natural gas production and reserves provides opportunities for LDCs. However, the complexity and lead-time required to construct incremental pipeline capacity will significantly influence how and where those supplies are delivered. Finally, the changing focus of regional imported LNG facility owners will impact gas supply strategy and decisions.

B. EnergyNorth's Planning Process

EnergyNorth's long-term process of planning for and meeting customer load requirements involves the coordination of a number of activities including demand forecasting, long-term resource planning, gas supply management, gas distribution, and energy efficiency. The majority of these activities are centralized within the Company's Energy Procurement Group, which provides the Company's Gas Load Forecasting, Gas Supply Planning, Portfolio Optimization, and Scheduling functions, and also includes the Customer Choice Team, which is responsible for managing the Supplier Service program. The Energy Procurement Group coordinates closely with the Gas Control Department, which is responsible for gas deliveries across the EnergyNorth distribution system in New Hampshire, and the Energy Efficiency Team, which is responsible for the design, implementation, and management of the Company-sponsored energy efficiency programs. Among the responsibilities of the Energy Procurement Group are to project the resource requirements of the EnergyNorth system and to assemble a best-cost portfolio of reliable resources to meet those requirements. The forecast of resource requirements consists of two steps: (1) the preparation of forecasts of long-term trends in customer requirements under normal weather conditions ("Normal Year"); and (2) the preparation of forecasts of customer requirements under defined (i.e., Design Day and Design Year) weather conditions. Assembling the best-cost portfolio is also a two-step process involving: (1) the procurement of a sufficient and appropriate portfolio of resources to meet the various sendout requirements resulting from the demand forecasting process; and (2) the economic dispatch of those volumes given available resources. The Company's resource portfolio provides a range of flexibility in making these economic dispatch determinations in the course of the day-to-day management of the portfolio.

EnergyNorth's short-term forecasting and gas supply planning activities are coordinated through its local Energy Procurement and Gas Control groups. Each day, Gas Control provides Energy Procurement with projected sendout requirements that are developed based on the results of a load forecasting process. Energy Procurement determines the availability, reliability, and pricing information necessary to satisfy the predicted customer loads taking into account both currently available projections of weather and prices as well as the possibility of design-forward weather conditions for the remainder of the heating season (design-forward planning). Energy Procurement and Gas Control then establish a daily "Game Plan" that matches available resources with sendout requirements for the EnergyNorth system. The

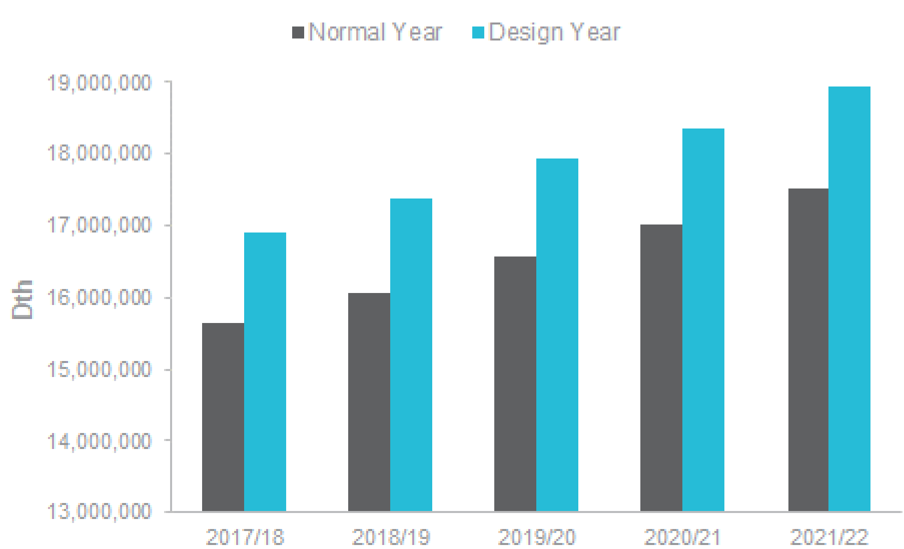
Game Plan is designed to balance the demand requirements of the system for the current gas day with scheduled supply volumes and also to project a seven-day supply/demand balance.

As described in Section III, the Company's long-term planning process is based on a comprehensive methodology for forecasting customer load requirements using an econometric analysis to determine growth expected for residential heating, residential non-heating, C&I heating, and C&I non-heating customer segments. Two out-of-model adjustments were made to the econometric forecast to account for additional demand that is not reflected in the historical data. Those adjustments were related to: (1) expected increases in the number of customers in the Company's existing service territory related to increasing sales and marketing efforts; and (2) estimates of the number of customers in new service territories in which the Company is expanding.

The results of the Company's forecasting methodology indicate that, over the Forecast Period, demand is forecast to grow by an average of nearly 475,000 Dth per year, or at a CAGR of 2.9 percent under normal weather conditions.

The Company developed two additional planning standards to ensure that: (1) its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the coldest planning day ("Design Day"); and (2) it maintains sufficient supplies under contract and in storage (consisting of underground storage, LNG, and propane) to meet its customers' requirements over the coldest planning year ("Design Year"). The Design Year and Design Day planning standards are based on a Monte Carlo statistical analysis to establish a reasonable level of reliability for firm customers. As a result of this analysis, the Company defined a Design Year at 6,869 heating degree days ("HDD") and a Design Day at 71 HDDs. Combining the results of the design planning standards definition and the load forecasting process, the Company is projecting Design Year sendout to increase over the Forecast Period by an average of approximately 508,000 Dth per year, or at a CAGR of 2.9 percent, and Design Day sendout to increase by an annual average of approximately 4,275 Dth/day, or at a CAGR of 2.6 percent.

Figure 1: Planning Load



After the forecast of customer requirements is determined, the Company then designs a resource portfolio to meet forecast demand requirements in a reliable and best-cost manner. To that end, the

Company uses the SENDOUT® model to determine the adequacy of the existing and potential portfolio in meeting the forecast requirements and to identify any shortfalls during the Forecast Period. By using the SENDOUT® model, the Company can determine the best-cost, economic dispatch of its existing resources while taking into account the contractual and operating constraints, and can identify the need for, and type of, additional resources during the Forecast Period, if any. In the context of this report, EnergyNorth has reflected the rollover of all existing capacity resources for which the Company has the Right of First Refusal ("ROFR") or a rollover right that requires renewal during the five-year planning horizon of the Plan. These long-term contracts have provided competitively-priced services and offer important supply diversity benefits to the Company's portfolio. To evaluate the flexibility and adequacy of the resource portfolio under a range of potential conditions, the portfolio is assessed under Base Case, Normal Year, and Design Year conditions. The results of the Company's SENDOUT® analyses demonstrates that the resource plan, with the addition of incremental capacity resources, is sufficient to meet Base Case Design Year load requirements throughout the Forecast Period.

The next step in the planning process is to test the adequacy of the portfolio by evaluating how it would perform under High and Low Growth demand scenarios. The High and Low Growth demand scenarios were developed by adjusting the annual growth rate that resulted from its Base Case forecast upward or downward by one percentage point in each year of the Forecast Period. The Company's resource plan shows that the portfolio, with the addition of incremental gas supply resources, is adequate under design conditions in all years of the Forecast Period in both growth scenarios.

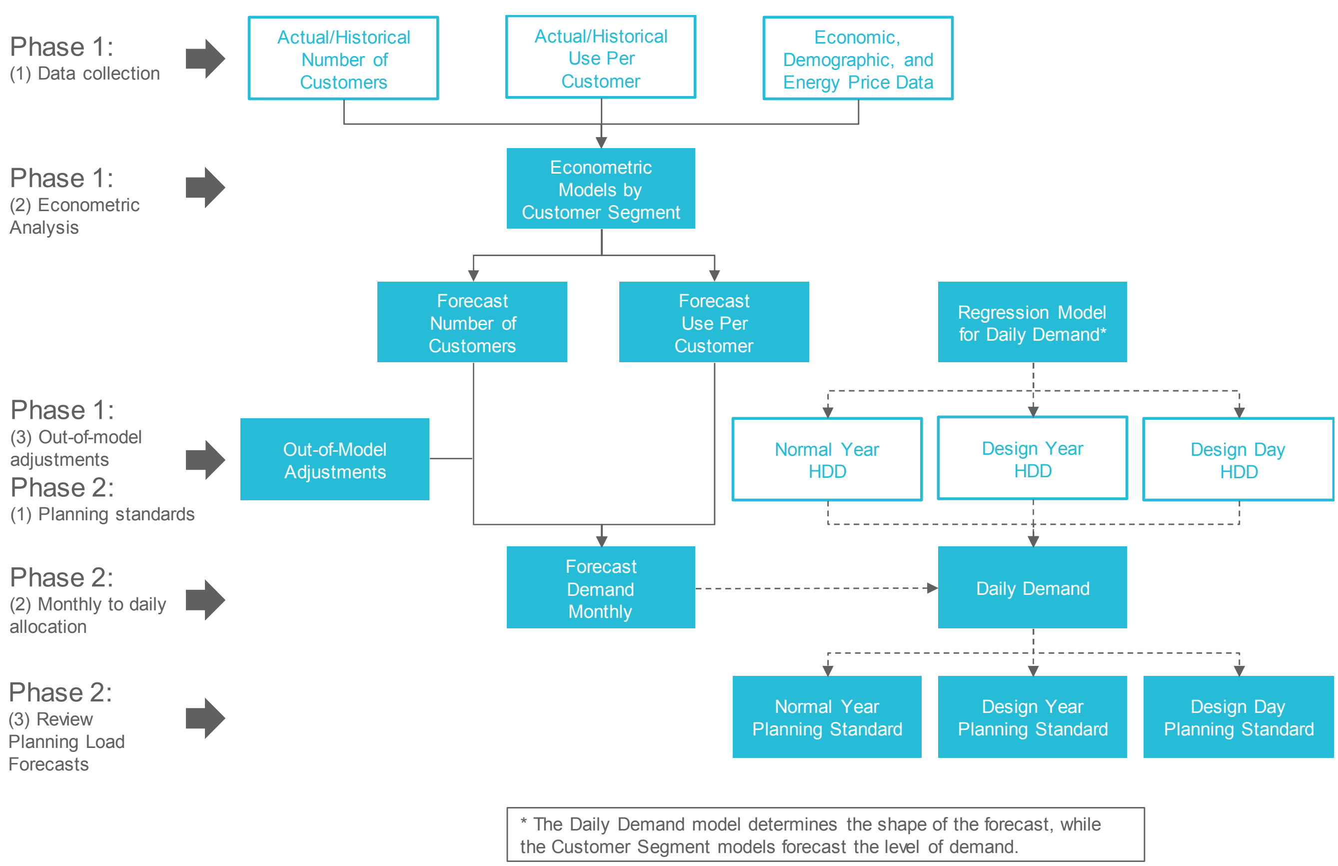
The Company notes that when making renewal, replacement, or incremental capacity decisions, it will employ the planning, supply, and capacity acquisition methods approved under this Plan to further ensure that the decision-making process used is reasonable and appropriate, and that the decision is based on the best information available to EnergyNorth, at the time it is made. Further, EnergyNorth's planning process will reflect the Company's objective of achieving a best-cost portfolio, where resource decisions appropriately balance cost considerations with those related to supply security, contract flexibility, and supply viability.

III. DEMAND FORECAST

The Company's overall demand forecasting methodology used in this 2017 IRP is similar to the methodology used in the 2013 IRP, which was accepted by the Commission in the 2013 IRP Order. The Company's demand forecasting methodology supports its supply planning goals of ensuring that its resource portfolio maintains sufficient supply deliverability to meet customer requirements on the Design Day; and it maintains sufficient supplies under contract and in storage (underground storage, LNG, and propane) to meet its customers' requirements during a Design Year.

The Company develops its customer requirements forecast from econometric models of historical billing data, which is available by month and rate class. The Company's demand forecast was developed in two phases: (1) econometric analysis was utilized to forecast levels of natural gas demand for the Company's service territory; and (2) a daily demand allocation was prepared to estimate daily results under various weather scenarios for supply planning purposes. That process is outlined in Figure 2, below.

Figure 2: Demand Forecast Methodology



As discussed in Section III.A.1, the first step in developing the econometric forecast was to collect and review the appropriate data for use in the modeling process. The Company collected monthly billing data, weather data, economic and demographic data, and energy pricing data. The data was then reviewed for reasonableness to ensure that the demand forecast was based on appropriate and reliable data.

As discussed in Sections III.A.2 through III.A.9, all econometric models were developed using regression analyses, proper and appropriate economic theory, and sound statistical practices and procedures.[6] Econometric models by customer segment were developed to forecast the number of customers, use per customer, and volumes.

As discussed in Section III.A.11, the results of the econometric model forecast were augmented by certain out-of-model adjustments that were not captured in the historical relationship used in the econometric models due to EnergyNorth's increased sales and marketing efforts and expansion into new service territories. The monthly volumetric results of the demand forecast (i.e., econometric models plus out-of-model adjustments) were reduced by energy efficiency savings to determine the Company's net monthly demand requirements (see Sections III.A.12 and III.A.13).

The Company modeled its resources and requirements under various weather conditions, including Normal Year, Design Year, and Design Day. The Design Year standard, in conjunction with the Design Day standard, established the weather conditions that informed the amount of firm volume that the Company must plan for to maintain reliable service (see Section IV).

Once the planning standards were determined, the Company then translated the monthly demand forecast (which is lagged in time due to the Company's monthly billing cycle schedule) into a demand forecast of unlagged daily resource requirements at the Company's city-gates. This translation (i.e., allocating the monthly volumes to daily volumes) involves adjustments for unaccounted for gas and unbilled sales (see Section III.B).

The resulting daily demand forecast was then reviewed for reasonableness. That forecast represents the Company's Planning Load on a daily basis (see Section III.B.4) and is used as an input into the SENDOUT® model to determine the adequacy for the resource portfolio.

A. Phase 1 – Econometric Models for Demand Forecast

The purpose of the customer segment forecasts[7] is to develop long-term projections of Planning Load based on forecast changes in economic and demographic conditions in the Company's service territory. To develop the forecasts, the Company's 17 rate classes were combined into four customer segments for sales and capacity-assigned transportation customers: residential heating, residential non-heating, C&I heating and C&I non-heating; and two customer segments for capacity-exempt customers (C&I heating and C&I non-heating). See Table 1.

The Company used monthly customer billing data (volume and number of customers) for the period August 2010 through April 2017 to define the dependent variables in its econometric modeling to ensure that the most reliable, consistent, and robust data was used in the models.

These sales and transportation categories were chosen since the Company maintains provider-of-last-resort responsibility for the sales and capacity-assigned transportation customers and, by including the

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[6] All regression analyses for the customer segment models were conducted using the SAS software package.

[7] All forecasts represent firm demand only (i.e., firm sales and capacity-assigned, and capacity-exempt transportation) and exclude interruptible and special contract demand.

capacity-exempt customers, total retail volumes can be correlated with total natural gas flow into the Company's distribution system.

Appropriate causal drivers were tested in the development of each of the forecast models and each potential causal variable was tested and reviewed to develop models, which were robust, accurate, and consistent with economic theory. In addition, and consistent with the Company's 2013 IRP forecast methodology, each of the econometric models was tested for autocorrelation, heteroskedasticity, goodness of fit, significant values of the 'F' and 't' statistics, and multicollinearity.

1. Description of Variables

a. Customer Segment Data

The Company relied on monthly billing data by customer segment (volumes and customers) for the period from August 2010 through April 2017. As discussed above, the Company's 17 rate classes were combined, as illustrated below, to four customer segments for sales and capacity-assigned transportation customers and two customer segments for capacity-exempt customers.[8]

Table 1: Customer Segments

Customer Segment	Rate Classes
Residential Non-Heating	R-1
Residential Heating	R-3, R-4
C&I Heating[9]	G-41, G-42, G-43, G-41T, G-42T, G-43T
C&I Non-Heating[10]	G-51, G-52, G-53, G-54, G-51T, G-52T, G-53T, G-54T
C&I Heating Capacity-Exempt	G-41T, G-42T, G-43T
C&I Non-Heating Capacity-Exempt	G-51T, G-52T, G-53T, G-54T

The monthly customer data served as the dependent variable for the sales and capacity-assigned transportation customer models, and the monthly use per customer (i.e., volumes divided by number of customers) served as the dependent variable for the use per customer models.

In addition, monthly usage data was relied on for capacity-exempt transportation customers. This usage data was aggregated by customer segment and served as the dependent variable in the capacity-exempt econometric models.[11]

[8] The Company does not have any residential transportation customers.

[9] The C&I Heating customer segment includes C&I heating sales and capacity-assigned transportation customers.

[10] The C&I Non-Heating customer segment includes C&I non-heating sales and capacity-assigned transportation customers.

[11] The Company did not develop separate number of customers and use per customer models for the capacity-exempt customer segments because there are a limited number of capacity-exempt customers.

b. Weather Variable

HDDs and billing degree days (“BDD”)[12] were used in the customer segment models to account for the effect of weather on customer usage. The HDD and BDD data used to develop the weather-related variables were measured at the Manchester, New Hampshire weather station (“KMHT”), and provided for the period January 1977 through April 2017.[13] The KMHT weather station was selected because it is close to the center of the Company's service territory, on a load-weighted basis.

c. Economic and Demographic Variables

Similar to the approach in the 2013 IRP, economic and demographic variables specific to Belknap, Coos, Hillsborough, Merrimack, and Rockingham counties were purchased from Moody’s Analytics. The economic and demographic variables for each of the counties were combined to arrive at an estimate that represents the Company’s service territory. Lag variables of between one and three months were developed for each of the economic and demographic variables listed in Table 2, below. In addition, Table 2 includes energy price variables developed and tested in the modeling process.

Table 2: Independent Variables

Series	Description	Variable	Source
FHHOLDA	Total Households, (Ths., SA)	HH	Moody's
FPOPA	Total Population, (Ths., SA)	POP	Moody's
FNMA	Total Net Migration, (Ths., SAAR)	NMA	Moody's
FGDP$A	Gross Product: Total, (Mil. Chained 2000$)	GDPR	Moody's
FYHHMEDA	Income: Median Household, ($, SAAR)	INC	Moody's
FYPA	Income: Total Personal, (Mil. $, SAAR)	PI	Moody's
FYPCPIA	Income: Per Capita, (2005 $, SAAR)	PIP	Moody's
FYPDPIA	Income: Disposable Personal, (Mil. $, SAAR)	PID	Moody's
FLBFA	Household Survey: Total Labor Force, (Ths., SA)	LBF	Moody's
FLBEA	Household Survey: Total Employed, (Ths., SA)	EMP	Moody's
FLBUA	Household Survey: Total Unemployed, (Ths., SA)	UEM	Moody's
FLBRA	Household Survey: Unemployment Rate, (%, SA)	UER	Moody's
FHSTA	Housing Starts: Total, (#, SAAR)	HST	Moody's
FHST1A	Housing starts: Single-family privately owned, (# of units, SAAR)	HSS	Moody's
FHSTMFA	Housing starts: Multi-family privately owned, (# of units, SAAR)	HSM	Moody's
FHPNRA	Permits: Residential - Total, (# of units, SAAR)	HPT	Moody's
FHPN1A	Permits: Residential - Single-Family, (# of units, SAAR)	HPS	Moody's
FHPNMA	Permits: Residential - Multifamily, (# of units, SAAR)	HPM	Moody's
FHX1MEDA	Median Existing Home Sales Price, (Ths., SA)	XHP	Moody's
FHXAFFA	Affordability Index - Single-family Housing, (Index)	HID	Moody's
FHX1A	Existing Home Sales, (Ths., SA)	XHS	Moody's

[12] Billing degree days are similar to HDDs; however, they account for the lag that occurs because billing cycles are spread throughout the month.

[13] Weather data was provided by EnergyNorth’s weather service vendor Telvent.

Series	Description	Variable	Source
FHSTKA	Housing stock: Total, (Ths., SA)	HTT	Moody's
FHSTK1A	Housing stock: Single-family, (Ths., SA)	HSF	Moody's
FHSTKMFA	Housing stock: Multi-family, (Ths., SA)	HMF	Moody's
FHSTKOTA	Housing Stock: Other, (Ths.)	HOT	Moody's
FRTFSA	Total Retail Sales, (Mil $, SAAR)	RSL	Moody's
FETA	Employment: Total nonfarm, (Ths., SA)	EE	Moody's
FERMA	Employment: Natural Resources & Mining, (Ths.)	ERMA	Moody's
FE23A	Employment: Construction, (Ths.)	ECON	Moody's
FEMFA	Employment: Manufacturing, (Ths., SA)	EMFA	Moody's
FETLA	Employment: Trade, Transportation, & Utilities, (Ths.)	ETLA	Moody's
FE51A	Employment: Information, (Ths.)	EINF	Moody's
FEFIA	Employment: Financial Activities, (Ths., SA)	EFIA	Moody's
FEPSA	Employment: Professional & Business Services, (Ths.)	EPSA	Moody's
FEEHA	Employment: Education & Health Services, (Ths.)	EEHA	Moody's
FELHA	Employment: Leisure & Hospitality, (Ths.)	ELHA	Moody's
FE81A	Employment: Other Services (except Public Administration), (Ths.)	EOTH	Moody's
FEGVA	Employment: Government, (Ths., SA)	EGVA	Moody's
FEGVFA	Employment: Federal government, (Ths.)	EGVF	Moody's
FEGVSA	Employment: State government, (Ths.)	EGVS	Moody's
FEGVLA	Employment: Local government, (Ths.)	EGVL	Moody's
FGDP	Gross Product: Total, (Mil. $)	GDP	Moody's
FCPIU.US	CPI: Urban Consumer - All Items, (Index, 1982-84=100, SA)	CPI	Moody's
FNMDA	Net migration - Domestic, (Ths.)	NMDA	Moody's
FNMIA	Net migration - International, (Ths.)	NMIA	Moody's
FBIRTHA	Births, (Ths.)	BIR	Moody's
FDEATHA	Deaths, (Ths.)	DIE	Moody's
FYPEWSA	Income: Earnings - Wage & Salary, (Mil. $)	WSA	Moody's
FEOFFA	Employment: Office-using Industries, (Ths.)	EOFF	Moody's
FEZTECA	Employment: High Technology Industries, (Ths.)	EZTE	Moody's
FRMOSDA	Mortgage Originations: 1-4 unit Total transaction, (Bil. $)	MOD	Moody's
FRMOSNA	Mortgage Originations: 1-4 unit Total transaction, (Ths.)	MON	Moody's
EPH	Employed per household (EE / HH)	EPH	Moody's
HHSIZE	Household size (POP / HH)	HHSIZE	Moody's
	Natural Gas Price delivered to Residential	NGPRCR	EIA
	Natural Gas Price delivered to Commercial	NGPRCC	EIA
	Natural Gas Price delivered to Industrial	NGPRCI	EIA
	Heating Oil Price for all ($/Dth)	OILPRC	EIA
	Heating Oil Price delivered to Residential ($/Dth)	OILPRCR	EIA
	Heating Oil Price delivered to Commercial ($/Dth)	OILPRCC	EIA
	Heating Oil Price delivered to Industrial ($/Dth)	OILPRCI	EIA
	Natural Gas / Oil Price Ratio – Residential	GORR	EIA

Series	Description	Variable	Source
	Natural Gas / Oil Price Ratio – Commercial	GORC	EIA
	Natural Gas / Oil Price Ratio – Industrial	GORI	EIA
Note:	Independent variables as provided by Moody's Analytics. The "Series" represents Moody's abbreviation for the data series, and "Variable" represents the variable term the Company used in its models. "SA" is seasonally adjusted and "SAAR" is seasonally adjusted annual rate.		

d. Natural Gas Price Variable

Historical natural gas prices were developed using data from the U.S. Department of Energy/Energy Information Administration ("EIA"), which was available at the monthly level for New Hampshire. Table 3 below details the specific data series obtained from EIA.

Table 3: EIA Historical Natural Gas Prices[14]

Variable Name	Data Availability	Region
Price of Natural Gas Delivered to Residential Consumers	January 1989 to February 2017	New Hampshire
Price of Natural Gas Delivered to Commercial Consumers	January 1989 to February 2017	New Hampshire
Price of Natural Gas Delivered to Industrial Consumers	January 2001 to February 2017	New Hampshire

Forecasted natural gas prices were developed using EIA's Short-Term Energy Outlook ("STEO")[15] and Annual Energy Outlook ("AEO").[16] The STEO forecasts monthly natural gas prices for the New England region over the upcoming two years (i.e., January 2017 through December 2018). To develop the forecast of natural gas prices from March 2017 through December 2018,[17] the growth rates for the New England region from the STEO were applied to the historical New Hampshire natural gas prices. Specifically, the year-over-year percentage change for each month in the STEO natural gas price forecast for the residential, commercial, and industrial customers were applied to the historical New Hampshire natural gas prices for each respective customer segment. For example, to develop the forecast of the residential natural gas price in November 2017, the growth rate from the STEO for the period from November 2016 to November 2017 (i.e., the year-over-year growth rate) was applied to the historical residential natural gas price in November 2016.

The AEO forecasts annual natural gas prices for residential, commercial, and industrial customers for the New England region. To develop a forecast of monthly natural gas prices for New Hampshire for the January 2019 to October 2022 period, the annual growth rates for the New England region from the AEO were applied to the New Hampshire natural gas prices. The annual percentage changes in the forecast for residential natural gas prices were used to develop the residential natural gas prices starting in January 2019. Similarly, the annual percentage changes for commercial natural gas prices were applied

[14] U.S. Department of Energy/Energy Information Administration, Natural Gas Prices, released April 2017.

[15] U.S. Department of Energy/Energy Information Administration, Short-Term Energy Outlook, released April 2017.

[16] U.S. Department of Energy/Energy Information Administration, Annual Energy Outlook, released January 5, 2017.

[17] As noted in Table 3, historical natural gas prices were available through February 2017.

to the commercial natural gas prices, and the annual percentage changes in industrial natural gas prices were applied to industrial natural gas prices. Those annual growth rates were applied to the previous year's natural gas prices in each month. For example, the residential natural gas price in July 2019 is equal to the July 2018 residential natural gas price adjusted by the annual growth rate between 2018 and 2019 from the AEO. Similarly, the residential natural gas price in August 2019 is equal to the August 2018 residential natural gas price adjusted by the same growth rate. That methodology was used to develop the forecast between January 2019 and the end of the Forecast Period.

Table 4, below, generally describes the data used to develop the natural gas prices relied on in the 2017 IRP.

Table 4: Summary of Natural Gas Prices

Data Source	Data Period	Region
EIA	August 2010 – February 2017	New Hampshire
EIA STEO	March 2017 – December 2018	New England
EIA AEO	January 2019 – October 2022	New England

2. Summary of Customer Segment Forecasts

For the 2016/2017 split-year, the residential heating customer segment comprised approximately 42 percent of firm sendout,[18] C&I heating and C&I non-heating segment volumes represented approximately 44 percent and 13 percent, respectively, while the residential non-heating segment accounted for less than 0.5 percent of firm sendout.

A summary of the results of the Company's regression analysis for each customer segment are discussed in the following sections. All results are based on the split-year November through October. Detailed results of the regression analysis for each customer segment forecast are provided in Appendix 1.

3. Residential Heating

a. Number of Customers

Based on the econometric model developed, the number of customers for the residential heating customer segment is forecasted to increase over the Forecast Period. The forecast equation for the number of residential heating customers includes an autoregressive ("AR") term, a trend variable, and a variable for total households lagged one month, as well as monthly dummy variables. The R^2 of the model is 0.999 and the independent variables are significant at the 95-percent level. The model results in the following forecast of residential heating customers:

[18] Calculated as the volumes associated with sales and capacity-assigned transportation customers.

Table 5: Residential Heating Customer Forecast

Split-Year	Avg. # of Customers
2017/18	77,675
2018/19	78,814
2019/20	79,927
2020/21	81,020
2021/22	82,117
CAGR (2017/18-2021/22)	1.4%

b. Use Per Customer

Over the Forecast Period, the residential heating use per customer is forecasted to slightly decrease. The forecast equation for residential heating use per customer includes AR terms, variables for the price of natural gas lagged one month, weather, and monthly dummy variables. The R^2 of the model is 0.994 and the independent variables are significant at the 95-percent level. The model results in the following forecast of annual residential heating use per customer:

Table 6: Residential Heating Use Per Customer Forecast (Dth/Customer)

Split-Year	Use Per Customer
2017/18	77.6
2018/19	77.3
2019/20	77.2
2020/21	77.0
2021/22	76.8
CAGR (2017/18-2021/22)	-0.2%

c. Total Customer Segment

The monthly residential heating customer forecast was multiplied by the monthly use per customer forecast to determine the monthly demand forecast, which was then aggregated to an annual basis. Those results are shown in Table 7, below. Residential heating demand is expected to increase by over 280,000 Dth over the Forecast Period, or at a CAGR of 1.2 percent.

Table 7: Residential Heating Demand Forecast (Dth)

Split-Year	Demand
2017/18	6,025,297
2018/19	6,088,685
2019/20	6,167,810
2020/21	6,234,702
2021/22	6,308,336
CAGR (2017/18-2021/22)	1.2%

4. Residential Non-Heating

a. Number of Customers

The number of residential non-heating customers is forecasted to decline over the Forecast Period. The forecast equation for the number of residential non-heating customers includes AR terms, a variable for total households, and a trend variable. The R^2 of the model is 0.999 and the independent variables are significant at the 95-percent level. The model results in the following forecast of residential non-heating customers:

Table 8: Residential Non-Heating Customer Forecast

Split-Year	Avg. # of Customers
2017/18	2,913
2018/19	2,843
2019/20	2,765
2020/21	2,678
2021/22	2,595
CAGR (2017/18-2021/22)	-2.8%

b. Use Per Customer

Residential non-heating use per customer is forecasted to slightly decrease over the Forecast Period. The forecast equation for residential non-heating use per customer includes AR terms and variables for the price of natural gas lagged two months and weather. The R^2 of the model is 0.953 and the independent variables are significant at the 95-percent level. The model results in the following forecast of residential non-heating use per customer:

Table 9: Residential Non-Heating Use Per Customer Forecast (Dth/Customer)

Split-Year	Use Per Customer
2017/18	23.2
2018/19	23.2
2019/20	23.1
2020/21	23.0
2021/22	22.9
CAGR (2017/18-2021/22)	-0.3%

c. Total Customer Segment

The monthly residential non-heating customer forecast was multiplied by the monthly use per customer forecast to determine the monthly demand forecast, which was then aggregated to an annual basis. Those results are shown in Table 10, below. Residential non-heating demand is expected to decrease by approximately 8,200 Dth during the Forecast Period, or at a negative CAGR of 3.2 percent.

Table 10: Residential Non-Heating Demand Forecast (Dth)

Split-Year	Demand
2017/18	67,566
2018/19	65,884
2019/20	63,797
2020/21	61,501
2021/22	59,377
CAGR (2017/18-2021/22)	-3.2%

5. Total Residential Demand Forecast

Total residential volumes are forecasted to increase at a CAGR of 1.1 percent, or by almost 275,000 Dth, over the Forecast Period. Although residential non-heating demand is forecasted to continue to decrease, that segment comprises a small fraction of total residential customer usage (i.e., approximately 1.1 percent in 2016/2017). As a result, the effect of decreasing volumes associated with the residential non-heating customers is minimal compared to the forecast increase in residential heating demand.

Table 11: Total Residential Econometric Demand Forecast (Dth)[19]

Split-Year	Residential Heating	Residential Non-Heating	Total Residential Planning Load
2017/18	6,025,297	67,566	6,092,863
2018/19	6,088,685	65,884	6,154,569
2019/20	6,167,810	63,797	6,231,607
2020/21	6,234,702	61,501	6,296,203
2021/22	6,308,336	59,377	6,367,712
CAGR (2017/18-2021/22)	1.2%	-3.2%	1.1%

6. Commercial and Industrial Heating

a. Number of Customers

The number of C&I heating sales and capacity-assigned transportation customers is forecasted to increase over the Forecast Period. The forecast equation for the number of C&I heating customers includes AR terms, total nonfarm employment, and a trend variable and monthly dummy variables. The R^2 of the model is 0.940 and the independent variables are significant at the 95-percent level. The model results in the following forecast of C&I heating customers:

[19] Forecasts are prior to the inclusion of energy efficiency and out-of-model adjustments.

Table 12: C&I Heating Customer Forecast

Split-Year	Avg. # of Customers
2017/18	10,451
2018/19	10,617
2019/20	10,764
2020/21	10,868
2021/22	11,019
CAGR (2017/18-2021/22)	1.3%

b. Use Per Customer

The C&I heating use per customer is forecasted to decrease slightly over the Forecast Period. The forecast equation for C&I heating use per customer includes an AR term and a variable for weather, as well as monthly dummy variables. The R^2 of the model is 0.982 and the independent variables are significant at the 95-percent level. The model results in the following forecast of C&I heating use per customer:

Table 13: C&I Heating Use Per Customer Forecast (Dth/Customer)

Split-Year	Use Per Customer
2017/18	597.3
2018/19	596.5
2019/20	596.6
2020/21	596.6
2021/22	596.0
CAGR (2017/18-2021/22)	-0.1%

c. Total Customer Segment

The monthly C&I heating customer forecast was multiplied by the monthly use per customer forecast to determine the monthly demand forecast, which was then aggregated to an annual basis. Those results are shown in Table 14, below. Specifically, C&I heating sales and capacity-assigned transportation demand is expected to increase by approximately 325,000 Dth over the Forecast Period, or at a CAGR of 1.3 percent.

Table 14: C&I Heating Demand Forecast (Dth)

Split-Year	Demand
2017/18	6,241,917
2018/19	6,332,305
2019/20	6,422,114
2020/21	6,483,987
2021/22	6,567,644
CAGR (2017/18-2021/22)	1.3%

7. Commercial and Industrial Non-Heating

a. Number of Customers

The number of C&I non-heating sales and capacity-assigned transportation customers is forecasted to increase over the Forecast Period. The forecast equation for the number of C&I non-heating customers includes AR terms, variables for retail sales, and the price of oil lagged two months, and monthly dummy variables. The R^2 of the model is 0.755 and the independent variables are significant at the 95-percent level.[20] The model results in the following forecast of C&I non-heating customers:

Table 15: C&I Non-Heating Customer Forecast

Split-Year	Avg. # of Customers
2017/18	1,635
2018/19	1,654
2019/20	1,668
2020/21	1,681
2021/22	1,696
CAGR (2017/18-2021/22)	0.9%

b. Use Per Customer

Over the Forecast Period, use per customer by the C&I non-heating segment is forecasted to decline. The forecast equation for C&I non-heating use per customer includes AR terms and a variable for weather lagged one month. The R^2 of the model is 0.964 and the independent variables are significant at the 95-percent level. The model results in the following forecast of C&I non-heating use per customer:

Table 16: C&I Non-Heating Use Per Customer Forecast (Dth/Customer)

Split-Year	Use Per Customer
2017/18	1,213.8
2018/19	1,196.6
2019/20	1,176.8
2020/21	1,155.3
2021/22	1,133.8
CAGR (2017/18-2021/22)	-1.7%

c. Total Customer Segment

The monthly C&I non-heating customer forecast was multiplied by the monthly use per customer forecast to determine the monthly demand forecast, which was then aggregated to an annual basis. Those results are shown in Table 17, below. C&I non-heating sales and capacity-assigned transportation demand is expected to decrease by 61,700 Dth over the Forecast Period, or at a negative CAGR of 0.8 percent.

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[20] One AR term was included in the model that was not significant at the 95-percent level. However, the variable was necessary to correct for autocorrelation, and was significant at the 89-percent confidence level.

Table 17: C&I Non-Heating Demand Forecast (Dth)

Split-Year	Demand
2017/18	1,984,088
2018/19	1,979,256
2019/20	1,963,304
2020/21	1,942,080
2021/22	1,922,388
CAGR (2017/18-2021/22)	-0.8%

8. Total Commercial and Industrial Demand Forecast

As shown in Table 18 below, the CAGR for the total demand forecasted for C&I sales and capacity-assigned transportation customers over the Forecast Period is 0.8 percent,[21] resulting in an increase of almost 265,000 Dth of load. The increase in the total C&I sales and capacity-assigned transportation demand forecast is driven by an increase in the C&I heating customer segment.

Table 18: Total C&I Demand Forecast (Dth)[22]

Split-Year	C&I Heating	C&I Non-Heating	Total C&I Demand
2017/18	6,241,917	1,984,088	8,226,004
2018/19	6,332,305	1,979,256	8,311,560
2019/20	6,422,114	1,963,304	8,385,418
2020/21	6,483,987	1,942,080	8,426,068
2021/22	6,567,644	1,922,388	8,490,032
CAGR (2017/18-2021/22)	1.3%	-0.8%	0.8%

9. Total Commercial and Industrial Capacity-Exempt Demand Forecast

The C&I capacity-exempt forecasts were used to calculate total system sendout as part of the monthly-to-daily demand forecast allocation process. Natural gas demand by the C&I heating capacity-exempt customer segment is forecasted to remain relatively flat over the Forecast Period. The forecast equation for C&I heating capacity-exempt volume includes a variable for weather, as well as total employment. The R^2 of the model is 0.976 and the independent variables are significant at the 95-percent level.

Natural gas demand by the C&I non-heating capacity-exempt customer segment is forecasted to decrease over the Forecast Period. The forecast equation for C&I non-heating capacity-exempt volume includes an AR term, and variables for the natural gas price and total labor force. The R^2 of the model is 0.989 and the independent variables are significant at the 95-percent level.

The results of those models are shown in Table 19, below.

[21] That growth rate is prior to the inclusion of energy efficiency and out-of-model adjustments.

[22] The results do not include capacity-exempt demand and are prior to adjustments for energy efficiency and out-of-model adjustments.

Table 19: C&I Capacity-Exempt Demand Forecast (Dth)

Split-Year	C&I Heating Capacity-Exempt	C&I Non-Heating Capacity-Exempt
2017/18	650,425	2,129,266
2018/19	650,256	2,091,249
2019/20	650,005	2,024,348
2020/21	649,582	2,010,390
2021/22	650,614	2,019,638
CAGR (2017/18-2021/22)	0.0%	-1.3%

10. Total Econometric Demand Forecast

As shown in Table 20 below, the CAGR for the total econometric demand forecast for sales and capacity-assigned transportation customers over the Forecast Period is 0.9 percent,[23] resulting in an increase of almost 540,000 Dth of load.

Table 20: Total Econometric Demand Forecast (Dth)[24]

Split-Year	Residential Heating	Residential Non-Heating	C&I Heating	C&I Non-Heating	Total Econometric Demand Forecast
2017/18	6,025,297	67,566	6,241,917	1,984,088	14,318,868
2018/19	6,088,685	65,884	6,332,305	1,979,256	14,466,129
2019/20	6,167,810	63,797	6,422,114	1,963,304	14,617,025
2020/21	6,234,702	61,501	6,483,987	1,942,080	14,722,271
2021/22	6,308,336	59,377	6,567,644	1,922,388	14,857,744
CAGR (2017/18-2021/22)	1.2%	-3.2%	1.3%	-0.8%	0.9%

11. Out-of-Model Adjustments

Two out-of-model adjustments were made to the econometric forecast to account for additional growth that is not reflected in the historical billing data. Those out-of-model adjustments were related to: (1) expected increases in the number of customers in the Company's existing service territory related to

[23] That growth rate is prior to the inclusion of energy efficiency and out-of-model adjustments.

[24] The results are prior to energy efficiency and out-of-model adjustments, and do not include unaccounted for gas and unbilled sales, which are discussed in Phase 2 (i.e., Section III.B below).

increasing sales and marketing efforts; and (2) estimates of the number of customers in new service territories in which the Company is expanding.[25]

With respect to the existing service territory, EnergyNorth's Sales and Marketing Group provided annual six-year estimates of customer additions by rate class (2017 through 2022), which were aggregated to the customer segment level. The Company recently expanded its sales and marketing efforts and expects to continue to do so throughout 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.

To properly reflect the expected increase in customer additions, the annual customer growth associated with the econometric forecast was compared to the annual customer addition estimates from EnergyNorth's Sales and Marketing Group by customer segment over the Forecast Period. Where the annual sales and marketing estimates for a customer segment were higher than the econometric forecast customer additions, the customer additions of the econometric forecast were adjusted by the difference between the sales and marketing estimates and the econometric forecast. For the customer segments in which the Sales and Marketing Group does not expect to add customers (e.g., residential non-heating) or years in which the econometric forecast of customer additions was equal to or above the estimated customer additions for a customer segment, the econometric forecast was relied on with no adjustment. The use per customer associated with the additional customers was assumed to be equal to the use per customer resulting from the econometric models for the respective customer segments.

EnergyNorth is in the process of expanding into new service territories in New Hampshire. EnergyNorth's Sales and Marketing Group provided annual six-year estimates of customer additions by rate class (2017 through 2022) for the new service territories, which were aggregated to the customer segment level. The additional customers associated with those new service territories are not reflected in the historical billing data (or the econometric forecast), so it was necessary to rely on an out-of-model adjustment. To determine forecast volumes, the use per customer associated with the customers in the new service territories was assumed to be equal to the use per customer resulting from the econometric models for the respective customer segments.

Figure 3 below summarizes the out-of-model adjustments to the results of the econometric models in the Base Case demand forecast.

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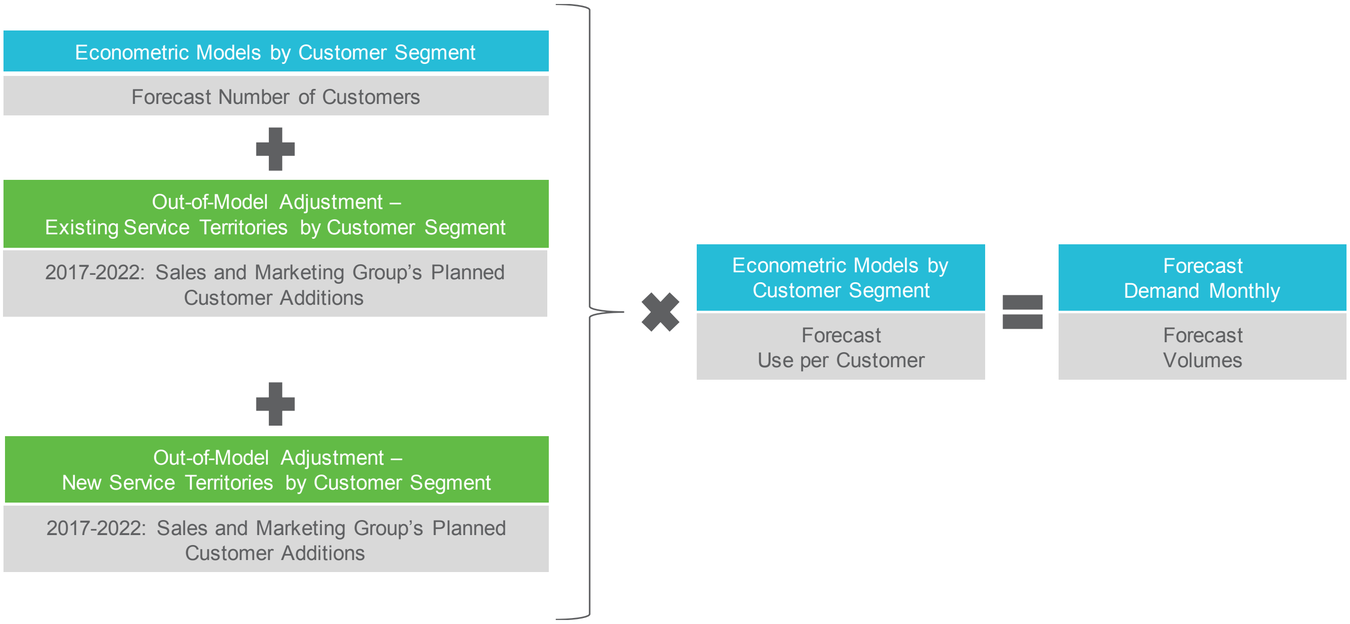
[25] An out-of-model adjustment was developed to account for the iNATGAS demand requirements based on the recently amended special contract approved by the Commission in Order No. 26,002 (April 6, 2017) and the actual/historical usage of iNATGAS since commencing service on December 1, 2016. Specifically, a regression model was developed to estimate monthly load (i.e., volume) requirements for iNATGAS based on actual daily usage data from December 2016 through July 2017. However, the demand from iNATGAS is not currently expected to have a significant effect on the demand forecast.

Figure 3: Base Case Demand Forecast



12. Energy Efficiency

The demand forecast including out-of-model adjustments was reduced by energy efficiency savings to determine the Company's net demand requirements. A detailed description of the various energy efficiency programs, and savings associated with those programs is provided in Appendix 2. Table 21 below summarizes the Company's current energy efficiency goals, used as a decrement to EnergyNorth's demand forecast.

Table 21: Calendar Year Goals (Dth)

Year	Residential	C&I
2017	34,584	88,970
2018	39,079	90,993
2019	39,586	98,494
2020	42,663	104,266

Because the forecast for energy efficiency only extends through 2020, the Company assumed the percentage of residential energy efficiency volumes relative to residential firm demand continued to be equivalent to the 2020 levels through the end of the Forecast Period (i.e., 2022). The same assumption was made for energy efficiency volumes for C&I customers. The resulting calendar year energy efficiency deductions to the demand forecast are presented in Table 22 below.

Table 22: Calendar Year Energy Efficiency

Year	Residential		C&I	
	Energy Efficiency / Demand	Energy Efficiency (Dth)	Energy Efficiency / Demand	Energy Efficiency (Dth)
2017	0.57%	34,584	0.82%	88,970
2018	0.61%	39,079	0.79%	90,993
2019	0.61%	39,586	0.84%	98,494
2020	0.64%	42,663	0.87%	104,266
2021	0.64%	43,732	0.87%	106,989
2022	0.64%	44,845	0.87%	109,954

The monthly demand forecasts for the residential and C&I customer segments were multiplied by the percentages in Table 22 in each respective year to calculate the deduction to the demand forecast due to energy efficiency. Although the percentage is held constant, the amount of energy efficiency volume grows over the Forecast Period, thus the Company has assumed incremental savings in each year.

13. Demand Forecast Results

The results of the demand forecast after adjusting for the out-of-model adjustments and energy efficiency are provided in Tables 23 and 24 below.

Table 23: Demand Forecast Results by Customer Segment Including Out-of-Model Adjustments (Dth)[26]

Split-Year	Residential Heating	Residential Non-Heating	C&I Heating	C&I Non-Heating	Econometric Forecast Including Out-of-Model Adjustments
2017/18	6,302,382	67,566	6,669,794	2,102,341	15,142,084
2018/19	6,426,952	65,884	6,870,710	2,119,393	15,482,939
2019/20	6,568,083	63,797	7,106,575	2,146,804	15,885,260
2020/21	6,732,604	61,501	7,374,664	2,191,680	16,360,449
2021/22	6,908,215	59,377	7,655,379	2,227,547	16,850,517
CAGR (2017/18-2021/22)	2.3%	-3.2%	3.5%	1.5%	2.7%

[26] Results are prior to energy efficiency and do not include unaccounted for gas and unbilled sales, which are discussed in Phase 2 (i.e., Section III.B below).

Table 24: Demand Forecast Results (Dth)[27]

Split-Year	Econometric Forecast Including Out-of-Model Adjustments	Energy Efficiency	Demand Net of Energy Efficiency
2017/18	15,142,084	107,908	15,034,176
2018/19	15,482,939	114,101	15,368,838
2019/20	15,885,260	122,256	15,763,003
2020/21	16,360,449	126,928	16,233,521
2021/22	16,850,517	130,799	16,719,718
CAGR (2017/18-2021/22)	2.7%	4.9%	2.7%

B. Phase 2 - Translation of Demand Forecast into Customer Requirements

In the second phase of EnergyNorth's forecasting methodology, the Company translated its monthly demand forecast into monthly customer requirements, unaffected by billing cycle lag. This translation required the Company to account for the difference between gas delivered to its city-gates and gas metered at its customers' burner tips. This translation required adding to the demand forecast an amount of supply which represents unaccounted for gas, and then accounting for the billing lag. Once these adjustments were completed the monthly customer requirements are allocated into daily demand values.

1. Unaccounted For Gas

Unaccounted for gas is the difference between the total system sendout as measured at the gate-station and the volumes recorded at customer meters in the Company's billing system.[28]

To calculate unaccounted for gas over the Forecast Period, an average percentage was calculated by dividing the eight-year (September 2009 through August 2017) sum of unaccounted for gas (total system sendout) by the eight-year sum of accounted for gas (billing data). The eight-year average of 2.03 percent was applied to the demand forecast on a monthly basis. Those volumes represent additional volumes not accounted for in the customer segment forecasts, but for which the Company must plan.

2. Unbilled Sales

To align the demand forecast with the supply forecast, a model of the lag in billing customers was developed based on the underlying historical and future meter reading schedule. The model was used to determine the lag-induced difference between the gas deliveries as metered at the city-gate and the gas deliveries as metered at customers' burner tips.

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[27] Results are prior to unaccounted for gas and unbilled sales, which are discussed in Phase 2 (i.e., Section III.B below).

[28] There are a variety of factors that contribute to unaccounted for gas. Those factors include: system loss, metering variances, theft of service, purging during construction activities, and third-party damages.

The Company calculated the unbilled volumes by taking the difference between the historical monthly sendout figures and the historical billed sales figures (including unaccounted for gas). Next, the Company calculated a linear regression model of the unbilled volumes versus the difference between actual monthly HDDs and monthly BDDs over the period from September 2009 through August 2016. Since unbilled volumes are a function of timing of delivery versus meter reading, the resulting regression equation was specified with a zero intercept, with the theory being that the differences between sendout and actual billed sales tend to zero over time, with only minor differences caused by the year-to-year adaptation of the Company's billing schedule to the actual calendar.

The normalized unbilled volumes were estimated by calculating the difference between monthly normal BDDs and monthly normal calendar HDDs, and multiplying the result by the coefficient of the regression model described above. The results of that analysis were added to the normal forecast billing volumes for the Forecast Period to determine the forecast of normal monthly volumes to be delivered to the city-gates.

3. Monthly to Daily Allocation Model

The next step in Phase 2 of the Company's demand forecasting process was to determine EnergyNorth's Normal Year and Design Year forecasts of daily customer requirements over the Forecast Period for resource planning purposes. The Company used a regression equation of daily sendout versus daily temperature for the most recent twelve months to allocate its monthly normal forecast customer requirements to daily normal customer requirements. To perform its regression analysis, the Company used version 3.3.3 of the R statistical software package.[29] A detailed description of that analysis is provided in Appendix 3.

The Normal Year and Design Year weather patterns were applied to the daily regression model to calculate the daily shape of the Normal Year and Design Year total sendout demand forecasts ("Base Year").[30] The monthly forecast including unaccounted for gas and unbilled sales was then allocated to a daily basis using the daily shape of the Base Year.

Applying those models resulted in daily Planning Load forecasts based on Normal Year and Design Year weather, including the effects of energy efficiency, unaccounted for gas, and unbilled sales on a billing cycle and gas year basis.

4. Total Planning Load Results

The results of the Company's Planning Load requirements are illustrated in Table 25 below. The total Planning Load demand is forecast to increase over the Forecast Period by almost 1.9 million Dth, or at a CAGR of 2.9 percent.

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[29] "R is a language and environment for statistical computing and graphics. It is a GNU project which is similar to the S language and environment which was developed at Bell Laboratories (formerly AT&T, now Lucent Technologies). R can be considered as a different implementation of S. There are some important differences, but much code written for S runs unaltered under R.

***

R is available as Free Software under the terms of the Free Software Foundation's GNU General Public License in source code form. It compiles and runs on a wide variety of UNIX platforms and similar systems (including FreeBSD and Linux), Windows and MacOS." *See*, https://www.r-project.org/about.html.

[30] *See* Section IV below for a description of the development of the Normal Year and Design Year weather patterns.

Table 25: Normal Year Planning Load Forecast (Dth)

Split-Year	Total Planning Load
2017/18	15,634,082
2018/19	16,075,247
2019/20	16,575,525
2020/21	17,000,558
2021/22	17,527,589
CAGR (2017/18-2021/22)	2.9%

C. Comparison of Demand Forecast to 2013 IRP

As illustrated in Table 26 below, the Company's total Planning Load in 2017/2018 is higher in the 2017 IRP than in the 2013 IRP (the only overlapping year of the two forecasts). The CAGR over the Forecast Period in the 2017 IRP is also somewhat higher than in the 2013 IRP.

Table 26: Comparison of Planning Load (Dth)

Split-Year	2013 IRP (DG 13-313) – Total Planning Load	2017 IRP – Total Planning Load
2013/14	12,849,714	--
2014/15	13,162,317	--
2015/16	13,532,759	--
2016/17	13,822,754	--
2017/18	14,136,177	15,634,082
2018/19	--	16,075,247
2019/20	--	16,575,525
2020/21	--	17,000,558
2021/22	--	17,527,589
CAGR (2013/14-2017/18)	2.4%	--
CAGR (2017/18-2021/22)	--	2.9%

IV. PLANNING STANDARDS

A. Normal Year Planning Standard

To establish the Normal Year's daily HDD data, the average annual number of HDDs was calculated for the KMHT weather station for the 30 years from January 1987 through December 2016, resulting in an average of 6,325 HDD. A Normal Year was then developed by replacing the thirty-year average months with actual months in the dataset that were similar to the average HDD and standard deviation for each month. This step was taken to avoid an artificially smooth Normal Year that does not reflect the day-to-day variation in HDDs. The Normal Year HDDs are summarized by month in Table 27.

Table 27: Normal Year HDD

Month	HDD
January	1,226
February	1,086
March	891
April	517
May	228
June	54
July	6
August	11
September	115
October	421
November	708
December	1,060
Total	6,325

B. Design Year and Design Day Planning Standards

1. Methodology

The Design Year standard, in conjunction with the Design Day standard, establishes the weather conditions that inform the amount of firm volume that the Company must plan for to maintain reliable service, but is expected to occur infrequently. The Design Year and the Design Day Planning Loads were calculated by using a Monte Carlo analysis based on average daily temperature as the dependent variable and HDD as the independent variable for its regression analysis.

For its Monte Carlo analysis, the Company used temperature data from the KMHT weather station for the period January 1, 1979 through December 31, 2016. The Company's Monte Carlo analysis, which is described in more detail in Appendix 4, is similar to the analysis in its 2013 IRP.

2. Determination of Design Year and Design Day Planning Standards

The Design Day standard is based on the statistical distribution of the coldest day of each calendar year, while the Design Year standard is based on the statistical distribution of the total HDDs in each calendar year. The Company based its planning standards on its Monte Carlo analysis, using a Design Day and Design Year of the mean results plus two standard deviations. The Company's Design Day is defined as 4.27 minus two times 5.33, or negative 6.39 ^{o}F. Converting to HDD yields a Design Day of approximately 71.4 HDD.

The Company's Design Year is defined as approximately 6,314 plus two times approximately 277 HDD, or 6,869 HDD.

Once the annual Design Year was determined the monthly shape was then calculated. First, the Design Year summer (i.e., the months of May through October) was assumed to be the same as the Normal Year. Next, for each winter month (i.e., November through April), the standard deviation of monthly HDDs over the most recent 30 years was calculated, and the resulting standard deviations were summed. An adjustment factor was calculated by dividing the difference in the total Design Year winter HDDs and the Normal Year winter HDDs by the sum of the standard deviations. The monthly standard deviations multiplied by the adjustment factor were then added to the Normal Year monthly HDDs to arrive at the monthly values of the Design Year. Table 28 displays the monthly Design Year HDD.

Table 28: Design Year HDD

Month	HDD
January	1,350
February	1,155
March	980
April	574
May	228
June	54
July	6
August	11
September	115
October	421
November	786
December	1,186
Total	6,869

A process similar to the one used to develop the daily shape of the Normal Year was used to develop the daily shape of the Design Year. The monthly HDDs and standard deviations were compared to actual historical months to select representative months that reflect daily variability in weather. Each representative month was calibrated so that the total HDDs in the month equaled the calculated values shown in Table 28.

The resulting Design Year Planning Load is provided in Table 29.

Table 29: Design Year Planning Load Forecast (Dth)

Split-Year	Total Planning Load
2017/18	16,901,795
2018/19	17,376,013
2019/20	17,944,792
2020/21	18,367,180
2021/22	18,933,736
CAGR (2017/18-2021/22)	2.9%

The resulting Design Day Planning Load is provided in Table 30.

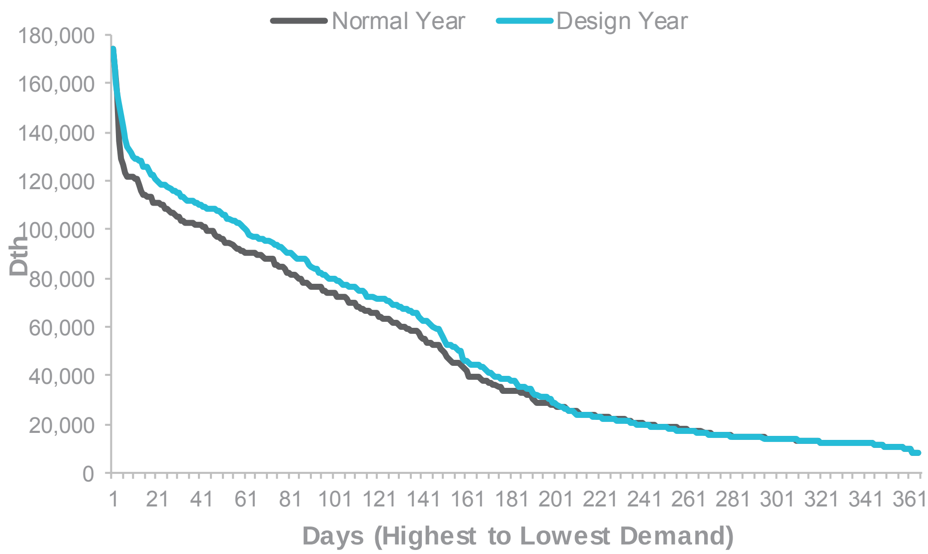
Table 30: Design Day Planning Load Forecast (Dth)

Split-Year	Total Planning Load
2017/18	156,822
2018/19	160,989
2019/20	164,640
2020/21	168,934
2021/22	173,917
CAGR (2017/18-2021/22)	2.6%

C. Summary of Planning Load Forecasts

The load duration curves for the Normal Year and Design Year planning scenarios are illustrated in Figure 4.

Figure 4: Daily Planning Load – Load Duration Curves (2021/2022)



The demand associated with each planning standard (i.e., Normal Year, Design Year, and Design Day) is provided in Table 31 below.

D. High and Low Growth Scenarios

The High and Low Growth scenarios were developed to determine the adequacy of the Company's supply portfolio under a range of demand scenarios.

1. High Growth Scenario

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. The Normal Year High Growth forecast resulted in an average per annum growth in demand of over 650,000 Dth per year, or approximately 179,000 Dth per year higher than the Base Case, with a CAGR of 3.9 percent compared to the Base Case CAGR of 2.9 percent. The results of the High Growth Planning Load forecast are presented in Table 32 below.

2. Low Growth Scenario

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. The Normal Year Low Growth forecast resulted in an average per annum growth in demand of over 302,000 Dth per year, or almost 171,000 Dth per year lower than the Base Case, with CAGR of 1.9 percent compared to the Base Case CAGR of 2.9 percent. The results of the Low Growth Planning Load forecast are presented in Table 33 below.

E. Demand Forecast Results

The final Base Case, High Growth, and Low Growth Planning Load forecasts are presented in Tables 31 through 33. These forecast results are utilized to determine the Company's resource adequacy, as discussed in Section V.

Table 31: Summary of Base Case Planning Load Forecasts (Dth)

Split-Year	Normal Year	Design Year	Design Day
2017/18	15,634,082	16,901,795	156,822
2018/19	16,075,247	17,376,013	160,989
2019/20	16,575,525	17,944,792	164,640
2020/21	17,000,558	18,367,180	168,934
2021/22	17,527,589	18,933,736	173,917
CAGR (2017/18-2021/22)	2.9%	2.9%	2.6%

Table 32: Summary of High Growth Planning Load Forecasts (Dth)

Split-Year	Normal Year	Design Year	Design Day
2017/18	15,782,889	17,062,548	158,314
2018/19	16,386,082	17,711,902	164,101
2019/20	17,059,895	18,468,795	169,448
2020/21	17,667,947	19,088,204	175,565
2021/22	18,392,347	19,867,884	182,498
CAGR (2017/18-2021/22)	3.9%	3.9%	3.6%

Table 33: Summary of Low Growth Planning Load Forecasts (Dth)

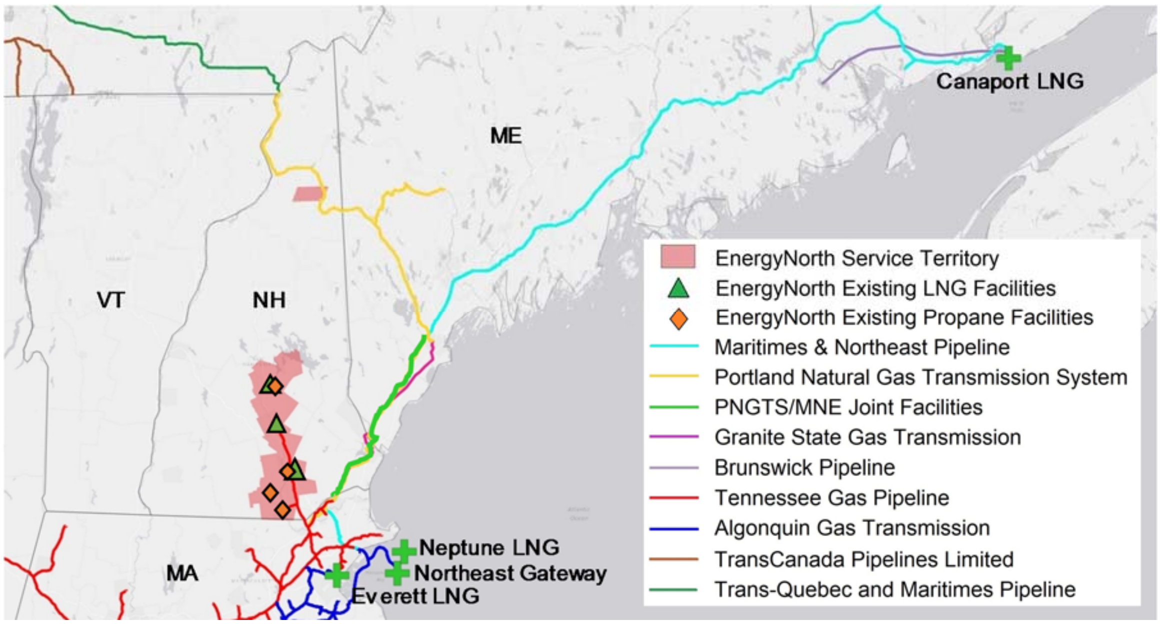
Split-Year	Normal Year	Design Year	Design Day
2017/18	15,485,275	16,741,042	155,331
2018/19	15,767,388	17,043,339	157,907
2019/20	16,100,412	17,430,795	159,924
2020/21	16,352,258	17,666,776	162,492
2021/22	16,695,668	18,035,060	165,662
CAGR (2017/18-2021/22)	1.9%	1.9%	1.6%

V. ASSESSMENT OF RESOURCE PORTFOLIO

A. Introduction

As discussed above, EnergyNorth currently provides natural gas service to customers in thirty-three cities and towns in southern and central New Hampshire and the city of Berlin. As illustrated in Figure 5 below, the EnergyNorth service territory is served exclusively by TGP's Concord Lateral except for the city of Berlin, which is served by PNGTS.

Figure 5: Liberty Utilities Service Territory and Infrastructure Map



With respect to upstream capacity, EnergyNorth has firm transportation contracts on TGP (106,833 Dth/day) and PNGTS (1,000 Dth/day) to provide a total daily deliverability of 107,833 Dth/day to its city-gate stations from three natural gas supply sources (i.e., Canadian supply, domestic supply from production and market area regions, and underground storage in Pennsylvania and New York).

In addition to the upstream capacity contracts, the Company owns three LNG facilities and four propane facilities. The three LNG facilities are located in Concord, Manchester, and Tilton, and have a combined operational vaporization and storage capacity of approximately 12,600 Dth. Three of EnergyNorth's propane facilities, located in Manchester, Nashua, and Tilton, are directly connected to the Company's distribution system with a fourth "satellite" propane facility in Amherst, which is used solely for storage. The propane facilities have a combined design vaporization rate of approximately 34,600 Dth/day and storage capacity of approximately 134,485 Dth.

In total, the Company has Design Day resources of approximately 155,033 Dth/day, which are comprised of upstream transportation contracts and on-system LNG and propane facilities.

As detailed below, and in addition to this Introduction, the Assessment of Supply Resource Portfolio section addresses three general areas regarding EnergyNorth's supply resource portfolio: a review of the Company's current resource portfolio, a description of the Company's resource planning process with an overview of the market factors influencing the Company's resource strategy and future portfolio decisions, and an evaluation of the adequacy of the resource portfolio to meet the projected Planning Load requirements under various weather and growth scenarios.

B. Current Supply Resource Portfolio

As discussed in detail below, EnergyNorth's existing supply resource portfolio is comprised of the following types of resources: (1) long-haul and short-haul transportation; (2) underground storage services; (3) peaking resources; and (4) gas supply contracts. Appendix 5 provides a schematic of the Company's transportation and underground storage contracts effective November 1, 2017, and a table listing and description of these contracts.

1. Pipeline Transportation

EnergyNorth has capacity entitlements on multiple upstream pipelines that provide access to various supply sources that afford the Company a level of operational flexibility to ensure the best-cost and reliable delivery of gas supplies to its customers. The Company's pipeline capacity contracts fall into four primary categories. First, the Company has contract entitlements to long-haul capacity on Tennessee that are used to transport gas from traditional production areas (e.g., Gulf of Mexico) to the Company's New Hampshire city-gates. The long-haul transportation capacity also is used to transport gas supplies to underground storage facilities in Pennsylvania and New York in which the Company has contracted for service. By using long-haul capacity to for both deliveries to the city-gate and to fill storage, the Company uses these resources at a higher load factor.

Second, the Company has contract entitlements to short-haul capacity on Tennessee that is used to transport gas supplies from underground storage facilities in Pennsylvania and New York to the Company's city-gates. These short-haul capacity entitlements have an option to transport non-storage supplies (i.e., natural gas production from the Marcellus and Utica shale plays) to the Company's city-gates when that capacity is not being used to transport underground storage supplies.

Third, EnergyNorth has contracted for pipeline capacity entitlements to deliver natural gas supplies from certain interconnections with the TransCanada PipeLines Limited ("TCPL") Mainline, which include the following. The Company has contracted for pipeline capacity on Union Gas Limited ("Union Gas"), TCPL Mainline, Iroquois Gas Transmission System ("Iroquois"), and Tennessee to deliver gas supplies from the Dawn Hub to the Company's city-gates. The Company has contracted for pipeline capacity on Tennessee from Niagara, an interconnection with the TCPL Mainline, to the Company's city-gates. EnergyNorth has a contract for capacity on PNGTS from East Hereford, an interconnection with the TCPL Mainline,[31] to the Company's city-gates. Finally, the Company has short-haul contracts to transport gas supplies from Dracut, Massachusetts, where Tennessee connects to the PNGTS/MNE Joint Facilities, to the Company's city-gates.

The Company's long-haul and short-haul transportation contracts are described in more detail below:

- Union Gas: The Company has contract entitlements of up to 4,092 Dth/day of capacity from the Dawn Hub to an interconnection with the TCPL Mainline, with an expiration date of October 31, 2022.

[31] Please note, the TCPL Mainline connects to the Trans-Québec and Maritimes Pipeline ("TQM"), which is jointly owned by TCPL and Gaz Métro, and the TQM system connects to PNGTS at the Québec/New Hampshire border at East Hereford.

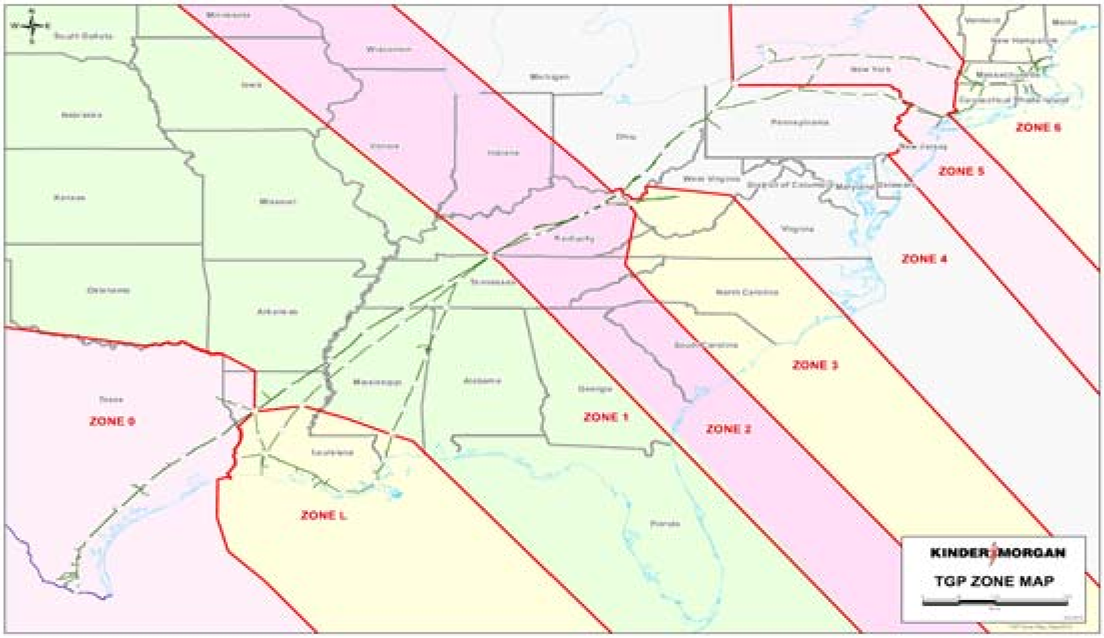
- TCPL Mainline: EnergyNorth has contract entitlements of up to 4,047 Dth/day of firm transportation service on the TCPL Mainline to the interconnection with Iroquois at Waddington. This contract expires on October 31, 2022.

- Iroquois: The Company has contract entitlements of up to 4,047 Dth/day of firm transportation service on Iroquois. Canadian supplies are transported from the Canadian/New York border at Waddington, New York (i.e., an interconnection with the TCPL Mainline) to the Tennessee interconnect at Wright, New York. The transportation contract with Iroquois expires on November 1, 2022.

- PNGTS: The Company has contract entitlements of up to 1,000 Dth/day of firm transportation service on PNGTS from East Hereford (i.e., an interconnection with TCPL Mainline) to the Company's city-gate in Berlin, New Hampshire. This contract expires on October 31, 2019.

- Tennessee: In the traditional production area (e.g., Gulf Coast, Texas and Louisiana), the Tennessee system splits into three legs: the 100 leg, the 800 leg, and the 500 leg. In addition to the supply legs, the Tennessee system is divided into six market zones, from Zone 0 and Zone 1 in Texas and Louisiana to Zone 6 in New England. See Figure 6 for a map showing Tennessee Zone locations. EnergyNorth currently has capacity entitlements of 106,833 Dth/day on the Tennessee system to its New Hampshire city-gates, which are comprised of the following:
    - Contract entitlements from Zone 0 and Zone 1 of up to 21,596 Dth/day to the Company's city-gates in New Hampshire located in Zone 6, with an expiration date of October 31, 2020;
    - Contract entitlements for transport of up to 28,115 Dth/day from the storage area in Zone 4 and Zone 5 to the Company's city-gates, with an expiration date of October 31, 2020;
    - Contract entitlements from the interconnect with the TCPL Mainline at Niagara in Zone 5 of up to 3,122 Dth/day to the Company's city-gates, with an expiration date of October 31, 2020;
    - Contract entitlements from the interconnect with Iroquois at Wright, New York in Zone 5 of up to 4,000 Dth/day to the Company's city-gates, with an expiration date of November 30, 2021;
    - Contract entitlements of up to 20,000 Dth/day from Dracut, Massachusetts located in Zone 6 to the Company's city-gates, with an expiration date of October 31, 2020; and
    - Contract entitlements of up to 30,000 Dth/day from Dracut, Massachusetts located in Zone 6 to the Company's city-gates, with an expiration date of October 31, 2029.

Figure 6: Map of Tennessee Zone Locations



2. Underground Storage Resources

The Company's underground storage contracts provide EnergyNorth with the ability to meet winter-season loads while avoiding the expense of adding 365-day long-haul transportation capacity. These contracts enable the Company to store approximately 2.5 million Dth of gas. These underground storage supplies allow EnergyNorth to serve certain winter period requirements with gas injected during the off-peak period and to manage short-term fluctuations in demand during the winter period. It is the Company's practice to have storage inventories approximately 95 percent full as of November 1st of each year, thus leaving approximately 5 percent of the storage capacity available for balancing purposes.

The Company contracts with the following underground storage providers:

- Tennessee: EnergyNorth has contract entitlements that provide 1,560,391 Dth of storage capacity, a withdrawal rate of up to 21,844 Dth/day, and an injection rate of 10,403 Dth/day. This contract with Tennessee expires on October 31, 2020.

- Dominion Transmission, Incorporated ("Dominion"): EnergyNorth has contract entitlements that provide 102,700 Dth of storage capacity, a withdrawal rate of up to 934 Dth/day, and an injection rate of 571 Dth/day. This contract with Dominion expires on March 31, 2021.

- Honeoye Storage Corporation ("Honeoye"): EnergyNorth has contract entitlements that provide 245,280 Dth of storage capacity, a withdrawal rate of up to 1,957 Dth/day, and an injection rate of 1,168 Dth/day. This contract with Honeoye expires on March 31, 2020.

- National Fuel Supply Corporation ("National Fuel"): Under rate schedule FSS, EnergyNorth has contract entitlements that provide 670,800 Dth of storage capacity, a withdrawal rate of up to 6,098 Dth/day, and an injection rate of 4,472 Dth/day. Along with this storage service, the

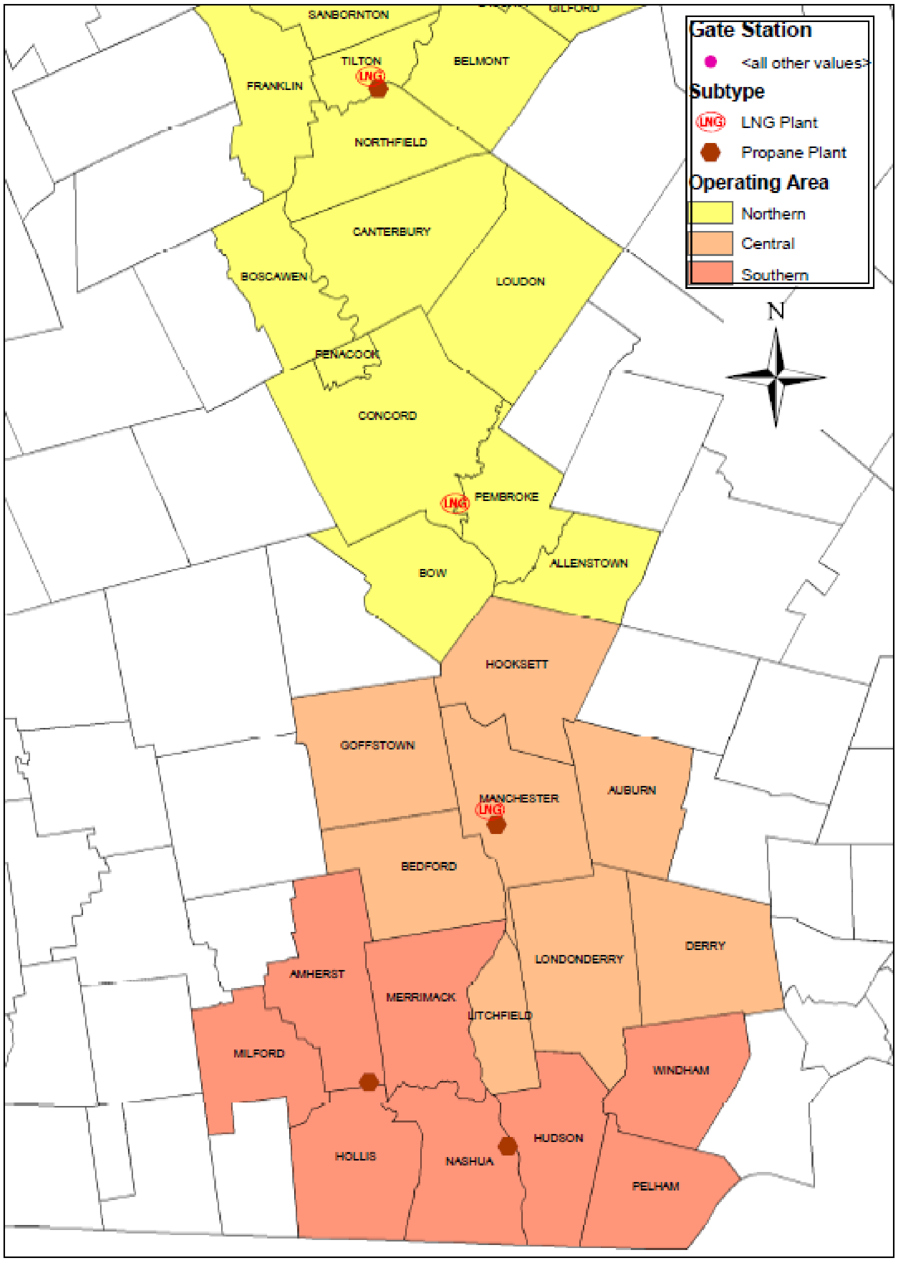
Company also contracts for 365-day firm transportation under rate schedule FST to transport supply to and from the storage field. These contracts with National Fuel expire on March 31, 2019.

3. Supplemental Peaking Resources

In addition to interstate pipeline and underground storage resources, EnergyNorth utilizes on-system peaking supplies to meet its Design Day and Design Year requirements. Peaking supplies are an important component of the EnergyNorth resource mix because these supplies provide the Company with the ability to respond to fluctuations in weather, economics, and other factors driving the Company's sendout requirements. As discussed above, EnergyNorth's peaking supplies include on-system propane facilities located in Nashua, Manchester, and Tilton that are directly connected to the Company's distribution system, and a fourth "satellite" propane facility in Amherst. The Company's propane facilities have a combined vaporization rate of approximately 34,600 Dth/day and storage capacity of approximately 134,485 Dth. The Company's three LNG facilities have a daily operational vaporization capability and storage capacity of 12,600 Dth. The Company's peaking resources provide approximately 30 percent of the gas supplies on the Design Day by contributing 47,200 Dth of supply, with the propane and LNG facilities representing approximately 75 percent and 25 percent, respectively, of the peaking supply.

It is the Company's practice to have its on-system propane and LNG facilities full as of November 1st of each year. EnergyNorth's on-system peaking facilities are distributed strategically across its service territory, which enhances service reliability and provides a source of supply for the entire distribution system. Figure 7 shows the locations of these peaking facilities. Because these resources can be brought on-line quickly, the on-system propane and LNG facilities can be used to meet hourly fluctuations in demand, maintain deliveries to customers, and balance pressures across portions of the distribution system during periods of high demand. These peaking resources are the supplies that must be available throughout the winter period to ensure reliability of service to customers when the Company has exhausted its available pipeline supplies.

Figure 7: Map of EnergyNorth's Supplemental On-System Peaking Facilities



Pursuant to N.H. Code Admin. Rule Puc 506.03, the Company must maintain adequate LNG and propane storage levels throughout the winter period. Thus, the availability of LNG and propane gas to refill the Company's local storage tanks throughout the winter season is a necessity. The Company's contract with ENGIE for combination liquid/vapor service is the primary source of LNG refill throughout the winter season. The Company contracts for annual trucking services for the transportation of its LNG and propane supply contracts to its facilities with various carriers that it selects through a comprehensive RFP process on a year-to-year basis.

4. Gas Commodity

The Company contracts for quantities of gas to ensure sufficient supply to reliably meet design weather conditions and to account for daily and seasonal load variations. The Company's supply resource portfolio contains a variety of transportation contracts utilized to transport baseload and swing supplies, as well as underground storage and related transportation contracts – all with varying degrees of flexibility with respect to such features as no-notice requirements and nomination changes. These no-notice contracts allow for nominations to be made throughout the day up until the last hour of the gas day, allowing the Company the ability to balance system load.

Supply contract durations are generally limited to a maximum term of one seasonal period. Baseload volumes are mainly one-month in duration, augmented with daily firm spot purchases allowing for the ability to respond to fluctuations in demand and maintain planned storage inventory targets. In the winter, the Company typically uses storage as the primary swing supply, however, since storage alone cannot account for all possible conditions, transportation capacity is often left open allowing for the flexibility to meet changing conditions (e.g., demand, weather, operational, storage inventory level, and/or price).

The Company's gas supply contracts are priced at various locations at market-based prices for both monthly and daily purchases. The Company uses North American Energy Standards Board ("NAESB") form standard contracts, which have been established with over one-hundred qualified and reliable gas suppliers.

5. Changes to Resource Portfolio Since 2013 IRP

Since EnergyNorth's 2013 IRP, the mix of firm pipeline transportation and storage contracts and on-system peaking resources in the Company's resource portfolio have not changed.

C. Resource Planning Process

As part of EnergyNorth's resource planning process, the Company evaluates the existing supply resource portfolio in relation to the firm Planning Load requirements developed in Section IV above. Based on a review of the incremental demand requirements compared to its portfolio of existing supply resources, the Company makes a determination of resource need. If incremental resources are required, the Company will identify the resources available to meet the incremental demand requirements and procure a resource, or mix of resources, which achieves a reliable, best-cost supply resource portfolio for its customers. In evaluating the resource options, the Company analyzes both price and non-price factors. Examples of non-price factors include reliability, flexibility, viability, and diversity of supply source. Next, the Company looks at its currently available resources and determines if there are any "decision points" with respect to any of its contracts, such as expiration dates or options to increase or decrease volumes. If so, the Company determines whether to renew those supplies or replace them with an available alternative. Finally, the Company analyzes its portfolio of expected resources against a range of weather scenarios to determine if those resources are sufficient to reliably meet firm Planning Load requirements.

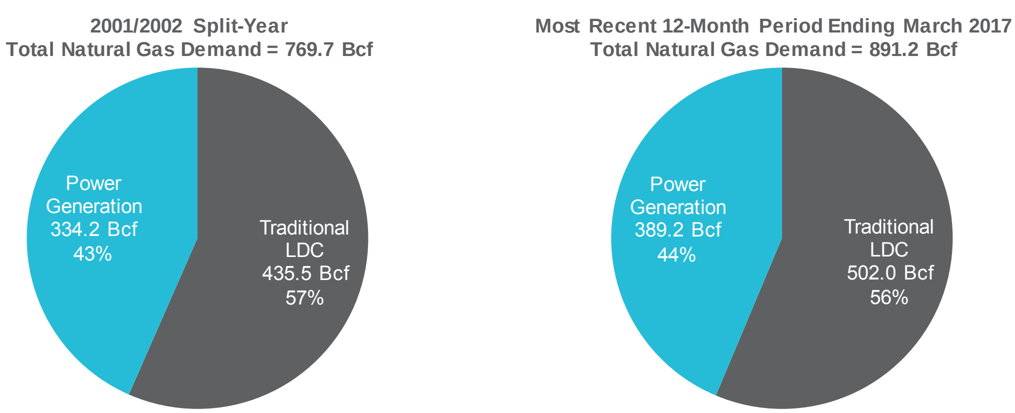
As discussed in detail below, a number of important resource decisions must be made during the Forecast Period. Several upstream pipeline capacity contracts require notice of renewal or termination up to one year in advance. Analysis of renewal or replacement of specific expiring resources, as well as the acquisition of an incremental resource, if required, must take place early in the planning process for EnergyNorth to appropriately evaluate all alternatives. The overarching objective of the Company's gas supply resource portfolio, and the planning process used to develop that portfolio, is to meet projected demand requirements in a reliable manner at the best cost. Given the inherent uncertainty in forecasting (e.g., changing market conditions, adapting to federal and state policy and regulatory priorities, and responding to gas supply and pipeline projects), the Company, as part of its planning and evaluation process, values asset and portfolio flexibility.

The Company is actively involved in the natural gas marketplace ranging from conducting request for proposals for natural gas supply and/or asset management arrangements, to monitoring and participating in FERC-related activities, to reviewing trade and industry information. As a result of this market activity, there are several natural gas demand and supply trends that the Company is continuously monitoring. As these market conditions change and evolve, the Company's supply resource portfolio needs to have the flexibility to adapt to these new market conditions, while maintaining reliability. Prior to the discussion of the Company's specific supply resource plans, a broader review of the regional natural gas market issues will provide necessary context and background information. Specifically, EnergyNorth's gas supply planning is influenced by, and addresses, the regional trends in natural gas demand and supply, some of which are discussed below.

1. Regional Natural Gas Demand and Supply Dynamics

From a demand perspective, the New England region has experienced significant growth in natural gas consumption over the past fifteen years. As illustrated by Figure 8, the total annual natural gas demand for the New England region has grown from 770 Bcf to 890 Bcf, an increase of almost 16 percent with both the LDC and power generation segments experiencing significant increases in natural gas consumption.

Figure 8: Annual Natural Gas Consumption by Sector[32]



Focusing on the winter season, the New England region has seen an increase in natural gas consumption of 23 percent, growing from 374 Bcf in the winter of 2001/2002 to almost 460 Bcf in the winter of 2016/2017. Stated differently, the winter demand for natural gas in New England has grown by 86 Bcf over the past fifteen years, which is approximately 570,000 Dth/d of incremental natural gas demand.

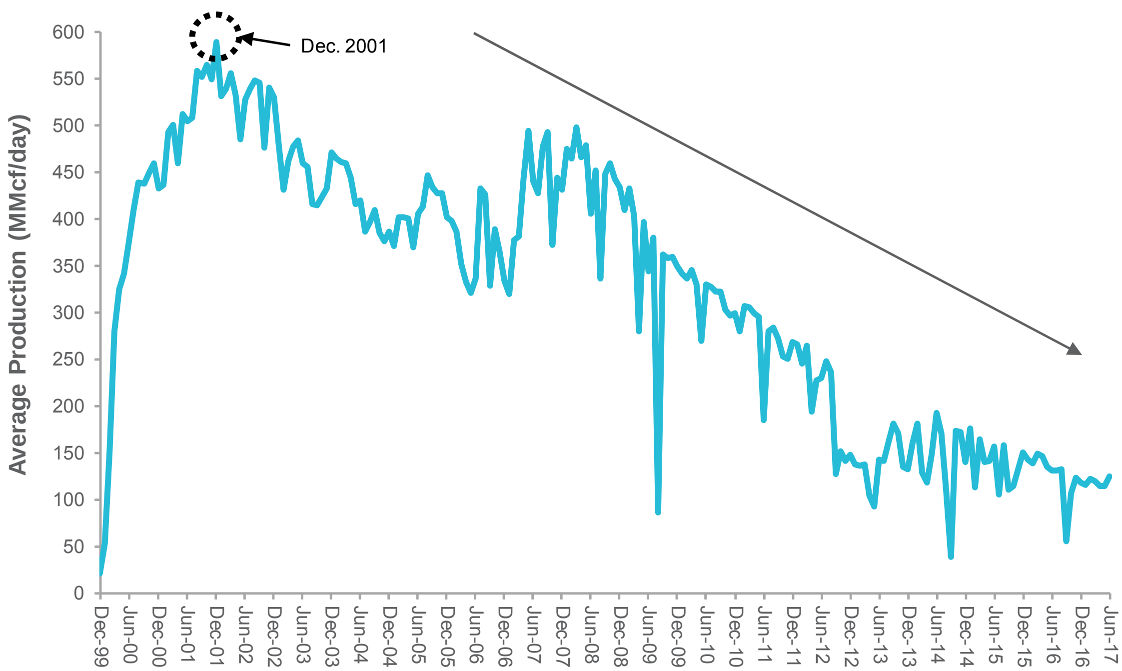
32 Source: U.S. Energy Information Administration, Natural Gas Consumption by End Use for Massachusetts, Connecticut, Rhode Island, New Hampshire, Vermont and Maine, release date May 31, 2017. Data for certain months in 2016 and 2017 are based on estimates.

From a gas supply perspective, the New England region has various supply and transportation trends including: (1) dwindling natural gas supplies from off-shore Nova Scotia, which have been a major source of supply for the region; (2) significant increases in domestic natural gas production and reserves estimates, which is supporting certain infrastructure development; (3) more complexity and time needed to construct incremental pipeline capacity into the region; and (4) seasonality of imported LNG. Each of these gas supply trends is discussed below.

The New England market has access to natural gas resources from off-shore Nova Scotia via the MNE system, which extends from Goldboro, Nova Scotia through New Brunswick to a point at the Canada-U.S. border near Baileyville, Maine (i.e., MNE-Canada), and continues through Maine and New Hampshire into Massachusetts (i.e., MNE-US). The natural gas supplies from off-shore Nova Scotia are comprised of the Sable Offshore Energy Project ("SOEP") and Deep Panuke Offshore Gas Development Project ("Deep Panuke").

SOEP, which has been producing natural gas since late 1999, has been in a steady decline since 2009. As illustrated in Figure 9 below, average daily production from SOEP was approximately 120 MMcf/day this past winter (i.e., winter 2016/17), which is an 80 percent decrease from its peak production in December 2001 of nearly 600 MMcf/day.[33]

Figure 9: Average Daily SOEP Production[34]



Natural gas production from Deep Panuke, which began in the summer of 2013, was expected to augment the natural gas supplies from SOEP. However, Deep Panuke production has fallen short of

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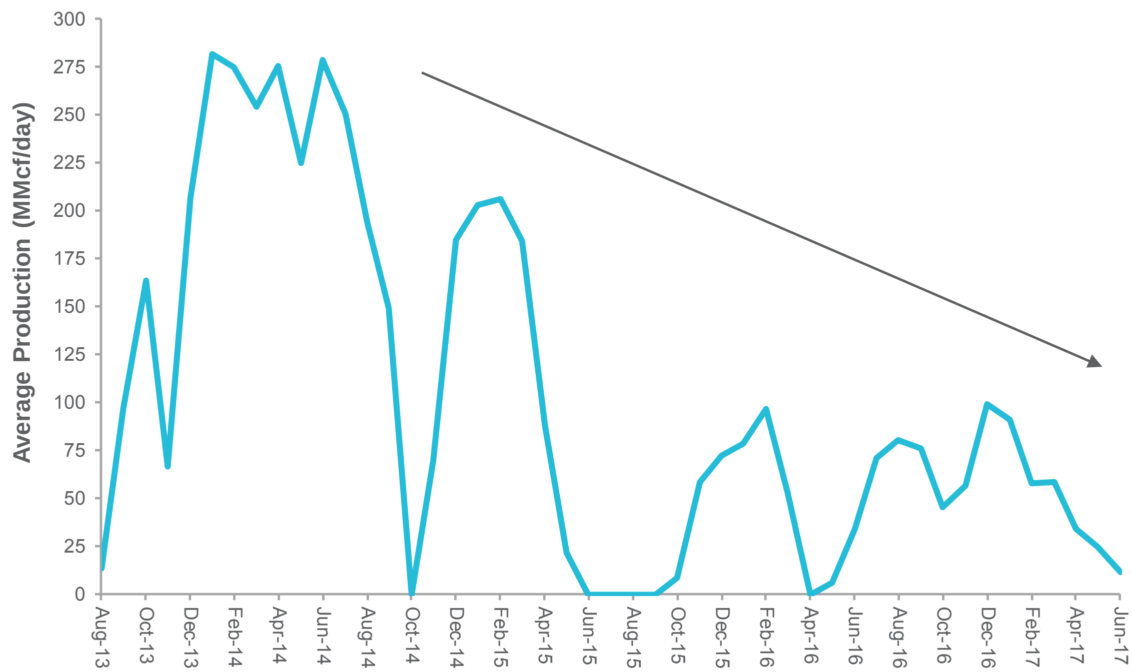
[33] Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date July 31, 2017.

[34] Source: Canada-Nova Scotia Offshore Petroleum Board, Sable Monthly Production Reports, access date July 31, 2017.

expectations. Since inception, natural gas production from Deep Panuke has been variable, with daily production averaging less than 100 MMcf/day since April 2015,[35] which is only one-third of the expected production level of 300 MMcf/day.[36] The average daily natural gas production from Deep Panuke is illustrated in Figure 10 below.

Figure 10: Average Daily Deep Panuke Production[37]



Since natural gas supplies from off-shore Nova Scotia are also used to serve demand in the Canadian Maritimes (i.e., Nova Scotia and New Brunswick), the decline in production from SOEP and Deep Panuke has resulted in little, if any, natural gas supplies available for the New England market. In addition, decommissioning activity has started with respect to the SOEP and Deep Panuke facilities, which will likely result in limited to no natural gas supplies from off-shore Nova Scotia by 2020.

In stark contrast to the decline in natural gas production from off-shore Nova Scotia, there has been a significant increase in domestic natural gas production resulting in a decline in natural gas prices in supply areas. As illustrated in Figure 11 below, total annual natural gas production has increased from approximately 55 Bcf/day in 2008 to approximately 72 Bcf/day in 2016.[38] Over that same time period, the Henry Hub spot price decreased from an annual average of $8.86/MMBtu to $2.52/MMBtu.[39]

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[35] Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date July 31, 2017.

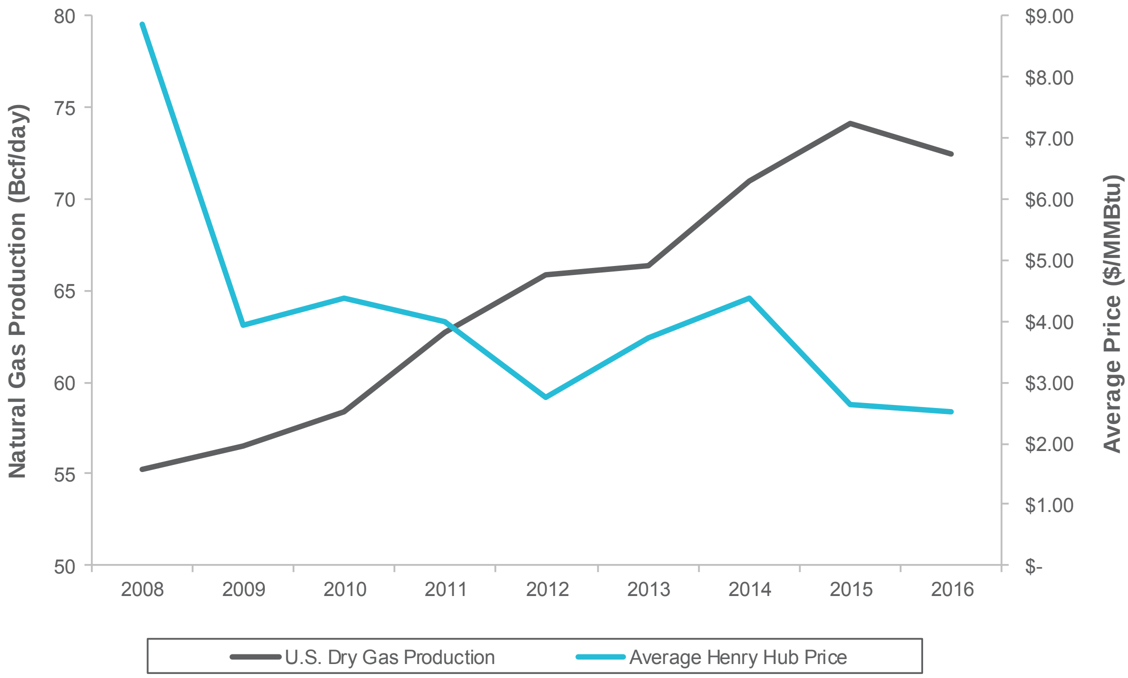
[36] Source: Nova Scotian Department of Energy; The Future of Natural Gas Supply for Nova Scotia. Prepared by ICF Consulting Canada, Inc., March 2013, at 35.

[37] Source: Canada-Nova Scotia Offshore Petroleum Board, Deep Panuke Monthly Production Reports, access date July 31, 2017.

[38] Source: U.S. Energy Information Administration, Natural Gas Dry Production, release date May 31, 2017.

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

Figure 11: Henry Hub Pricing and U.S. Domestic Natural Gas Production[40]



The increase in natural gas production is expected to be sustainable given recent forecasts of natural gas production. Specifically, the latest EIA AEO shows that total domestic natural gas production will reach approximately 110 Bcf/day by 2050. As illustrated in Figure 12 below, the EIA expects that most of the growth in natural gas production will be driven by an increase in shale gas production.

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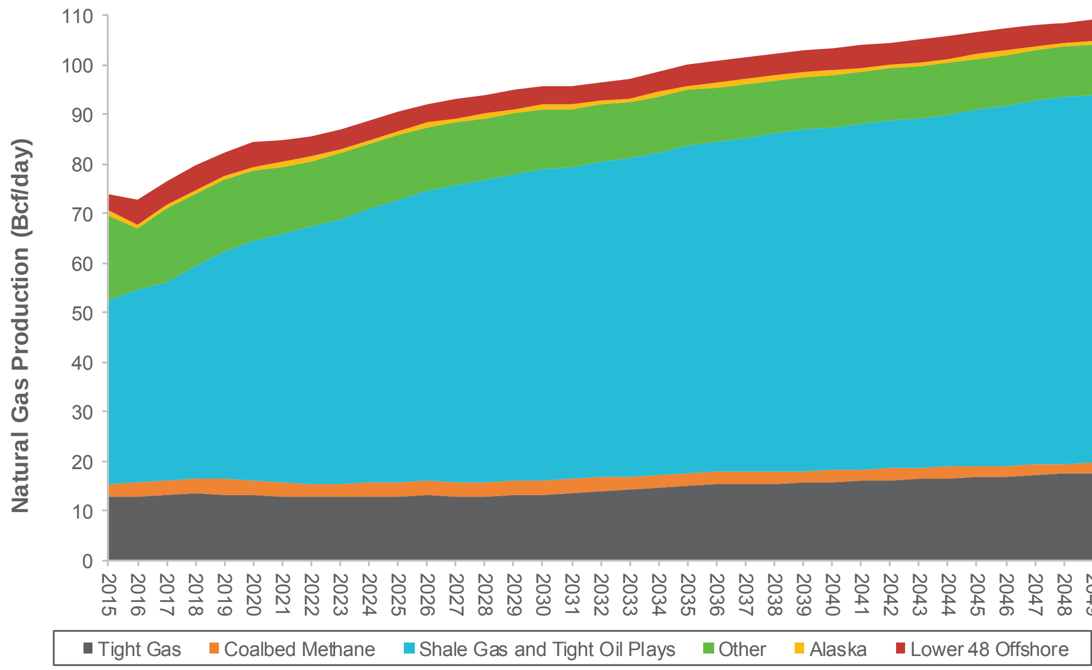
[40] Sources: U.S. Energy Information Administration, Natural Gas Spot and Futures Prices (NYMEX), release date June 7, 2017; and U.S. Energy Information Administration, Natural Gas Dry Production, release date May 31, 2017.

Figure 12: EIA U.S. Natural Gas Production Forecast[41]



The expected increases in natural gas production are supported by an increase in the estimate of natural gas resources. The EIA provides an annual estimate of Proved Reserves of natural gas, which are defined as "the estimated quantities which analysis of geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." The EIA has increased its estimate of the total Proved Reserves in the U.S. by 46 percent from approximately 211 Tcf in 2006 to approximately 308 Tcf in its most recent 2015 estimate.[42]

Although the increase in natural gas production and expected life of natural gas resources has resulted in new natural gas infrastructure for New England, most of that incremental volume is targeted for southern New England. The shippers on certain recent projects (i.e., the Algonquin Incremental Market, TGP Connecticut Expansion, and Atlantic Bridge projects) are LDCs and end-users predominantly located in the southern New England area. These three projects, if completed, will increase the total pipeline capacity into the New England region by approximately 550,000 Dth/day, with 85 percent of the total incremental capacity contracted by project shippers located in southern New England.

While certain projects for additional pipeline capacity have been placed in service or are under construction, there is significant complexity and increasing lead time required for development of incremental pipeline capacity projects into the New England region. Most recently, two major projects proposed to deliver incremental natural gas supplies to the New England region have been suspended or cancelled. Given the complexity and long lead time needed to develop large incremental interstate

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[41] Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, Table 14. Oil and Gas Supply, release date January 5, 2017.

[42] Source: U.S. Energy Information Administration, Dry Natural Gas Proved Reserves as of 12/31 (Summary), release date December 14, 2016.

pipeline capacity projects, LDCs may need to increase their reliance on existing infrastructure that require limited facilities for expansion and invest in on-system resources that address each LDC's unique circumstances.

Finally, as illustrated in Figure 5 above, the New England region has access to several LNG importation facilities, including ENGIE's Distrigas LNG facility in Everett, Massachusetts, two off-shore LNG facilities near Cape Ann, Massachusetts (i.e., Excelerate Energy's Northeast Gateway Deepwater Port and ENGIE's Neptune LNG facility),[43] and the Canaport LNG facility, which is owned as a partnership between Repsol (75 percent) and Irving Oil (25 percent).[44] While the New England region continues to import LNG, there has been a trend in the U.S. as a whole for developing LNG export facilities. In fact, most of the LNG importation facilities in the U.S. have not been actively importing LNG cargoes over the past few years, and seven of the eleven existing U.S. LNG import terminals are in various stages of developing LNG export capability.[45]

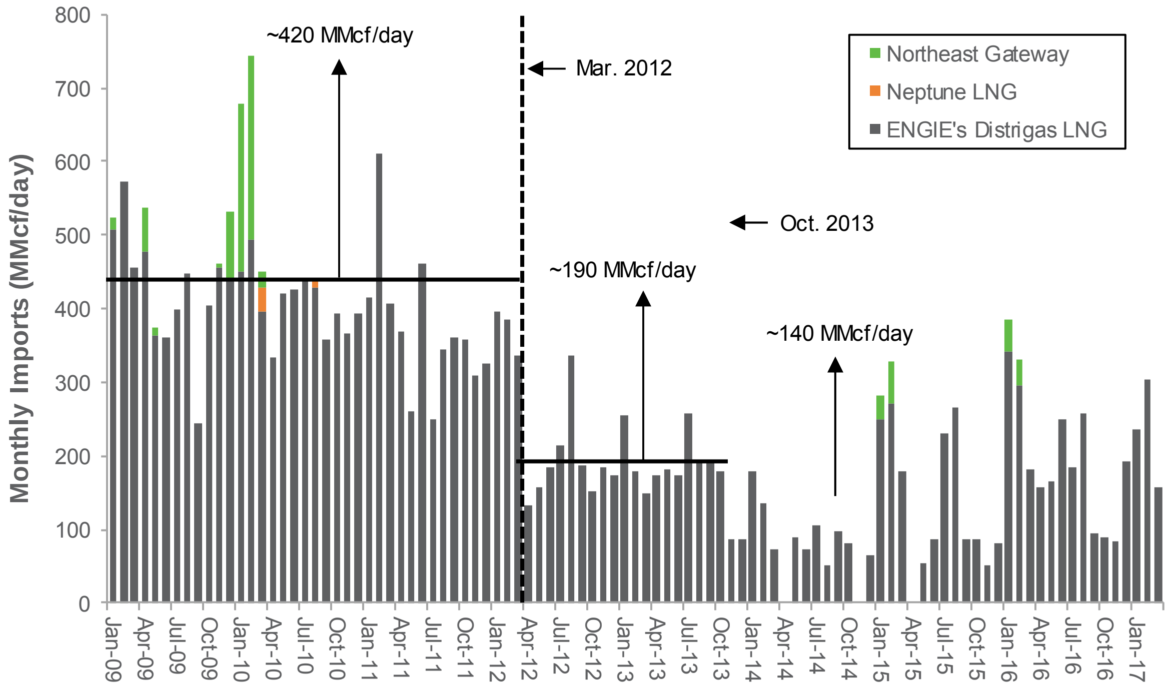
Although the New England region continues to have certain volumes of imported LNG, those volumes have been variable and are becoming winter season focused. As illustrated in Figure 13 below, the two off-shore LNG importation facilities (i.e., Northeast Gateway and Neptune LNG) had limited activity since commencing service in 2009 and 2010, respectively, and ENGIE's Distrigas LNG facility has experienced a declining trend in LNG import volumes since 2009.

[43] In early 2017, Neptune LNG filed for a permit to commence decommissioning work on the facility. *See*, U.S. Army Corps of Engineers, "Neptune LNG seeks permit to work in U.S. waters to decommission deepwater LNG port off Marblehead", February 28, 2017.

[44] The Brunswick Pipeline connects the Canaport LNG facility, which is located in Saint John, New Brunswick, to MNE-US at Calais, Maine.

[45] Sources: FERC, North American LNG Import/Export Terminals: Existing, release date May 1, 2017; and FERC, North American LNG Import/Export Terminals: Proposed, release date May 1, 2017.

Figure 13: Imported LNG Volumes to New England[46]



Since the LNG market is a global market, the New England/Maritime Canada region must compete with international markets for imported LNG supplies. The volume of LNG imported into the region is influenced by various factors, including the demand for LNG in alternative markets and the need for the New England market to pull the supply by contracting for imported LNG volumes.

2. Contract Expiration and Renewal of Existing Resources

Over the next five years, EnergyNorth will be faced with decisions regarding the expiration of nearly all of its existing pipeline transportation and underground storage contracts, as well as key decisions related to its aging propane facilities and limited LNG storage capacity. As a result of EnergyNorth's resource planning process, the Company's current strategies related to each of its existing upstream capacity and underground storage contracts are provided in Table 34 below.

[46] Source: U.S. Department of Energy, LNG Annual and Monthly Reports, accessed on June 6, 2017.

Table 34: Contract Expiration and Renewal of Existing Resources

Contract Entity	Rate Schedule	Contract Number	MDQ/ MDWQ (Dth)	Storage MSQ (Dth)	Expiration Date	Renew (Yes/No)
Pipeline Transportation						
Union	M12	M12200	4,092	-	10/31/2022	Yes
TCPL	FT	41232	4,047	-	10/31/2022	Yes
Iroquois	RTS	470-01	4,047	-	11/1/2022	Yes
PNGTS	FT	1999-001	1,000	-	10/31/2019	Yes
Tennessee	FT-A (Zone 5 to Zone 6)	95346	4,000	-	11/30/2021	Yes
Tennessee	FT-A (Zone 5 to Zone 6)	2302	3,122	-	10/31/2020	Yes
Tennessee	FT-A (Zones 0,1 to Zone 6)	8587	25,407	-	10/31/2020	Yes
Tennessee	FT-A (Zone 6 to Zone 6)	42076	20,000	-	10/31/2020	Will evaluate
Tennessee	FT-A (Zone 6 to Zone 6)	72694	30,000	-	10/31/2029	Will evaluate
Underground Storage and Associated Pipeline Transportation						
Tennessee	FS-MA	523	21,844	1,560,391	10/31/2020	Yes
Tennessee	FT-A (Zone 4 to Zone 6)	632	15,265	-	10/31/2020	Yes
Honeoye	SS-NY	11234	1,957	245,280	3/31/2020	Yes
Tennessee	FT-A (Zone 5 to Zone 6)	11234	1,957	-	10/31/2020	Yes
Dominion	GSS	300076	934	102,700	3/31/2021	Yes
Tennessee	FT-A (Zone 4 to Zone 6)	11234	932	-	10/31/2020	Yes
National Fuel	FSS	O02357	6,098	670,800	3/31/2019	Yes
National Fuel	FST	N02358	6,098	-	3/31/2019	Yes
Tennessee	FT-A (Zone 4 to Zone 6)	11234	6,150	-	10/31/2020	Yes

As shown in Table 34 above, nearly all of the pipeline capacity and storage contracts currently held by the Company are scheduled to expire and require notice of renewal during the Forecast Period. EnergyNorth will need to renew all of these existing capacity resources for which the Company has a ROFR or a rollover right, with the exception of contract number 42076, firm transportation from Dracut, MA, which the Company will evaluate based on market conditions at the time of renewal. These capacity contracts are needed over the long-term to meet customer demand, they are competitively priced, and they offer important supply diversity benefits to the Company's best-cost portfolio. Therefore, in this filing, the Company is requesting that the Commission approve the renewal of those pipeline contracts designated as "Yes" in the table above as these contracts have a renewal notice within three years of the filing of the LCIRP. The Company does not expect any material changes to the contracts as a result of renewal. In addition, renewing the contracts is in the public interest because the contracts are needed to adequately meet the Company's expected customer demands under the various planning standards outlined in Section V.D. below, and the renewal of these contracts is the only viable option currently available for the Company to serve its customers reliably and flexibly at the best-cost.

In addition to the above contractual decisions, the Company must also address its aging propane facilities and the continued reliance on these facilities to perform at peak capacity during the coldest days of the year. In particular, the propane facilities in Manchester and Nashua, which provide the Company with peaking supply service, have been in operation for nearly 50 years. As with any aging facility, it becomes increasingly expensive (e.g., parts and equipment become scarcer and more expensive) and labor intensive to operate and maintain the propane facilities at peak efficiency. Moreover, the Company's customers have experienced problems with their high efficiency furnaces at various times when these propane facilities are used extensively. As more and more customers switch to higher efficiency furnaces and appliances, the Company is concerned that the customer complaints will escalate. For reliability, efficiency, security, economic, and customer satisfaction reasons, the Company concludes that the replacement of these propane facilities is necessary and appropriate to maintain reliable service and achieve a best-cost portfolio.

3. Future Portfolio Decisions

Although the Company has determined that it will renew all or nearly all of its existing upstream capacity contracts, during the forecast horizon there may be opportunities to re-optimize the Company's supply resource portfolio. When faced with making a decision, EnergyNorth employs a three-step analysis to reach its conclusions regarding contract renewals. 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 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 flexibility, diversity, reliability, viability, and contract term 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 addition to renewing existing contract resources, EnergyNorth continuously monitors and evaluates new opportunities, and adjusts the supply resource portfolio if the Company determines that incremental supply resources would contribute to a best-cost portfolio, balanced with reliability, flexibility, diversity, and viability of the resource. When these opportunities arise, the Company uses an appropriate decision-making process to determine whether modifications to the current resource plan are appropriate.

EnergyNorth's demand forecast, discussed in Section IV above, shows an increase in demand requirements over the forecast horizon, with growth in both winter period and Design Day demand. Based on a review of the Company's demand forecast and existing supply resource portfolio, the Company has incremental resource requirements on Design Day of 18,884 Dth by 2021/2022. As shown in Table 35 below, the incremental resource requirement becomes more significant if the Company's propane facilities are retired.

Table 35: Design Day Demand and Supply Resources (Dth)

Split-Year	Design Day Planning Load	Design Day Resources, including Propane	Reserve / (Deficiency) including Propane	Reserve / (Deficiency) excluding Propane
2017/18	156,822	162,033[47]	5,211	(29,389)
2018/19	160,989	155,033	(5,956)	(40,556)
2019/20	164,640	155,033	(9,607)	(44,207)
2020/21	168,934	155,033	(13,901)	(48,501)
2021/22	173,917	155,033	(18,884)	(53,484)

With respect to gas supply alternatives available in the marketplace, the Company has identified a wide range of resource options including, but not limited to, pipeline supplies, imported LNG, on-system assets, delivered supplies, compressed natural gas ("CNG"), renewable natural gas, and portable LNG vaporization.

As discussed in Section V.C.1, given the complexity and long lead times needed to develop large incremental interstate pipeline capacity projects, LDCs may need to increase their reliance on existing infrastructure that require limited facilities for expansion and invest in on-system resources that address each LDC's unique circumstances. Based on EnergyNorth's review of available and viable resources in the marketplace to meet the Company's existing and projected load requirements, the following gas supply options have been identified:

- ENGIE delivered supply to the EnergyNorth city-gates and LNG facilities;
- Repsol delivered supply to Dracut, Massachusetts;
- Pipeline transportation capacity from the Dawn Hub on the TCPL Mainline and PNGTS pipeline systems to Dracut, Massachusetts; and
- Increasing on-system LNG storage and vaporization capacity with additional infrastructure to access new gas supplies.

As noted in the Company's most recent cost-of-gas filing in Docket No. DG 17-135, the Company has contracted with ENGIE for a combination liquid/vapor service for up to 7,000 Dth/day that can be used to either refill its LNG storage tanks during the peak period and/or deliver incremental supply to its city-gates for the 2017/18 split-year. The ENGIE service is delivered to the Company's city-gates using existing infrastructure and requires no facility expansion or construction. Based on the unique attributes (i.e., incremental supply delivered to the Company's city-gates and liquid/vapor service flexibility) of the ENGIE contract, the Company included the ENGIE service in its SENDOUT® analysis discussed below in Section V.D.

Repsol is capable of delivering Canaport LNG supplies via existing infrastructure (i.e., the Brunswick Pipeline and MNE pipeline systems) to the Dracut, Massachusetts interconnect between Tennessee and the Joint Facilities, or to other potential delivery points as discussed below. Based on initial discussions with Repsol, the Company may be able to contract for bundled service for the winter period. As discussed below, EnergyNorth has evaluated the Repsol service as a potential gas supply option in the Resource

[47] The 2017/18 Design Day resources include the contract with ENGIE for a combination liquid/vapor service for up to 7,000 Dth/day. *See*, Docket No. DG 17-135.

Mix module of its SENDOUT® analysis discussed in Section V.D.

An open season has been conducted for firm transportation on the TCPL Mainline from the Dawn Hub to East Hereford in conjunction with the proposed downstream expansion on PNGTS.[48] Specifically, the proposed PNGTS Portland XPress project is an expansion of the PNGTS system, which will provide firm transportation of up to 122,900 Dth/day of gas supplies from the East Hereford interconnect with TCPL Mainline to Westbrook, Maine (i.e., the interconnect with MNE-US) and Dracut, Massachusetts (i.e., the interconnect with Tennessee), or other potential delivery points as discussed below.[49] The Portland XPress project involves construction of compression only on both the TCPL Mainline and PNGTS/MNE Joint Facilities, and will be phased-in over three years beginning on November 1, 2018.[50] Capacity on the TCPL/PNGTS systems would provide the Company with access to the Dawn Hub, which is one of the most liquid gas supply points in North America with access to numerous suppliers and significant storage capacity. The Company has also included the TCPL/PNGTS capacity as a potential option in the Resource Mix module of its SENDOUT® analysis discussed below in Section V.D.

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.

As part of the Company's evaluation of its long-term gas supply portfolio, the Company assessed not only the available gas supply options, but also the delivery options associated with those supplies. 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.

The Company will continue to monitor market trends and opportunities so that when portfolio decisions need to be made, the Company will be prepared to act swiftly using its best-cost planning process.

D. Adequacy of the Supply Resource Portfolio

1. Analytical Process

In the third step of EnergyNorth's resource planning process, the Company evaluates the ability of its resource portfolio to meet the projected Planning Load 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 (described below), the Company is able to (1) determine the least-cost portfolio that will meet forecasted customer demand, and (2) test the

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[48] *See*, TransCanada's Firm Transportation, New Capacity Open Season, dated August 31, 2017.

[49] *See*, Portland XPress Project Binding Open Season, dated August 30, 2017.

[50] *See*, PNGTS, presentation at the Northeast LDC Forum, June 6, 2017.

sensitivity of the portfolio to key inputs and assumptions, as well as its ability to meet all of the Company's planning standards and contingencies. Based on the results of this analysis, the Company is able to make preliminary decisions on the adequacy of the resource portfolio and its ability to meet system requirements.

2. SENDOUT® Model

Since 1996, the Company has been using the SENDOUT® model developed by ABB (formerly Ventyx) as its primary analytical tool in the portfolio design process. The SENDOUT® model is used on behalf of more than 100 energy companies for their gas supply planning and portfolio optimization process. The SENDOUT® model is a linear-programming optimization software tool used to assist in evaluating, selecting, and explaining long-term portfolio strategies. The SENDOUT® model can accommodate a number of resources allowing the Company to model these options more realistically and receive more meaningful information via the output reports. The model also allows the Company to examine the effect of various contracts on the total portfolio cost.

In that regard, the SENDOUT® model can be used in two ways. First, the model can be used to determine the best use of a given portfolio of supply, capacity, and storage contracts to meet a specified demand. That is, it can solve for the dispatch of resources that minimizes the cost of serving the specified demand given the existing resource and system-operating constraints. The SENDOUT® model dispatches resources based on the lowest variable cost to meet demand, assuming that demand charges are fixed. Second, the SENDOUT® model can be used to determine the optimal portfolio to meet a given demand using the Resource Mix module. To do this, the model uses a linear programming algorithm to analyze the combination of contracts and the size of each contract (e.g., maximum daily quantity ("MDQ")) to determine the combination that results in the lowest total cost, taking into account both variable and fixed costs.

3. Analytical Assumptions

The SENDOUT® model was used to evaluate EnergyNorth's resource portfolio over various weather (i.e., Normal Year, Design Year, and Design Day) and growth scenarios (i.e., Base Case, Low Growth, and High Growth), which were described in Section IV. The examination of these various scenarios enables the Company to test the adequacy and flexibility of its existing and potential resource portfolio.

The inputs to the SENDOUT® model included (1) the Company's Planning Load requirements under the various planning scenarios, and (2) the resource-specific data elements (e.g., capacity cost; fuel and variable cost; gas commodity cost; and MDQ and annual contract quantity). To perform the analysis of these various planning scenarios, the Company incorporated several key assumptions:

- First, the Company assumed that, throughout the Forecast Period, there is no change in the Company's service obligation to plan for the capacity requirements of firm sales and capacity-assigned customers.

- Second, the Company's analysis assumed that all legacy contracts expiring during the Forecast Period (see Table 34 above) would be renewed with no change in rates/tolls, quantities, or operating characteristics.

- Third, the Company used natural gas prices and/or basis values based on closing settlement prices on August 18, 2017, provided by S&P Global Market Intelligence for the length of the Forecast Period.

- Fourth, gas supplies were assumed to be available at Dracut, with the daily price for those supplies reflective of the weather pattern (i.e., colder weather days will have higher daily prices at the Dracut point).

Given the Company's growing Design Day and peak period demand requirements discussed in Section IV, the Company also incorporated the following assumptions in its SENDOUT® analysis to determine the incremental resources and associated capacity levels to meet the projected demand requirements:

- EnergyNorth assumed a contract with ENGIE for combination liquid/vapor service delivered to the Company's city-gates or LNG facilities with an MDQ of up to 7,000 Dth/day would be available for the five-year forecast horizon to help meet the Company's projected Design Day shortfall (see Table 35 above).

- The Company assumed that an extension of its system would be capable of accessing incremental deliveries of natural gas supplies to serve incremental demand requirements.

- The Company included the following gas supply resource options in the Resource Mix module to determine the most cost-effective mix of resources and capacity levels (see Section V.C.3 above):

    - Repsol delivered service to Dracut, Massachusetts and/or directly to its distribution system, with an MDQ of up to 150,000 Dth/day of winter service; and
    - Pipeline transportation capacity from the Dawn Hub on the TCPL Mainline and PNGTS pipeline systems to Dracut, Massachusetts and/or directly to its distribution system, with an MDQ of up to 150,000 Dth/day.

The SENDOUT® model produces an optimization solution for each planning scenario according to a least-cost economic dispatch of supplies, given the constraints on supply availability, storage or transportation capacity, which are always honored to avoid penalties and to ensure reliability of supply. Table 36 below summarizes the results of the Resource Mix runs in SENDOUT® for the various planning scenarios and identifies the location of the detailed SENDOUT® output for each scenario in Appendix 6.

Table 36: Summary of SENDOUT® Resource Mix Runs

Scenario	Existing Portfolio	System Extension	ENGIE MDQ (Dth/day)	Repsol MDQ (Dth/day)	TCPL/PNGTS MDQ (Dth/day)
Base Case – Normal (Appendix 6.A)	✓	✓	7,000	16,550	0
Base Case – Design (Appendix 6.B)	✓	✓	7,000	13,00	6,030
High Growth – Normal (Appendix 6.C)	✓	✓	7,000	24,800	0
High Growth – Design (Appendix 6.D)	✓	✓	7,000	17,930	8,600
Low Growth – Normal (Appendix 6.E)	✓	✓	7,000	8,800	0
Low Growth – Design (Appendix 6.F)	✓	✓	7,000	7,860	3,670

The Company's first analysis was to run the Base Case, Normal Year scenario in the Resource Mix module, allowing the SENDOUT® model to determine the most cost-effective mix of resources and capacity levels. As shown in Table 36 above, the results of this SENDOUT® run demonstrate that the Company's existing portfolio (assuming rollover and renewal of all legacy contracts), the extension of its system, 7,000 Dth/day of ENGIE capacity, a Repsol contract of 16,550 Dth/day, and zero TCPL/PNGTS capacity, contribute to a least-cost portfolio under normal weather conditions (see also, Appendix 6.A.1).

The Company's second analysis was to run the Base Case, Design Year scenario in the Resource Mix module. The results of this run demonstrate that the existing portfolio, the extension of its system, 7,000 Dth/day of ENGIE capacity, a Repsol contract of 13,000 Dth/day, and TCPL/PNGTS capacity of approximately 6,000 Dth/day, contribute to a least-cost portfolio under design weather conditions (see Appendix 6.B.1).

The Company then ran Normal and Design Year SENDOUT® model runs for its High and Low Growth forecasts as sensitivities to test the adequacy of the resource portfolio. Under normal weather conditions, the existing portfolio, the extension of its system, 7,000 Dth/day of ENGIE capacity, a Repsol contract ranging from 8,800 Dth/day to 24,800 Dth/day for Low Growth and High Growth scenarios, respectively, and zero TCPL/PNGTS capacity, contribute to a least-cost portfolio (see Appendix 6.C.1 and 6.E.1). Under design weather conditions, the portfolio includes the extension of its system, 7,000 Dth/day of ENGIE capacity, a Repsol contract of approximately 7,900 Dth/day and 17,900 Dth/day for Low Growth and High Growth, respectively, and TCPL/PNGTS capacity of approximately 3,700 Dth/day for the Low Growth scenario and 8,600 Dth/day for the High Growth scenario (see Appendix 6.D.1 and 6.F.1).

4. SENDOUT® Model Results

The adequacy of the Company's resources to meet the projected Planning Load requirements for each of the weather and growth scenarios is discussed in detail below.

<u>Base Case</u>

Given the rollover and renewal of all of EnergyNorth's existing pipeline transportation and storage capacity contracts that expire in the near-term (see Table 34 above), the Company's resource plan shows that it can meet both Base Case, Normal Year and Design Year load requirements throughout the Forecast Period, with the addition of ENGIE capacity and the extension of its system to access other upstream gas supply resources (e.g., Repsol and PNGTS). These requirements are set forth in Appendix 6.B.2: Base Case – Design Year: Monthly Resources and Requirements. Therefore, to ensure continued deliverability over the peak season to meet the projected needs of its customers, the Company will refine and evaluate the addition of incremental resources.

As previously illustrated in Table 35 above, volumes in addition to the Company's existing portfolio are required to meet Design Day sendout requirements beginning in 2018/19. The SENDOUT® analysis demonstrates that the addition of ENGIE, the extension of its system to access other supply resources (e.g., Repsol and PNGTS) allow the Company to meet its Design Day sendout requirements (see Appendix 6.B.3). The Company will refine and evaluate the addition of incremental resources.

High Growth

The Company's resource plan shows that it can meet High Growth, Normal Year and Design Year load requirements throughout the Forecast Period, with the extension of its system and incremental capacity resources (e.g., ENGIE, Repsol, and TCPL/PNGTS), during the peak period and on Design Day. These incremental resources are set forth in Appendix 6.D.2: High Growth, Design Year: Monthly Resources and Requirements and Appendix 6.D.3: High Growth, Design Year: Annual Design Day. Should incremental demand increase consistent with the High Growth demand case projections, the Company would acquire adequate, least-cost, reliable resources to address the need.

Low Growth

The Company's resource plan shows that it can meet Low Growth, Normal Year and Design Year load requirements throughout the Forecast Period, with the extension of its system and incremental capacity resources (e.g., ENGIE, Repsol, and TCPL/PNGTS), during the peak period and on Design Day (see Appendices 6.E.2, 6.F.2, and 6.F.3).

Under all of the planning scenarios, the Company will need to use its resource planning process to evaluate and fill the identified needs with a best-cost, reliable mix of capacity. As the decisions for certain incremental resources (e.g., TCPL/PNGTS) require infrastructure expansions and long-term contract commitments, the Company will need to further evaluate its requirements and resource portfolio over a longer-term planning horizon. The Company will also continue to evaluate the resource options that may not require a long-term contract commitment (e.g., Repsol, LNG liquid refill alternatives, CNG, and portable LNG vaporization) to meet the incremental resource needs. The resource planning approach will need to provide a high level of flexibility to meet uncertainties in future demand, while ensuring the adequacy of the overall resource portfolio. Further, the future resource decisions will need to balance cost considerations with qualitative benefits, such as supply security, optionality, and viability.

VI. SUMMARY OF COMPLIANCE WITH DG 13-313 ORDER

In the 2013 IRP Order, the Commission provided directives to the Company for the current filing. The directives and the actions taken to comply with them are described below.

- The Company should incorporate "Staff's methodological suggestions", which include "apply[ing] a more nuanced approach in evaluating its energy-efficiency options" and "apply[ing] a cross-check on a company-wide basis to its modelling outputs."[51]

The Company based its forecast of energy efficiency on the multi-year estimates developed in Docket No. DE 17-136, which was based on a comprehensive review of potential options and the reasonableness of implementation.

To evaluate the reasonableness of the demand forecast the Company reviewed recent historical trends in customer additions and volumes. Given the expansion in the Company's sales and marketing efforts, as noted in Section III.A.11, the Company expects somewhat higher levels of growth, relative to actual experience, over the Forecast Period. Based on the information and analysis presented in this filing, the Company believes its demand forecast is reasonable.

- "Also, for the purposes of the next LCIRP, we ask that Liberty address all of the statutory elements of RSA 378:38 and RSA 378:39 in its plan development in a granular way, so that reviewing parties may track the correspondence of the plan with the relevant statutory standards."[52]

The statutes that govern LCIRPs consist of those sections of RSA 378 that fall under the heading "Least Cost Energy Planning," which are RSA 378:37 through RSA 378:40. The first statute in this subdivision, RSA 378:37, is the Legislature's articulation of the state's energy policy:

> The general court declares that it shall be the energy policy of this state to [1] meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while [2] providing for the reliability and diversity of energy sources; [3] to maximize the use of cost effective energy efficiency and other demand side resources; and [4] to protect the safety and health of the citizens, the physical environment of the state, and the future supplies of resources, [5] with consideration of the financial stability of the state's utilities.

(Numbers added.)

The second statute, RSA 378:38, contains the requirement that utilities must file LCIRPs and lists the topics that the utilities must address in those plans. EnergyNorth explains below how its plan addresses each of the applicable topics listed in RSA 378:38.

The third substantive statute[53] in this subdivision is RSA 378:39, which directs the Commission to "evaluate the consistency of each utility's plan with this subdivision." The Commission's charge in this docket, therefore, is to evaluate whether EnergyNorth's LCIRP is consistent with the State's energy policy as articulated in RSA 378:37.

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[51] 2013 IRP Order, at 4-5.

[52] Ibid., at 5.

[53] RSA 378:38-a authorizes the Commission to extend the deadline for a utility to file its next LCIRP.

RSA 378:39 also provides the Commission with guidance in conducting its review: "In deciding whether or not to approve the utility's plan," i.e., whether to find that EnergyNorth's LCIRP is consistent with the State's energy policy as articulated in RSA 378:37, "the commission shall consider potential environmental, economic, and health-related impacts of each proposed option." RSA 378:39 concludes with the following sentence:

> Where the commission determines the options have equivalent financial costs, equivalent reliability, and equivalent environmental, economic, and health-related impacts, the following order of energy policy priorities shall guide the commission's evaluation: I. Energy efficiency and other demand-side management resources; II. Renewable energy sources; III. All other energy sources.

EnergyNorth's interpretation of this sentence is that, to the extent the Company has supply options for meeting its customers' projected demand, and assuming those supply options are equal in terms of cost, reliability, and impact on the environment, economy, and health, then the Commission should determine whether the Plan chooses from those options in the order required by the statute. If, however, the supply options available to EnergyNorth are not equivalent in the above respects, then the Commission must more generally determine whether the Company's supply choices are consistent with the state energy policy contained in RSA 378:37, while considering the "potential environmental, economic, and health-related impacts of each proposed option," RSA 378:39. EnergyNorth describes below why its LCIRP is consistent with the State's energy policy.

EnergyNorth's LCIRP addresses all the applicable elements of RSA 378:38 as follows. First, RSA 378:38, I, states that LCIRPs shall include a "forecast of future demand for the utility's service area." Section III of the plan provides a detailed and comprehensive demand forecast.

Second, the plan must include an "assessment of demand-side energy management programs, including conservation, efficiency, and load management programs." RSA 378:38, II. Section III(A)(13) of this LCIRP describes the Company's energy efficiency programs, how these programs are integrated with those of the other New Hampshire utilities, and how those programs benefit customers. This section details the savings achieved by the programs to date and that will be realized through their useful lives. The Plan also describes the recently-adopted Energy Efficiency Resource Standard, Order No. 25,932 (Aug. 2, 2016), the savings goals established in that order, and their expected costs. Finally, this section of the Plan calculates how these programs reduce the Company's demand forecast and demonstrates that the Company reduced its demand forecast based on the savings that these programs are expected to realize going forward.

Third, the plan must provide an "assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources." RSA 378:38, III. Section V of the Plan describes all of the Company's supply options, consisting of supply contracts, capacity on certain pipelines, out-of-state storage, and LNG and propane storage and capacity within New Hampshire. "Distributed energy resources" is not a factor to be considered in planning for a gas distribution utility. Renewable sources of gas are not yet readily available in quantities that will have a material effect on EnergyNorth's planning.[54]

Fourth, the plan must contain an "assessment of distribution and transmission requirements, including an assessment of the benefits and costs of "smart grid'' technologies, and the institution or extension of

[54] EnergyNorth is nonetheless exploring opportunities to develop renewable sources of methane, and will report to the Commission as those projects become more certain.

electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages, including but not limited to, infrastructure automation and technologies." RSA 378:38, IV. This subsection of the statute is geared toward electric distribution companies and is thus not applicable here.

Fifth, the Plan must assess how it integrates with and impacts "state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers." RSA 378:38, V. "[B]ecause [these] environmental issues primarily relate to the operation of … generation units," and because the Company does not own or operate generation units, this section does not apply here. *Public Serv. Co. of N.H.*, Order No. 25,828 at 8 (Oct. 19, 2015). The Company filed a motion seeking waiver of this requirement.

Sixth, the statute requires an LCIRP to assess the "long- and short-term environmental, economic, and energy price and supply impact on the state." RSA 378:38. This is another requirement that is intended to address the impacts of electric generation, and is thus inapplicable here. Order No. 25,828 at 8 ("We recognize the difficulties for Eversource to develop such assessments, particularly given potential divestiture of Eversource's generation units"); (Because "PSNH's retention of its generation assets" was being considered in other proceedings, PSNH "need not address … consideration of the Clean Air Act (as amended) or the assessment of the plan's impact on the environment, economy, energy price and supply in New Hampshire."); *Public Serv. Co. of N.H.*, Order No. 25,659 at 8 (May 1, 2014) ("We consider the following to be LCIRP requirements that are related to generation: the Clean Air Act amendments of 1990").

Finally, the plan must describe how it is integrated and consistent with "the state energy strategy ("SES") under RSA 4-E:1." RSA 378:38. The state energy strategy[55] generally supports the expanded use and availability of natural gas, as a cheaper and cleaner alternative to oil, propane, and gasoline and diesel as vehicle fuels. EnergyNorth's growth plans, described in this Plan, dovetail with the State's goals and help implement the SES. The following examples illustrate how EnergyNorth's plan is integrated and consistent with the SES.

At pages 47-48, the SES calls for the state to continue to be "engaged in regional efforts to explore ways to encourage additional pipeline capacity in the region" and ensure "that New Hampshire's interests are represented in larger decision□making forums." EnergyNorth continues to participate in various forums, including with other New England distribution companies to work on solutions to the supply issues facing New England, as well as working with industry organizations such as the Northeast Gas Association and the American Gas Association on broader natural gas policy matters.

EnergyNorth has expanded into several communities in New Hampshire, and its goal is to continue such expansion, in part because of the PUC's decision to "change[] the acceptable payback period limit for Liberty Utilities" to construct new main extensions, which will "help Liberty bring natural gas to more customers in communities that are already served by the local gas distribution network." See, e.g., Order No. 25,624 (Jan. 24, 2014).

EnergyNorth supports the SES's recommendations, at page 48, that companies should "increase the utilization of existing infrastructure in order to provide access to natural gas to more customers already on existing networks, while minimizing environmental disruption and making existing systems more cost effective," and at page 50, "to fully utilize the capacity of existing gas pipelines." As described above, EnergyNorth has increased its internal sales force, which has resulted in growth within existing EnergyNorth service territories and where the Company is replacing its cast iron and bare steel mains.

[55] Available at https://www.nh.gov/osi/energy/programs/documents/energy-strategy.pdf.

The Company is also expanding its system into new service territories, most recently Windham and Pelham. The Company will continue these efforts.

The SES recommends that the state "should encourage targeted, strategic installations for trucked CNG in areas where the impact will be maximized." EnergyNorth is in the process of converting its Keene division to trucked CNG, and has proposed similar facilities to serve Lebanon and Hanover.

Finally, at page 55, the SES urges expansion of alternate fuels for vehicles, including CNG. The SES notes that the "largest obstacle is the need for initial infrastructural changes to fueling and maintenance docks and regional refueling locations." EnergyNorth has helped develop a CNG fueling station, and is constructing similar stations for its own vehicle fleet.

This Plan thus "address[ed] all of the statutory elements of RSA 378:38 and RSA 378:39 in its plan development in a granular way," as directed in the 2013 IRP Order.