Liberty Utilities

EXHIBIT
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DE 16-097

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 16-______

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities
Least Cost Integrated Resource Plan

January 15, 2016

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1. Executive Summary

Pursuant to RSA 378:37, et seq., Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") submits this least-cost integrated resource plan ("LCIRP") for the period 2016 through 2020. The Company's most recent LCIRP was approved by the New Hampshire Public Utilities Commission ("Commission") in Order No. 25,625 (Jan. 27, 2014). The current LCIRP was prepared in compliance with the Commission's directives in Order No. 25,625.

The purpose of the LCIRP is to provide the Commission with an understanding of the resource planning process employed by the Company to meet its obligation to provide safe, reliable, and least-cost electric service to its customers. The LCIRP describes the Company's approach to develop a forecast of electricity demand under several planning scenarios, and the Company's ability to meet its supply, transmission, and distribution obligations under various planning conditions.

The LCIRP follows the general approach, format, and objectives of the Company's most recent LCIRP filing in 2012, which is to comply with RSA 378:37 New Hampshire Energy Policy:

> *"[I]t shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while providing for the reliability and diversity of energy sources; to maximize the use of cost effective energy efficiency and other demand side resources; and to protect the safety and health of the citizens, the physical*

environment of the state, and the future supplies of resources, with consideration of the financial stability of the state's utilities."

RSA 378:38 requires electric and natural gas utilities to file an LCIRP and specifies that the LCIRP shall include the following:

- A forecast of future demand for the utility's service area;
- An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs;
- An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources;
- 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 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;
- An assessment of plan integration and impact on state compliance with the Clean Air Act of 1990, as amended, and other environmental laws that may impact a utility's assets or customers;
- An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state; and
- An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1.

This LCIRP filing, as summarized in Appendix A, meets the requirements of RSA 378:38.

This LCIRP also addresses Commission's directives in Order No. 25,625, which required the Company to:

- Provide a more detailed methodology of how Liberty intends to engage in distribution planning provided in the past by National Grid;
- Better integrate actual enterprise planning with the LCIRP process, and provide a business process model that indicates the Liberty personnel responsible for each stage of distribution planning, the input involved in each stage, the outputs produced, and the time commitment for each stage;
- Provide additional details regarding how environmental, economic, and to some degree, health-related impacts inform Liberty's planning and decision-making process;
- Provide a more comprehensive discussion of how Liberty assesses non-wires alternatives in its distribution planning;
- Explain, in greater detail, how demand- and supply-side options for distribution planning are integrated by Liberty as part of its planning process; and
- Include energy efficiency and demand-side resources, renewable and distributed energy resources, and smart grid distribution technologies in future LCIRP filings.

The LCIRP consists of four planning phases. The first phase is the development of a long-term forecast of demand requirements. The second phase is the development of a detailed energy supply plan to meet those requirements. The third phase is the development of a distribution plan that includes evaluation of wires and non-wires alternatives to address system deficiencies. The fourth and final phase is the evaluation and integration of the energy efficiency and demand side management programs into the LCIRP.

In the first phase, the Company developed an econometric model to forecast peak demands through 2031. The forecast model incorporates the impact of weather as well as demographic and local economic conditions on peak demands. The forecast model was then adjusted for spot loads to reflect new customer demands larger than 300 kilowatts ("kW"). The forecast model projects an increase in summer peak demand from 202.4 megawatts ("MW") in 2016 to 210.6 MW in 2020, an average annual increase of 1.1%.[1] The Company developed an "extreme weather" forecast of summer peak demands based on a 1-in-20 weather scenario. The extreme weather forecast model projects an increase from 222.1 MW in 2016 to 230.5 MW in 2020, or an average annual rate of 1.0%. The Company also developed a forecast of peak demands by Planning Supply Area ("PSA") for Liberty's Eastern and Western PSAs.[2] Under the normal weather scenario, the forecast model projects an increase in summer peak demand in Eastern PSA from 100.9

1 Liberty's distribution system in New Hampshire is, in general, summer peaking and summer limited.
2 The Eastern PSA includes the towns of Derry, Pelham, Salem, and Windham. The Western PSA includes the towns of Acworth, Alstead, Bath, Canaan, Charlestown, Cornish, Enfield, Grafton, Hanover, Langdon, Lebanon, Lyme, Marlow, Monroe, Orange, Plainfield, Surry, and Walpole.

MW in 2016 to 105.0 MW in 2020, an average annual increase of 1.1%. In the Western PSA, the model projects an increase in summer peak demand from 101.5 MW in 2016 to 105.6 MW in 2020, an average annual increase of 1.1%.

In compliance with New Hampshire's electric market restructuring and generation divestiture, the Company procures power for its energy service customers through a competitive solicitation process in semi-annual, short-term commitments consistent with the Commission's orders and regulations. The Company monitors market rules and other wholesale electricity issues that impact electric prices.

The Company performed a detailed evaluation of its distribution system based on the forecast results presented above and the condition of its distribution facilities. The evaluation utilized the forecast of peak demands for each feeder and substation based on extreme weather conditions, as well as data depicting the operating performance and condition of the distribution facilities. The evaluation is used to determine whether the operating capacity of the distribution facilities is adequate under normal and contingency conditions.

Liberty established planning criteria for normal and contingency operating conditions that are applied in concert with the thermal ratings of the distribution facilities to identify violations or deficiencies in the capacity of the distribution facilities. The deficiencies are then prioritized by risk of occurrence and impact on customers. The Company develops solutions to the deficiencies in the form of individual project proposals, which are then included in the Company's five year capital budget based on their level of priority and cost considerations. Non-wires alternatives are evaluated and considered as potential solutions to distribution system deficiencies, subject to certain screening criteria. The Company performed a detailed assessment of its NHSaves energy efficiency measures and programs to ensure they meet the requirements of the LCIRP. The assessment shows that the Company's energy efficiency programs have resulted in savings of more than 910,000 lifetime megawatt hours at a benefit value of almost $89 million, reductions in peak load, and significant environmental and health benefits.

Key results and findings of the LCIRP include:

- Liberty's summer peak demand is projected to grow 1.1% per year on average over the 2016 to 2020 planning period. Winter peak demand is projected to grow 0.8% per year on average over the same time period. Under the extreme weather scenario, peak demand is higher, but is projected to grow at a slower rate than the normal weather scenario;
- The Company's five-year capital budget is $64.3 million, with spending on mandated and regulatory programs representing 46% of the budget, while spending on growth and discretionary items represent 15% and 39%, respectively;
- The Company's distribution planning process integrates non-wires alternatives, although the Company's pursuit of non-wires alternative solutions requires a more detailed analysis of the benefits and costs, including technical studies that would require additional resources;

- The LCIRP assumes a "business as usual" scenario for energy efficiency, recognizing there is an ongoing Energy Efficiency Resource Standard ("EERS") proceeding that may affect future energy efficiency programs;
- The LCIRP includes known Distributed Generation ("DG") interconnections;
- The key impacts of the Company's LCIRP on environmental, economic, and energy price and supply impact on the state include the following:
    - The Company's competitively sourced energy supply procurement process, consistent with the Settlement Agreement approved by the Commission in Order No. 24,577 (Jan. 13, 2006), ensures energy supply is delivered to customers at the lowest reasonable cost, while considering certain financial and qualitative criteria.

      The Company's renewable energy credit procurement, energy efficiency programs, and net metering program provide economic and environmental benefits to the state by supporting jobs in the renewable energy industry and reducing reliance on sources of electric generation produced outside the state that emit greater amounts of pollutants.[3]
    - The integration of non-wires alternatives into the Company's distribution planning process has the potential to provide economic and environmental benefits to the state through lower costs to the customer and the reduction of peak loads.

3 Specifically, carbon dioxide (CO_2), sulfur oxides (SOx), nitrogen oxides (NOx), particulates, and other pollutants.

These results and findings are consistent with RSA 378:37 *et seq*., as detailed in the following sections.

The remainder of this LCIRP filing is organized as follows.

<u>Section 2:</u> Discusses the Company's demand forecast methodology, including the econometric model used to develop the demand forecast.

<u>Section 3:</u> Describes energy supply options, which are met by the wholesale markets and administered by the ISO-NE. This section describes how energy markets within ISO-NE are structured such that the Company can procure an adequate supply and provide demand resources to meet reliability objectives at the lowest reasonable cost. The LCIRP also details the transmission planning process and the Company's ongoing collaboration with National Grid.

<u>Section 4:</u> Describes the process to ensure the reliable operations of the electric distribution system that provide electric service to Liberty's customers.

<u>Section 5:</u> Describes the role of non-wires alternatives in Liberty's distribution planning and procurement process.

<u>Section 6:</u> Describes the role of energy efficiency and demand side management programs in resource planning and procurement process.

2. Demand Forecast

2.1 Purpose

The planning process begins with a forecast of customer demand, or load. The demand forecast at the system level is based on an econometric model that is developed on both a weather-normalized and weather-probabilistic basis. The demand forecast provides a foundation for the evaluation of energy supply and distribution facilities that follow. The demand forecast is utilized in three types of planning studies:

- Area studies – determine expected circuit overloads and evaluate alternatives for system reinforcements. The studies are generally prepared for a three to 15 year time frame and address specific load areas, including the area supply system, substations, and distribution feeders;
- Interconnection studies – designed to determine the required interconnection facilities and system reinforcements required for specific generation and transmission projects; and
- Annual plan – includes the process steps described Appendix C and results in specific project proposals that have been prioritized and submitted for inclusion in the capital plan.

2.2 Methodology

The Company utilizes a multi-step, top-down / bottom-up process. First, the Company uses an econometric model to forecast Liberty's system summer and winter peak loads (i.e., "bottom-up") for each PSA. The explanatory variables in this model include historical and forecasted economic conditions at the county level, historical peak demand data for each PSA, and a forecast of weather conditions based on historical data from a Concord, New Hampshire weather station. The model also applies certain demographic variables, including employment and number of households. The system seasonal peak forecasts are then split into Eastern and Western jurisdictions using Liberty's township sales information, as well as July and December 2014 peak coincident Eastern and Western PSA percent contributions. Appendix B includes the Company's detailed demand forecast report.

The econometric model is used to simulate the historical and forecasted peak demand for each PSA under normal and extreme weather conditions. The normal weather simulation assumes average weather conditions for each year of the forecast. Normal weather conditions are determined by averaging the weather for the highest peak day of a 20-year historical period. As an average of historical weather, the normal weather forecast becomes a "50/50" case with a 50% probability that actual weather is greater than or less than the forecasted conditions. The extreme weather scenario takes the weather conditions associated with the highest peak day over a 20-year history and applies these conditions to all future years of the forecast. Based on the historical experience, there is only a five percent probability that actual peak-producing weather will be equal to or more extreme than the extreme weather scenario. That is, the extreme weather forecast is a "1 in 20" case.

The peak demand forecast for each PSA incorporates historic energy efficiency savings achieved, since such savings are reflected in the historical usage data employed by the model. The energy efficiency measures are those specifically installed through the NHSaves efficiency programs relating to both residential and non-residential customers. Similarly, the impact of distributed generation installed to date is also included in the historical peak demand. In developing the peak demand forecasts, the forecast assumes that load reductions achieved historically through the Company's energy efficiency programs continue through the time period of the forecast.

Once the forecast is developed, Liberty makes certain "out of model adjustments" to account for known future loads or generation (i.e., "top-down"). Specifically, adjustments are made for new load greater than 300 kW interconnecting to Liberty's distribution system in the near future, or distributed generation greater than 1,000 kW that is expected to interconnect. To the extent that any distributed generation below 1,000 kW occurred in the historical period, it is captured in the historical peak data used to develop regression models and therefore is considered "embedded" in the data.

The PSA growth rates are applied to each of the substations and feeders within the area.

Liberty's distribution planners then adjust the forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planners use the forecasted peak loads for each feeder/substation under the extreme weather scenario to perform planning studies and to determine if the thermal and contingency capacity of its facilities is adequate.

System seasonal peak forecasts are divided into Eastern and Western jurisdictions using town-level sales information, as well as July and December 2014 peak coincident Eastern and Western PSA percent contributions. Separate annual forecasts are estimated for 19 towns in the Company's New Hampshire service territory.[4] The regression equations relate annual town-level kilowatt-hour ("kWh") deliveries to a time trend variable and Cooling Degree Days ("CDD") to predict town kWh load for each forecast year. In order to flatten the change in township usage over the historic period, the time trend variable is expressed as a log function. The system peak day values are allocated to the individual townships by utilizing the annual township sales regression models.

2.3 Results

The results of the demand forecast show that the summer peak, based on normal weather, is projected to increase by an annual average of 1.0% from 2016 to 2031, which is consistent with peak demand growth from 2001 to 2014. Over the five year planning period of 2016 to 2020, the summer peak is projected to grow from 202.4 MW in 2016 to 210.6 MW in 2020.

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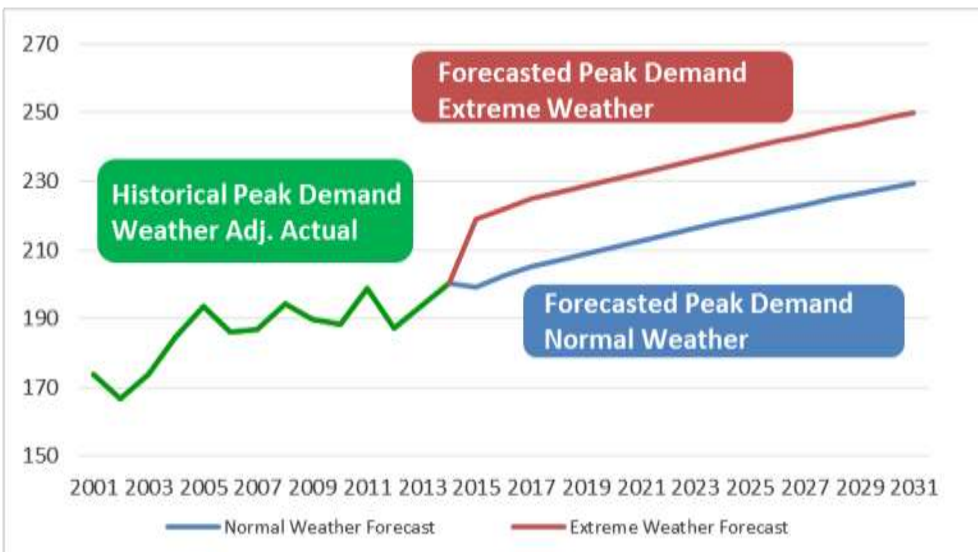
4 The town of Langdon is included in the Acworth forecast and the town of Orange is included in the Canaan forecast, thus generating 19 forecasts for 21 towns.

Summer peak based on extreme weather (1-in-20 winter) is expected to increase by 0.9% from 2016 to 2031. Over the five year planning period, the summer peak is projected to grow from 222.1 MW in 2016 to 230.5 MW in 2020 under the extreme weather scenario.

Figure 2.1 shows the historical and projected growth in peak demand under normal and extreme weather scenarios.

Figure 2.1. Summary of Peak Demand Forecast



3. <u>Energy Supply & Transmission Planning</u>

3.1 Electricity Market Overview

The Independent System Operator New England ("ISO-NE") is the independent, not-for-profit company authorized by the Federal Energy Regulatory Commission ("FERC") to perform three critical, complex, and interconnected roles for the New England region: (1)

wholesale electric grid operation, (2) market administration, and (3) power system planning.[5]

The ISO-NE, with input from the New England Power Pool ("NEPOOL") stakeholder process, is responsible for the administration of the wholesale electricity markets and for ensuring reliability throughout the New England region.

The wholesale electric market consists of energy, capacity, and various ancillary services. For five of the six New England states (excluding Vermont), electric generation ownership is severed from transmission and distribution ownership. That is, electric utilities do not own generation; rather electric generators bid their power into the ISO-NE wholesale market. Load serving entities, such as Liberty, then procure supply from across the region to best meet the demands of their retail customers receiving energy service. As a result, Liberty is actively monitoring the wholesale energy markets to ensure it provides its customers with a reliable and least-cost supply of electric power.

Summary of the ISO-NE Wholesale Market

To maintain the reliable and efficient operation of the New England power system, the ISO-NE undertakes a comprehensive regional system planning process each year. Notwithstanding the region's system improvements, the ISO-NE notes that challenges remain across the 10-year planning horizon for maintaining system reliability, including the following:

5 http://www.iso-ne.com/about/what-we-do/three-roles

- Improving resource performance and flexibility;
- Maintaining reliability and fuel certainty, given the region's increased reliance on natural-gas-fired capacity and the limited availability of fuels necessary to generate electrical energy;
- Planning for the potential retirement of generators; and
- Integrating a greater level of intermittent resources.[6]

The ISO-NE and its stakeholders are modifying the market design, system operations, and planning activities to address these regional strategic planning issues, prepare for changes likely to confront the New England power system, and assess potential system enhancements. These planning activities, which are designed to ensure a reliable and economical power system, take place through an open stakeholder process that includes input from the Planning Advisory Committee ("PAC"). The ISO-NE also receives advisory input through the NEPOOL committee structure on potential changes to the market design, provisions of the Open Access Transmission Tariff ("OATT"), and supporting procedures.[7]

Auctions in the Forward Capacity Market ("FCM") ensure the system has sufficient resources to meet the future demand by paying resources to exist and be available to meet the projected demand for electricity three years out. For the first seven auctions, excess capacity in the region helped keep capacity prices relatively low. The eighth Forward

6 2014 Regional System Plan, ISO-NE, at 1.
7 *Ibid*.

Capacity Auction ("FCA #8") concluded in a small deficit in necessary power system resources, resulting in higher prices to meet consumer demand in New England in 2017–2018. FCA #9 concluded with sufficient resources for 2018–2019 in most of the region, but with a shortfall in Southeastern Massachusetts and Rhode Island. Clearing prices were higher than in previous auctions, reflecting the need for new resources to ensure a reliable supply of power in New England during the capacity commitment period running from June 1, 2018, through May 31, 2019.

According to the ISO-NE, New England's wholesale electricity markets have thus far attracted investment in nearly 15,000 MW of new, efficient, low-carbon-emitting power generation facilities and demand-side assets. Over 12,000 MW more are proposed as of June 2015, of which:

- 66% is natural gas-fired generation;
- 33% is wind projects; and
- The remainder includes projects with other types of fuels.[8]

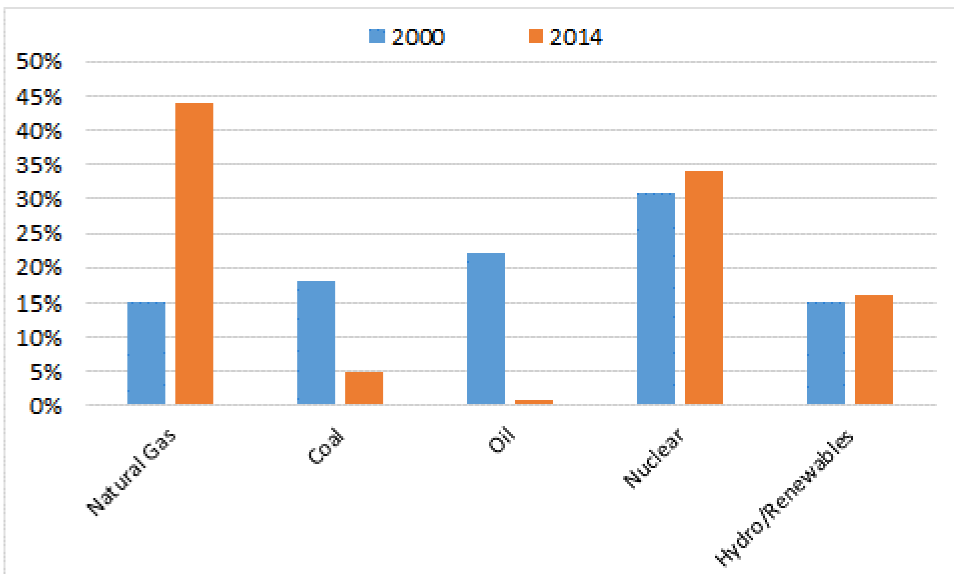
Additionally, as a result of the New England states' goals for energy efficiency and renewable resources, the ISO-NE anticipates that by 2022 energy efficiency and renewables will equal approximately one-third of the region's projected energy consumption.[9]

8 http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix
9 *Ibid*.

Energy Market Prices

In 2014, natural gas accounted for 44% of total electric energy production in the New England region, while coal, oil, nuclear, and hydro/renewables[10] accounted for 5%, 1%, 34%, and 15%, respectively. This compares to a resource mix of 15% natural gas, 18% coal, 22% oil, 31% nuclear, and 15% hydro/renewables in 2000 (See Figure 3.1 below).[11]

Figure 3.1 Percent of Total Electric Energy Production by Fuel Type[12]

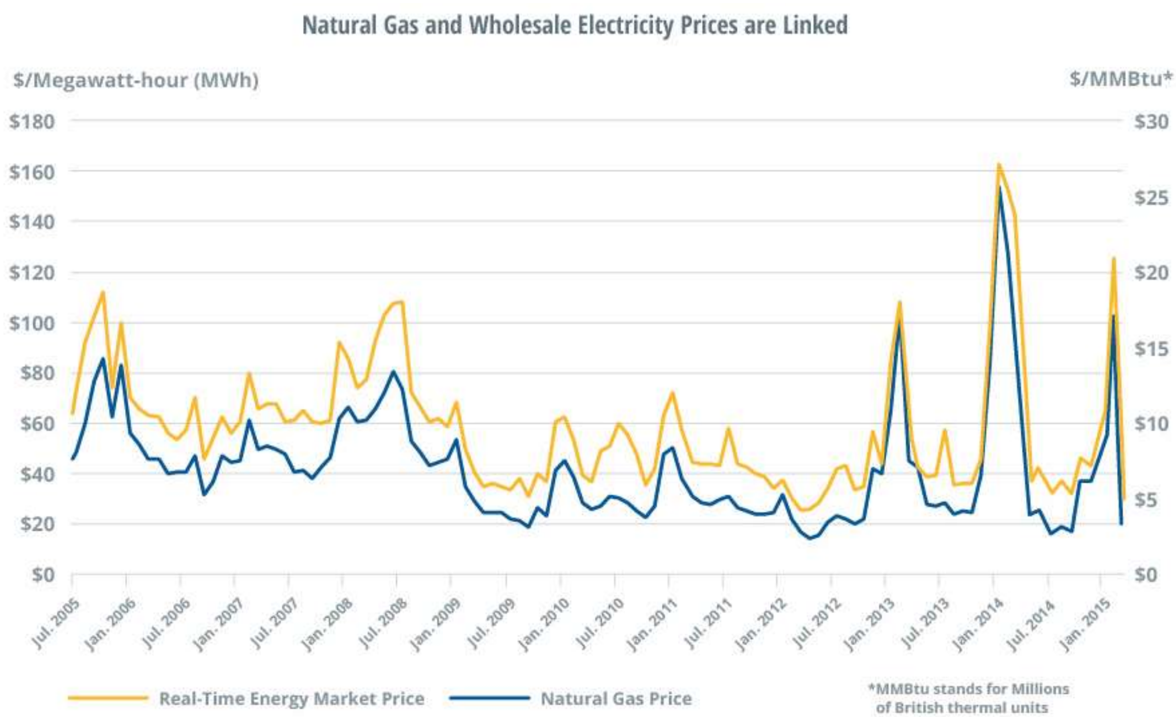


Because a majority of New England's electricity generation is fueled by natural gas, energy market prices in New England closely track movement in natural gas market costs (see Figure 3.2 below). The marginal unit setting the energy market clearing price is most often a natural gas fired generator, and such generating units were the marginal units

10 Including pumped storage.
11 http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix
12 http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix

setting the energy market clearing price during approximately 70% of the hours during 2014.[13]

Figure 3.2. Link between Natural Gas and New England Wholesale Electricity Prices[14]



From 2008 through 2012, the price of natural gas declined significantly in New England with increasing production from the Marcellus Shale and moderate winter weather that resulted in minimal natural gas pipeline constraints. As such, wholesale electricity prices declined simultaneously.[15]

13 ISO New England's Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, at 39-40.
14 Source: http://www.iso-ne.com/about/what-we-do/key-stats/markets
15 http://isonewswire.com/updates/2015/10/30/summer-2015-the-lowest-natural-gas-and-power-prices-since-20.html. In fact, summer 2015 saw the lowest average wholesale power prices since the competitive wholesale electric markets were implemented in 2003.

However, this began to change in the winter of 2012/2013. As pipelines into the region ran at full capacity to meet growing heating needs, New England experienced some of the highest natural gas prices in the country. In 2013, the region spent 54% more in the energy markets as a result of higher natural gas prices. Higher demand for natural gas in the region, combined with pipeline constraints and the increased global price for liquefied natural gas, drove up the price of fuel.

Figure 3.3 below provides the most recent year-over-year wholesale market cost summary and comparison as provided by the ISO-NE internal market monitoring unit's Annual Market Report, released in May of 2015, which reflects the changes in costs experienced over the past year. The trend in wholesale costs to meet the Company's default service requirements over this same period is similar to that depicted below.

Figure 3.3. ISO-NE Wholesale Market Cost Summary[16]

Type	Annual Cost ($ billion)			Average Costs ($/MWh)		
	2013	2014	% Change	2013	2014	% Change
Energy	7.49	8.42	12%	58.14	66.25	14%
Capacity	1.06	1.06	1%	8.20	8.36	2%
Ancillary Services	0.27	0.41	50%	2.12	3.23	52%
Total	**8.82**	**9.90**	**12%**	**68.47**	**77.84**	**14%**

16 ISO New England's Internal Market Monitor, 2014 Annual Markets Report, May 20, 2015, at 3.

3.2 Supply Planning

New Hampshire partially restructured its retail electricity market in 1998, severing generation from distribution (with the exception of Public Service Company of New Hampshire, which owns 1.2 gigawatts, "GW," of generation). As such, most of New Hampshire's electric distribution companies, such as Liberty, do not own generation. Instead, Liberty procures electricity supply for its customers on energy service every six months through a solicitation process that is reviewed and approved by the Commission.

The solicitation, bid evaluation, and procurement process that is used to procure energy service for Liberty's customers complies with a Settlement Agreement approved by the Commission in Order No. 24,577. The Settlement Agreement has been amended multiple times to respond to changes in the wholesale market. The most recent amendment was the result of extreme price volatility in the natural gas and electric wholesale markets experienced during the last two winters. As a result of the Commission's investigation in Docket IR 14-338, Liberty requested, and the Commission approved, a shift in the two six-month solicitation periods from November 1/May 1 to February 1/August 1 to reduce the retail price volatility of the winter period by splitting the two highest cost winter months (January and February) into two separate periods. The Commission approved this change in Order No. 25,806 (Sept. 2, 2015). The Commission later found that Liberty Utilities' most recent solicitation for Energy Service complied with the procedures approved in the Settlement Agreement, that the selection of the winning suppliers was reasonable and appropriate, and that the resulting retail rates were market-based and thus approved the filing. Order No. 25,819 (Sept. 28, 2015). Liberty expects to issue its next solicitation in May 2016 for a six-month energy service supply starting on August 1, 2016.

3.3 Renewables Planning

Liberty, like all retail suppliers of electricity in New Hampshire, is required to meet annual Renewable Portfolio Standards ("RPS") based on its sales of energy service. Liberty's process to comply with the RPS is specified in a Settlement Agreement approved by the Commission in Order No. 24,953 (Mar. 23, 2009). Liberty issues a solicitation for RPS Renewable Energy Certificates ("REC") twice a year around the same time as its energy service solicitations are issued. Liberty contracts for RECs on a short term basis to reflect both the actual or expected energy service sales. This is done to minimize any oversupply of RECs due to migration of energy service customers to a retail choice supplier.

3.4 Transmission Planning

The New England transmission system, while owned by various transmission owning utilities (including National Grid), is subject to ISO-NE's operational, reliability, and planning authority pursuant to the ISO New England Transmission, Markets and Services Tariff ("ISO Tariff"). Because Liberty does not own any transmission facilities, it is a transmission customer of National Grid. As the transmission owner, National Grid provides service through the ISO Tariff. National Grid manages its New England transmission system – its New England facilities that are operated at voltages of 69 kV and up – as a single integrated system, and part of the larger New England transmission system, in order to achieve efficiencies and align processes across its business. It is Liberty's responsibility, as the transmission customer, to provide National Grid with the electrical system information necessary to enable National Grid to fulfill its transmission owner service requirements. The information provided by Liberty to National Grid typically includes electric distribution system peak and off peak loads, power factor, and the actual or estimated impact of distributed generation and demand-management efforts. These parameters are available to both companies and are periodically reviewed and collaboratively utilized.

3.5 Impact Assessment

The Commission-approved processes used to secure both a reliable and competitively sourced supply for its energy service customers and to meet its RPS obligations have been found to be consistent with RSA 374-F and RSA 362-F. As a result, Liberty meets its obligations at the lowest reasonable cost to its customers.

4. **Distribution Planning**

4.1 Introduction

The purpose of this section is to describe Liberty's distribution planning process, including the evaluation of wire and non-wire alternatives to address system deficiencies. This section will also discuss compliance with the Commission's requirements in Docket No. DE 12-347, the proceeding in which the Company's most recent LCIRP was reviewed and approved.

The goal of distribution planning is to provide adequate capacity for safe, reliable, and economic service to customers with minimal impact on the environment. To achieve that goal, the distribution system is planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal" or "N-0") and first contingency conditions ("N-1") incorporating existing planning criteria. Planning engineers apply tools and criteria to evaluate the capacity and performance of the system, while harnessing the capability of existing facilities that are under-utilized before constructing new facilities. When new facilities are required to address system needs, the Company has initiated a process to evaluate non-wire alternates in addition to more traditional wire alternatives, as circumstances permit.

Since the purchase of the New Hampshire electric assets from National Grid in 2012 and its last LCIRP filing in Docket No. DE 12-347, Liberty has refined its distribution planning criteria to better fit its strategy and scale of facilities. Liberty now has a Distribution Planning Department and engineering staff to support all of its planning requirements. A summary of Liberty's distribution planning criteria and strategy are included as Appendix D to this LCIRP.

4.2 Background

In 2012, Liberty purchased the New Hampshire electric assets from National Grid. During the initial transition period, Liberty employed the National Grid distribution planning methodology and criteria and, under an arrangement pursuant to a transition services agreement, Liberty used National Grid's engineering staff to support most of its planning requirements. Liberty has now transitioned to its own distribution planning methodology and criteria and has its own engineering staff to support all of its planning requirements.

For purposes of distribution planning it is important to distinguish between the terms "supply system," "supply line," "distribution system," and "distribution line."

- A supply system is a collection of electrical facilities including transformers and lines that transports power between substations. The objective of a supply system is to move power from one substation to another for use at its final destination. From a distribution perspective, Liberty's supply system in New Hampshire operates at voltages below 23 kV down to 13.8 kV, and the voltage is not regulated. Lines 34.5 kV and above are considered to be transmission facilities. All of Liberty's supply system is either 23 kV or 13.8 kV.
- Supply lines may be overhead or underground and operate within the voltage levels described above. At least two supply lines usually serve any one substation, providing redundant electric service if one line fails.
- A distribution system is a collection of overhead and underground lines that route the power from the substation to customers for direct use. Transformers change voltage at substations from transmission or supply lines to primary distribution levels, which range from 13.2 kV to 2.4 kV. Distribution voltages are regulated for utilization within specified ranges in accordance with Puc 304.02. Additional

transformation occurs along each distribution line to convert voltage to a useable value, such as 120 or 240 volts.

- A distribution line is a single radial feeder that can serve up to 12 MVA of load. The main line of each feeder branches into several main routes that end at open interconnection points. Here, the feeder may be interconnected to an adjacent circuit to facilitate manual reconfiguration in order to isolate faulted sections of the line and to "switch before fixing" to quickly restore customers. Each feeder is usually divided into several switchable elements. During emergencies, segments can be reconfigured to isolate damaged sections and re-route power to customers who would otherwise have to remain out of service until repairs were made. All individual distribution lines in an area constitute a distribution system.
- Liberty's distribution system is comprised of supply (or sub-transmission) and distribution lines shown on Figure 4.1.

Figure 4.1. Supply and Distribution Lines

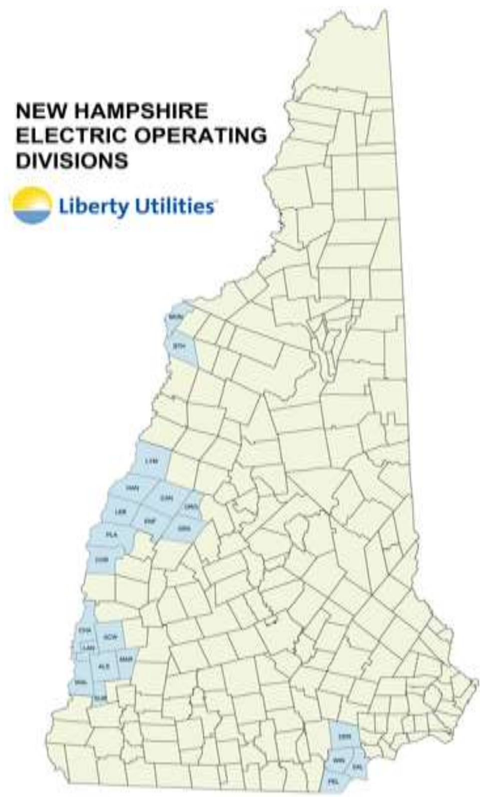
Voltage	Line Miles
13.2 kV Distribution	1,081
2.4 kV Distribution	13
13.8 kV Sub-Transmission (Supply)	15
23 kV Sub-Transmission (Supply)	**13**

4.3 Overview of Distribution System

Liberty provides electric service to the communities of Acworth, Alstead, Bath, Canaan, Charlestown, Cornish, Derry, Enfield, Grafton, Hanover, Langdon, Lebanon, Lyme, Marlow, Monroe, Orange, Pelham, Plainfield, Salem, Surry, Walpole, and Windham (see Figure 4.2)

Distribution Substations

Figure 4.2 Service Area



The distribution substations within Liberty's territory are a mixture of stations with one, two, three, or more transformers. A typical Liberty substation involves 23/13.8 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Distribution substations supplied by the 115 kV circuits are jointly owned between Liberty and National Grid.[17] Currently, Liberty and National Grid maintain six distribution substations[18] containing seven power transformers in the Liberty service territory.

17 The Charlestown substation is 46/13kV, but is jointly owned.
18 Golden Rock, Pelham, Slayton Hill, Mt Support, Michael Avenue, and Charlestown.

Sub-Transmission System

Liberty's sub-transmission system is designed to provide adequate capacity between load centers at reasonable cost and with minimal impact on the environment. It provides supply to distribution substations as well as large three-phase customers and consists of those parts of the system that are neither bulk transmission nor distribution. The voltages for the sub-transmission system include 23 and 13.8 kV. The sub-transmission system is designed in an open loop system and generally provides a redundant supply for distribution substations. Currently, Liberty maintains nine sub-transmission lines.[19]

Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses on the branch circuits. The feeder may be interconnected to an adjacent circuit to facilitate manual reconfiguration in order to isolate faulted sections on the line and to "switch before fixing" to quickly restore customers. Each feeder is usually divided into several switchable elements. During emergencies, segments can be reconfigured to isolate damaged sections and re-route power to customers who would otherwise have to remain

19 Of the nine sub-transmission lines, four are jointly maintained by National Grid and Liberty.

without service until repairs were made. Currently, the Liberty distribution system is comprised of approximately 40 feeders ranging from 2.4 kV to 13.2 kV.

4.4 Distribution Planning Process

Liberty's distribution system in New Hampshire is, in general, summer peaking and summer limited. Liberty conducts an annual capacity planning process with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the system to respond to contingencies that might occur. The distribution planning process is illustrated in Appendix C and includes the following tasks:

- Forecast peak demand using an econometric model, which includes: (a) weather adjustment to reflect recent actual peak loads; (b) projected customer and demand growth; (c) incorporation of historical energy efficiency savings; (d) incorporation of DG; and (e) incorporation of nontraditional demands, such as electric vehicles;
- Review and evaluate system performance, which includes: (a) capacity loadings on each sub-transmission line, substation transformer, and distribution feeder for forecasted peak loads vs. ratings; (b) reliability; (c) asset condition; and (d) power quality and voltage performance;
- Implement strategies for Planning Criteria, Area Strategy, and Asset Strategy;
- Identify system deficiencies that need addressing to ensure safe, reliable, and economic service to customers, which includes consideration of system flexibility in response to various contingency scenarios;

- Identify wires and non-wires solutions, reflecting the guidelines for non-wires solutions;
- Perform evaluation of wires and non-wires solutions;
- Decide on solutions that best meet distribution planning goals, informed by economic, environmental, and health-related impacts; and
- Develop proposals for system enhancement projects.

Prepare Demand Forecast

As described in Section 2.0, the planning process begins with a forecast of demand, or load. The demand forecast at the system level is based on an econometric model that is developed on both a weather-normalized and weather-probabilistic basis. The explanatory variables in the model include historical and forecasted economic conditions at the county level, historical peak load data for each PSA, and a forecast of weather conditions based on historical data from a Concord, New Hampshire weather station. Significant known or planned load additions and demand side management ("DSM") programs are incorporated into the load forecast.

Evaluate and Identify System Deficiencies

Forecasted PSA growth rates are applied to each of the substations and feeders within the area. The distribution planner then adjusts the forecasts for specific substations and feeders to account for known spot load additions or subtractions, as well as for any planned load transfers due to system reconfigurations. The planner uses the forecasted peak loads for each feeder/substation under the extreme weather conditions to perform planning studies and to determine if the thermal and contingency capacity of its facilities is adequate. The Company evaluates its system performance based on the following criteria:

- Capacity – Planning criteria for normal and contingency load serving requirements are applied in concert with the thermal ratings of the facilities to identify capacity violations. Specifically, the distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact (normal conditions or "N-0") and N-1 first contingency conditions incorporating existing planning criteria.
- Asset condition – Asset condition assessments involve monitoring electric equipment periodically, and using the data collected from those inspections to determine the condition of each asset and if any mitigation is required to repair or replace the equipment.
- Voltage performance – The normal and emergency voltage to all customers shall be in line with limits specified by the State of New Hampshire and within the limits of ANSI C84.1-2006. The ultimate goal is to plan and operate the system such that delivery voltages are within the limits.
- Reliability – To measure system performance, Liberty utilizes several performance measures of reliability. These reliability indices include measures of outage duration, frequency of outages, system availability, and response time.

Liberty's target is for its annual SAIDI and SAIFI[20] metrics to be below the five year rolling average, excluding severe weather events.

A distribution system that has adequate capacity is one in which all customers, in the event of an outage, can be restored in a timely manner through system reconfiguration by means of electrical switching or automatic reclosing schemes. Adequate N-0 and N-1 capacity on power transformers, sub-transmission lines, and feeders are key design and operation objectives. The Company considers these criteria when identifying deficiencies with existing distribution systems and identifying improvements to address the identified deficiencies. These criteria are described in the Company's Distribution Planning Criteria, summarized in Figure 4.3 below (see Appendix D for a more detailed summary).

Liberty has reviewed and refined its planning criteria since the transition from National Grid. The refined planning criteria are summarized in Figure 4.3. The planning criteria refinements, such as lowering the equipment rating "take action" limit from 100% to 75% on transformers and feeders, reflect Liberty's philosophy to strategically plan well ahead of system upgrade need dates. Additionally, these refinements better reflect Liberty's smaller equipment, facilities, and resource base, as well as increased customer focus.

20 The system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI"), as defined further in Section 4.6.

Figure 4.3. Summary of Liberty Utilities Distribution Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	• Loading to remain within 90% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced.	• Loading to remain within 75% of normal rating. • Voltage at customer meter to remain within acceptable range. • Circuit phasing is to remain balanced. • Each feeder should have at least three feeder ties to adjacent feeders.
N-1 Contingency, which results in facilities operating above their Long Term Emergency (LTE) rating but below their Short Term Emergency (STE) rating.	• Load must be transferred to other supply lines in the area to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 36 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby transformers to within their LTE rating. • Repairs or installation of Mobile Transformer expected to take place within 24 hours. • Evaluate alternatives if more than 60 MWhr of load at risk results following post-contingency switching.	• Load must be transferred to nearby feeders to within their LTE rating. • Repairs expected to be made within 24hrs. • Evaluate alternatives if more than 16 MWhr of load at risk results following post-contingency switching.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables	• Loads must be reduced within 15 minutes to operate within their LTE rating	• As Needed – Typically 15min for OH conductors and 1-24 hours for UG cables

Environmental Training and Guidance provided by the Environmental Engineer on a periodic basis. The training includes process steps for identifying environmental considerations related to project and work order preparation. During the planning, design, and estimating stages, it is the responsibility of the Engineering Department to identify and address any environmental considerations related to project or work order activities. The environmental evaluation assesses certain environmental conditions described in the Planning Criteria through discussions with the property owner, review of site plans, and/or field observations. A checklist included in the Planning Criteria is used as an aid in identifying and documenting any potential environmental concerns.

Based on the results of sample areas (expanded to the overall system), Liberty has estimated that additional facilities may be required to meet the new criteria over the next 15 years. The estimates are summarized in Figure 4.4.

Figure 4.4. Estimate of Additional Facilities to Meet the New Criteria

Asset	Additional Quantity Required
Transformers (at existing or new substations	2
Sub-Transmission Lines	0
Distribution Feeders	2

The new planning criteria will be applied initially to new installations and/or significant rebuilds and will be phased in over the 15 year horizon to coordinate with substation asset replacement requirements as existing assets reach the end of their useful reliable and economic life.

Application of these criteria will result in somewhat less load at risk than previous criteria, which generally limited load at risk to between 4 and 20 MW pending the installation of a mobile substation. Therefore, it is expected that the capital budgets will increase from historical levels for a given load growth rate. The capital cost associated with meeting the new criteria for both normal and N-1 contingency conditions are shown in Figure 4.5 below.

Figure 4.5. Cost Estimate of Additional Facilities to Meet the New Criteria

Capital Category	Capital Cost ($million)
Substation Scope	$13.5
Distribution Line Scope	$3.0
Total Cost	$16.5

Prioritize System Deficiencies

System deficiencies are evaluated and prioritized based on two criteria: (1) the impact of the system deficiency (including the number of customers and demand impacted by the deficiency), the loading (or percent of rated capacity) on the distribution facilities, and the safety and environmental impact; and (2) the likelihood that such impacts will occur, ranging from 1 in 100 years to each year. Liberty is in the process of transitioning to this ratings system from the system used previously. Liberty's prioritization of the system deficiencies is illustrated on page 3 of Appendix C. This prioritization process was developed recently and will be implemented in the next budgeting cycle (i.e., 2017-2021).

Identify Wires Solutions

Wires solutions are Company initiatives that address system deficiencies through construction of new distribution facilities. Wires solutions are evaluated in the form of individual project proposals that are prioritized and submitted for inclusion in future capital work plans. Projects in the load relief program are typically new or upgraded substations and distribution feeder mainline circuits. Other projects in this program are designed to improve the switching flexibility of the network, improve voltage profile, or to release capacity via improved reactive power support. Wires solutions are evaluated based on the project's scope, schedule, and overall cost effectiveness. Wires solutions may also address asset replacement needs and reliability opportunities in conjunction with their impact on capacity.

Identify Non-Wires Alternative ("NWA") Solutions

Non-wires alternative ("NWA") solutions are initiatives that may reduce, avoid, or defer the need for investment in distribution facilities through actions that reduce peak demand via targeted energy efficiency and load control programs, or increase peak generation via distributed generation. As described more fully in Section 5, NWAs include energy efficiency programs, demand response and load control programs, and DG programs that complement and improve operation of existing transmission and distribution systems, and that individually or in combination defer the need for upgrades to the transmission and/or distribution system.

The Company has developed guidelines for the consideration of non-wires alternatives in the distribution planning process. The goal is to seek the combination of wires and non-wires alternatives that best solves capacity deficiencies in a cost effective manner considering the net potential benefits and risks, as well as economic, environmental, and health impacts (see Section 5 for a summary of the Company's risk evaluation). As part of this process, an analysis is conducted at a level of detail commensurate with the scale of the problems and the cost of potential solutions. Non-wires alternatives are screened for initial feasibility, according to the following criteria:

- Distribution deficiency is not based on asset condition;
- Distribution deficiency needs to be addressed in no less than two years, allowing for development of a NWA solution;
- Wires solution, based on engineering judgement, will likely cost more than $0.5 million, providing sufficient cost savings to evaluate and implement a NWA solution;
- Wires solution will likely start construction at least 24 months in the future, providing sufficient time to evaluate and implement a NWA solution; and
- A NWA solution would be for less than 20% of the total load in the area of the distribution deficiency.

This screening criteria results in a threshold of acceptance for non-wires projects stemming from the planning process that seeks to maximize the in-service life and utilization of existing assets. A non-wires solution is often determined to be infeasible or noncompetitive when one wires solution can address a combination of issues that includes asset condition. For example, wires solutions typically address a combination of load capacity, reliability, and asset condition issues. As with wires solutions, specific non-wires solutions are evaluated based on the project’s scope, schedule, and overall cost effectiveness.

4.5 Tools to Evaluate the Distribution System

A variety of tools enable engineers to evaluate fault duty, coordination of protective devices, loading on all facilities, and voltage on all electrical system elements. The actual electrical configuration can be modeled in these tools, which allow the simulation of various system conditions and subsequent analysis. The primary modeling and analysis application tools are:

- The SynerGee Electric 5.1 load flow program models supply system and distribution feeders. It also assists in determining the short circuit duty at all sub-transmission and distribution facilities.
- The Geographical Information System ("GIS") geographically maps supply and distribution lines and is used to determine customer demands at a service point level and/or a supply transformer level.
- The Supervisory Control and Data Acquisition ("SCADA") system provides real time loading and voltage data for monitored facilities and provides historical load and voltage data for various electrical facilities.
- The Responder System serves as an outage management system and provides real time outage information and a consolidation and statistical analysis of reliability data.
- The Quadra system serves as a work management tool, as well as an estimation tool.

Figure 4.6 below compares the evaluation tools and applications used by Liberty with those used previously by National Grid:

Figure 4.6. Evaluation Tools: Liberty Utilities vs. National Grid

Application	Previous NG	Existing LU
Load Flow	PSSE	SynerGee Electric 5.1
Feeder Analysis	CYMEDIST	SynerGee Electric 5.1
Circuit Protection	ASPEN /CYMETCC	SynerGee Electric 5.1 / Lighttable
Mapping/GIS	Smallworld	ArcMap
Energy Management	ABB	Telvent Oasis / Responder Explorer
Plant Information	Power Plant / STORMS	Great Plains
Circuit Loading	FeedPro	Telvent Oasis
Peak/Min Loadings	RAPR	Telvent Oasis
Interruption Analysis	IDS	Responder Archive

4.6 Reliability Metrics

Since the total system is involved in supplying the customer, ensuring an acceptable reliability of service to all customers requires designing the supply and the distribution systems in an integrated manner, taking into account both capacity limitations and reliability of service initiatives to limit the interruption of energy delivery. The metrics that measure service reliability are the system average interruption frequency index

("SAIFI") and the customer average interruption duration index ("CAIDI"). The product of these two indices is the system average interruption duration index ("SAIDI") per customer served. The Company measures its reliability performance using SAIDI and SAIFI, as required by the Commission. These indices are mathematically calculated as follows:

SAIFI= Number of Customer Interruptions ("CI") / Number of Customers Served ("CS")

SAIDI= Customer Interruption Durations ("CMI") / Number of Customers Served ("CS")

Where:

CI = Customers Interrupted

CMI = Customer Minutes Interrupted

CS = Customers Served (averaged over a period of time, such as month or year)

Liberty employs a five year rolling average to determine annual targets for both SAIDI and SAIFI, excluding major storm events. The worst performing facilities are then targeted for reliability improvements.

The primary causes of distribution system-related outages in New Hampshire are tree contacts, equipment deterioration, and lightning. To limit the number of customers affected by these outages the Company has implemented several infrastructure improvement programs that includes: (1) fast feeder patrols,[21] (2) an inspection and maintenance ("I&M") program, (3) lightning protection, (4) a recloser program, (5) bare conductor replacement, (6) underperforming area mitigation, and (7) distribution automation ("DA")/smart grid, among others.

Infrastructure Improvement Program

Liberty's Infrastructure Improvement Program includes the following initiatives:

- Inspection and Maintenance Program ("I&M") – The inspection and maintenance program identifies overhead equipment, including cutouts, crossarms, insulators, poles, guys and anchors, and switches that are at the end of its useful life and in need of replacement. Lightning protection upgrades include the installation of arresters, grounding, and equipment bonding. The I&M program is augmented with infrared inspections of line and substation equipment, substation equipment visual and operational inspections, and patrols of distribution supply facilities.

21 As part of Liberty's I&M and Reliability awareness and proactive approach, the Company implements fast feeder patrols on the feeder mainlines to identify reliability issues before they pose a larger threat on the system. These are performed twice a year with patrols planned in the Spring and Fall.

- Animal Intrusion Program – Additional actions include application of wildlife protective devices and substation animal fencing to limit animal intrusion on distribution equipment and at substations.
- Overloaded Transformer Program – This program targets replacement of overloaded transformers prior to summer peak loading.
- SCADA / Distribution Automation Program – Other reliability initiatives include improving reliability in distribution system areas that have historically underperformed by implementing new SCADA devices with communication abilities to improve response time to outages. Applications for automatic restoration of load from adjacent facilities are also considered.
- Lebanon Area low voltage mitigation program – Voltage mitigation is planned for those areas in Lebanon that have experienced issues with low voltage. Mitigation includes the installation of capacitor banks and voltage regulators, load balancing, and/or reconductoring.
- Underground Residential Development ("URD") refurbishment program – This program recommends URD cable for replacement and/or cable injection. Cables that meet the failure frequency criteria are replaced.
- Underground cable replacement program – This program recommends replacement of Company-owned underground cable based on poor operating history. Typically all cable over 60 years of age is replaced and cables that have experienced three faults in a five year period are targeted for replacement. Direct buried cables are replaced with duct lay cables.

- Worst performing feeder program – This program mitigates reliability concerns on distribution feeders by reporting details regarding the three most under-performing feeders, based upon the SAIDI performance for the preceding three years.

Reliability Enhancement Program

Liberty's Reliability Enhancement Program includes the following initiatives:

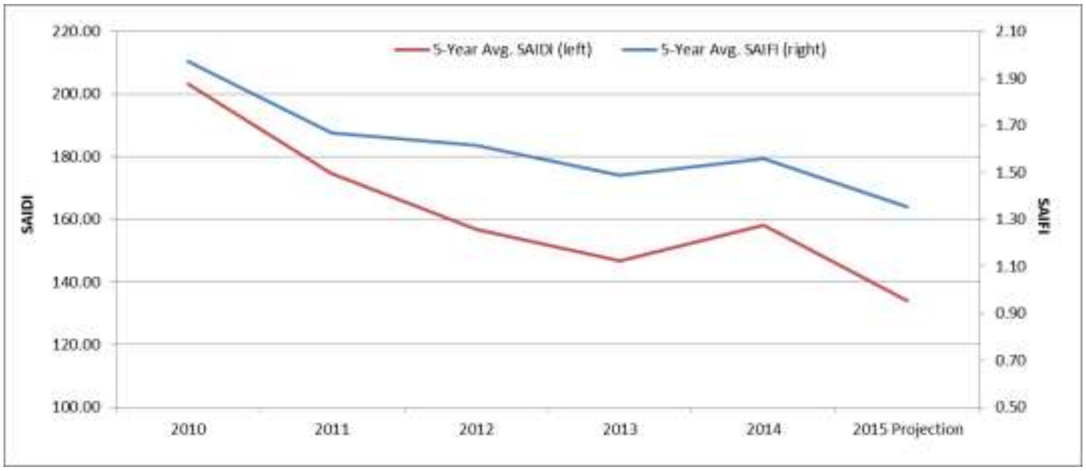
Bare conductor replacement – Spacer cable is installed in areas prone to tree outages that are too costly to rely on vegetation management practices alone to mitigate feeder lockouts. The application of spacer cable (a covered conductor resistant to tree related outages) significantly improves mainline circuit performance during windy and stormy conditions and affords protection against incidental tree-conductor contact at the end of the trim cycle, as well as contact resulting from branches falling from above the trim zone.

- Single-phase recloser and trip saver program – Single-phase reclosers and "Trip Saver" cutouts target circuit segments that would realize reliability benefits from single-phase tripping and reclosing, as well as isolating faults down to the smallest single-phase segment possible. These devices are designed to interrupt circuit segments following a transient or temporary fault condition and then automatically restore the segment after a short period to allow the fault to clear. These devices not only improve reliability of service, but also avoid the cost of dispatching a troubleshooter or line crew to the scene to replace the fuse.

The recloser program allows for the installation of automatic switching devices at selected locations to isolate faulted feeder sections, which can limit the number of customers affected by a fault on the electric distribution system. Liberty uses single-phase reclosing devices to provide mitigation against transient faults as well as limit the number of customers impacted for permanent faults. Replacement of mainline bare conductor with spacer cable has proved highly beneficial. Spacer cable is an overhead primary distribution system that consists of covered conductors held in a close triangular configuration by spacers that are supported by a messenger and attached to a bracket on a pole. Spacer cable installations are recommended in heavily treed areas to mitigate the potential for outages caused by incidental contact of tree limbs to the primary conductors. In some instances, it may be possible to use tree wire on crossarms as a lower cost alternative to spacer cable.

As shown in Figure 4.7 below, Liberty's reliability performance improved over the last five years, as demonstrated by the decline in SAIDI and SAIFI metrics since 2010.

Figure 4.7. Calendar Year Electric Reliability Trends, 2010 – 2015



4.7 Demand-Side Resources

Demand-side resources can be broadly defined as systems and controls in customer facilities that allow customers, or the utility, to reduce or control their use of energy. These generally consist of energy efficiency measures, demand response efforts, distributed generation, energy storage, and load controls. Energy efficiency measures generally produce savings whenever a particular load is running, while renewable distributed generation, such as wind and solar photovoltaic ("PV"), provides energy on an intermittent and uncontrollable basis. These types of resources are therefore considered passive resources. Other demand resources are dynamic and can be called on and utilized when economically justified; these are considered active demand resources.

Active demand resources, coupled with incentives such as demand response payments or dynamic time-of-use rate design, can create opportunities for customers to benefit from time-specific reductions in energy consumption and/or a shift in the hours that energy is consumed. Through the use of active demand resource technologies and appropriate incentive mechanisms, retail costs can more closely reflect the time varying cost to produce and deliver electricity, and result in behavior changes that create higher system efficiencies. Generally, this approach works in conjunction with smart metering systems that measure consumption data at regular intervals and provide such data directly to the customer.

As described previously, significant known or planned DSM programs, as well as DG installations and the Company's NHSaves energy efficiency programs, are incorporated into the load forecast and the Company's distribution planning process.

4.8 The Link Between Demand Response and Planning

As of June 1, 2010, demand response resources participate on a comparable basis with generation in the regional FCM administered by ISO-NE. Such resources are able to compete with generation and imports, allowing New England to meet its resource adequacy requirements. On June 1, 2012, ISO-NE implemented changes to the demand response program to comply with FERC Order 745. FERC Order 745 requires active demand resources to be fully integrated into the competitive energy markets administered by ISO-NE. As a result of *Electric Power Supply Ass'n v. FERC*, 753 F.3d 216 (D.C.Cir. 2014), in which the court vacated FERC Order 745, the integration of demand response resources into the ISO-NE markets has been postponed until after a decision by the U.S. Supreme Court is rendered. ISO-NE has announced it will delay full implementation of demand resources until after this decision is reached. If the U.S. Supreme Court affirms

FERC Order 745, active demand response resources will be treated on an equivalent basis with other generating resources. The development and ownership of active demand response resources will then be based on market incentives as perceived by the developers of such resources. The impact of these resources on Liberty's distribution system will be dependent on the response by these resources to market signals and a decision by the U.S. Supreme Court.

The Company is considering screening targeted demand response programs into its alternative analysis for system upgrades going forward, potentially leveraging the increasing amounts of demand response resources participating in the FCM and energy markets.

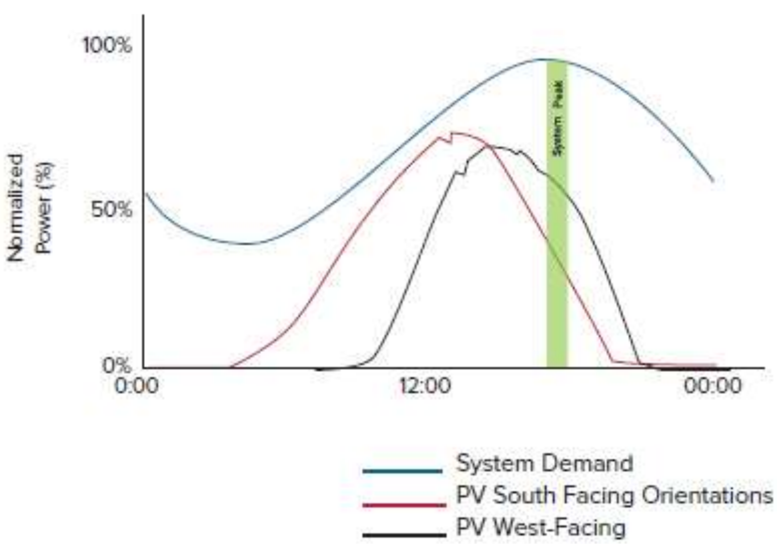
4.9 Incorporation of DG Facilities into Distribution Planning

Liberty has experienced a significant increase in the amount of DG being interconnected to its distribution system through the installation of customer-sited generation.[22] The decision to install and run DG systems is made by customers based on economic, environmental, and operational drivers. Because the Company does not control and cannot be assured of the development or operation of specific DG systems, their impact on system planning is typically experienced after they are in place. Once in place, the Company assumes DG output will continue in its future load projections, while at the same time recognizing its obligation in some cases to provide standby service to customers with DG systems.

22 Utility-owned distributed generation is discussed in Section 5.

The majority of the newer DG systems are renewable photovoltaic ("PV") and wind generation systems. The output of these systems is intermittent and, in general, uncontrollable. PV systems typically offer peak reductions during summer peaks in the range significantly below their ratings, because summer peaks typically occur in the mid-afternoon on the hottest days when the sun is not at the optimal angle and PV panels are less efficient due to ambient temperatures. Figure 4.8 below, as published in a 2013 study from the Rocky Mountain Institute, illustrates this effect:

Figure 4.8. Illustrative Example of the Effect of PV positioning on System Peak[23]



PV typically does not impact winter peak loads, because winter peaks occur in the evenings. Wind resources are also highly variable and may not impact peak loads the Company expects to experience at any given location due to this variability. It is likely

23 Source: Rocky Mountain Institute, "A Review of Solar PV Benefit and Cost Studies," 2nd Edition, September 2013, at 30.

that additional combined heat and power generation may be installed as fuel prices increase and technologies become more mature. However, in many cases such systems run coincident with thermal requirements that are heavily weighted towards the winter months and therefore may not be able to significantly impact summer peak loads. To the extent that DG does impact peak loads, the Company incorporates their historic output into system planning going forward through the distribution planning process discussed in Section 4.4.

The interconnection process for customers to install and run DG in parallel with Liberty's distribution system is dependent on the DG system's size and technology. DG systems with power ratings of 100 kW or less may utilize a simplified application process to facilitate interconnection with the Company's electric power system. Larger DG systems proposing to interconnect with the Company must undergo a more robust application process and must supply sufficient technical information to allow the Company to determine the scope and cost of any potential modifications to the Company's distribution system required in order to accommodate the DG system. This typically requires an engineering study performed by the Company at the DG developer's cost. Safety, system operation and protection, and service quality are the Company's primary consideration in such studies. For larger DG systems, the Company takes into consideration such parameters as voltage and frequency fluctuations, protective device coordination, available fault duty impact, potential for islanding, and ability to automatically and manually isolate the DG from the system.

4.10 Smart Grid

RSA 378:38, IV requires a utility's LCIRP to include an assessment of "Smart Grid" technologies. For the purposes of this LCIRP filing, Liberty defines smart grid technologies as digital technology that allows for two-way communication between the utility and its customers, and the application of computer-based remote control and automation technologies to electric transmission and distribution systems.[24] Smart Grid consists of controls, computers, automation, and new technologies and equipment working together, which respond digitally to quickly changing electric demand conditions.[25]

Smart grid technologies consist of grid-facing (i.e., interfacing primarily with the utility's distribution system) and customer-facing (i.e., interfacing primarily with customers) technologies and applications. These include advanced digital versions of investment currently in place, such as meters, as well as newer technologies to provide customers information and tools to control energy usage. "Smart grid" technologies also include the communication network and systems to automate and control the technologies and applications.

24 As defined by the U.S. Department of Energy's definition of "smart grid." *See*, U.S. Department of Energy, http://energy.gov/oe/services/technology-development/smart-grid, and https://www.smartgrid.gov/the_smart_grid/smart_grid.html.

25
…..
.0https://www.smartgrid.gov/the_smart_grid/smart_grid.html.

A 2011 report by the Electric Power Research Institute ("EPRI") estimated that, industry-wide, smart grid investments could generate 2.8 to 6.0 dollars in benefits for every dollar in net investment (that is, above the investment needed to maintain the current system and meet electric load growth). However, total industry costs of a fully implemented Smart Grid were estimated to be between approximately $340 billion and $475 billion, or approximately $17 to $24 billion per year over the next 20 years.[26] Accordingly, although smart grid technologies could provide significant benefits, the substantial investment required to achieve those benefits must also be carefully considered.

Liberty evaluates grid-facing smart grid technologies such as remote sensors, reclosers, and other distribution automation technologies using the same distribution planning and evaluation process and criteria described in Section 4.4 above.

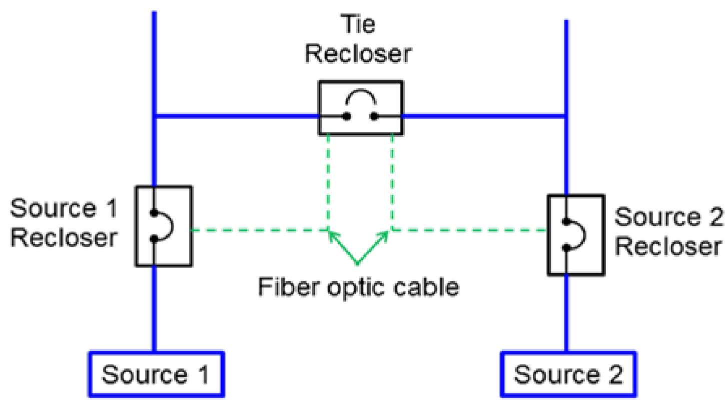
For example, as part of the REP/VM Program, Liberty has installed Vyper ST reclosers with remote control and monitoring capabilities in areas that are suitable for single phase reclosing and/or on existing reclosers that currently lack the ability to remotely control or monitor. The existing reclosers being replaced are typically of an older style and oil filled.

As part of the New Enfield Supply project in 2013, Liberty installed a high speed automatic source transfer switching scheme based on three new Vyper ST reclosers

26 *Estimating the Costs and Benefits of the Smart Grid: A Preliminary Estimate of the Investment Requirements and the Resultant Benefits of a Fully Functioning Smart Grid*, EPRI, 2011 Technical Report, at 1-4.

incorporating a Main-Tie-Main-Source transfer scheme, as illustrated in Figure 4.9 below.

Figure 4.9. Enfield Main-Tie-Main-Source Scheme



The main-tie-main voltage loss transfer scheme employs peer-to-peer communications utilizing a fiber optic communication path between the three recloser controls.

DNP3 via Telemetric RTM II Radio allows remote monitoring and control from Liberty's SCADA system.

Liberty has also installed Grid Sentry GS-200 sensors for continuous measurement of current and line temperature as well as the identification of fault locations on the distribution system.[27]

The GS-200 provides the following functionality: (1) measurement of RMS line current and conductor line temperature, (2) reporting of occurrences of fault currents, and (3)

27 *See*, http://gridsentry.us/index.php?option=com_content&view=article&id=7&Itemid=8

indications of line-out condition. Together, the Grid Sentry GS-200 and communications network provide a high-performance platform to supply information that allows a utility to reduce power losses (and therefore costs), increase the efficiency of the distribution grid, and improve knowledge of outages and their locations, thereby bringing the benefits of the Smart Grid to the Company's distribution control center and its customers.

Other types of smart grid investment may require regulatory changes. For example, some smart grid technologies rely on innovative rate structures (i.e., time of use rates), which would require approval through additional regulatory proceedings. The Commission has opened an investigation into Grid Modernization with the objective of addressing many of the broad issues that are also covered under the umbrella of "smart grid."[28] Liberty has submitted comments in this investigation and will continue to be an active participant as this investigation progresses.

4.11 Capital Investment Plans

System capacity, performance, and reliability improvement capital projects are identified as a result of one-off studies and the annual capacity planning process. The adopted solutions are cash flowed by year and entered into the five-year capital investment plan along with other capital initiatives such as new business, public requirements, response to damage and failure, and other mandatory category projects. The five-year plan is then optimized according to project need, risk management, and availability of resources.

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28 *See*, the State of New Hampshire Public Utilities Commission, Docket No. IR 15-296, *Electric Distribution Utilities Investigation into Grid Modernization*, Order of Notice, July 30, 2015.

Once initiated, multi-year projects are typically progressed to completion with their system solutions incorporated into current and future studies. The annual budget of capital projects greater than $100,000 is filed with the Commission as part of the E-22 filing required pursuant to Puc 308.07.

Figure 4.10 summarizes the Company's five-year capital investment plan totaling $64.3 million, and provides the definition for each of Liberty's budget categories.

Figure 4.10. Summary of 5-Year Capital Investment Plan and Budget Category Definitions

Category	2016-2020 Capital Budget ($)	2016-2020 Capital Budget (%)	Project Prioritization Category	Definition
Mandated	$15.6	24%	Mandated / Impending regulatory obligations / Damage/Failure Facilities relocations	Programs that are required by Statutes, Codes, etc. that have limited, if any, discretionary component relative to meeting a prescribed program. These programs would be related to specific obligations that have been imposed on the utility to carry out the project
Growth	$9.7	15%	Growth	Capital needed to support servicing growth in the customer base
Regulatory Programs	$14.1	22%	Regulatory programs with mechanisms	Programs such as the Bare Conductor Replacement and Recloser/Trip Saver Programs.
Discretionary	$24.9	39%	Discretionary projects	All other programs with a business case justification
5-Year Total	$64.3	100%		

5. <u>Non-Wires Alternatives T&D Integration Process</u>

5.1 Introduction and Background

The Commission ordered the Company "to provide a more comprehensive discussion of how Liberty assesses non-wires alternative in its distribution planning" and to "explain in greater detail, how demand- and supply-side options for distribution planning are integrated by Liberty as part of its planning process." Order No. 25, 625 at 8 (Jan. 27, 2014). In doing so, the Commission recognized that improvements in energy efficiency, localized distributed generation, and demand response programs have the potential to reduce the need for capital investments in electric system transmission and distribution ("T&D") system upgrades and expansion, while providing obvious benefits to participating customers, and to all customers on the electric system through lower rates.

In some cases where the expansion of the T&D system is required on a localized basis to meet increased demand, there may be alternatives that reduce demand at a potentially lower cost than T&D infrastructure investments. When non-wires alternatives can be provided at a lower cost than traditional infrastructure, these programs can enhance the Company's ability to provide service at the lowest reasonable cost, while protecting the environment and preserving the availability of nonrenewable resources. In this section, the Company describes how it incorporates non-wires alternatives into its distribution planning process.

5.2 Liberty Process

Liberty has developed a cross-functional planning team and process, under the leadership of its President, and includes the evaluation of non-wires alternatives. *See* Figure 5.1; Appendix C. To ensure proper coordination and communication at all levels of the organization, the cross-functional team includes representatives from electric supply planning, electric system planning, energy efficiency administration, and system standards, policies and codes. With the planning team in place, the Company is prepared to evaluate non-wires alternatives on an equal basis as T&D infrastructure.

As described in Section 4.4 above, the Company applies a set of screening criteria for evaluating non-wires solutions specific to its service territory and size of its operation.

The process begins with demand forecasts that are prepared in sufficient geographic detail to make non-wires alternatives viable. Demand forecasts are prepared for each substation, sub-transmission line, and feeder under extreme weather scenarios to determine if capacity is adequate to meet demand under normal and contingency configurations. Planning criteria of normal and contingency configurations are then applied in concert with the thermal ratings of the facilities to identify if and when any of the planning criteria are violated. The geographic detail of the starting point enhances the feasibility of non-wires alternatives, and the operating characteristics ensure that the deficiency is not based on asset condition. Next, the planning group develops wires and non-wires alternative proposals that address those instances when and where the planning criteria are violated. The group then performs a financial analysis of each proposal and prioritizes them. Finally, the group submits the proposals as part of the Company's capital plan. Figure 5.1 below summarizes Liberty's NWA process.

Figure 5.1. Liberty's Non-Wires Alternative Evaluation Process

	Step	Description
1.	Review Demand Forecast	Review demand forecasts prepared for each substation, sub-transmission line, and feeder under extreme weather scenarios to determine if capacity is adequate to meet demand under normal and contingency configurations
2.	Review T&D Deficiencies	Develop a list of distribution deficiencies based on planning criteria.
3.	Screen Projects based on Screening Criteria	Screen project options based on the list of distribution deficiencies according to Company's Screening Criteria.
4.	Evaluate NWA solutions for technical feasibility	Review potential NWA solutions for technical feasibility: alternatives that have successfully reduced, avoided or deferred a wires solution in the region
5.	Perform Cost-Benefit Analysis for NWA solutions	Evaluate cost effectiveness of NWA solutions according to Commission-approved TRC test.
6.	Finalize NWA program recommendations	Finalize NWA recommendations and present for approval in capital and operating expenditures plans.

Two important aspects of the comparative evaluations involve the load profile of the solutions relative to the demand on the system and the financial analysis to put the alternatives on an equal footing. The T&D system can experience peak demand at different times of the day, in different geographic locations, and during different seasons. The ability of a non-wires alternative to reduce, defer, or eliminate a T&D infrastructure investment, therefore, depends on the alignment of hour and season of the peak demand, with the hourly and seasonal profile of the non-wires alternatives savings. The non-wires alternative solutions are designed to include those measures that provide a saving profile that best matches the demand profile it is intended to reduce. The Company also compares a solution's risk profile (for both wires and non-wires) based on a number of risk factors, including: project size, number of lead elements, project complexity, project completion time, success risk factor, level of customer involvement, and complexity of regulatory approvals. For each potential solution, each of these risk factors is rated on a scale of one to ten, then summed to calculate a total project risk score. Figure 5.2 below provides a summary of each of the risk factors.

Figure 5.2. Project Risk Factor Summary

	Step	Description
1.	Project Size	Percentage of target area load; non-wires solutions considered only if <20%.
2.	Number of Lead Elements	Project steps prior to completion (e.g., design, permitting).
3.	Internal Complexity	Level of project's complexity for the Company, internally.
4	Construction Time (Years)	Length of time to complete Construction.
5.	Total Project Time (Years)	Length of time to design, permit, and build project.
6.	Success Risk Factor	Company's experience with successful implementation of similar projects.
7.	Customer Involvement	Level of customer involvement/participation to achieve expected outcome.
8.	Regulatory Approvals	Complexity of regulatory approvals to achieve expected outcome.

Liberty's financial evaluation of the non-wires alternatives and wires solutions relies on the Total Resource Cost test, which is the method used by the Commission to evaluate the state's energy efficiency programs. Order No. 23,574 (Nov. 1, 2000) outlines the approved cost-effectiveness test as follows:

- Avoided generation, transmission, and distribution costs for program participants;
- Program cost (e.g. administration, monitoring, evaluation, etc.) for program participants;
- Both the benefits and costs associated with market effects (e.g. spillover, post-program adoptions);
- Quantifiable benefits and costs associated with other resources in addition to electricity (e.g. water, gas, oil);
- A 15% adder for additional non-quantified benefits (e.g. environmental and other benefits);
- The cost of utility shareholder incentives, but applied to all programs together rather than to individual programs; and
- The Prime Rate adjusted annually on or around June 1 to state projected costs and benefits in present value terms.

The final result of the financial analysis for each non-wires and wires alternative solution is, therefore, the calculation of the benefit/cost ratio which is derived by dividing the net present value of benefits by the net present value of costs. These results allow the group to compare and prioritize the solutions based on their relative net benefits.

Other Considerations for Implementing Non-Wires Alternative Solutions

Although Liberty has developed the non-wires alternative evaluation process described above, the Company's pursuit of non-wires alternative solutions requires a more detailed analysis of the benefits and costs, including: (1) current saturation levels and peak demands of targeted equipment; (2) consumer research on customer interest, incentives and likelihood to install targeted efficiency measures, and/or distributed generation equipment within a specific geographic location; and (3) the costs associated with development and implementation of a NWA program. Such analysis is important to develop a solid foundation for program development and implementation. The Company needs to retain outside expertise to assist with such an analysis, however, there is not a current mechanism to recover such costs.

Currently, the Company is allowed to recover the costs of traditional T&D infrastructure including a return on the investments through distribution rate case proceedings. However, there is no mechanism in place to recover lost revenues or return on investment for certain non-wires solutions, such as distributed generation.

Appendix E provides an example of the process Liberty would undertake to evaluate and implement a non-wires alternative solution using a hypothetical case study project.

5.3 Company-Owned Distributed Generation

In addition to customer owned distributed generation, the Company also recognizes the potential value of Company ownership or investment in contracted DG installations, as allowed for in RSA Chapter 374-G. Liberty would be eligible for up to 6%

(approximately 12 MW) of utility owned or invested DG under the statute. The pursuit and application of such generation would be driven by consideration of the factors described in RSA 374-G:5, including:

- The targeted reduction in feeder or area peak demand (in kW) as well as the timing for the reduction;
- The availability of potential sites on the feeder for utility owned generation; most likely open space, agricultural land, or unused industrial/commercial land or rooftops;
- The size, orientation, and type of DG, as well as the estimated capacity factor of the installation;
- Feeder engineering, operating, and performance considerations specific to the site, the feeder, and the size/type of installation;
- The installation cost on a dollars-per-kilowatt and total cost basis;
- The ability to permit the site according to local codes and requirements;
- The degree of acceptance and support exhibited by the local community for such an installation;
- Affirmation of the recovery of installation costs, including fair return on investment, through the appropriate tariff;
- The benefits to any specific customer as well as to all other customers; and
- The amount of investment to be made by Liberty and, for customer-sited distributed generation, the amount to be invested by the customer.

The process enables the Company to therefore treat the Company-owned or contracted DG option on an equal footing with other wires and non-wires alternatives when selecting the least cost alternative to reducing demand on a particular feeder or group of feeders serving an area.

Should Liberty determine that the benefits of a particular company-owned distributed generation project outweigh the project's cost, the Company could submit a filing to the Commission pursuant to RSA 374-G:5.

5.4 Best Practices for Non-Wires Alternative

In general, NWAs are intended to reduce demand via targeted energy efficiency and load control programs, or increase peak generation through distributed generation measures in specific constrained geographical areas in such a way that investments in utility transmission and distribution systems can be reduced, deferred, or eliminated. This is beneficial to the system as a whole only if NWAs can be implemented at a lower cost than infrastructure expansion. Another important element of designing non-wires programs is to match the hourly and seasonal load profile of the energy efficiency measures to the profile of the demand on the system. If the efficiency does not occur at the time that it is needed, it might not avoid the need for the additional capacity. The level and mix of the energy savings measures are important determinants of whether the T&D deferral, reduction, or elimination is possible and for how long.

Liberty reviewed non-wires alternatives implemented in other jurisdictions. Based on the documented experiences of other electric utilities, some features of successful non-wires alternative implementation processes include:[29]

- Leadership support on the value of non-wires alternatives;
- Cross-functional planning teams that include, in addition to system planning engineers and electric system operators, energy efficiency and demand management program administrators, community out-reach personnel, and financial analysts;
- Starting small and employing "modular" strategies that can be scaled with ease;
- Evaluation of non-wires alternative as part of the routine T&D system planning process; and
- Screening criteria for non-wire alternative solutions in appropriate situations.

6. <u>Energy Efficiency & Demand Side Management</u>

6.1 Purpose

The purpose of this section is to: (1) provide an overview of Liberty's current demand side management and energy efficiency programs, (2) present an assessment of these programs' impact on energy savings and environmental and health benefits, and (3)

29 See "*Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically Targeted Efficiency Programs to Defer T&D Investments*", Neme, Chris and Grevatt, Jim, Energy Futures Group. Presented to the Northeast Energy Efficiency Partnerships, January 9, 2015, at 55-61.

discuss new program initiatives and the proposed Energy Efficiency Resource Standard ("EERS") currently before the Commission.

6.2 NHSaves Energy Efficiency Programs

Introduction

Since 2002, Liberty has partnered with the New Hampshire electric and natural gas utilities to manage and administer the state's NHSaves Energy Efficiency Programs. Energy efficiency is a priority for Liberty and is a key strategy for building a modern and sustainable energy future. Since the NHSaves programs started, New Hampshire customers have saved over 10 billion electric kilowatt-hours and 16 million natural gas MMBtus over the life of the energy efficiency measures installed, which translates into customer savings of more than $1.6 billion.[30] Liberty, along with the other New Hampshire utilities, offers a suite of efficiency solutions designed to meet the varied needs of our customers, including helping homeowners retrofit and reinsulate their homes, helping businesses install high efficiency motors, processing and control systems, and helping municipal and school districts install more efficient lighting systems. Figure 6.1 summarizes the current NHSaves program offerings:

30 New Hampshire Public Utilities Commission (2014, September 12). New Hampshire Statewide CORE Energy Efficiency Plan, 2015-2016, New Hampshire Public Utilities Commission Docket No. DE 14-216. Retrieved from http://www.puc.state.nh.us/Electric/NH%20EnergyEfficiencyPrograms/14-216/14-216%202014-12-11%20PSNH%20Att-Jt%20Settlement%20Agreement.pdf

Figure 6.1. NHSaves Program Offerings

Program	Measure-Level Examples	Incentives
Residential Sector		
ENERGY STAR Products	High-efficient lighting devices and electric appliances	Instant coupons and in-store product markdowns
Home Performance with ENERGY STAR	Audit, air sealing and weatherization measures	50% rebate up to $4,000
ENERGY STAR Homes	New construction measures beyond current building code standards	Builder training and verification of code + measure installations
Home Energy Assistance	Low income air sealing, weatherization and electrical measures	No cost service
Non-Residential Sector		
Small Business	Lighting, refrigeration, compressed air, controls, electric hot water heating	Up to 50% of project costs
Large Business	Process manufacturing, custom controls, retro-commissioning, VFDs	Up to 35% of project costs
Municipal	Interior and exterior lighting, and thermal savings	35% to 50% of project costs

The NHSaves programs are adaptable to unique efficiency opportunities and provide turnkey solutions to help identify savings opportunities for customers and assist with measure installations. The programs also have an education and workforce training component and the utilities engage with numerous market actors, such as architects, builders, distributors, installers, product manufacturers, and retailers, to help drive customer activity.

Some of the ways the NHSaves programs are currently benefiting New Hampshire customers include:

- Working with Home Energy Raters and private builders to incent the construction of highly efficient homes using 15-20% less energy compared to a standard new home;
- Incentivizing investments in air-sealing and weatherization in existing homes performed by qualified private contractors to reduce homeowner's heating costs by more than 15%;
- Helping income qualified customers receive insulation, air-sealing, and other weatherization work, saving them about $350 per year on energy costs, through our collaboration with the New Hampshire Office of Energy and Planning's Weatherization Assistance Program and the Community Action Agencies around the state;
- Helping customers invest in highly efficient electric appliances, saving 10-20% of the energy used if they had purchased standard models, by working with over 100

appliance retailers across the state to on education, incentive and training programs;

- Helping customers purchase more efficient lighting technologies that can use 75% less energy than standard lighting products, while lasting 10 to 25 times longer, by partnering with lighting retailers across the state on education, incentive and training programs;
- Helping small, large business, and non-profit agencies identify and install more efficient lighting, controls, motors, HVAC equipment, air compressors, and industrial process equipment. These energy efficiency improvements are implemented in partnership with private contractors throughout the state who help the business sector reduce energy use and save significantly on energy bills, resulting in more money be available to invest in their businesses and agencies;
- Focusing special attention on energy savings opportunities with municipalities which helps to save energy in public buildings, reducing overall costs to taxpayers; and
- Working with local financial institutions to introduce a private lending program to assist customers in making energy efficiency investments and helping better address the up-front cost of projects.

In addition to the direct benefits to customers, the programs also result in:

- Reducing New England's peak load – in 2013, New England's peak load was reduced by 8.3 MWs as a result of the statewide programs; the equivalent peak load of approximately 5,500 residences.[31] This reduction in peak load helps to lessen the need and burden for additional energy infrastructure and its associated costs and environmental impacts.

- Reducing emissions – energy efficiency measures help decrease energy consumption, which reduces carbon dioxide emissions, airborne mercury, and other harmful pollutants that cause illnesses as power plants burn fewer fossil fuels to meet lower demand. This reduction in emissions helps create various health and well-being benefits including reduced symptoms of respiratory and cardiovascular conditions, rheumatism, arthritis, and allergies as well as fewer injuries. For reference, the cumulative emission reduction impact of the NHSaves programs to-date is the equivalent to taking 1.3 million cars off the road for a year.[32]
- Creating jobs – 338 jobs were supported by the programs in 2013.[33]

Lastly, the NHSaves programs are a cost-effective solution to helping meet the region's overall electrical energy needs. As illustrated in Figure 6.2, all of the New England states, including New Hampshire, deliver cost-effective energy efficiency programs; attaining greater kilowatt-hour savings for every dollar spent on energy efficiency

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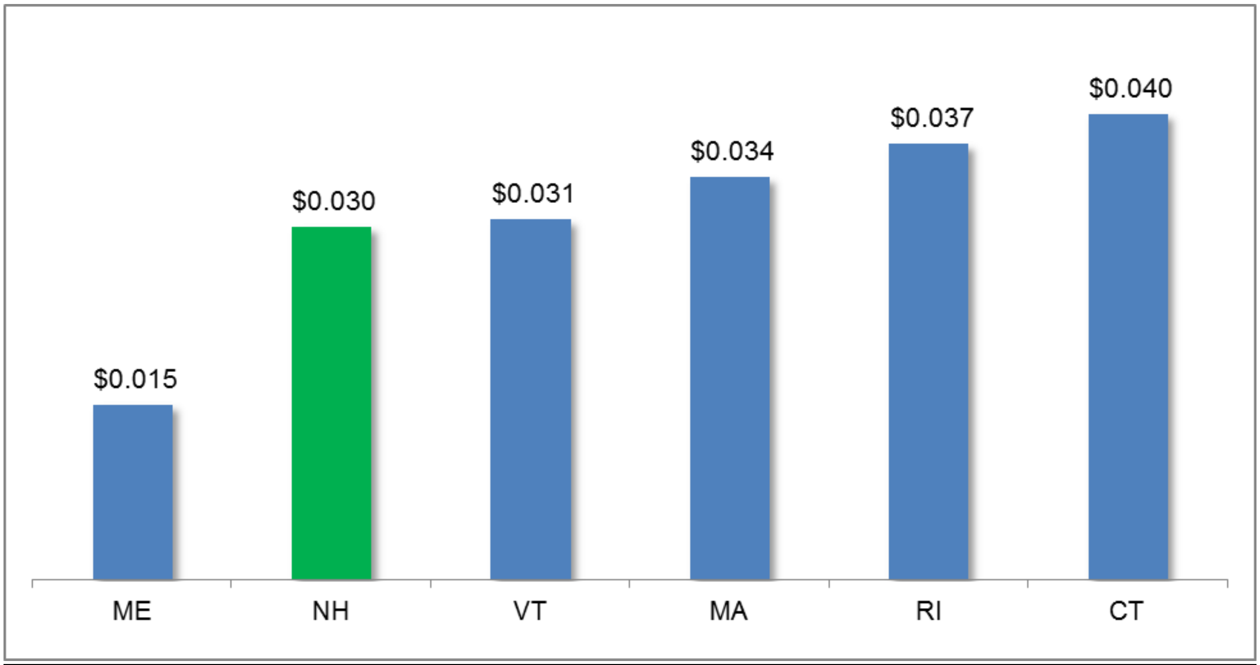
31 *Ibid.*
32 *Ibid.*
33 *Ibid*. Magnusson, M., Wake, C., Johnson, C. (2013, September). An Evaluation of the NH BetterBuildings Program. Retrieved from: https://www.nh.gov/oep/energy/programs/betterbuildings/documents/betterbuildings_economic_study.pdf

compared to the current retail cost of approximately 15 cents per kilowatt-hour to purchase electricity, as of December 14, 2015.[34]

Figure 6.2. Cost per Lifetime kWh Saved, 2011-2013 Average[35]



Impact of the NHSaves Programs on Energy Consumption

Figure 6.3 summarizes Liberty's annual and lifetime megawatt hour savings, customer participation, program costs, and benefits from 2001 through 2014. During this time, over $20 million in energy efficiency investments have been made, resulting in over 910,000 lifetime megawatt hours of savings at a benefit value of almost $89 million.

34 New Hampshire Office of Energy and Planning (December 14, 2015). Average Fuel Prices in New Hampshire – Electricity. Retrieved from http://www.nh.gov/oep/energy/energy-nh/fuel-prices/index.htm#note_2

35 Source: ISO New England, Energy Efficiency Forecast for 2019 to 2024, May 1, 2015, at 19-20. Retrieved from http://www.iso-ne.com/static-assets/documents/2015/05/eef-report-2019-2024.pdf

Figure 6.3. NHSaves Program Results – Liberty Utilities, 2001 - 2014

Year	Annual MWh Savings	Lifetime MWh Savings	EE Measures/ Participants	Expenditures (000's)	Benefits (000's)
2001	5,073	66,077	4,709	$1,357	$4,243
2002	5,035	64,825	4,648	$1,190	$4,554
2003	4,990	74,322	8,338	$1,252	$6,053
2004	4,019	61,104	6,733	$1,148	$5,122
2005	3,559	53,821	4,584	$1,298	$4,343
2006	4,001	56,958	4,441	$1,599	$5,726
2007	2,962	34,884	5,281	$1,311	$3,904
2008	6,120	74,641	22,649	$1,379	$7,894
2009	5,395	66,942	14,147	$1,673	$8,077
2010	5,848	72,485	17,550	$1,407	$8,847
2011	5,361	64,788	19,504	$1,458	$6,481
2012	5,644	74,465	7,595	$1,473	$6,245
2013	5,591	73,283	20,669	$1,417	$8,181
2014	5,347	71,943	18,476	$2,145	$9,285
2001-2014	**68,945**	**910,538**	**159,324**	**$20,107**	**$88,955**

Figure 6.4 details Liberty's annual and lifetime kilowatt-hour savings, customer participation, program cost, and benefits, by customer program and sector, for its most recently completed program year of 2014. Based on these results, Liberty's average cost of 2014 savings was 3.29 cents[36] per lifetime kilowatt-hour as compared to the current average retail price per kilowatt-hour of 15 cents, as of December 14, 2015.[37] This represents a simple net benefit ratio on program investments of 4.25 to 1.

36 Value calculated by dividing the total program costs and utility performance incentive ($2,167,931 + $196,915) by Lifetime kWh savings achieved (71,943,030).

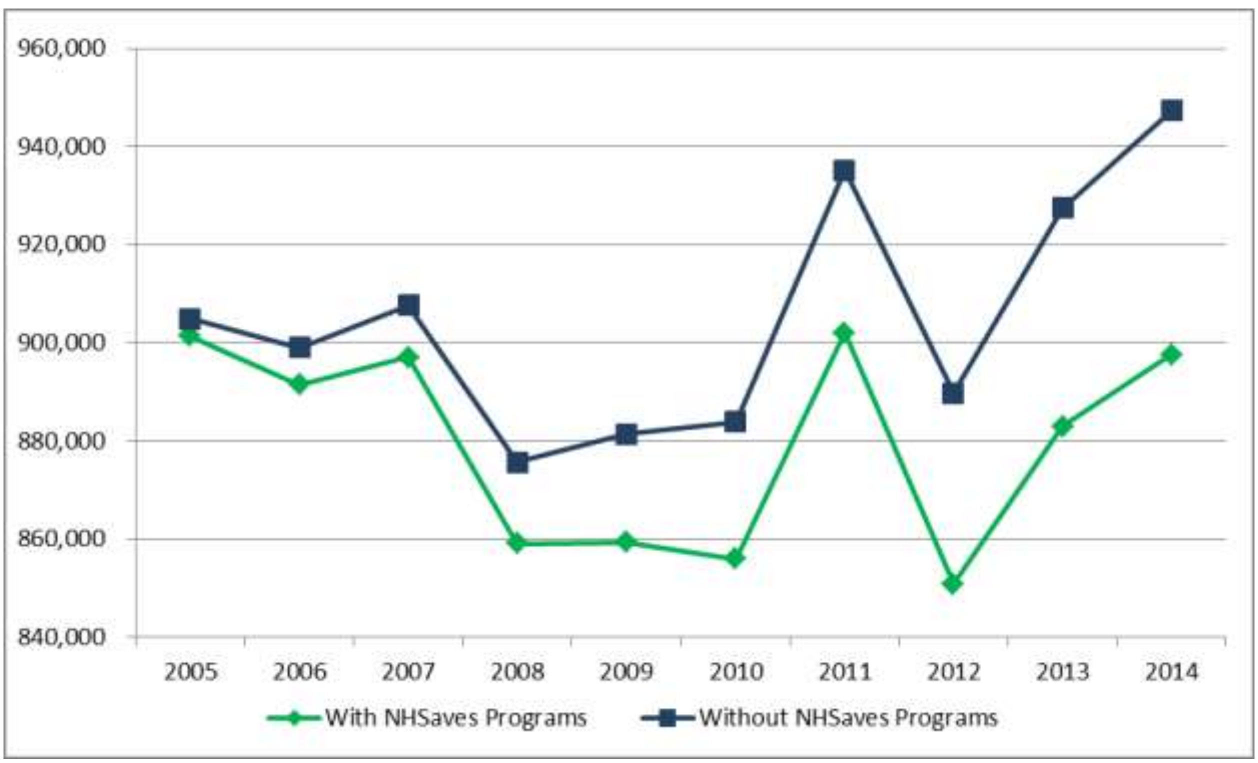
37 New Hampshire Office of Energy and Planning (December 14, 2015). Average Fuel Prices in New Hampshire – Electricity. Retrieved from http://www.nh.gov/oep/energy/energy-nh/fuel-prices/index.htm#note_2

1 **Figure 6.4. NHSaves Programs Results – Liberty Utilities, 2014**

Sector/Program	Annual kWh Savings	Lifetime kWh Savings	EE Measures / Participants	Expenditures	Benefits
Residential Sector					
ENERGY STAR Appliances	251,095	2,527,043	1,263	$193,939	$809,062
ENERGY STAR Homes	230	3,570	1	$16,090	$15,068
ENERGY STAR Lighting	364,391	5,659,061	16,849	$134,772	$440,361
Home Energy Assistance	58,086	945,256	27	$279,346	$679,364
Home Performance with ENERGY STAR	62,590	1,226,340	61	$213,684	$878,055
Residential Total	**736,391**	**10,361,270**	**18,201**	**$837,831**	**$2,821,910**
Commercial & Industrial Sector					
Large Business	2,912,240	39,668,340	85	$733,029	$3,568,083
Municipal	349,550	4,641,940	24	$168,932	$1,286,518
Small Business	1,349,090	17,271,480	166	$391,144	$1,608,661
C&I Education	-	-	-	$13,845	$0
C&I Total	**4,610,880**	**61,581,760**	**275**	**$1,306,949**	**$6,463,261**
Forward Capacity Market Reporting	-	-	-	$23,151	-
Overall Total	**5,347,271**	**71,943,030**	**18,476**	**$2,167,931**	**$9,285,172**

The 2014 annual kilowatt-hour savings are approximately 0.60% of Liberty's total billed delivery kilowatt-hour sales in 2014 (5,347,271 / 897,482,403). The average life of the installed energy efficiency measures is 13.35 years. As a result, the savings associated with the measures installed in 2014 will continue well into the future and the cumulative impact of the programs will become more significant over time. As illustrated in Figure 6.5, the cumulative impact of the NHSaves Programs over the past ten years has resulted in a decline of delivered MWh sales of 5.6% in 2014.

Figure 6.5. Cumulative Impact of NHSaves Program Savings on Liberty Utilities Annual MWh Sales



1 *Impact of the NHSaves Programs on Capacity or Peak Reduction*

In addition to the kilowatt-hour energy savings, the NHSaves Programs also provide capacity or peak demand reductions. Figure 6.6 summarizes the average annual capacity reduction coincident with the New England peak resulting from the NHSaves Programs efficiency measures installed by customers between June 16, 2006 and December 31, 2014. As shown, the NHSaves Programs implemented by Liberty reduced New England's peak load (which currently occurs in the summer) by 867.7 kW, which is approximately 0.42% of Liberty's system peak load[38] in New Hampshire.

38 Granite State Electric's Peak Load was 205,942 kW on June 22, 2011.

1 **Figure 6.6. NHSaves Programs Capacity Reduction Based on Operable Measures Installed Between**
2 **June 16, 2006 and December 31, 2014**

Sector/Program	Coincident with ISO-NE Peak	
	Summer kW	Winter kW
Residential Sector		
ENERGY STAR Appliances	248.8	214.9
ENERGY STAR Homes	156.4	151.4
ENERGY STAR Lighting	324.5	1,113.1
Home Energy Assistance	60.4	140.4
Home Performance with ENERGY STAR	83.9	308.9
Residential Total	874.0	1,928.8
Commercial & Industrial Sector		
Large Business	4,820.7	3,641.9
Municipal	135.7	78.9
Small Business	1,509.2	924.6
C&I Total	6,465.6	4,645.4
Overall Total	7,339.6	6,574.2
Average kW/Month (101.5 Months in Period)	72.3	64.8
Annualized Capacity Reduction	**867.7**	**777.2**

The New Hampshire electric utilities, including Liberty, are the only energy efficiency providers in New Hampshire participating in the ISO-NE's forward capacity market. The proceeds obtained through participation in this market have totaled $9 million from 2007 through 2014. These proceeds are utilized as a funding source for the NHSaves Programs, and represented approximately 7% of Liberty's NHSaves Program expenditures in 2014. In order to qualify for payments from the ISO-NE, Liberty must certify to the ISO-NE's satisfaction that the capacity reductions are operational during hours of peak electrical usage. Liberty has developed the necessary reporting, measurement, and verification plans needed to evaluate the impact of the efficiency measures at the time of the New England peak and the resulting capacity reduction load value that qualifies for payment from the ISO-NE. Liberty has met the rigorous reporting standards and requirements to participate in the forward capacity market. As a result, the estimated capacity reductions summarized above are an accurate representation of the capacity reductions resulting from the NHSaves Programs as they have been thoroughly reviewed by ISO-NE and independently certified.

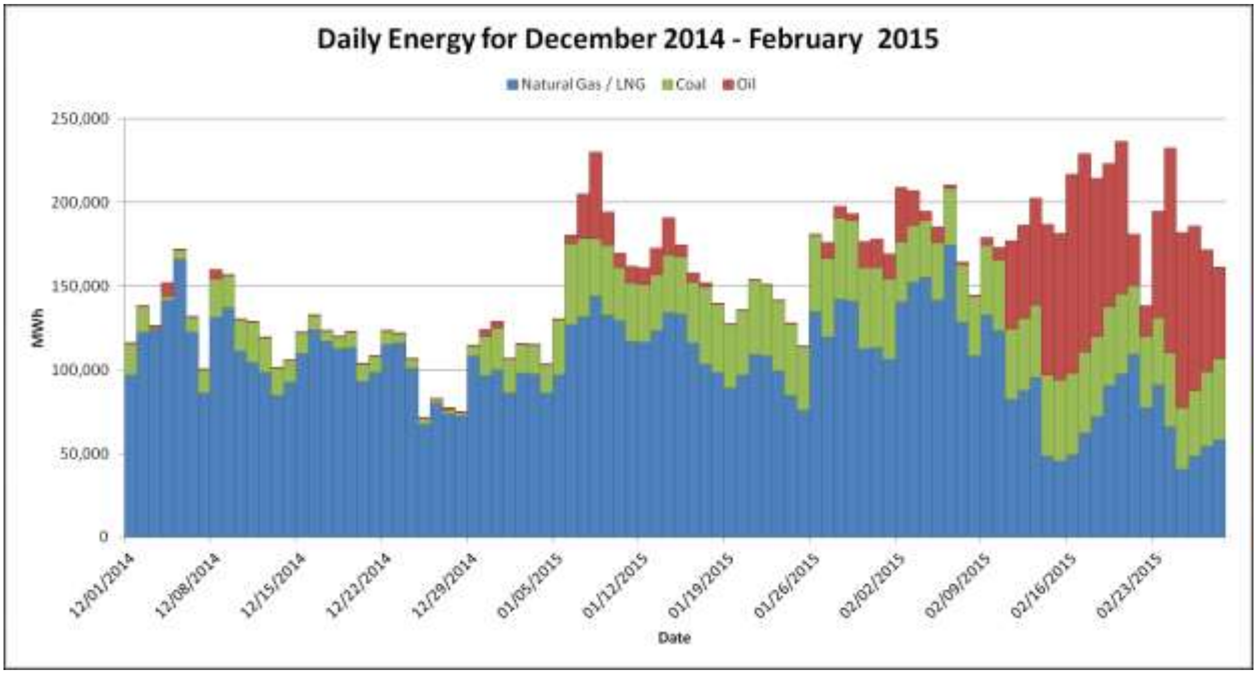
Impact of the NHSaves Program on Environment and Health

Reductions in energy consumption and peak demand through the NHSaves programs have significant environmental and health benefits. First, lower overall energy consumption as a result of energy efficiency programs results in lower overall demand and therefore less electric generation needed to meet demand. Second, as described in Section 3.1 above, the marginal unit setting the energy market clearing price in New

England is most often a natural gas fired generator, due to natural gas-fired units' economic cost. This means that higher cost generators, such as oil, are not economic and are therefore not called on. However, during times of peak demand, more units are needed in order to meet demand, and the marginal price is bid upward, making these higher cost units economic. To the extent that electricity generation during times of peak demand increases generation from coal and oil, reducing peak demand therefore reduces emissions of pollutants from these sources.

To that point, the ISO-NE reported that more oil and coal-fired generation was called on to meet higher demand during the winter cold snap in early 2015. *See* Figure 6.7 below.

Figure 6.7. Energy Contribution from Natural Gas, Coal, and Oil during Winter 2014/2015[39]



As Figure 6.7 shows, during times of higher demand (*i.e.*, MWh), coal- and oil-fired units were called on more often and generated greater amounts of energy.

6.3 NHSaves Programs as a Demand-Side Resource

The NHSaves Programs implemented by Liberty saved approximately 71.9 million lifetime kilowatt-hours in 2014 at a total cost of $2.36 million, and the operable energy efficiency measures installed between June 2006 and December 2014 reduced New England's peak load by 867.7 kW each year. The average life of the energy efficiency measures installed in 2014 is 13.4 years, which means the cumulative energy savings of the NHSaves Programs grows over time as more energy efficiency measures are installed.

39 ISO-NE Winter 2014/2015 Review, Electric/Gas Operations Committee (EGOC) Teleconference, June 29, 2015, Slide 20. http://www.iso-ne.com/static-assets/documents/2015/06/winter_2014_15_review.pdf

As shown in Figure 6.8, the forecasted Liberty load growth percentage would be approximately 53% higher (1.2% versus 0.8%) without the 2014 NHSaves Programs energy efficiency measures alone:

Figure 6.8. Estimated Overall Impact of NHSaves Programs on Projected Load Growth

(A)	(B)	(C) (A) x (B)	(D) (A) + (C)	(E)	(F) (D) + (E)
GSE System Peak (KW), 2008-2014	**Forecasted Load Growth % (Normal Weather), 2015-2019**	**Forecasted Load Growth (kW), First Year**	**Forecasted System Peak w/NHSaves Programs (kW)**	**System Peak Savings from NHSaves Programs (kW)**	**Forecasted System Peak w/out NHSaves Programs (kW)**
205,942	0.8%	1,647.54	207,589.54	867.7	208,457.24
		Load Growth %:	0.8%		1.2%
		% Difference in Load Growth:			5.3%

Although difficult to specifically quantify, system-wide comprehensive energy efficiency programs like the NHSaves Programs can lead to deferrals of specific T&D investments over time whose need is driven by economic conditions and/or growing peak loads. Investments related to aging infrastructure, equipment failure or reliability, which represent the majority of the current investment, are generally not impacted by energy efficiency programs. As noted in a 2015 Northeast Energy Efficiency Partnerships ("NEEP") report entitled *Energy Efficiency as a T&D Resource*:

> *Passive deferrals, almost by definition, will occur to some degree in any jurisdiction that has system-wide efficiency programs of any significance. However, the degree and value of passive deferrals will obviously be heavily dependent on the scale and longevity of the programs. The benefits may be modest, deferring a small number of planned investments a year or two. They can be also quite substantial.*[40]

Since the electric NHSaves Programs have been in place for over thirteen years and the cumulative savings from the programs have been relatively significant, some planned capital investments may have been deferred for a year or two over time as a result of the NHSaves Programs implemented by Liberty. And as compared to other demand-side resources, once energy efficiency measures are installed they do not require periodic renewal of customer participation agreements or ongoing customer incentive payments. In addition, the claimed capacity reductions are always "in service" during the life of the measures and do not depend upon Liberty Utilities staff, customer personnel, or communications equipment for activation. As a result, the NHSaves Programs measures are a highly reliable demand resource.

To date, Liberty has not identified a distribution system capital project that could feasibly be deferred by geographically targeting its existing energy efficiency programs. While future potential may exist, achieving geographic-specific peak load reductions from

40 Northeast Energy Efficiency Partnerships, *Energy Efficiency as a T&D Resource*, January 9, 2015, at 12. Retrieved from http://www.neep.org/sites/default/files/products/EMV-Forum-Geo-Targeting_Final_2015-01-20.pdf

energy efficiency can be difficult depending on site specific characteristics. The NHSaves Programs, in their current state, have been purposely deployed over Liberty entire geographic area, over a long time period, with initiatives addressing a variety of customer types.

Utility experiences in geo-targeting energy efficiency programs to avoid or delay the need for a transmission or distribution investment to date have reflected general difficulties. According to the 2015 NEEP Report,

> *Several of the geographic targeting projects that have occurred to date have found that the availability of savings was different from their initial expectations because their assumptions about the customers in the targeted areas were found to have been inaccurate. …contractors weren't able to meet their savings targets in the later years of their initial geo-targeting efforts and attributed this to the lack of a detailed understanding of the types of customers and predominant end uses in the targeted areas.*[41]

Legislative Guidance

While considering the NHSaves Programs as a demand resource, thought must be given to the guidance provided by the New Hampshire legislature in the Restructuring Policy Principles, RSA 374-F:3,VI, and Electric Utility Restructuring Implementation, RSA

41 *Ibid*.

374-F:4,VIII (e). RSA 374-F:3, VI states, in part, "Restructuring of the electric utility industry should be implemented in a manner that benefits all consumers equitably and does not benefit one customer class to the detriment of another. Costs should not be shifted unfairly among customers." Liberty interprets this to mean that the revenue collected from the energy efficiency portion of the system benefits charge be allocated to customers essentially in proportion to the amount of revenue collected from each customer class (Residential and Commercial/Industrial). Therefore, although shifting program funds to the Commercial/Industrial customer class may result in greater kilowatt-hour savings per dollar spent based on the current average cost to save a lifetime kilowatt-hour for each class, this type of allocation may not be consistent with current state law.

RSA 374-F:4,VIII (e) states:

> *Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution costs may be included in the distribution charge or the system benefits charge, provided that system benefits charge funds are only used for customer-based energy efficiency measures, and such funding shall not exceed 10% of the energy efficiency portion of a utility's annual system benefits charge funds. A proposal for such use of system benefits charge funds shall be presented to the commission for approval. Any such approval shall*

initially be on a pilot program basis and the results of each pilot program proposal shall be subject to evaluation by the commission.

Accordingly, and as noted in Section II.F., explicit Commission approval is required before SBC funds may be used on targeted energy efficiency (also referred to as “conservation and load management”) as “part of a strategy to minimize distribution costs.”

6.4 Initiatives Recently Implemented to Reduce Energy and Capacity

Market Assessment Study of Air Conditioning Equipment

Liberty, in conjunction with Commission Staff and the other New Hampshire electric utilities, contracted with The Cadmus Group to complete a market assessment study of air conditioning equipment in the residential and commercial/industrial sectors. On April 5, 2013, the New Hampshire electric utilities filed with the Commission a final report titled, “New Hampshire HVAC Load and Savings Research.” This research studied the drivers of the increasing air conditioning load in both the Residential and Commercial/Industrial sectors, recommended additional measures to reduce air conditioning electric loads, and provided estimates of the ancillary electric savings associated with various non-electric measures utilized in the Home Performance with ENERGY STAR Program.

With respect to air conditioning impact on the ISO-NE’s “On Peak Hours,” the research found that air conditioning loads contribute to the demand for electricity during on peak hours in New Hampshire. Cadmus recommended several cooling measures be included in the NHSaves Programs to enhance energy and peak demand reductions. As a result of this research, Liberty has included incentives within the NHSaves Programs for high efficiency ENERGY STAR central air conditioning and air source heat pumps, high efficiency ductless mini-split heat pump systems which provide heating and air conditioning, and Wi-Fi thermostats. These measures have been added to both the Residential and Commercial/Industrial sectors. Liberty offers incentives on ENERGY STAR room air conditioners, variable speed drives for ventilation and other equipment, and encourages replacement of inefficient HVAC equipment in existing buildings and the highest efficiency equipment in new construction.

The research also quantified the ancillary electric savings from non-electric energy efficiency measures, such as weatherization. Liberty has included the electric energy savings associated with the ancillary measures in its NHSaves Programs savings estimates. Specifically, the ancillary measure savings associated with weatherizing homes include: boiler circulator pump savings, furnace fan savings, furnace with new ECM motor savings, central AC savings, and room AC savings.

Lighting Incentives Now Focus on LEDs

Liberty is transitioning from lighting incentives on Compact Fluorescent Lightbulbs (“CFL”) to lighting incentives primarily on Light Emitting Diode (“LED”) lightbulbs to support the transition to this new technology in both the residential and commercial/industrial sectors. The energy savings associated with LEDs is higher than

CFLs, and the life expectancy of LEDs is longer than that for CFLs, which will lead to greater overall energy savings.

Marketing Campaign to Customers Likely to Utilize Electric Space Heating

In addition to giving priority to customers who heat their homes with electricity in the Home Performance with ENERGY STAR program, Liberty conducted a telemarketing and outbound direct mail campaign to customer segments identified as likely users of electric heat.

6.5 Energy Efficiency Resource Standard

On May 8, 2015, the Commission opened Docket No. DE 15-137 to institute an EERS to establish specific targets or goals for energy savings that utilities must meet in New Hampshire. The order of notice directs that the:

> *EERS will require electric and/or natural gas utilities to achieve, within short- and long-term time frames, energy-type-specific levels of customer energy savings (efficiency goals), based on sales volumes for the baseline year of 2014. In this proceeding, the Commission will define the savings targets and address issues related to public and private funding; program cost recovery; lost-revenue recovery (e.g., decoupling); performance-*

based incentives and penalties; program administration; and evaluation, measurement and verification.[42]

In 2014, the New Hampshire Office of Energy and Planning (OEP) released a 10-year State Energy Strategy, which acknowledged the need for an EERS:

In order to reduce energy costs by implementing more cost-effective efficiency programs, the State must set specific efficiency goals and metrics to measure progress. The Public Utilities Commission should open a proceeding that directs the utilities, in collaboration with other interested parties, to develop efficiency savings goals based on the efficiency potential of the State, aimed at achieving all cost effective efficiency over a reasonable time frame.[43]

Liberty supports the creation of an EERS and believes, if structured correctly, there can be significant benefits to businesses, residents, and communities in increasing energy efficiency and helping further reduce overall energy usage and demand. Drawing on Liberty's and the other New Hampshire utilities' collective experience implementing and observing robust efficiency programs in other New England states and around the country, we believe there are some key structural components that support a successful EERS and efficiency programs. Feedback during the Commission's stakeholder process

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42 The State of New Hampshire Public Utilities Commission, Docket No. DE 15-137, *Energy Efficiency Resource Standard*, Order of Notice, May 8, 2015, at 1.

43 New Hampshire Office of Energy & Planning, *New Hampshire 10-Year State Energy Strategy*, September 2014, at ii.

conveyed that there are four key areas that need to be incorporated in an effective economic model for energy efficiency programs:

1. Program cost recovery coincident with spending, including a reconciling mechanism in the subsequent program year;
2. Lost revenue recovery on energy efficiency driven savings;
3. Performance-based incentives that transform energy efficiency into a sustainable line of business for utilities; and
4. Low cost financing mechanisms that support customer investment in energy efficiency and leverage the capital of local financial institutions.

Liberty and the other New Hampshire utilities appreciate the opportunity they were given to provide input on the EERS, and are ready to scale up the level of energy efficiency programs and services offered to customers if an EERS becomes a reality in New Hampshire. The utilities' collective vision for the future under an EERS includes expanding the reach of existing award winning NHSaves Programs and implementing new and innovative initiatives, such as:

- Expanded behavioral energy efficiency programs;
- More in-depth exploration of emerging and innovative technologies;
- Codes and Standards initiatives;
- Energy performance certification and labeling initiatives;
- Workforce training and expanded trade partner outreach;

- Expanding weatherization services and fuel-neutral measures;
- Boosting energy efficiency education and customer outreach; and
- Expanding low cost financing options.

7. Conclusion

The purpose of the LCIRP is to provide the Commission with an understanding of the resource planning process employed by the Company to meet its obligation to provide safe, reliable, and least-cost electric service to its customers.

Key results and findings of the LCIRP include:

- Liberty's summer peak demand is projected to grow 1.1% per year on average over the 2016 to 2020 planning period. Winter peak demand is projected to grow 0.8% per year on average over the same time period. Under the extreme weather scenario, peak demand is higher, but is projected to grow at a slower rate than the normal weather scenario;
- The Company's five-year capital budget is $64.3 million, with spending on mandated and regulatory programs representing 46% of the budget, while spending on growth and discretionary items represent 15% and 39%, respectively;
- The Company's distribution planning process integrates non-wires alternatives, although the Company's pursuit of non-wires alternative solutions requires a more detailed analysis of the benefits and costs, including technical studies that would require additional resources;

- The LCIRP assumes a "business as usual" scenario for energy efficiency, recognizing there is an ongoing Energy Efficiency Resource Standard ("EERS") proceeding that may affect future energy efficiency programs;
- The LCIRP includes known Distributed Generation ("DG") interconnections;
- The key impacts of the Company's LCIRP on environmental, economic, and energy price and supply impact on the state include the following:
    - The Company's competitively sourced energy supply procurement process, consistent with the Settlement Agreement approved by the Commission in Order No. 24,577 (Jan. 13, 2006), ensures energy supply is delivered to customers at the lowest reasonable cost, while considering certain financial and qualitative criteria.
    - The Company's renewable energy credit procurement, energy efficiency programs, and net metering program provide economic and environmental benefits to the state by supporting jobs in the renewable energy industry and reducing reliance on sources of electric generation produced outside the state that emit greater amounts of pollutants.
    - The integration of non-wires alternatives into the Company's distribution planning process has the potential to provide economic and environmental benefits to the state through lower costs to the customer and the reduction of peak loads.

These results and findings are consistent with RSA 378:37 *et seq*.

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