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Granite State Electric Company
d/b/a Liberty Utilities

Least Cost Integrated Resource Plan

November 29, 2012

Submitted to:

New Hampshire Public Utilities Commission

Docket No. DE 12-____

Liberty Utilities℠

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1. Executive Summary

Granite State Electric Company d/b/a Liberty Utilities ("Liberty" or the "Company") is submitting this least-cost integrated resource plan (the "Plan") pursuant to RSA 378:38. This filing describes Liberty's forecast of future electrical demand and how the Company, as a distribution utility, plans to meet that demand in a least cost manner for the planning period which spans from 2013 through 2017. The Plan describes the Company's distribution planning processes, its interface with its transmission service provider, and explains how demand response and energy efficiency are incorporated into the planning processes. The Company's planning processes are intended to ensure that the Company provides safe, reliable, efficient and cost-effective service to its customers, while meeting the requirements of the North American Electric Reliability Council, the Northeast Power Coordinating Council, and all applicable federal and state laws and regulations. The Plan also details the Company's ongoing collaboration with National Grid, its transmission service provider, along with the associated stakeholders and market participants that support a transmission planning process that is transparent, complies with Federal Energy Regulatory Commission ("FERC") procedures, and is coordinated with neighboring utilities and the Independent System Operator of New England ("ISO-NE").

In traditional integrated resource planning ("IRP"), electric utilities evaluate different options for meeting future electricity demands of its customers and select the optimal mix of generation resources that minimizes the cost of electricity supply while meeting reliability needs and state policy objectives. With the advent of restructured electricity markets, many stakeholders, including state and federal policymakers, utilities, independent power producers, power markets, and regional transmission operators play an integral role in system planning. The role of an electric utility like Liberty that owns no generation has changed so that an IRP in the traditional sense can no longer be conducted. National Grid, as a transmission provider, coordinates with ISO-NE and other regional transmission owners to identify projects that have a regional benefit. Likewise, the Company's distribution planning process has also been restructured to accommodate distributed resources and will need to undergo further changes as smart grid, plug-in electric vehicles, and other innovative new technologies are deployed.

In this Plan, Liberty describes the processes that it uses to ensure that its distribution systems are planned to meet forecasted demand and state requirements. Section 2 of the Plan describes energy supply options which, given the current state of electric restructuring, are met by the wholesale markets administered by ISO-NE. Section 2 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 cost. Sections 3 and 4, respectively, describe the transmission and distribution planning processes, including load forecasting, that National Grid (transmission) and Liberty (distribution) have adopted to ensure the reliable operations of the electric grid that serves Liberty's customers. Section 5 describes the role of demand response and distributed generation in the electric markets and how National Grid incorporates, and Liberty plans to continue to include, such resources into their transmission and distribution planning processes respectively. Lastly, Section 6 describes Liberty's demand side management programs and how they interrelate to the Company's resource planning.

2. Energy Supply/Electricity Markets in New England

2.1 ISO-NE and NEPOOL

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. Wholesale markets consist of energy, capacity, and various ancillary services. Through the ISO-NE markets, load serving entities such as Liberty are able to procure supply from across the region to best meet the demands of its retail customers receiving default service.

As a distribution-only utility, Liberty monitors both the development of market rules and any proposed changes to the New England market structure to determine how they will impact the Company's customers. Liberty contracts for electric power for its default service customers in quarterly, short-term commitments through competitive solicitations consistent with New Hampshire Public Utilities Commission ("NHPUC" or "Commission") orders and regulations. 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.

2.2 Status/Summary of the ISO-NE Wholesale Markets

The chart below provides the most recent full 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 2012 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.

Wholesale Market Cost Summary

	Annual Costs ($ Billions)				Average Cost ($/MWh)		
Type	**2010**	**2011**	**% Change**		**2010**	**2011**	**% Change**
Energy	6.63	6.17	(7%)		50.98	48.00	(6%)
Capacity	1.65	1.35	(18%)		12.69	10.47	(17%)
Ancillary Services	0.25	0.11	(56%)		1.93	0.88	(55%)
Total	**8.53**	**7.63**	**(11%)**		**65.60**	**59.35**	**(10%)**

2.3 Energy Market Prices

Energy market prices in New England closely track movement in natural gas market costs since the marginal unit setting the energy market clearing price is most often a natural gas fired generator. Such generating units were the marginal units setting the energy market clearing price during approximately 70% of the hours during 2011. Thus the decrease in average energy market costs of 6% shown in the chart above is well aligned with the 4.5% decline in the average natural gas fuel prices in 2011 vs. 2010. The trend in changes in wholesale costs to meet the Company's default service requirements over this same period is similar to the results depicted above.

2.4 Capacity Markets

New England's Forward Capacity Market ("FCM") has now procured sufficient capacity in six Forward Capacity Auctions ("FCA") to satisfy the region's installed capacity requirement and assure resource adequacy through the capacity commitment period ending May 31, 2016.

The results of the first six FCAs are provided in the chart below.

Auction	Total Qualified Capacity (MW)	Cleared Generation (MW)	Cleared Demand Resources (MW)	Cleared Imports (MW)	Total Capacity Acquired (MW)	Installed Capacity Required (MW)	Floor Price ($/kW-month)	Excess Supply (MW)	Prorated Price ($/kW-month)
FCA 1 (2010–11)	39,165	30,865 (626 new)	2,279 (1,188 new)	933	34,077	32,305	$4.50	1,772	$4.25
FCA 2 (2011–12)	42,777	32,207 (1,157 new)	2,778 (448 new)	2,298	37,283	32,528	$3.60	4,755	$3.12
FCA 3 (2012–13)	42,745	32,228 (2,487 new)	2,867 (309 new)	1,901	36,996	31,965	$2.95	5,031	$2.54
FCA 4 (2013–14)	40,412	32,247 (144 new)	3,261 (515 new)	1,993	37,501	32,127	$2.95	5,374	$2.52
FCA 5 (2014–15)	40,077	31,439 (42 new)	3,468 (263 new)	2,011	36,918	33,200	$3.21	3,718	$2.86
FCA 6 (2015–16)	38,731	30,757 (79 new)	3,628 (314 new)	1,924	36,309	33,456	$3.43	2,853	$3.13

ISO-NE has reported these auctions to have been competitive, producing the expected results given the surplus of existing capacity resources remaining. The use of a floor price will continue for one more auction, FCA 7, scheduled to be held in February 2013, for the capacity commitment period beginning June 1, 2016. FERC has ordered the use of a floor price to be removed starting with FCA 8 in February 2013, for the procurement of capacity to be provided in the commitment period beginning June 1, 2017. As can be seen from the data provided above, significant demand side capacity resources have cleared the auctions and are expected to satisfy more that 10% of the Installed Capacity Requirement by 2015. ISO-NE is considering some enhancements to the FCM as part of its strategic planning initiative discussed below. This planning initiative will help the Company to meet its requirements to provide reliable service.

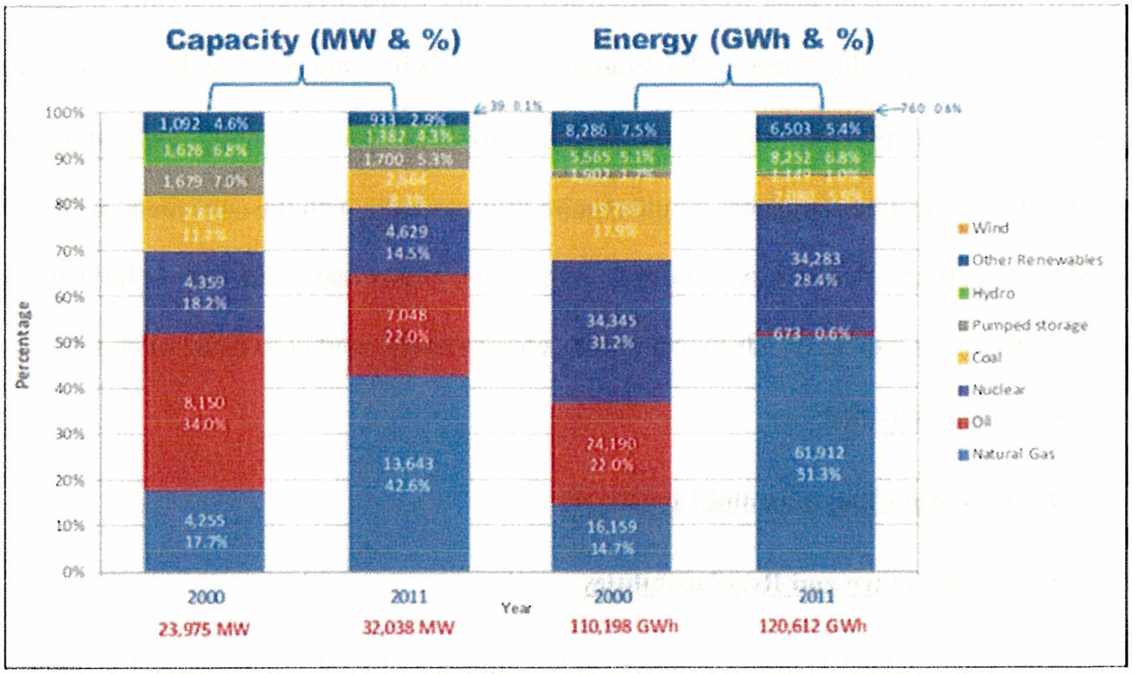
2.5 ISO-NE's Strategic Planning Initiative

ISO-NE has launched a Strategic Planning Initiative to address risks facing the New England wholesale markets and bulk power system. The identified risks have been categorized by ISO-NE in its March 2012 "Roadmap for New England" as follows:

1. *Resource Performance and Flexibility,* related to the uncertain performance and/or constrained operational accessibility of demand resources and aging supply resources, and the need to increase system flexibility.
2. *Increased Reliance on Natural Gas-Fired Capacity*, related to the risk to the New England electric system associated with reliance on natural-gas-only resources, as sufficient gas may not be available to meet power system needs during periods of very high seasonal demand, under other stressed system conditions, or when facing contingencies associated with natural gas supply/transportation system infrastructure.
3. *Retirement of Generators,* related to the risk that economic and policy factors will result in the potential exit of a substantial portion of existing, older fossil-fuel capacity.
4. *Integration of a Greater Level of Variable Resources,* related to the need for a steady increase in system flexibility as more variable resources, primarily renewable energy resources, are added to the system over the next several years.
5. *Alignment of Markets with Planning*, related to the need to better align – from timing and analytic perspectives – wholesale market procurements with transmission planning processes to allow reliability needs to be met through *either* market resources or backstop transmission solutions.

As shown in the following graph, the generation capacity mix in New England has changed significantly from 2000 to 2011. Accordingly, the risks facing the wholesale markets, described in part above, have also changed.

NEW ENGLAND GENERATING CAPACITY AND ELECTRIC ENERGY BY FUEL TYPE 2000 AND 2011



Source: *From 2012 Regional System Plan issued by ISO-NE on November 2, 2012*

ISO-NE is in the process of issuing whitepapers to share ideas of how to address these risks and challenges with stakeholders'. Among the approaches being considered are enhancements to New England's existing FCM. On May 11, 2012, ISO-NE issued a whitepaper "Using the Forward Capacity Market to Meet Strategic Challenges." As stated in this whitepaper, the ISO-NE is considering potential changes to the FCM to (1) better define the core capacity product and create appropriate incentives and consequences for failure to perform; (2) identify system operational needs (such as resource flexibility) and translate these into capacity product specifications and delivery incentives/consequences; and (3) better specify system location requirements and market constructs to induce location responses.

Many of the strategic risks and issues identified above are overlapping and involve the region's increasing dependence on natural gas fired resources. ISO-NE is concerned that many gas fired resources do not have firm gas supply contracts to ensure availability and real-time dispatch for electricity market needs on peak winter days when pipeline transport capacity is fully subscribed by local gas distribution utilities serving the heating needs of their customers. Studies are ongoing, but it appears significant pipeline infrastructure upgrades are necessary. Normally, such infrastructure upgrades by gas pipeline companies would require firm contracts with the customers, such as the natural gas generators. ISO-NE is working to provide the proper market incentives for generators to procure firm gas, as well as on advancing the day ahead electric market to better align with trading deadlines in the gas market.

3. Transmission Planning and Investment

3.1 Structure and Responsibilities

The New England Transmission System is comprised of Pool Transmission Facilities ("PTF") and Non-Pool Transmission Facilities ("non-PTF") within the New England Control Area that are subject to ISO-NE's operational authority or control pursuant to the applicable ISO Tariff and/or various transmission operating agreements. Because Liberty does not own any transmission facilities, it is a transmission customer of National Grid. As the transmission owner, National Grid is covered by the ISO New England FERC Electric Tariff No. 3 and GSE/NEP Service Agreement No. TSA-NEP 78. National Grid manages its New England transmission system - its facilities in New England that are operated at voltages of 69 kV and up - as a single integrated 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-side management efforts. Often, these parameters are available to both companies and are reviewed and collaboratively utilized. For example, PSA loading data is used both in the planning of transmission and distribution upgrades.

3.2 ISO-NE's Integrated Planning Structure

National Grid plans its transmission system in coordination with ISO-NE to meet applicable reliability standards and criteria. Due to the interconnected nature of the regional transmission system, National Grid's transmission system planning process necessarily requires extensive interaction and communication with the other transmission owners within the region. This coordination is accomplished through ISO-NE processes that ensure review and input from all appropriate stakeholders. ISO-NE annually issues a Regional System Plan that identifies the region's electricity needs and plans for meeting those needs over a 10 year planning window. Individual transmission owners have exclusive planning authority for those transmission facilities that are not considered PTF. However, under ISO-NE's rules for local planning, transmission owners are responsible for developing a local system plan, which is fully vetted in open stakeholder meetings. This ensures that all transmission is planned in accordance with FERC requirements and is considered with full input from all interested stakeholders.

4. Distribution Planning and Investment

4.1 Goals and Objectives

The primary goals of the distribution planning process are to provide adequate capacity for each element of the electrical system and to ensure safe, reliable and economic service to customers. System enhancements are planned to optimize capital expenditures while maintaining acceptable standards of service. In order to meet these goals, planning engineers utilize tools and processes to evaluate the capability and performance of the system with respect to anticipated loading. Efficiency is met by utilizing existing capability on circuits that are under-utilized before building new circuits to offset circuits loaded beyond capability, thus maintaining system reliability. Liberty currently utilizes the National Grid distribution planning methodology and criteria and, under its current arrangement pursuant to the Amended and Restated Transition Services Agreement, uses National Grid engineers to support most of its planning requirements. Liberty expects to conduct this function independently beginning in mid-2013 and will continue to utilize the National Grid distribution methodology described below.

This Plan incorporates a load forecast developed by National Grid in March of 2012. That forecast is included as Attachment A to the Plan. The forecast process and results are detailed below and in Attachment A.[1]

4.2 <u>Applicable Distribution Terminology</u>

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, a supply system in New England operates at voltages below 69 kV down to 13 kV, and the voltage is not regulated. Lines 69 kV and above are considered to be transmission facilities. Most of Liberty's supply system is either 23 kV or 13.8 kV.

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[1] The forecast includes Appendices E, F, I, J and K. The Company has omitted Appendices A through D and H as those appendices relate to National Grid entities that are no longer affiliated with Granite State Electric Company.

Supply lines may be overhead or underground, and operate within the voltage levels described above. With occasional exceptions, supply lines are part of a network grid, which is defined as more than one line connected between the same two substations. Usually, at least two supply lines 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 to 4 kV. Distribution voltages are regulated for utilization within specified ranges in accordance with Commission Rule Puc 304.02. Additional transformation occurs throughout 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 or 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.

4.3 <u>Distribution Planning Process</u>

The distribution systems in New England are, in general, summer peaking and summer limited. Reflecting the current National Grid process, Liberty will continue to conduct an annual capacity planning process that is intended to identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the network to respond to contingencies that might occur. The capacity planning process includes the following tasks:

- Econometric forecast of future peak demand growth;
- Weather adjustment of recent actual peak loads;
- Review of historic loading on each sub-transmission line, substation transformer, and distribution feeder;
- Analysis of forecasted peak loads versus equipment ratings;
- Consideration of system flexibility in response to various contingency scenarios; and
- Development of system enhancement project proposals.

The Company has developed a multi-step, top down / bottom up process to forecast the loading on these assets to identify the need for capacity expansion projects. First, the Company uses an econometric model to forecast summer and winter peak loads in power supply areas ("PSAs"). The explanatory variables in this 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, NH weather station. Appendix A includes the New Hampshire related information of the Company's 2012 Power Supply Area Forecast.

This model is used to simulate the historical and forecasted peak demand for each PSA under a normal and extreme weather scenario. The normal weather scenario 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 forecast of peak load for each PSA generated with the model incorporates the energy efficiency savings achieved since these savings would be reflected in the historical data used by the model. Similarly, the impact of distributed generation installed to date is also included in the historical peak demand. In developing future peak demand forecasts, the forecasted incremental energy efficiency savings beyond the amounts achieved in the current year are subtracted from the load forecast for each PSA. The incremental system-wide energy efficiency savings is apportioned to each PSA based on its proportion of total system-wide load.

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

Planning criteria for normal and contingency load serving requirements are applied in concert with the thermal ratings of the facilities to identify violations. Individual project proposals are identified to address planning criteria violations. At a conceptual level, these project proposals 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.

Guidelines have been developed 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 solves capacity deficiencies in a cost effective manner considering the net potential benefits and risks. 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-wire alternatives are screened for initial feasibility. The screening criteria are as follows:

- The wires solution, based on engineering judgment, will likely be more than $1 million;
- If load reduction is necessary, then it will be less than 20 percent of the total load in the area of the defined need;
- Start of construction is at least 36 months in the future; and
- The need is not based on Asset Condition.

The screening criteria has resulted in a relatively high 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. Also, wires solutions typically address a combination of load capacity, reliability, and asset condition issues. With combined issues, including asset condition, addressed by one wires solution, a non-wires solution is commonly determined to be infeasible or non-competitive. Furthermore, short term solution implementation; i.e. deferring the project and associated capital spending as long as practical, has resulted in cost effective solutions with shorter term need dates. Liberty intends to proceed using the current, aforementioned process applied by National Grid under the TSA with Liberty.

4.4 <u>Tools used to Model and Evaluate Liberty's Distribution System</u>

A variety of tools enable engineers to evaluate loading and voltage on all electrical system elements such as transformers, lines and other pieces of equipment. The actual electrical configuration can be modeled in these tools, which allow the simulation of various system conditions, and subsequent analysis. The main modeling and analysis applications and tools are:

- The PSSE load flow program is used to evaluate the transmission and supply systems.
- The CYME application enables analysis of distribution feeders.
- The ASPEN program assists in determining the short circuit duty at all transmission and distribution facilities that are modeled in the system.
- The Graphical Interface System geographically maps supply and distribution lines.
- The Energy Management System provides real time loading and voltage data for monitored facilities.
- The Plant Information system provides historical load and voltage data for various electrical facilities
- The FeedPro application records historic manual load readings for all New Hampshire facilities.
- The Remote Access Pulse Recorder ("RAPR") system provides monthly minimum and peak loading information for selected sites.
- The Interruption Disturbance System ("IDS") provides a consolidation and statistical analysis of reliability data compiled in the PowerOn outage management system.

4.5 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 indices of 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 average annual duration of interruption per customer served ("SAIDI"). The Company will measure its reliability performance using SAIDI and SAIFI as required by the New Hampshire Public Utilities Commission. These indices are mathematically calculated as follows:

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

SAIDI= Customer Interruption Durations ("CMI") / Total 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)

The main causes of distribution system related outages in New Hampshire are tree contacts, equipment deterioration and lightning. The planning strategy to limit the number of customers affected by these outages include the fast feeder patrols, inspection and maintenance ("I&M") program, recloser program, bare conductor replacement, underperforming area mitigation, and SCADA. The inspection and maintenance program identifies overhead equipment, including cutouts, crossarms, insulators, poles, guys and anchors and switches, that is at the end of its useful life and in need of replacement. Lightning protection upgrades include the installation of arresters, grounding and equipment bonding. Additional actions include application of animal protection and overloaded transformer replacement. The I&M program is augmented with infrared inspections of line and substation equipment, substation equipment visual and operational inspections and helicopter patrols of distribution supply facilities. The recloser program allows for 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 plans to investigate the use of single phase reclosing devices to provide mitigation against transient faults as well as limited 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 consisting 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. Other reliability initiatives include improving reliability in distribution system areas that have historically underperformed the system average and installation or upgrade of the SCADA system to improve response time to outages.

4.6 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. Multi-year projects, once initiated, 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 annually with the NHPUC as part of the E-22 filing.

5. Demand-Side Resources

Demand-side resources can be broadly defined as systems and controls in customer facilities that allow customers 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 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 utilized when economically justified; these are considered active demand resources.

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

5.1 The Link Between Demand Response and Planning

As of June 1, 2010, demand response resources participate on a comparable basis along 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, active demand response resources will eventually be treated on an equivalent basis with other generating resources. The development and ownership of active demand response resources will 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. The Company has begun screening of 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. (See non-wire alternatives discussion in Section 4.3)

5.2 Incorporation of DG Facilities Into Distribution Planning

National Grid has experienced a significant increase in the amount of distributed generation ("DG") being interconnected to its distribution system in New England. The amount is largely dependent upon incentives, including those specific to individual states. Liberty has seen a relatively modest amount of DG applications within its NH service territory. 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 felt 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.

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 of 20-25% of 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. PV typically does not impact winter peak loads, because winter peaks occur in the evenings after the sun is down. 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 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 are 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 4.3.

The interconnection process for customers to install and run DG in parallel with Liberty's distribution system is dependent on the DG size and technology.[2] DG systems with power ratings of 100 kVA 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 supply sufficient technical information to allow the Company to determine the scope and cost of any potential modifications to the Company's distribution system that may be 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.

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[2] The simplified process for inverter based systems less than 100 KW (typical most solar and small wind systems) can be found in the Company's tariff N.H.P.U.C. No. 18 on file with the Commission.

6. Energy Efficiency

6.1 Energy Efficiency Programs

New Hampshire's electric utilities, including Liberty, jointly prepare and file the CORE Energy Efficiency Programs. CORE programs have been offered since 2002. Liberty's most recently approved energy efficiency programs are described in the CORE filing in Docket No. DE 10-188, approved by Order Nos. 25,189 (December 30, 2010) and 25,315 (January 9, 2012).

Program plans must be filed every two years, but the utilities must also make mid-cycle adjustments which are subject to Commission approval. In addition, electric utilities have the authority to make commitments in the current year for projects that will be completed in future years.

There are eight CORE programs providing products and services tailored for business, residential, and income-eligible customers or members. Each year the gas and electric utilities work together to review the CORE Programs, make adjustments and improvements as needed or suggested by customers, interested parties, Staff, and energy efficiency program administrators. Program plans also include utility-specific programs that are used to test certain aspects of energy efficiency and to try new programs that may be pertinent to one utility's customers or to test new technologies.

Since the introduction of the CORE Programs in June 2002, the electric utilities have reported program results quarterly. In the beginning, results were slow to develop, but customer demand for energy efficiency products and services has steadily grown to the point where, today, the electric utilities are making commitments for projects that will be completed next year and the year after.

The CORE Energy Efficiency Programs in place today have been thoughtfully developed and enhanced by many different parties. The results of the CORE Energy Efficiency Programs since their inception in June, 2002, through December, 2011, have provided exceptional results. Key benchmarks highlighting these exceptional results include:

- The programs have saved 8.7 billion lifetime kWh, which is enough energy to power the City of Concord for 22 years.
- Saving 8.7 billion kWh is equivalent to saving $1.1 billion at today's average cost of 13.171¢/kWh[3]- benefiting both customers and the New Hampshire economy. Based on CORE Program expenditures, this represents a return for customers of more than $7 for every program dollar invested.
- The CORE Programs have provided customers with 795,000 efficiency products or services and reached customers in every city and town served by the utilities. In addition, the CORE Programs have provided training and information through customer seminars, point-of-sale displays, brochures, and catalogs to tens of thousands more.
- Reducing customers' energy needs has the added benefit of reducing power plant emissions. Based on the regional dispatch of plants, the electric utilities will reduce emissions of $C0_2$, $S0_2$, and NOx by 4.9 million tons - equivalent to the annual emissions of more than 1 million cars.

Table 6.1 below shows more information on savings since 2003.

Table 6.1. New Hampshire Core Electric Energy Efficiency Programs Results Summary – All Utilities

	kWh Savings	Customers Served	Saved (Millions)	Reductions (Tons)	kWh Cost (cents)
2003	1,368	59,467	$163.4	1,036,277	1.74
2004	925	54,323	$108.5	546,431	1.86
2005	1,022	81,581	$117.6	603,754	1.96
2006	973	86,555	$133.0	539,520	1.96
2007	986	86,113	$139.8	547,009	1.89
2008	812	109,155	$128.0	403,248	2.36
2009	806	90,664	$117.4	405,136	2.32
2010	793	109,104	$113.8	382,673	2.49
2010 RGGI-Funded Programs	249	17,275	$35.8	120,278	2.23
2011	754	100,397	$149.6	313,191	2.67
Total	**8,688**	**794,634**	**$1,206.9**	**4,897,517**	

[3] OEP's average fuel prices as of August 13, 2012: http://www.nh.gov/oep/programs/energy/fuelprice/details2.php?pid=264

Source: NHPUC Docket No. DE 12-262, 2013-2014 CORE Energy Efficiency Programs, September 17, 2012.
*In 2010, the CORE Programs received grant funding from RGGI to provide additional energy efficiency programs.
Note - C&I Measure Life adjustments were made in 2008, decreasing the Lifetime kWh Savings and increasing the Lifetime kWh Costs (e.g., New Construction measure life went from 20 to 15 years).

Overall, the programs have saved energy at an average cost of approximately 2.1 cents per lifetime kWh – as compared to the average retail price of 13.171 cents per kWh.[4] As energy costs continue to increase, these comparisons become even more compelling.

The electric utilities requested and the Commission approved the use of a single avoided cost methodology for generation, transmission, and distribution. In accordance with Commission Order No. 23,850, in DE 01-057, dated November 29, 2001, the electric utilities have based their avoided transmission and distribution costs on the weighted average of New Hampshire utility costs and have escalated them for inflation and put them in 2009 dollars. Use of common avoided costs by the utilities ensures that all New Hampshire customers will have access to the same programs and services. The electric utilities use the avoided generation costs from the *Avoided-Energy-Supply Costs in New England: 2011 Report* ("2011 AESC")[5] in determining the benefit-to-cost ratios of the CORE Programs.

The present value of avoided costs over the life of program measures was calculated using a nominal discount rate of 3.25% and a general inflation rate of 2.05%.[6] The 2011 AESC avoided costs also include a 9% generic wholesale risk premium to account for the expected differential between retail and wholesale market prices.[7]

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[4] *Id.*
[5] *Avoided Energy Supply Costs in New England: 2011Report,* Amended August 11, 2011.
[6] Prime rate as of June 1, 2012, in accordance with Energy Efficiency Working Group Report, Section 7, page 17. Prime rate data is taken from http://www.moneycafe.com/library/primerate.htm.
[7] In recognition of diversity among states and utilities in energy service procurement and retail pricing policies, the contractor provided the sponsors the option to remove the adder from the avoided cost data.

Table 6.2 below includes an adjustment to reduce the energy and capacity line loss multipliers by the estimated losses that are accounted for in the 2011 forecast of energy prices.

Table 6.2

Section 1: Marginal T&D Costs and Line Loss Factors ($2011)

	MDC ($/kW-yr)		MTC	Line Loss Multipliers				
				Transmission	Summer	Winter	On-Peak	Off-Peak
	Res.	C&I	($/kW-yr)	Capacity	Capacity	Capacity	Energy	Energy
LU	$118.71	$86.39	$49.63	1.1220	1.1500	1.1350	1.0630	1.0890
NHEC	$163.05	$163.05	$103.02	1.0207	1.0818	1.0818	1.0818	1.0818
PSNH	$31.61	$31.61	$1.77	1.0000	1.0820	1.0820	1.0820	1.0840
UNITIL	$73.03	$73.03	$29.26	1.0000	1.1217	1.1217	1.1217	1.0152

Section 2: MWh Sales to Ultimate Customers in 2011

	MWh	% of total
LU	911,923	8.52%
NHEC	744,000	6.95%
PSNH	7,815,462	73.03%
UNITIL	1,229,614	11.49%
Total	**10,700,999**	**100%**

Section 3 Weighted Average Marginal T&D Costs and Line Loss Factors
(Energy Line Loss Multipliers have been reduced by estimated transmission losses.)

	MDC ($/kW-yr)		MTC	Line Loss Multipliers				
				Transmission	Summer	Winter	On-Peak	Off-Peak
	Res	C&I	($/kW-yr)	Capacity	Capacity	Capacity	Energy	Energy
2011$	$52.93	$50.18	$16.05	1.0212	1.072	1.071	1.018	1.010

Avoided generation costs for New Hampshire, in 2011 dollars, may be found in Appendix B, pages B-23 and B-24 of the 2011 AESC study.

To evaluate each program, savings for each measure component are multiplied by the appropriate avoided cost factor for each year of the expected measure life. Program benefits are then computed through a present value formula using the real discount rate.

Savings projections for the Company's 2012 CORE Programs are found in Table 6.3. Program benefits for the Company's 2012 CORE programs are found in Table 6.4. Total Resource

Cost Test results for the Company's 2012 programs are found in Table 6.5. Because the CORE programs have reduced historic loads, they are by default incorporated into the Company's load forecasts used to conduct distribution and transmission planning efforts.

Table 6.3 Liberty's 2012 Savings

		Electric Savings, 2012								
		Capacity (kW)			Energy (MWh)					
		Annual		Lifetime	Summer (Annual)		Winter (Annual)		Total Annual MWh	Lifetime
		Summer	Winter		Peak	Off Peak	Peak	Off Peak		
		Data								
Sector	Program	Sum of Summer annual capacity saving	Sum of Winter annual capacity saving	Sum of Lifetime capacity saving	Sum of Annual Net MWh Savings	Sum of Lifetime MWh Savings	Sum of Summer annual Peak energy saving	Sum of Summer annual Off Peak energy saving	Sum of Winter annual Peak energy saving	Sum of Winter annual Off Peak energy saving
Residential		79.60	201.45	746.34	979.30	8,740.62	128.54	196.08	263.82	390.85
	A02a ENERGY STAR Homes	7.61	6.95	160.73	28.50	340.04	3.99	5.75	7.56	11.20
	A03b Home Performance with ENERGY STAR	14.78	30.05	201.13	332.45	4,621.78	43.22	66.49	89.76	132.98
	A04a ENERGY STAR Lighting	39.10	147.13	198.88	494.52	2,519.01	64.29	98.90	133.52	197.81
	A04b ENERGY STAR Products	18.11	17.32	185.60	123.83	1,259.79	17.05	24.93	32.98	48.86
Low Income		8.94	16.31	139.59	88.31	1,324.25	12.36	17.66	22.96	35.32
	B03a Home Energy Assistance	8.94	16.31	139.59	88.31	1,324.25	12.36	17.66	22.96	35.32
Com/Ind		834.98	579.34	10,825.77	4,346.65	56,484.15	941.93	506.95	1,883.86	1,013.91
	C02a New Equipment & Construction	142.84	102.06	2,155.42	592.39	9,104.73	125.93	71.54	251.85	143.07
	C03a C&I Large Retrofit	528.45	385.09	6,869.82	3,041.27	39,536.53	634.43	379.33	1,268.85	758.66
	C03b Small Business Energy Solutions	163.68	92.19	1,800.52	712.99	7,842.89	181.58	56.09	363.15	112.17
Grand Total		**923.52**	**797.10**	**11,711.69**	**5,414.26**	**66,549.02**	**1,082.84**	**720.69**	**2,170.65**	**1,440.09**

Table 6.4 Liberty's 2012 Program Cost-Effectiveness

	Total Benefits	Electric Benefits, 2012 ($)								Total Non Energy Benefits
		Capacity				Energy				
		Generation		Trans.	Distrib.	Winter		Summer		
		Summer	Winter			Peak	Off Peak	Peak	Off Peak	
Residential	$ 1,286,852	$ 36,063	$ -	$ 9,805	$ 32,474	$ 157,698	$ 203,932	$ 83,508	$ 100,390	$ 662,983
A02a ENERGY STAR Homes	$ 503,766	$ 10,748	$ -	$ 2,002	$ 6,630	$ 6,211	$ 7,979	$ 3,875	$ 4,171	$ 462,150
A03b Home Performance with ENERGY STAR	$ 367,466	$ 10,549	$ -	$ 2,633	$ 8,721	$ 87,052	$ 112,559	$ 45,002	$ 55,208	$ 45,741
A04a ENERGY STAR Lighting	$ 165,158	$ 7,388	$ -	$ 2,753	$ 9,118	$ 42,331	$ 54,561	$ 22,277	$ 26,731	$ -
A04b ENERGY STAR Products	$ 250,463	$ 7,378	$ -	$ 2,417	$ 8,006	$ 22,104	$ 28,833	$ 12,353	$ 14,280	$ 155,092
Low Income	$ 495,522	$ 8,014	$ -	$ 1,807	$ 5,984	$ 23,959	$ 32,250	$ 13,894	$ 15,794	$ 393,820
B03a Home Energy Assistance	$ 495,522	$ 8,014	$ -	$ 1,807	$ 5,984	$ 23,959	$ 32,250	$ 13,894	$ 15,794	$ 393,820
Com/Ind	$ 4,855,927	$ 518,957	$ -	$ 143,143	$ 474,085	$ 1,646,061	$ 791,881	$ 895,718	$ 386,079	$ -
C02a New Equipment & Construction	$ 849,752	$ 117,407	$ -	$ 28,167	$ 93,288	$ 267,461	$ 133,372	$ 144,846	$ 65,210	$ -
C03a C&I Large Retrofit	$ 3,315,860	$ 328,874	$ -	$ 90,883	$ 300,999	$ 1,115,141	$ 586,806	$ 607,171	$ 285,986	$ -
C03b Small Business Energy Solutions	$ 690,314	$ 72,675	$ -	$ 24,094	$ 79,798	$ 263,459	$ 71,703	$ 143,701	$ 34,884	$ -
Grand Total	**$ 6,638,301**	**$ 563,034**	**$ -**	**$ 154,755**	**$ 512,544**	**$ 1,827,718**	**$ 1,028,063**	**$ 993,120**	**$ 502,263**	**$ 1,056,803**

Table 6.5.Liberty's 2012 Total Resource Cost Test					
Program	**Total Resource Benefit/Cost Ratio**	**Benefit ($000)**	**Utility Costs ($000)**	**Customer Costs ($000)**	**Shareholder Incentive ($000)**
Residential Market					
Energy Star Homes	4.37	$504	$105	$11	
Home Performance w/Energy Star	2.46	$367	$141	$8	
Energy Star Lighting	1.37	$165	$81	$40	
Energy Star Appliances	1.90	$250	$80	$51	
Home Energy Assistance	2.23	$496	$222	$0	
Subtotal Residential	**2.26**	**$1,782**	**$629**	**$110**	**$50.3**
Commercial / Industrial Programs					
New Construction / Major Renovation	2.66	$850	$250	$70	
Large C&I Retrofit	3.32	$3,316	$406	$593	
Small C&I Retrofit	2.01	$690	$216	$127	
Subtotal C&I	**2.80**	**$4,856**	**$872**	**$790**	**$69.7**
Total Residential and C&I		**$6,638**	**$1,501**	**$900**	**$120.0**

Table 6.6 details the program-by-program participant, savings, benefit cost ratio and planned budget targets for all utility CORE Energy Efficiency programs in New Hampshire.

Table 6.6: New Hampshire CORE Energy Efficiency Goals – 2012: All Utilities					
Programs	**LU**	**NHEC**	**PSNH**	**UNITIL**	**Totals**
ES Homes					
Quantity	25	57	384	39	505
Lifetime kWh Savings	340,042	915,068	9,627,607	2,481,582	13,364,299
B/C Ratio	4.37	4.56	5.24	3.70	
Planned Budget	$104,606	$160,909	$1,033,392	$200,000	$1,498,907
Home Performance with ES					
Quantity	145	59	1,036	68	1,308
Lifetime kWh Savings	4,621,783	5,474,363	1,482,626	1,205,185	12,783,957
B/C Ratio	2.46	2.50	2.10	1.55	
Planned Budget	$141,234	$180,773	$1,660,101	$250,000	$2,232,108
ES Appliances					
Quantity	875	1,914	13,783	1,617	18,189
Lifetime kWh Savings	1,259,794	3,674,464	20,632,001	3,401,933	28,968,192
B/C Ratio	1.90	1.40	1.42	1.40	
Planned Budget	$80,477	$142,099	$779,277	$124,042	$1,125,895
Home Energy Assistance					
Quantity	54	61	760	73	948
Lifetime kWh Savings	1,324,252	883,391	10,469,536	1,261,874	13,939,053
B/C Ratio	2.23	2.21	2.22	2.90	
Planned Budget	$222,043	$215,596	$2,182,267	$359,456	$2,979,362
ES Lighting					
Quantity	14,507	39,467	222,353	54,375	330,702
Lifetime kWh Savings	2,519,006	6,791,203	38,397,028	8,742,738	56,449,975
B/C Ratio	1.37	2.35	2.37	2.52	
Planned Budget	$80,893	$108,145	$762,454	$165,431	$1,116,923
C&I New Equipment &Construction					
Quantity	13	14	94	14	135
Lifetime kWh Savings	9,104,723	5,803,325	85,348,090	9,197,573	109,453,715
B/C Ratio	2.66	1.22	3.39	2.70	
Planned Budget	$249,966	$129,381	$1,704,429	$237,805	$2,321,581
Large C&I Retrofit					
Quantity	26	23	101	26	176
Lifetime kWh Savings	39,536,529	6,004,825	101,484,572	28,244,540	175,270,465
B/C Ratio	3.32	1.04	1.51	1.90	
Planned Budget	$405,626	$147,991	$2,260,058	$520,000	$3,333,675

Table 6.6 continued					
Programs	LU	NHEC	PSNH	UNITIL	Totals
Small Business Energy Solutions					
Quantity	33	31	1,047	58	1,169
Lifetime kWh Savings	7,842,891	4,815,514	94,040,728	15,640,147	122,339,281
B/C Ratio	2.01	1.33	1.48	1.70	
Planned Budget	$216,109	$164,949	$2,816,642	$418,049	$3,615,749
Educational Programs (1)					
Planned Budget	$9,496	$35,609	$103,793	$0	$139,402
Company Specific Programs					
Quantity		20	25,079		
Lifetime kWh Savings		10,214,662	67,174,001		77,388,663
B/C Ratio		2.29			
Planned Budget	$0	$138,428	$1,211,033	$70,040	$1,419,501
Smart Start Program					
Planned Budget	$0	$13,424	$35,000	$0	$48,424
Utility Incentive					
Planned Budget	$120,076	$98,984	$1,161,076	$187,586	$1,567,721
TOTAL PLANNED BUDGET	**$1,621,030**	**$1,536,288**	**$15,709,522**	**$2,532,409**	**$21,399,249**

Note: Liberty's Educational Program budget is included within other program budgets and therefore is not included in the total to avoid double counting.

6.2 ISO-NE Forward Capacity Markets[8]

On June 16, 2006, FERC approved a Settlement Agreement that addressed the future capacity needs of New England and laid the groundwork for the Forward Capacity Market. Effective December 1, 2006, under the Forward Capacity Market Transition Period rules, ISO-NE was obligated to pay for qualified capacity reductions in accordance with a determined rate schedule from December 1, 2006 to May 31, 2010. All generation and demand resources installed after June 16, 2006, have been eligible to receive capacity payments in accordance with ISO-NE's Market

[8] http://www.iso-ne.com/markets/othrmkts_data/fcm/index.html

Rules. June 1, 2010 marked the end of the Forward Capacity Market Transition Period and the beginning of ISO-NE Forward Capacity Market.

The first Commitment Period of the Forward Capacity Market was June 1, 2010 through May 31, 2011. New Hampshire CORE Energy Efficiency Program capacity reductions continue to receive capacity payments under the Forward Capacity Market. The utilities have capacity supply obligations for their CORE program capacity reductions through the sixth Forward Capacity Market, which ends on May 31, 2016. The utilities recently submitted Qualification Packages to participate in the upcoming seventh Forward Capacity Auction, scheduled to commence on February 4, 2013. Liberty intends to take all necessary steps to continue to qualify capacity supply obligations from the CORE programs' capacity reductions in future Forward Capacity Markets.

As the Forward Capacity Market matures, ISO-NE continues to identify additional reporting requirements, resulting in increased workload on the utilities to continue to qualify energy efficiency program obligations in the market. In addition to the annual submission of the qualification package and monthly reporting of the performance values of energy efficiency assets, all of the electric utilities are now required to submit an annual certification based on an audit performed by an external auditor, provide historical energy efficiency data to allow ISO-NE to develop more accurate forecasts, provide a detailed database of all energy efficiency measures and their expiration dates, and respond to an increasing number of data requests.

As approved by the Commission in 2008, Liberty will continue the policy of reporting to ISO-NE the demand savings achieved via these energy efficiency programs in the Forward Capacity Market. Customers who participate in these energy efficiency programs must agree to forego any associated ISO-NE qualifying capacity payments and allow Liberty to report demand savings and collect the capacity payments on behalf of all customers. All ISO-NE capacity payments received will be used to supplement Liberty's energy efficiency program budgets which will provide additional energy efficiency opportunities for Liberty's electric customers.