Appendix A. LCIRP Statutory Requirements

Figure A-1. LCIRP Compliance with Statutory Requirements

RSA 378:37 Statutory Requirement	Location in LCIRP
A forecast of future demand for the utility's service area.	Section 2; Appendix B
An assessment of demand-side energy management programs, including conservation, efficiency, and load management programs.	Section 6.
An assessment of supply options including owned capacity, market procurements, renewable energy, and distributed energy resources.	Section 3; Section 4; Section 5.
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.	Section 3; Section 4.
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.	Executive Summary; Appendix A.
An assessment of the plan's long- and short-term environmental, economic, and energy price and supply impact on the state.	Executive Summary; Section 3; Section 4.4; Section 6.
An assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1	Executive Summary; Appendix A.

Consistency with the Federal Clean Air Act

RSA 378:38 V states that a utility's LCIRP shall include "an assessment of plan integration and impact on state compliance with the Clean Air Act of 1990 ("CAA"), as amended, and other environmental laws that may impact a utility's assets or customers."

As explained in more detail in Section 3, as a result of restructuring in 1998, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") does not own generation, and therefore is not subject to CAA Section 112 compliance requirements on electric generating facilities (i.e., "stationary sources"). Further, Liberty Utilities purchases electricity supply from the wholesale market, which is increasingly dominated by cleaner natural gas in the New England region, while generation from coal and oil has declined.[1]

In addition, renewable sources of electric generation and energy efficiency are increasing within the ISO-NE's resource mix. According to the ISO-NE, 42% of the proposed generation in the interconnection queue is for wind resources. Because much of the new capacity pending is from renewable resources and natural gas, the regional resource mix is becoming increasingly less carbon intensive. Since Liberty's electricity supply as procured through its Energy Service RFP (described in Section 3), and therefore is representative of the regional resource mix, Liberty's electricity supply is expected to become increasingly less carbon intensive over time.

1 See, "State of the Grid: Managing a System in Transition," Presentation by Gordon Van Welie, CEO ISO-NE, January 21, 2015, slide 13. http://www.iso-ne.com/static-assets/documents/2015/01/stateofgrid_presentation_01212015.pdf

Finally, the recently released Clean Power Plan[2] (which is promulgated under the CAA) established greenhouse gas emission guidelines specifically targeted to fossil fuel-fired electric generating plants. As noted earlier, Liberty does not own generation which would be subject to the Clean Power Plan's regulations. However, New England's evolvement away from coal-fired plants, combined with the increase in low- and zero-carbon generation means that the New England is well positioned to benefit and comply with Clean Power Plan. In fact, one analysis ranked New Hampshire second among U.S. states regarding its ease of compliance with the Clean Power Plan.[3] According to that analysis, New Hampshire is already 35% below its emissions goal set by the Clean Power Plan.

Consistency with the New Hampshire State Energy Plan

RSA 378:38 requires an LCIRP to include "an assessment of plan integration and consistency with the state energy strategy under RSA 4-E:1." As described below, Liberty's LCIRP is consistent with the New Hampshire 10-year State Energy Strategy ("SES"), released by the New Hampshire Office of Energy and Planning in September 2014, and implemented by Governor Hassan on July 8, 2015.

The SES provides recommendations regarding New Hampshire's energy policies and programs organized into four categories: (1) Electric Grid of the Future, (2) Energy Efficiency (3) Fuel Diversity and Choice, and (4) Transportation Options.[4] As the first

2 http://www2.epa.gov/sites/production/files/2015-08/documents/cpp-final-rule.pdf

3 Grant, Annalee, "Some states still have long road to Clean Power Plan compliance," SNL Financial, August 5, 2015.

4 New Hampshire Office of Energy & Planning, *New Hampshire 10-Year State Energy Strategy*, September

three categories apply to the electric utilities, this section addresses the LCIRP's compliance with those categories.

Electric Grid of the Future

The SES recommends the Commission open an investigation into Grid Modernization.[5] Pursuant to House Bill 614, the Commission opened Docket No. IR 15-296 *Electric Distribution Utilities Investigation into Grid Modernization* on July 30, 2015. The purpose of the proceeding is to gather information and "give stakeholders a chance to learn about grid modernization and to explore to what extent that grid modernization is workable in New Hampshire."[6] On September 17, 2015, Liberty Utilities filed initial comments and will continue to be an active participant in the proceeding. As described in Section 4.10, Liberty has provided an assessment of Smart Grid technologies (technologies that are often encompassed in the discussion of grid modernization), and has installed certain distribution automation technologies onto its distribution system. Therefore, this LCIRP is consistent with the SES's recommendations with respect to grid modernization and the "electric grid of the future."

Energy Efficiency

The SES recommends that the state prioritize capturing more energy efficiency in all sectors through (1) establishing an efficiency goal, (2) addressing utility disincentives, (3) improving program coordination, (4) increasing access to financing, and (5) increasing

---

2014, at i-ix.

5 *Ibid*., at 21.

6 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, at 2.

funding for low-income energy efficiency programs.[7] The recommendations also included increasing state "lead by example" programs, and adopting newest building codes, however these recommendations are not relevant to utility energy efficiency efforts. Liberty supports these recommendations, and will participate in efforts to address these recommendations.

With respect to establishing an efficiency goal, Liberty is an active participant in Docket No. DE 15-137, the Commission's EERS proceeding. As described in Section 6.5, Liberty Utilities 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.

Fuel Diversity and Customer Choice

The SES recommends fostering sustainable, diverse energy development through enabling policies and regulatory frameworks.[8] One important aspect of this is encouraging distributed generation.[9] As noted in Section 4.9, Liberty has experienced a significant increase in the amount of distributed generation being interconnected to its distribution system in New Hampshire through the installation of customer-sited generation. In fact, Liberty reached its net metering cap on July 28, 2015. In addition, as described in Section 5.3, Liberty is in the process of evaluating investment in a renewable distributed energy resource, although such discussions are in the infancy stage. Should

7 New Hampshire Office of Energy & Planning, *New Hampshire 10-Year State Energy Strategy*, September 2014, at 23.

8 *Ibid*., at 47.

9 *Ibid*., at iv.

Liberty determine the benefits of a particular company-owned distributed generation project outweigh the project’s cost, the Company will submit a filing to the Commission pursuant to RSA 374-G:5, and would treat 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. Therefore, Liberty’s distribution planning process currently considers and incorporates distributed generation, and has begun the evaluation process of owning distributed generation, in light of the current net metering cap.

Accordingly, in Liberty’s assessment, this LCIRP consistent with the SES as required in RSA 378:38.

Liberty Utilities New Hampshire

Final Seasonal Peak Forecasts 2015-2031

Prepared By

Business Economic Analysis and Research

November 2015

Summary of Results

The weather adjusted actual seasonal peaks appear in Table 1 below for Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities (”Liberty” or the “Company”). Note that the peak load series reflects the historic impacts of both energy efficiency programs and distributed generation activities in the Company’s service territory. Since the forecast is based on normal weather conditions, weather adjusting actual peaks enhances comparisons between historic and forecasted peaks.

Table 1
Historic Weather Adjusted Peaks

year	Summer month	Wthr Adj Peak Mw	Growth	Winter month	Wthr Adj Peak Mw	Growth
2001	8	173.875		12	137.045	
2002	7	166.678	-4.14%	12	144.988	5.80%
2003	7	173.651	4.18%	12	143.697	-0.89%
2004	7	184.579	6.29%	1	150.739	4.90%
2005	7	193.663	4.92%	12	161.986	7.46%
2006	7	186.289	-3.81%	1	153.941	-4.97%
2007	7	186.814	0.28%	12	151.874	-1.34%
2008	7	194.471	4.10%	12	145.805	-4.00%
2009	7	189.679	-2.46%	12	153.104	5.01%
2010	7	188.461	-0.64%	12	147.963	-3.36%
2011	8	198.758	5.46%	2	151.458	2.36%
2012	7	187.254	-5.79%	1	152.763	0.86%
2013	7	193.896	3.55%	12	154.56	1.18%
2014	7	200.129	3.21%	1	158.652	2.65%
2010-2014 Avg			1.10%			0.72%

The summer peak has grown 1.1% per year over the past five years compared to the winter peak rising .7% annually over the same period.

Table 2 displays the Company’s 2015-2031 seasonal peak forecasts under normal peak day weather conditions. The forecasted peak values include the historic impacts from both energy efficiency programs and distributed generation activities in the Company's service territory. The 2015 growth is based on the 2014 weather adjusted actual shown in Table 1.

Table 2
Forecasted Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	199.313	-0.41%	12	155.796	-1.80%
2016	7	202.412	1.55%	12	157.98	1.40%
2017	7	205.062	1.31%	12	159.445	0.93%
2018	7	207.097	0.99%	12	160.367	0.58%
2019	7	208.843	0.84%	12	161.184	0.51%
2020	7	210.61	0.85%	12	162.111	0.58%
2021	7	212.504	0.90%	12	163.176	0.66%
2022	7	214.425	0.90%	12	164.191	0.62%
2023	7	216.315	0.88%	12	165.186	0.61%
2024	7	218.118	0.83%	12	166.048	0.52%
2025	7	219.853	0.80%	12	166.888	0.51%
2026	7	221.551	0.77%	12	167.681	0.48%
2027	7	223.187	0.74%	12	168.401	0.43%
2028	7	224.798	0.72%	12	169.129	0.43%
2029	7	226.386	0.71%	12	169.812	0.40%
2030	7	227.977	0.70%	12	170.533	0.42%
2031	7	229.572	0.70%	12	171.235	0.41%
2017-2021 Avg			1.00%			0.66%

The average annual summer growth rate in peak for 2017-2021 is 1% while the winter average annual growth rate is .66% over the same period.

Table 3 provides the Liberty's 2015-2031 seasonal peak forecasts under extreme weather. Although the peaks are higher, the annual growth rates for 2017-2021 are slightly less than the growth rates using normal weather.

Table 3

Forecasted Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	218.904		12	171.95	
2016	7	222.054	1.44%	12	174.134	1.27%
2017	7	224.755	1.22%	12	175.599	0.84%
2018	7	226.84	0.93%	12	176.521	0.53%
2019	7	228.637	0.79%	12	177.338	0.46%
2020	7	230.455	0.80%	12	178.265	0.52%
2021	7	232.399	0.84%	12	179.33	0.60%
2022	7	234.371	0.85%	12	180.345	0.57%
2023	7	236.311	0.83%	12	181.34	0.55%
2024	7	238.165	0.78%	12	182.202	0.48%
2025	7	239.951	0.75%	12	183.042	0.46%
2026	7	241.7	0.73%	12	183.835	0.43%
2027	7	243.387	0.70%	12	184.555	0.39%
2028	7	245.048	0.68%	12	185.283	0.39%
2029	7	246.686	0.67%	12	185.966	0.37%
2030	7	248.328	0.67%	12	186.687	0.39%
2031	7	249.974	0.66%	12	187.389	0.38%
2017-2021 Avg			0.93%			0.60%

In previous peak day studies performed by National Grid, Eastern PSA and Western PSA hourly data was the source of historic peak day analysis and subsequent forecasts. In this study, Liberty's system hourly data was the only source of historic peak day analysis. Once the Company's system seasonal peak day forecasts were developed in this analysis, Eastern PSA and Western PSA forecasts were derived by using July and December 2014 coincident peak Eastern and Western PSA percent contributions. Table 4 below reveals the Eastern PSA seasonal forecasts under normal weather conditions.

Table 4

Eastern PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	99.3675		12	73.9954	
2016	7	100.9126	1.55%	12	75.0327	1.40%
2017	7	102.2336	1.31%	12	75.7283	0.93%
2018	7	103.2482	0.99%	12	76.1664	0.58%
2019	7	104.1187	0.84%	12	76.5543	0.51%
2020	7	104.9995	0.85%	12	76.9946	0.58%
2021	7	105.9439	0.90%	12	77.5004	0.66%
2022	7	106.9016	0.90%	12	77.9825	0.62%
2023	7	107.8438	0.88%	12	78.4551	0.61%
2024	7	108.7428	0.83%	12	78.8644	0.52%
2025	7	109.6078	0.80%	12	79.2635	0.51%
2026	7	110.4542	0.77%	12	79.6401	0.48%
2027	7	111.27	0.74%	12	79.982	0.43%
2028	7	112.073	0.72%	12	80.3279	0.43%
2029	7	112.8648	0.71%	12	80.6522	0.40%
2030	7	113.6579	0.70%	12	80.9946	0.42%
2031	7	114.4531	0.70%	12	81.3281	0.41%
2017-2021 Avg			1.00%			0.66%

Table 5 lists the Western PSA seasonal forecasts under normal weather conditions. The summer Western PSA numbers are just slightly higher than the Eastern peak day values while the winter Western PSA peaks are around 10% higher than the Eastern numbers.

Table 5

Western PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	99.9454		12	81.8007	
2016	7	101.4994	1.55%	12	82.9473	1.40%
2017	7	102.8283	1.31%	12	83.7168	0.93%
2018	7	103.8489	0.99%	12	84.2007	0.58%
2019	7	104.7246	0.84%	12	84.6296	0.51%
2020	7	105.6103	0.85%	12	85.1164	0.58%
2021	7	106.5601	0.90%	12	85.6756	0.66%
2022	7	107.5235	0.90%	12	86.2086	0.62%
2023	7	108.4709	0.88%	12	86.7308	0.61%
2024	7	109.3754	0.83%	12	87.1835	0.52%
2025	7	110.2453	0.80%	12	87.6244	0.51%
2026	7	111.0966	0.77%	12	88.0409	0.48%
2027	7	111.9171	0.74%	12	88.419	0.43%
2028	7	112.725	0.72%	12	88.8013	0.43%
2029	7	113.5213	0.71%	12	89.1598	0.40%
2030	7	114.3191	0.70%	12	89.5383	0.42%
2031	7	115.1188	0.70%	12	89.9069	0.41%
2017-2021 Avg			1.00%			0.66%

Tables 6 and 7 provide the Eastern PSA and Western PSA seasonal forecasts under extreme weather conditions. As the case with the normal weather forecasts, The summer Eastern PSA values are just slightly lower than the Western PSA numbers while the winter Western PSA peaks are 10% than Eastern PSA peak values..

Table 6

Eastern PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	109.1346		12	81.6677	
2016	7	110.7051	1.44%	12	82.7049	1.27%
2017	7	112.0515	1.22%	12	83.4008	0.84%
2018	7	113.0911	0.93%	12	83.8387	0.53%
2019	7	113.987	0.79%	12	84.2266	0.46%
2020	7	114.8934	0.80%	12	84.667	0.52%
2021	7	115.8625	0.84%	12	85.1728	0.60%
2022	7	116.8456	0.85%	12	85.655	0.57%
2023	7	117.8128	0.83%	12	86.1274	0.55%
2024	7	118.7372	0.78%	12	86.5368	0.48%
2025	7	119.6276	0.75%	12	86.9358	0.46%
2026	7	120.4995	0.73%	12	87.3125	0.43%
2027	7	121.3406	0.70%	12	87.6544	0.39%
2028	7	122.1687	0.68%	12	88.0002	0.39%
2029	7	122.9852	0.67%	12	88.3246	0.37%
2030	7	123.8039	0.67%	12	88.6669	0.39%
2031	7	124.6246	0.66%	12	89.0005	0.38%
2017-2021 Avg			0.93%			0.60%

Table 7
Western PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2015	7	109.7695		12	90.2823	
2016	7	111.3491	1.44%	12	91.429	1.27%
2017	7	112.7035	1.22%	12	92.1985	0.84%
2018	7	113.7489	0.93%	12	92.6823	0.52%
2019	7	114.65	0.79%	12	93.1112	0.46%
2020	7	115.5617	0.80%	12	93.598	0.52%
2021	7	116.5364	0.84%	12	94.1573	0.60%
2022	7	117.5254	0.85%	12	94.69	0.57%
2023	7	118.4981	0.83%	12	95.2126	0.55%
2024	7	119.4276	0.78%	12	95.6653	0.48%
2025	7	120.3233	0.75%	12	96.1062	0.46%
2026	7	121.2006	0.73%	12	96.5226	0.43%
2027	7	122.0464	0.70%	12	96.9005	0.39%
2028	7	122.8793	0.68%	12	97.2829	0.39%
2029	7	123.7009	0.67%	12	97.6414	0.37%
2030	7	124.524	0.67%	12	98.02	0.39%
2031	7	125.3498	0.66%	12	98.3887	0.38%
2017-2021 Avg			0.93%			0.60%

The report describes the analytical approach employed in developing the seasonal Company forecasts and details the data available for the analysis.

Introduction

This report presents the Liberty Utilities (Granite State Electric) d/b/a Liberty Utilities (”Liberty” or the “Company”) seasonal peak forecasts for 2015-2031 under both normal and extreme weather. Regression analysis was used to estimate the Liberty’s historic monthly peak day model. The historic monthly peaks were net of all energy efficiency and distributed generation load impacts. The monthly peak day model coefficients were then employed to develop seasonal peak forecasts at the Company’s system level. The Liberty’s system seasonal peak forecasts were then split into Eastern and Western jurisdictions using the Company’s township sales information as well as July and December 2014 peak coincident Eastern and Western PSA percent contributions.

The remainder of this report is organized as follows. First, the data used in the analysis is described. Second, the regression model specifications are provided. Third, the results from the regression models are discussed. Finally, the 2015-2031 seasonal forecast process is detailed.

Data

There were three data sources employed to perform the historic peak day modeling. These sources include Liberty’s hourly load and annual township sales, economic drivers for the Company’s service area, and daily weather information.

Hourly system load for the Company from October 2000 through April 2014 was supplied by National Grid while historic system loads from May 2014 through June 2015 was provided by Liberty staff. The Company also supplied hourly Eastern and Western PSA loads for March 2014 through June 2015. The historic peak load data includes the impacts of energy efficiency programs as well as distributed generation activities. Also, National Grid supplied annual sales data for 21 townships from 1996 through 2013 and 2014 township volumes came from Liberty. The 2014 township volumes collapsed 2 small townships into larger ones so the 1996 through 2013 data was aggregated as well down to 19 townships.

The system load and annual township sales information was utilized to create the dependent variables for the various regression models estimated. For the monthly peak day analysis, the maximum hourly load for each month from October 2000 through June 2015 was identified as the dependent variable. A total of 177 months of peaks are used in the peak day analysis. Each of the 19 townships has 19 years of annual sales in the annual usage analysis. Appendix A contains the historic monthly peak values for Liberty.

Annual employment and number of households for Rockingham and Grafton counties from 1970 through 2043 was purchased from Moody's Economy.com to develop an economic variable for the monthly peak model. Employment and household values were summed across the two counties. Each series was then divided by the 2014 employment and household value to create annual ratios. The annual ratios were then combined using a 60% weight for employment and 40% weight for households based on previous work performed by National Grid. The annual ratios were converted to monthly numbers over the historic and forecast period by spreading the annual growth rate into 12 equal parts. Appendix B reveals the annual total employment and total households for Rockingham and Grafton counties from 2000 to 2031 along with the development of the annual employment/household ratio term.

Weather information came from NOAA. Daily high temperature, low temperature, and dew point temperature information from the Concord New Hampshire Airport (WBAN #14745) was obtained for March 1994 through June 2015. Using the above mentioned weather elements, the temperature humidity index (THI) and heating degree days (HDD) were used in the peak day modeling analysis while annual cooling degree days (CDD) was used when modeling annual township sales. The discussion of how each specific weather element is computed resides in the model specification section of this report.

Specification of Models

This section first provides the specification of the peak day model followed by a description of the annual township sales models.

Peak Day Model Specification

The monthly peak day usage was primarily driven by weather conditions. The most important weather term was the temperature humidity index (THI). The daily THI was defined as follows:

THI = .55 * maximum temperature + .2 * average dew point temperature + 17.5

A weighted THI variable (WTHI) was used in the model to account for the heat buildup impact on energy usage. The WTHI equaled:

WTHI = .7 * THI on the peak day + .2 * THI day before + .1 * THI two days before

In addition to the WTHI term, a summer period (June through September) indicator was interacted with the WTHI as follows:

WTHI_SUMMER = WTHI * summer period

To account for the increased saturation of air conditioning in the service territory, the WTHI_SUMMER term defined above was also interacted with a time trend term (the value of the trend started at 1 in year 2000 and increased to 16 in year 2015) as described below:

WTHI_SUMMER_T = WTHI_SUMMER * time trend

The coefficient values of three THI terms defined above are expected to be positive in the regression model based on the assumption that the higher the WTHI value, the higher the peak day value will be. To account for peaks during the winter period, a heating degree day (HDD) term was added based on the maximum daily temperature on the peak day, the day before the peak, and two days prior to the peak (WTMAX). WTMAX equaled:

WTMAX = .7*max temp on peak day + 2*max temp day before +.1*max temp 2 days before

The term HDD was defined as

HDD = (55 – WTMAX), or 0 if the value of WTMAX was greater than or equal to 55

The expected value of the HDD coefficient in the regression equation is greater than zero which suggests the peak day use rises as the temperature becomes colder. The economic variable included in the peak day model was the weighted employment and household (EMP_HH) index variable discussed in the previous section of this report. EMP_HH was defined as

EMP_HH = .6 * employment index + .4 * household index

The index portion of this variable was computed by dividing the actual employment and household count variables by the 2014 values. It is expected that a positive relationship exists between peak day use and the value of the index. The remaining variables included in the peak day model were monthly indicators. These indicators take the value of one for a particular month, zero otherwise. The monthly indicators included are as follows:

FEB = one if month is February, zero otherwise
MAR = one if month is March, zero otherwise
APR = one if month is April, zero otherwise
MAY = one if month is May, zero otherwise
JUN = one if month is June, zero otherwise
JUL = one if month is July, zero otherwise
AUG = one if month is August, zero otherwise
SEP = one if month is September, zero otherwise

OCT = one if month is October, zero otherwise

NOV = one if month is November, zero otherwise

DEC = one if month is December, zero otherwise

The final Liberty Utilities' peak day model expressed in mathematical terms is as follows:

PeakDay Mw = a + b * WTHI + c * WTHI_SUMMER + d * WTHI_SUMMER_T
+ e * HDD + f * EMP_HH + g * FEB + h * MAR + i * APR + j * MAY
+ k * JUN + l * JUL + m * AUG + n * SEP + o * OCT + p * NOV
+ q * DEC

Values of the estimated coefficients (a, b …, q) will be presented and discussed in the next section of the report.

Annual Township Sales Model Specification

The principal factor that influences annual sales at the township level has been a time trend that takes the value of one in 1996 and increases to nineteen in 2014. In order to flatten the change in township usage over the historic period, the time trend variable was expressed as a log function. The trend term variable was expressed as follows:

TIME = log(time trend value + 1)

The value of TIME is expected to have a positive coefficient value if the township experienced sales growth from 1996 through 2014 and a negative value if township sales declined from 1996 through 2014. The other term included in the annual township sales models was annual cooling degree days (CDD). CDD was based on the average daily temperature (daily maximum temperature plus daily minimum temperature divided by two). Daily cooling degree days was defined as:

CDD = (average temp – 60), or 0 if the average temp was less than or equal to 60.

The daily CDD values were then summed for the entire calendar year for final inclusion into the township models. It was expected that a positive relationship existed between CDD and annual sales. Township regression models that generated a negative coefficient for CDD had that variable removed from the analysis. The final Liberty's annual township models expressed in mathematical terms are as follows:

Annual kWh = a + b * TIME + c * CDD

Values of the estimated coefficients (a, b, and c) will be presented and discussed in the next section of the report.

Regression Results

This section provides the overall model statistics as well as estimated coefficient values for the peak day and annual township models. The peak day model adjusted R-Squared value was .8849 which means that nearly 89% of the monthly historic peak day variation was explained by the model coefficients. The monthly peak day Mw model coefficients are as follows:

Variable	Paramete Estimate	Standard Error	t Value	Pr > |t|
INTERCEPT	-46.8292	25.40824	-1.84	0.0672
WTHI	0.76096	0.18505	4.11	<.0001
WTHI_SUMMER	3.25022	0.41489	7.83	<.0001
WTHI_SUMMER_T	0.01083	0.00333	3.25	0.0014
HDD	0.96334	0.22181	4.34	<.0001
EMP_HH	142.2944	23.1543	6.15	<.0001
FEB	-3.48033	2.66356	-1.31	0.1932
MAR	-5.34398	3.04075	-1.76	0.0808
APR	-12.9568	4.46431	-2.9	0.0042
MAY	0.71348	5.11165	0.14	0.8892
JUN	-245.913	32.64396	-7.53	<.0001
JUL	-239.727	33.12579	-7.24	<.0001
AUG	-239.712	32.70451	-7.33	<.0001
SEP	-247.548	31.59307	-7.84	<.0001
OCT	-8.24361	4.62948	-1.78	0.0769
NOV	-1.39235	3.8702	-0.36	0.7195
DEC	5.12178	2.8728	1.78	0.0765

The values of the WTHI terms have the expected positive coefficient signs and significant. The HDD term also has a significant expected positive coefficient sign. Likewise, the EMP_HH term has a significant expected positive coefficient sign. Only the MAY and NOV monthly terms are not significant at the 80% level. The JUN through SEP indicators have large negative values to offset the impact of the WTHI_SUMMER and WTHI_SUMMER_T terms.

The Eastern area annual kWh models by township appear as follows:

Eastern Township Regression Results

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Derry					R-Square	0.3529
INTERCEPT	-3493264	2136944	-1.63	0.1216		
TIME	998428	404077	2.47	0.0251		
CDD	3572.64828	2104.691	1.7	0.109		
Town=Pelham					R-Square	0.834
INTERCEPT	19232924	8360317	2.3	0.0352		
TIME	13322218	1580860	8.43	<.0001		
CDD	19574	8234.131	2.38	0.0303		
Town=Salem, NH					R-Square	0.3383
Intercept	256536329	22096730	11.61	<.0001		
TIME	5279480	4045708	1.3	0.2116		
CDD	26369	21928	1.2	0.2478		
YEAR 2005	26898621	11744909	2.29	0.0369		
Town=Windham					R-Square	0.7112
INTERCEPT	8335088	1538759	5.42	<.0001		
TIME	1732772	290965	5.96	<.0001		
CDD	2586.33988	1515.534	1.71	0.1072		

Note that the Salem Township had a year 2005 indicator variable added to capture a spike in annual usage for that year. All the CDD terms were significant at the 75% confidence level which is reasonable for a nineteen year historic series.

Western area annual kWh models by township are displayed below. The Grafton Township had a year 2002 indicator variable to capture a spike in usage for that year.

Western Township Regression Results #1

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Acworth					R-Square	0.3069
INTERCEPT	1130816	46617	24.26	<.0001		
TIME	56367	20488	2.75	0.0142		
Town=Alstead					R-Square	0.248
INTERCEPT	9821812	750006	13.1	<.0001		
TIME	386451	141819	2.72	0.015		
CDD	8.50767	738.6861	0.01	0.991		
Town=Bath					R-Square	0.5497
INTERCEPT	-24660	21340	-1.16	0.2648		
TIME	16285	4035.252	4.04	0.001		
CDD	35.25448	21.01818	1.68	0.1129		
Town=Canaan					R-Square	0.7445
INTERCEPT	9263950	894915	10.35	<.0001		
TIME	1137419	169220	6.72	<.0001		
CDD	1121.183	881.4081	1.27	0.2215		
Town=Charlestown, NH					R-Square	0.6091
INTERCEPT	8303211	6348242	1.31	0.2094		
TIME	6220352	1200395	5.18	<.0001		
CDD	2733.54913	6252.425	0.44	0.6678		
Town=Cornish					R-Square	0.6462
INTERCEPT	573760	98296	5.84	<.0001		
TIME	87311	18587	4.7	0.0002		
CDD	221.99731	96.81239	2.29	0.0357		

Western Township Regression Results #2

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Enfield					R-Square	0.7826
INTERCEPT	13648133	1157187	11.79	<.0001		
TIME	1630583	218814	7.45	<.0001		
CDD	1582.19763	1139.721	1.39	0.1841		
Town=Grafton, NH					R-Square	0.2942
INTERCEPT	56985	6837.222	8.33	<.0001		
TIME	2810.65301	2932.623	0.96	0.3521		
YEAR 2002	25110	8432.559	2.98	0.0089		
Town=Hanover, NH					R-Square	0.7844
INTERCEPT	68812079	11262322	6.11	<.0001		
TIME	16272278	2129603	7.64	<.0001		
CDD	11239	11092	1.01	0.326		
Town=Lebanon					R-Square	0.8111
INTERCEPT	62402945	29707083	2.1	0.0519		
TIME	43867815	5617340	7.81	<.0001		
CDD	64124	29259	2.19	0.0435		
Town=Marlow					R-Square	0.0654
INTERCEPT	28697	8313.087	3.45	0.0033		
TIME	2639.98599	1571.929	1.68	0.1125		
CDD	1.82563	8.18761	0.22	0.8264		

Western Township Regression Results #3

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Monroe, NH					R-Square	0.1007
INTERCEPT	1694572	98442	17.21	<.0001		
TIME	35580	18614	1.91	0.074		
CDD	10.28049	96.95596	0.11	0.9169		
Town=Plainfield					R-Square	0.4213
INTERCEPT	4783826	594055	8.05	<.0001		
TIME	365358	112330	3.25	0.005		
CDD	730.48021	585.0884	1.25	0.2298		
Town=Surry					R-Square	0.6197
INTERCEPT	95895	51409	1.87	0.0806		
TIME	50362	9720.964	5.18	<.0001		
CDD	38.3967	50.633	0.76	0.4593		
Town=Walpole					R-Square	0.5513
INTERCEPT	20871822	1584905	13.17	<.0001		
TIME	1289037	299691	4.3	0.0005		
CDD	1906.41256	1560.984	1.22	0.2397		

Except for the Grafton, all the western area townships had significant time trend coefficients at the 90% confidence level. All of the larger usage Western Townships had CDD coefficients significant at the 70% confidence level.

An explanation of how the peak day and township model coefficients are employed to generate seasonal peak day forecasts appears in the next section.

Seasonal Forecast Development for 2015-2031

The peak day model coefficients detailed in the previous section of the report are used along with the economic driver forecast (shown in Appendix B) and normal/extreme weather to estimate seasonal peak forecasts for 2015 through 2031. The normal monthly WTHI and HDD values were computed by taking the average values for those terms during the October 2000 through June 2015 Company system monthly peak days. The extreme monthly WTHI and HDD values were extracted by taking the maximum values for those monthly terms during the October 2000 through June 2015 Company system monthly peak days. The normal and extreme monthly WTHI and HDD values appear below.

	Weather Values Used in Forecast			
Month	Normal WTHI	Extreme WTHI	Normal HDD	Extreme HDD
January	28.2279	40.26	35.4714	44.9
February	32.5364	40.23	29.5857	48.5
March	37.9296	47.02	23.1071	33.3
April	64.6857	77.505	3.8214	17.5
May	74.7965	81.25	0	0
June	80.3273	83.94	0	0
July	81.4931	84.485	0	0
August	80.4123	84.485	0	0
September	76.7354	82.05	0	0
October	65.3961	74.265	1.7929	10
November	48.2085	60.85	11.0571	24.6
December	35.0779	42.42	26.4714	38.3

The normal and extreme Liberty system seasonal peak day forecasts appear in Tables 2 and 3 in the Summary of Results section of the report. The system peak day values were allocated to the Eastern and Western PSA regions by using the July and December 2014 coincident peak contribution proportions. The July Eastern coincident peak proportion was 49.855% while the Western proportion was 50.145%. The December Eastern coincident peak contribution was 47.495% compared to the Western value of 52.505%. Appendix C lists the Eastern and Western coincident peak contributions for March 2014 through June 2015.

The individual township peaks were then calculated by utilizing the annual township sales regression models. For townships with CDD in the model, normal CDD value equaled 1027.93 and the extreme CDD took the value of 1265 which were computed based upon 1995 through 2014 Concord weather data. Once the annual township forecasts were completed, they were totaled so that individual township annual proportions under normal and extreme weather could be applied to the area peak values.

The Derry township results are shown below. The annual growth rates for 2017-2021 are much larger than the overall system average.

Derry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.8014		0.5968		1.0784		0.807	
2016	0.8236	2.77%	0.6124	2.61%	1.1038	2.36%	0.8246	2.18%
2017	0.8437	2.44%	0.6249	2.04%	1.1266	2.07%	0.8386	1.70%
2018	0.861	2.05%	0.6352	1.65%	1.1462	1.74%	0.8497	1.32%
2019	0.877	1.86%	0.6448	1.51%	1.164	1.55%	0.8601	1.22%
2020	0.8927	1.79%	0.6546	1.52%	1.1818	1.53%	0.8709	1.26%
2021	0.9088	1.80%	0.6648	1.56%	1.1999	1.53%	0.8821	1.29%
2022	0.9249	1.77%	0.6747	1.49%	1.218	1.51%	0.8929	1.22%
2023	0.9406	1.70%	0.6843	1.42%	1.2357	1.45%	0.9034	1.18%
2024	0.9558	1.62%	0.6932	1.30%	1.2529	1.39%	0.9131	1.07%
2025	0.9706	1.55%	0.7019	1.26%	1.2695	1.32%	0.9226	1.04%
2026	0.985	1.48%	0.7102	1.18%	1.2858	1.28%	0.9317	0.99%
2027	0.9991	1.43%	0.7181	1.11%	1.3016	1.23%	0.9402	0.91%
2028	1.0129	1.38%	0.726	1.10%	1.3171	1.19%	0.9487	0.90%
2029	1.0265	1.34%	0.7335	1.03%	1.3324	1.16%	0.9569	0.86%
2030	1.0399	1.31%	0.7411	1.04%	1.3476	1.14%	0.9651	0.86%
2031	1.0534	1.30%	0.7485	1.00%	1.3627	1.12%	0.9732	0.84%
2017-2021 Avg		2.07%		1.71%		1.74%		1.39%

The Pelham township results are provided next. The 2017-2021 annual growth rates for Pelham are not as large as Derry but larger than the overall system.

Pelham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	19.8959		14.8158		22.4264		16.7821	
2016	20.3115	2.09%	15.1024	1.93%	22.8607	1.94%	17.0786	1.77%
2017	20.6797	1.81%	15.3182	1.43%	23.2462	1.69%	17.3023	1.31%
2018	20.9834	1.47%	15.4795	1.05%	23.5652	1.37%	17.4698	0.97%
2019	21.2551	1.29%	15.628	0.96%	23.8514	1.21%	17.6241	0.88%
2020	21.5264	1.28%	15.785	1.00%	24.137	1.20%	17.787	0.92%
2021	21.8085	1.31%	15.9534	1.07%	24.4333	1.23%	17.9614	0.98%
2022	22.0913	1.30%	16.1151	1.01%	24.7304	1.22%	18.1289	0.93%
2023	22.3691	1.26%	16.2732	0.98%	25.0222	1.18%	18.2925	0.90%
2024	22.6362	1.19%	16.4166	0.88%	25.3029	1.12%	18.441	0.81%
2025	22.8946	1.14%	16.5564	0.85%	25.5747	1.07%	18.5856	0.78%
2026	23.1476	1.11%	16.69	0.81%	25.8408	1.04%	18.7239	0.74%
2027	23.3927	1.06%	16.8149	0.75%	26.0987	1.00%	18.8533	0.69%
2028	23.6337	1.03%	16.9394	0.74%	26.3524	0.97%	18.9821	0.68%
2029	23.8711	1.00%	17.0581	0.70%	26.6021	0.95%	19.1049	0.65%
2030	24.1076	0.99%	17.1795	0.71%	26.851	0.94%	19.2304	0.66%
2031	24.3433	0.98%	17.2979	0.69%	27.0991	0.92%	19.3528	0.64%
2017-2021 Avg		1.47%		1.13%		1.38%		1.03%

Salem forecasts are displayed next. The Salem annual growth rates are lower than the overall system rates and since Salem contributes the most to Eastern PSA total, Salem pushes down the Eastern PSA numbers that appear in Tables 4 through 7 in the Summary of Results section.

Salem Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	74.6197		55.5665		81.1521		60.7278	
2016	75.6539	1.39%	56.2518	1.23%	82.1877	1.28%	61.4004	1.11%
2017	76.5229	1.15%	56.6835	0.77%	83.0602	1.06%	61.8223	0.69%
2018	77.1655	0.84%	56.9251	0.43%	83.7084	0.78%	62.0562	0.38%
2019	77.7035	0.70%	57.1323	0.36%	84.2537	0.65%	62.2563	0.32%
2020	78.2524	0.71%	57.3813	0.44%	84.81	0.66%	62.498	0.39%
2021	78.8512	0.77%	57.6815	0.52%	85.4156	0.71%	62.7907	0.47%
2022	79.4623	0.78%	57.9661	0.49%	86.0341	0.72%	63.0682	0.44%
2023	80.0641	0.76%	58.2457	0.48%	86.6432	0.71%	63.3408	0.43%
2024	80.6358	0.71%	58.4802	0.40%	87.223	0.67%	63.569	0.36%
2025	81.1842	0.68%	58.7088	0.39%	87.78	0.64%	63.7915	0.35%
2026	81.7208	0.66%	58.9226	0.36%	88.3254	0.62%	63.9995	0.33%
2027	82.2363	0.63%	59.1124	0.32%	88.8501	0.59%	64.1838	0.29%
2028	82.7441	0.62%	59.3065	0.33%	89.367	0.58%	64.3726	0.29%
2029	83.2451	0.61%	59.4863	0.30%	89.8772	0.57%	64.5473	0.27%
2030	83.7486	0.60%	59.6807	0.33%	90.3904	0.57%	64.7366	0.29%
2031	84.2549	0.60%	59.8698	0.32%	90.9066	0.57%	64.9208	0.28%
2017-2021 Avg		0.85%		0.51%		0.79%		0.45%

The last Eastern PSA township, Windham, forecasts are displayed next. The annual growth rate in peaks for Windham from 2017-2021 are somewhat higher than the overall system average.

Windham Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	4.0505		3.0163		4.4777		3.3508	
2016	4.1236	1.80%	3.0661	1.65%	4.5529	1.68%	3.4013	1.51%
2017	4.1873	1.54%	3.1017	1.16%	4.6185	1.44%	3.4376	1.07%
2018	4.2383	1.22%	3.1266	0.80%	4.6713	1.14%	3.463	0.74%
2019	4.2831	1.06%	3.1492	0.72%	4.7179	1.00%	3.4861	0.67%
2020	4.328	1.05%	3.1737	0.78%	4.7646	0.99%	3.5111	0.72%
2021	4.3754	1.10%	3.2007	0.85%	4.8137	1.03%	3.5386	0.78%
2022	4.4231	1.09%	3.2266	0.81%	4.8631	1.03%	3.565	0.75%
2023	4.47	1.06%	3.2519	0.78%	4.9117	1.00%	3.5907	0.72%
2024	4.515	1.01%	3.2744	0.69%	4.9584	0.95%	3.6137	0.64%
2025	4.5584	0.96%	3.2964	0.67%	5.0034	0.91%	3.6361	0.62%
2026	4.6008	0.93%	3.3173	0.63%	5.0475	0.88%	3.6574	0.59%
2027	4.6419	0.89%	3.3366	0.58%	5.0902	0.85%	3.6771	0.54%
2028	4.6823	0.87%	3.356	0.58%	5.1322	0.83%	3.6968	0.54%
2029	4.7221	0.85%	3.3743	0.55%	5.1735	0.80%	3.7155	0.51%
2030	4.7618	0.84%	3.3933	0.56%	5.2149	0.80%	3.7348	0.52%
2031	4.8015	0.83%	3.4119	0.55%	5.2562	0.79%	3.7537	0.51%
2017-2021 Avg		1.22%		0.88%		1.15%		0.81%

The Western Township forecasts are shown next starting with Acworth. The Acworth annual growth rates are much lower than the overall system for 2017-2021.

Acworth Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.258		0.2111		0.2726		0.2242	
2016	0.2608	1.09%	0.2131	0.95%	0.2754	1.03%	0.2261	0.85%
2017	0.2631	0.88%	0.2142	0.52%	0.2776	0.80%	0.2271	0.44%
2018	0.2646	0.57%	0.2146	0.19%	0.2791	0.54%	0.2274	0.13%
2019	0.2658	0.45%	0.2148	0.09%	0.2803	0.43%	0.2276	0.09%
2020	0.2671	0.49%	0.2153	0.23%	0.2815	0.43%	0.228	0.18%
2021	0.2685	0.52%	0.2159	0.28%	0.2829	0.50%	0.2286	0.26%
2022	0.2701	0.60%	0.2165	0.28%	0.2844	0.53%	0.2292	0.26%
2023	0.2715	0.52%	0.2171	0.28%	0.2859	0.53%	0.2297	0.22%
2024	0.273	0.55%	0.2176	0.23%	0.2873	0.49%	0.2301	0.17%
2025	0.2743	0.48%	0.218	0.18%	0.2886	0.45%	0.2305	0.17%
2026	0.2756	0.47%	0.2184	0.18%	0.2899	0.45%	0.2309	0.17%
2027	0.2769	0.47%	0.2188	0.18%	0.2912	0.45%	0.2312	0.13%
2028	0.2782	0.47%	0.2191	0.14%	0.2924	0.41%	0.2315	0.13%
2029	0.2794	0.43%	0.2194	0.14%	0.2937	0.44%	0.2318	0.13%
2030	0.2807	0.47%	0.2198	0.18%	0.2949	0.41%	0.2322	0.17%
2031	0.2819	0.43%	0.2202	0.18%	0.2962	0.44%	0.2325	0.13%
2017-2021 Avg		0.59%		0.26%		0.54%		0.22%

Alstead township forecast appears next. As the case with Acworth, Alstead annual growth in peak is quite a bit lower than the system average.

Alstead Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	2.1784		1.783		2.3025		1.8937	
2016	2.2014	1.06%	1.7991	0.90%	2.3247	0.96%	1.9088	0.80%
2017	2.2199	0.84%	1.8073	0.46%	2.3426	0.77%	1.9164	0.40%
2018	2.232	0.55%	1.8097	0.13%	2.3544	0.50%	1.9183	0.10%
2019	2.2413	0.42%	1.8112	0.08%	2.3635	0.39%	1.9195	0.06%
2020	2.2512	0.44%	1.8143	0.17%	2.3732	0.41%	1.9221	0.14%
2021	2.2627	0.51%	1.8192	0.27%	2.3844	0.47%	1.9265	0.23%
2022	2.2747	0.53%	1.8238	0.25%	2.3963	0.50%	1.9307	0.22%
2023	2.2867	0.53%	1.8284	0.25%	2.408	0.49%	1.9348	0.21%
2024	2.2979	0.49%	1.8317	0.18%	2.419	0.46%	1.9377	0.15%
2025	2.3086	0.47%	1.8349	0.17%	2.4296	0.44%	1.9406	0.15%
2026	2.3192	0.46%	1.8379	0.16%	2.44	0.43%	1.9432	0.13%
2027	2.3292	0.43%	1.8402	0.13%	2.4499	0.41%	1.9452	0.10%
2028	2.3391	0.43%	1.8427	0.14%	2.4598	0.40%	1.9474	0.11%
2029	2.349	0.42%	1.8449	0.12%	2.4696	0.40%	1.9493	0.10%
2030	2.3591	0.43%	1.8477	0.15%	2.4795	0.40%	1.9518	0.13%
2031	2.3693	0.43%	1.8504	0.15%	2.4897	0.41%	1.9542	0.12%
2017-2021 Avg		0.56%		0.22%		0.51%		0.19%

The Bath township forecasts are displayed below. The annual growth in the Bath peaks from 2017-2021 is higher than the system average although the peaks are very small.

Bath Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.0121		0.0099		0.0145		0.012	
2016	0.0124	2.48%	0.0101	2.02%	0.0148	2.07%	0.0122	1.67%
2017	0.0126	1.61%	0.0103	1.98%	0.0151	2.03%	0.0123	0.82%
2018	0.0128	1.59%	0.0104	0.97%	0.0153	1.32%	0.0124	0.81%
2019	0.013	1.56%	0.0105	0.96%	0.0154	0.65%	0.0125	0.81%
2020	0.0131	0.77%	0.0106	0.95%	0.0156	1.30%	0.0126	0.80%
2021	0.0133	1.53%	0.0107	0.94%	0.0158	1.28%	0.0128	1.59%
2022	0.0135	1.50%	0.0108	0.93%	0.016	1.27%	0.0129	0.78%
2023	0.0136	0.74%	0.0109	0.93%	0.0162	1.25%	0.013	0.78%
2024	0.0138	1.47%	0.011	0.92%	0.0163	0.62%	0.0131	0.77%
2025	0.014	1.45%	0.0111	0.91%	0.0165	1.23%	0.0132	0.76%
2026	0.0141	0.71%	0.0112	0.90%	0.0167	1.21%	0.0133	0.76%
2027	0.0143	1.42%	0.0113	0.89%	0.0168	0.60%	0.0134	0.75%
2028	0.0144	0.70%	0.0114	0.88%	0.017	1.19%	0.0135	0.75%
2029	0.0146	1.39%	0.0114	0.00%	0.0172	1.18%	0.0135	0.00%
2030	0.0147	0.68%	0.0115	0.88%	0.0173	0.58%	0.0136	0.74%
2031	0.0149	1.36%	0.0116	0.87%	0.0175	1.16%	0.0137	0.74%
2017-2021 Avg		1.45%		1.19%		1.35%		0.98%

Forecasts for the Canaan Township appear below. The annual growth rate in Canaan is less than the system average during the 2017-2021 years.

Canaan Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	2.7469		2.2482		2.9584		2.4332	
2016	2.7819	1.27%	2.2735	1.13%	2.9932	1.18%	2.4577	1.01%
2017	2.811	1.05%	2.2886	0.66%	3.0222	0.97%	2.4724	0.60%
2018	2.8319	0.74%	2.2961	0.33%	3.0432	0.69%	2.4796	0.29%
2019	2.8491	0.61%	2.3024	0.27%	3.0606	0.57%	2.4856	0.24%
2020	2.8668	0.62%	2.3105	0.35%	3.0785	0.58%	2.4934	0.31%
2021	2.8864	0.68%	2.3207	0.44%	3.0982	0.64%	2.5033	0.40%
2022	2.9066	0.70%	2.3304	0.42%	3.1186	0.66%	2.5126	0.37%
2023	2.9265	0.68%	2.3399	0.41%	3.1386	0.64%	2.5219	0.37%
2024	2.9454	0.65%	2.3478	0.34%	3.1577	0.61%	2.5294	0.30%
2025	2.9634	0.61%	2.3554	0.32%	3.176	0.58%	2.5368	0.29%
2026	2.9812	0.60%	2.3625	0.30%	3.194	0.57%	2.5437	0.27%
2027	2.9982	0.57%	2.3687	0.26%	3.2113	0.54%	2.5496	0.23%
2028	3.015	0.56%	2.3751	0.27%	3.2283	0.53%	2.5558	0.24%
2029	3.0316	0.55%	2.381	0.25%	3.2452	0.52%	2.5615	0.22%
2030	3.0483	0.55%	2.3876	0.28%	3.2622	0.52%	2.5679	0.25%
2031	3.0652	0.55%	2.3939	0.26%	3.2794	0.53%	2.574	0.24%
2017-2021 Avg		0.75%		0.42%		0.70%		0.37%

The Charlestown township forecasts are shown next below. The annual growth rate in peak forecasts is higher than the system average during the 2017-2021 years.

Charlestown Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	5.9475		4.8677		6.4205		5.2807	
2016	6.0583	1.86%	4.9509	1.71%	6.5329	1.75%	5.3642	1.58%
2017	6.1551	1.60%	5.0111	1.22%	6.6315	1.51%	5.425	1.13%
2018	6.2329	1.26%	5.0536	0.85%	6.7113	1.20%	5.4684	0.80%
2019	6.3014	1.10%	5.0923	0.77%	6.782	1.05%	5.5079	0.72%
2020	6.37	1.09%	5.1339	0.82%	6.8526	1.04%	5.5502	0.77%
2021	6.442	1.13%	5.1794	0.89%	6.9265	1.08%	5.5964	0.83%
2022	6.5144	1.12%	5.223	0.84%	7.0008	1.07%	5.6405	0.79%
2023	6.5855	1.09%	5.2656	0.82%	7.0737	1.04%	5.6836	0.76%
2024	6.6535	1.03%	5.3035	0.72%	7.1436	0.99%	5.7222	0.68%
2025	6.7192	0.99%	5.3405	0.70%	7.211	0.94%	5.7597	0.66%
2026	6.7834	0.96%	5.3756	0.66%	7.277	0.92%	5.7953	0.62%
2027	6.8454	0.91%	5.4081	0.60%	7.3409	0.88%	5.8284	0.57%
2028	6.9063	0.89%	5.4406	0.60%	7.4036	0.85%	5.8614	0.57%
2029	6.9663	0.87%	5.4714	0.57%	7.4653	0.83%	5.8926	0.53%
2030	7.0262	0.86%	5.5031	0.58%	7.5269	0.83%	5.9249	0.55%
2031	7.0859	0.85%	5.5341	0.56%	7.5884	0.82%	5.9562	0.53%
2017-2021 Avg		1.27%		0.92%		1.20%		0.87%

The Cornish township forecast numbers are displayed next. The annual growth in Cornish peaks is less than the 2017-2021 system average growth.

Cornish Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.2113		0.173		0.2343		0.1927	
2016	0.214	1.28%	0.1749	1.10%	0.2371	1.20%	0.1946	0.99%
2017	0.2163	1.07%	0.1761	0.69%	0.2393	0.93%	0.1958	0.62%
2018	0.2179	0.74%	0.1766	0.28%	0.241	0.71%	0.1963	0.26%
2019	0.2192	0.60%	0.1771	0.28%	0.2423	0.54%	0.1968	0.25%
2020	0.2205	0.59%	0.1777	0.34%	0.2437	0.58%	0.1974	0.30%
2021	0.2221	0.73%	0.1785	0.45%	0.2453	0.66%	0.1982	0.41%
2022	0.2236	0.68%	0.1793	0.45%	0.2468	0.61%	0.1989	0.35%
2023	0.2251	0.67%	0.18	0.39%	0.2484	0.65%	0.1996	0.35%
2024	0.2266	0.67%	0.1806	0.33%	0.2499	0.60%	0.2002	0.30%
2025	0.228	0.62%	0.1812	0.33%	0.2513	0.56%	0.2007	0.25%
2026	0.2293	0.57%	0.1817	0.28%	0.2527	0.56%	0.2013	0.30%
2027	0.2306	0.57%	0.1822	0.28%	0.2541	0.55%	0.2017	0.20%
2028	0.2319	0.56%	0.1827	0.27%	0.2554	0.51%	0.2022	0.25%
2029	0.2332	0.56%	0.1832	0.27%	0.2567	0.51%	0.2026	0.20%
2030	0.2345	0.56%	0.1837	0.27%	0.2581	0.55%	0.2031	0.25%
2031	0.2358	0.55%	0.1842	0.27%	0.2594	0.50%	0.2036	0.25%
2017-2021 Avg		0.76%		0.41%		0.69%		0.37%

Enfield Township seasonal peak forecasts are listed next. Much like Cornish, the annual 2017-2020 growth in Enfield peaks is lower than the system average numbers.

Enfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	4.0055		3.2783		4.3113		3.5459	
2016	4.0564	1.27%	3.3149	1.12%	4.3618	1.17%	3.5815	1.00%
2017	4.0985	1.04%	3.3368	0.66%	4.4038	0.96%	3.6026	0.59%
2018	4.1288	0.74%	3.3476	0.32%	4.4342	0.69%	3.613	0.29%
2019	4.1536	0.60%	3.3566	0.27%	4.4592	0.56%	3.6215	0.24%
2020	4.1791	0.61%	3.3682	0.35%	4.4851	0.58%	3.6326	0.31%
2021	4.2075	0.68%	3.3829	0.44%	4.5137	0.64%	3.6469	0.39%
2022	4.2367	0.69%	3.3969	0.41%	4.5431	0.65%	3.6603	0.37%
2023	4.2655	0.68%	3.4106	0.40%	4.5721	0.64%	3.6736	0.36%
2024	4.2929	0.64%	3.4219	0.33%	4.5997	0.60%	3.6845	0.30%
2025	4.319	0.61%	3.4328	0.32%	4.6262	0.58%	3.6951	0.29%
2026	4.3447	0.60%	3.4431	0.30%	4.6522	0.56%	3.7049	0.27%
2027	4.3693	0.57%	3.4519	0.26%	4.6772	0.54%	3.7135	0.23%
2028	4.3937	0.56%	3.4612	0.27%	4.7018	0.53%	3.7224	0.24%
2029	4.4177	0.55%	3.4697	0.25%	4.7262	0.52%	3.7306	0.22%
2030	4.4419	0.55%	3.4791	0.27%	4.7508	0.52%	3.7396	0.24%
2031	4.4664	0.55%	3.4882	0.26%	4.7757	0.52%	3.7485	0.24%
2017-2021 Avg		0.74%		0.41%		0.70%		0.37%

Grafton Township forecast results are provided below. Annual growth in Grafton peaks is lower than the system average.

Grafton Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.013		0.0106		0.0137		0.0113	
2016	0.0131	0.77%	0.0107	0.94%	0.0138	0.73%	0.0114	0.88%
2017	0.0132	0.76%	0.0108	0.93%	0.014	1.45%	0.0114	0.00%
2018	0.0133	0.76%	0.0108	0.00%	0.014	0.00%	0.0114	0.00%
2019	0.0134	0.75%	0.0108	0.00%	0.0141	0.71%	0.0114	0.00%
2020	0.0134	0.00%	0.0108	0.00%	0.0142	0.71%	0.0115	0.88%
2021	0.0135	0.75%	0.0109	0.93%	0.0142	0.00%	0.0115	0.00%
2022	0.0136	0.74%	0.0109	0.00%	0.0143	0.70%	0.0115	0.00%
2023	0.0136	0.00%	0.0109	0.00%	0.0144	0.70%	0.0115	0.00%
2024	0.0137	0.74%	0.0109	0.00%	0.0144	0.00%	0.0116	0.87%
2025	0.0138	0.73%	0.011	0.92%	0.0145	0.69%	0.0116	0.00%
2026	0.0139	0.72%	0.011	0.00%	0.0146	0.69%	0.0116	0.00%
2027	0.0139	0.00%	0.011	0.00%	0.0146	0.00%	0.0116	0.00%
2028	0.014	0.72%	0.011	0.00%	0.0147	0.68%	0.0116	0.00%
2029	0.014	0.00%	0.011	0.00%	0.0148	0.68%	0.0117	0.86%
2030	0.0141	0.71%	0.011	0.00%	0.0148	0.00%	0.0117	0.00%
2031	0.0142	0.71%	0.0111	0.91%	0.0149	0.68%	0.0117	0.00%
2017-2021 Avg		0.61%		0.37%		0.58%		0.18%

The Hanover township forecasts appear next. As one of the larger Western PSA townships, the Hanover annual growth rate from 2017-2021 is slightly lower than the system average growth.

Hanover Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	25.7101		21.0425		27.7262		22.804	
2016	26.0903	1.48%	21.3215	1.33%	28.1078	1.38%	23.0794	1.21%
2017	26.4132	1.24%	21.504	0.86%	28.4332	1.16%	23.2601	0.78%
2018	26.6575	0.92%	21.614	0.51%	28.6811	0.87%	23.3693	0.47%
2019	26.8653	0.78%	21.7103	0.45%	28.8932	0.74%	23.4652	0.41%
2020	27.0762	0.79%	21.822	0.51%	29.1084	0.74%	23.5761	0.47%
2021	27.3041	0.84%	21.9528	0.60%	29.3401	0.80%	23.7057	0.55%
2022	27.5358	0.85%	22.0772	0.57%	29.5756	0.80%	23.8291	0.52%
2023	27.7639	0.83%	22.1994	0.55%	29.8075	0.78%	23.9502	0.51%
2024	27.9813	0.78%	22.304	0.47%	30.0289	0.74%	24.0541	0.43%
2025	28.1903	0.75%	22.4061	0.46%	30.2421	0.71%	24.1553	0.42%
2026	28.3949	0.73%	22.5022	0.43%	30.4509	0.69%	24.2507	0.39%
2027	28.5919	0.69%	22.5887	0.38%	30.6522	0.66%	24.3367	0.35%
2028	28.786	0.68%	22.6767	0.39%	30.8504	0.65%	24.4241	0.36%
2029	28.9774	0.66%	22.7589	0.36%	31.046	0.63%	24.5058	0.33%
2030	29.1694	0.66%	22.8464	0.38%	31.2424	0.63%	24.5927	0.35%
2031	29.3622	0.66%	22.9316	0.37%	31.4395	0.63%	24.6773	0.34%
2017-2021 Avg		0.93%		0.59%		0.88%		0.54%

Lebanon township seasonal peak forecasts are listed next. As the largest Western PSA township, Lebanon peak growth from 2017-2021 is somewhat higher than the overall system growth.

Lebanon Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	51.8282		42.4189		57.9485		47.661	
2016	52.6975	1.68%	43.0654	1.52%	58.8428	1.54%	48.316	1.37%
2017	53.448	1.42%	43.5142	1.04%	59.6163	1.31%	48.7698	0.94%
2018	54.0364	1.10%	43.8128	0.69%	60.2245	1.02%	49.0708	0.62%
2019	54.5474	0.95%	44.0807	0.61%	60.7543	0.88%	49.3407	0.55%
2020	55.0619	0.94%	44.377	0.67%	61.2879	0.88%	49.6396	0.61%
2021	55.6081	0.99%	44.7096	0.75%	61.8534	0.92%	49.9753	0.68%
2022	56.1599	0.99%	45.027	0.71%	62.425	0.92%	50.2958	0.64%
2023	56.7022	0.97%	45.3377	0.69%	62.9867	0.90%	50.6095	0.62%
2024	57.2205	0.91%	45.6107	0.60%	63.5243	0.85%	50.8848	0.54%
2025	57.7198	0.87%	45.8765	0.58%	64.0427	0.82%	51.153	0.53%
2026	58.2082	0.85%	46.1283	0.55%	64.5501	0.79%	51.4069	0.50%
2027	58.6794	0.81%	46.359	0.50%	65.0399	0.76%	51.6394	0.45%
2028	59.143	0.79%	46.591	0.50%	65.5219	0.74%	51.8733	0.45%
2029	59.5997	0.77%	46.8097	0.47%	65.9968	0.72%	52.0937	0.42%
2030	60.0563	0.77%	47.038	0.49%	66.472	0.72%	52.3239	0.44%
2031	60.5131	0.76%	47.2603	0.47%	66.9475	0.72%	52.548	0.43%
2017-2021 Avg		1.10%		0.76%		1.02%		0.69%

1 Marlow township forecast values are shown next. The Marlow growth is lower than the system average during the 2017-2021 years.

Marlow Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.0076		0.0063		0.0082		0.0067	
2016	0.0077	1.32%	0.0063	0.00%	0.0083	1.22%	0.0068	1.49%
2017	0.0078	1.30%	0.0064	1.59%	0.0083	0.00%	0.0068	0.00%
2018	0.0079	1.28%	0.0064	0.00%	0.0084	1.20%	0.0068	0.00%
2019	0.0079	0.00%	0.0064	0.00%	0.0084	0.00%	0.0068	0.00%
2020	0.008	1.27%	0.0064	0.00%	0.0085	1.19%	0.0069	1.47%
2021	0.008	0.00%	0.0064	0.00%	0.0085	0.00%	0.0069	0.00%
2022	0.0081	1.25%	0.0065	1.56%	0.0086	1.18%	0.0069	0.00%
2023	0.0081	0.00%	0.0065	0.00%	0.0086	0.00%	0.0069	0.00%
2024	0.0082	1.23%	0.0065	0.00%	0.0087	1.16%	0.007	1.45%
2025	0.0082	0.00%	0.0065	0.00%	0.0087	0.00%	0.007	0.00%
2026	0.0082	0.00%	0.0065	0.00%	0.0088	1.15%	0.007	0.00%
2027	0.0083	1.22%	0.0066	1.54%	0.0088	0.00%	0.007	0.00%
2028	0.0083	0.00%	0.0066	0.00%	0.0089	1.14%	0.007	0.00%
2029	0.0084	1.20%	0.0066	0.00%	0.0089	0.00%	0.007	0.00%
2030	0.0084	0.00%	0.0066	0.00%	0.0089	0.00%	0.007	0.00%
2031	0.0085	1.19%	0.0066	0.00%	0.009	1.12%	0.0071	1.43%
2017-2021 Avg		0.78%		0.32%		0.48%		0.29%

Monroe township peak forecasts are shown below. The annual growth in Monroe Township is much lower than the system average during the 2017-2021 years.

Monroe Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.3589		0.2937		0.3798		0.3124	
2016	0.3624	0.98%	0.2962	0.85%	0.3832	0.90%	0.3146	0.70%
2017	0.3652	0.77%	0.2973	0.37%	0.3859	0.70%	0.3157	0.35%
2018	0.367	0.49%	0.2975	0.07%	0.3875	0.41%	0.3158	0.03%
2019	0.3683	0.35%	0.2976	0.03%	0.3888	0.34%	0.3158	0.00%
2020	0.3697	0.38%	0.2979	0.10%	0.3902	0.36%	0.316	0.06%
2021	0.3713	0.43%	0.2986	0.23%	0.3918	0.41%	0.3165	0.16%
2022	0.3731	0.48%	0.2992	0.20%	0.3935	0.43%	0.317	0.16%
2023	0.3749	0.48%	0.2997	0.17%	0.3952	0.43%	0.3176	0.19%
2024	0.3765	0.43%	0.3001	0.13%	0.3968	0.40%	0.3179	0.09%
2025	0.3781	0.42%	0.3005	0.13%	0.3984	0.40%	0.3182	0.09%
2026	0.3796	0.40%	0.3008	0.10%	0.3999	0.38%	0.3185	0.09%
2027	0.3811	0.40%	0.3011	0.10%	0.4013	0.35%	0.3186	0.03%
2028	0.3826	0.39%	0.3014	0.10%	0.4027	0.35%	0.3189	0.09%
2029	0.384	0.37%	0.3016	0.07%	0.4042	0.37%	0.319	0.03%
2030	0.3855	0.39%	0.3019	0.10%	0.4056	0.35%	0.3193	0.09%
2031	0.387	0.39%	0.3022	0.10%	0.4071	0.37%	0.3196	0.09%
2017-2021 Avg		0.49%		0.16%		0.45%		0.12%

Plainfield township forecasts appear next. The Plainfield growth rate is peak form 2017-2021 is much lower than the system average over this time frame.

Plainfield Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	1.3155		1.0767		1.4264		1.1732	
2016	1.3306	1.15%	1.0874	0.99%	1.4414	1.05%	1.1835	0.88%
2017	1.343	0.93%	1.0934	0.55%	1.4537	0.85%	1.1892	0.48%
2018	1.3514	0.63%	1.0957	0.21%	1.4621	0.58%	1.1913	0.18%
2019	1.3582	0.50%	1.0975	0.16%	1.4689	0.47%	1.1929	0.13%
2020	1.3652	0.52%	1.1003	0.26%	1.476	0.48%	1.1954	0.21%
2021	1.3732	0.59%	1.104	0.34%	1.484	0.54%	1.199	0.30%
2022	1.3814	0.60%	1.1076	0.33%	1.4923	0.56%	1.2023	0.28%
2023	1.3896	0.59%	1.1111	0.32%	1.5005	0.55%	1.2057	0.28%
2024	1.3974	0.56%	1.1139	0.25%	1.5083	0.52%	1.2082	0.21%
2025	1.4048	0.53%	1.1165	0.23%	1.5158	0.50%	1.2107	0.21%
2026	1.412	0.51%	1.119	0.22%	1.5232	0.49%	1.213	0.19%
2027	1.419	0.50%	1.1211	0.19%	1.5302	0.46%	1.2149	0.16%
2028	1.4259	0.49%	1.1233	0.20%	1.5372	0.46%	1.217	0.17%
2029	1.4327	0.48%	1.1252	0.17%	1.5441	0.45%	1.2188	0.15%
2030	1.4396	0.48%	1.1275	0.20%	1.5511	0.45%	1.2209	0.17%
2031	1.4465	0.48%	1.1297	0.20%	1.5582	0.46%	1.223	0.17%
2017-2021 Avg		0.64%		0.31%		0.59%		0.26%

Surry Township forecast values are listed next. The annual growth in the Surry peak from 2017-2021 is higher than the system average.

Surry Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	0.0571		0.0468		0.0623		0.0512	
2016	0.0581	1.75%	0.0475	1.50%	0.0633	1.61%	0.052	1.56%
2017	0.059	1.55%	0.048	1.05%	0.0641	1.26%	0.0525	0.96%
2018	0.0596	1.02%	0.0483	0.63%	0.0648	1.09%	0.0528	0.57%
2019	0.0602	1.01%	0.0487	0.83%	0.0654	0.93%	0.0531	0.57%
2020	0.0608	1.00%	0.049	0.62%	0.066	0.92%	0.0535	0.75%
2021	0.0614	0.99%	0.0494	0.82%	0.0667	1.06%	0.0539	0.75%
2022	0.062	0.98%	0.0497	0.61%	0.0673	0.90%	0.0542	0.56%
2023	0.0626	0.97%	0.0501	0.80%	0.0679	0.89%	0.0546	0.74%
2024	0.0632	0.96%	0.0504	0.60%	0.0685	0.88%	0.0549	0.55%
2025	0.0638	0.95%	0.0507	0.60%	0.0691	0.88%	0.0552	0.55%
2026	0.0643	0.78%	0.051	0.59%	0.0697	0.87%	0.0555	0.54%
2027	0.0649	0.93%	0.0513	0.59%	0.0702	0.72%	0.0558	0.54%
2028	0.0654	0.77%	0.0515	0.39%	0.0708	0.85%	0.056	0.36%
2029	0.0659	0.76%	0.0518	0.58%	0.0713	0.71%	0.0563	0.54%
2030	0.0664	0.76%	0.052	0.39%	0.0718	0.70%	0.0565	0.36%
2031	0.0669	0.75%	0.0523	0.58%	0.0724	0.84%	0.0568	0.53%
2017-2021 Avg		1.14%		0.80%		1.07%		0.73%

The final township, Walpole forecasts of peak appear below. The Walpole average annual growth is less than the system average for the 2017-2021 years.

Walpole Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2015	5.2953		4.334		5.6903		4.6801	
2016	5.3545	1.12%	4.3758	0.96%	5.7486	1.02%	4.7202	0.86%
2017	5.4024	0.89%	4.3983	0.51%	5.7959	0.82%	4.7414	0.45%
2018	5.4349	0.60%	4.4066	0.19%	5.828	0.55%	4.7487	0.15%
2019	5.4605	0.47%	4.4127	0.14%	5.8536	0.44%	4.7539	0.11%
2020	5.4873	0.49%	4.4225	0.22%	5.8803	0.46%	4.7627	0.19%
2021	5.518	0.56%	4.4366	0.32%	5.9109	0.52%	4.7758	0.28%
2022	5.55	0.58%	4.4498	0.30%	5.9428	0.54%	4.7881	0.26%
2023	5.5816	0.57%	4.4629	0.29%	5.9744	0.53%	4.8004	0.26%
2024	5.6115	0.54%	4.4729	0.22%	6.0042	0.50%	4.8096	0.19%
2025	5.64	0.51%	4.4827	0.22%	6.0328	0.48%	4.8186	0.19%
2026	5.668	0.50%	4.4917	0.20%	6.0609	0.47%	4.8268	0.17%
2027	5.6947	0.47%	4.499	0.16%	6.0878	0.44%	4.8335	0.14%
2028	5.7212	0.47%	4.507	0.18%	6.1144	0.44%	4.8408	0.15%
2029	5.7474	0.46%	4.514	0.16%	6.1409	0.43%	4.8472	0.13%
2030	5.774	0.46%	4.5224	0.19%	6.1677	0.44%	4.8549	0.16%
2031	5.801	0.47%	4.5305	0.18%	6.1949	0.44%	4.8625	0.16%
2017-2021 Avg		0.61%		0.28%		0.56%		0.24%

Historic Peak Day Values

	Liberty Historic Peak Day Values			
year	month	day	hour	Mw
2000	10	30	18	120.587
2000	11	21	18	132.537
2000	12	14	18	133.21
2001	1	10	18	130.276
2001	2	22	19	131.967
2001	3	1	19	117.486
2001	4	24	14	125.857
2001	5	11	16	134.29
2001	6	27	16	159.728
2001	7	24	15	168.319
2001	8	6	14	173.866
2001	9	10	15	142.882
2001	10	4	14	121.58
2001	11	29	18	126.458
2001	12	17	18	137.219
2002	1	21	18	129.462
2002	2	11	19	130.548
2002	3	26	19	125.758
2002	4	17	15	133.886
2002	5	31	15	133.063
2002	6	27	15	159.353
2002	7	3	14	174.716
2002	8	14	15	181.939
2002	9	10	16	165.336
2002	10	2	15	134.005
2002	11	18	18	131.437
2002	12	9	18	143.227
2003	1	21	18	142.216
2003	2	13	19	135.745
2003	3	3	19	136.926
2003	4	3	18	127.502
2003	5	20	14	153.099
2003	6	27	14	175.018
2003	7	8	16	167.576

2003	8	22	15	171.589
2003	9	15	14	139.494
2003	10	29	18	129.818
2003	11	11	18	136.054
2003	12	16	18	141.432
2004	1	14	19	150.948
2004	2	17	19	138.039
2004	3	16	19	135.111
2004	4	30	15	126.933
2004	5	12	16	137.766
2004	6	9	15	166.476
2004	7	22	14	172.492
2004	8	3	15	169.516
2004	9	17	14	141.094
2004	10	8	15	124.583
2004	11	17	18	140.077
2004	12	21	19	151.159
2005	1	18	19	148.961
2005	2	21	19	137.439
2005	3	9	19	141.04
2005	4	20	13	125.3
2005	5	11	15	127.421
2005	6	27	15	184.603
2005	7	19	14	191.871
2005	8	10	16	179.92
2005	9	14	16	158.878
2005	10	25	19	145.312
2005	11	23	18	135.463
2005	12	13	18	161.546
2006	1	23	19	149.003
2006	2	8	19	139.41
2006	3	1	19	134.011
2006	4	4	20	123.651
2006	5	31	17	147.724
2006	6	19	13	181.58
2006	7	18	16	191.959
2006	8	2	15	195.419
2006	9	18	16	138.005
2006	10	4	20	126.699
2006	11	30	18	132.703
2006	12	4	18	146.719

2007	1	26	18	141.539
2007	2	5	19	146.216
2007	3	6	19	144.084
2007	4	4	19	130.327
2007	5	25	16	148.856
2007	6	27	14	187.416
2007	7	27	14	178.707
2007	8	3	15	187.522
2007	9	7	16	165.591
2007	10	22	19	150.267
2007	11	26	18	139.867
2007	12	5	18	152.389
2008	1	3	18	144.175
2008	2	1	18	139.664
2008	3	5	19	132.501
2008	4	23	16	127.896
2008	5	27	14	135.302
2008	6	10	15	195.262
2008	7	8	15	186.04
2008	8	18	16	159.613
2008	9	5	15	163.176
2008	10	9	20	127.515
2008	11	5	18	133.241
2008	12	8	18	146.578
2009	1	14	18	147.427
2009	2	5	19	142.883
2009	3	2	19	138.703
2009	4	28	15	140.767
2009	5	21	16	145.009
2009	6	26	13	145.615
2009	7	29	15	176.68
2009	8	18	14	190.698
2009	9	3	16	139.939
2009	10	28	19	131.489
2009	11	30	18	136.288
2009	12	17	18	154.02
2010	1	12	18	143.943
2010	2	4	19	140.447
2010	3	3	19	131.958
2010	4	7	20	124.039
2010	5	26	16	174.742

2010	6	28	14	171.967
2010	7	7	16	196.543
2010	8	31	17	187.363
2010	9	1	16	186.389
2010	10	1	10	139.359
2010	11	29	18	138.456
2010	12	15	18	149.16
2011	1	24	19	150.041
2011	2	2	18	155.316
2011	3	21	20	144.149
2011	4	28	12	140.458
2011	5	31	16	162.456
2011	6	9	15	183.139
2011	7	22	15	205.939
2011	8	1	15	186.77
2011	9	14	14	157.534
2011	10	10	16	139.923
2011	11	28	18	138.63
2011	12	19	18	146.848
2012	1	16	18	150.194
2012	2	29	19	139.924
2012	3	1	19	140.808
2012	4	16	18	142.882
2012	5	31	14	149.487
2012	6	21	16	192.762
2012	7	17	17	191.846
2012	8	3	16	188.008
2012	9	7	16	165.842
2012	10	15	19	137.546
2012	11	7	18	141.017
2012	12	16	18	149.861
2013	1	24	18	154.659
2013	2	5	19	146.904
2013	3	7	19	139.796
2013	4	12	14	130.322
2013	5	31	16	182.108
2013	6	24	12	191.469
2013	7	19	13	203.761
2013	8	21	17	181.325
2013	9	11	16	191.313
2013	10	2	15	140.756

2013	11	25	18	145.9
2013	12	17	19	159.28
2014	1	2	18	161.33
2014	2	11	19	145.35
2014	3	3	19	144.09
2014	4	15	14	122.63
2014	5	12	16	133.566
2014	6	30	17	172.905
2014	7	23	16	193.21
2014	8	27	16	175.731
2014	9	2	15	177.966
2014	10	16	12	134.995
2014	11	18	18	135.778
2014	12	8	18	143.234
2015	1	8	18	148.541
2015	2	16	19	144.885
2015	3	5	19	137.502
2015	4	2	11	123.717
2015	5	27	16	159.605
2015	6	23	17	149.229

1 # Rockingham and Grafton Economic Variables

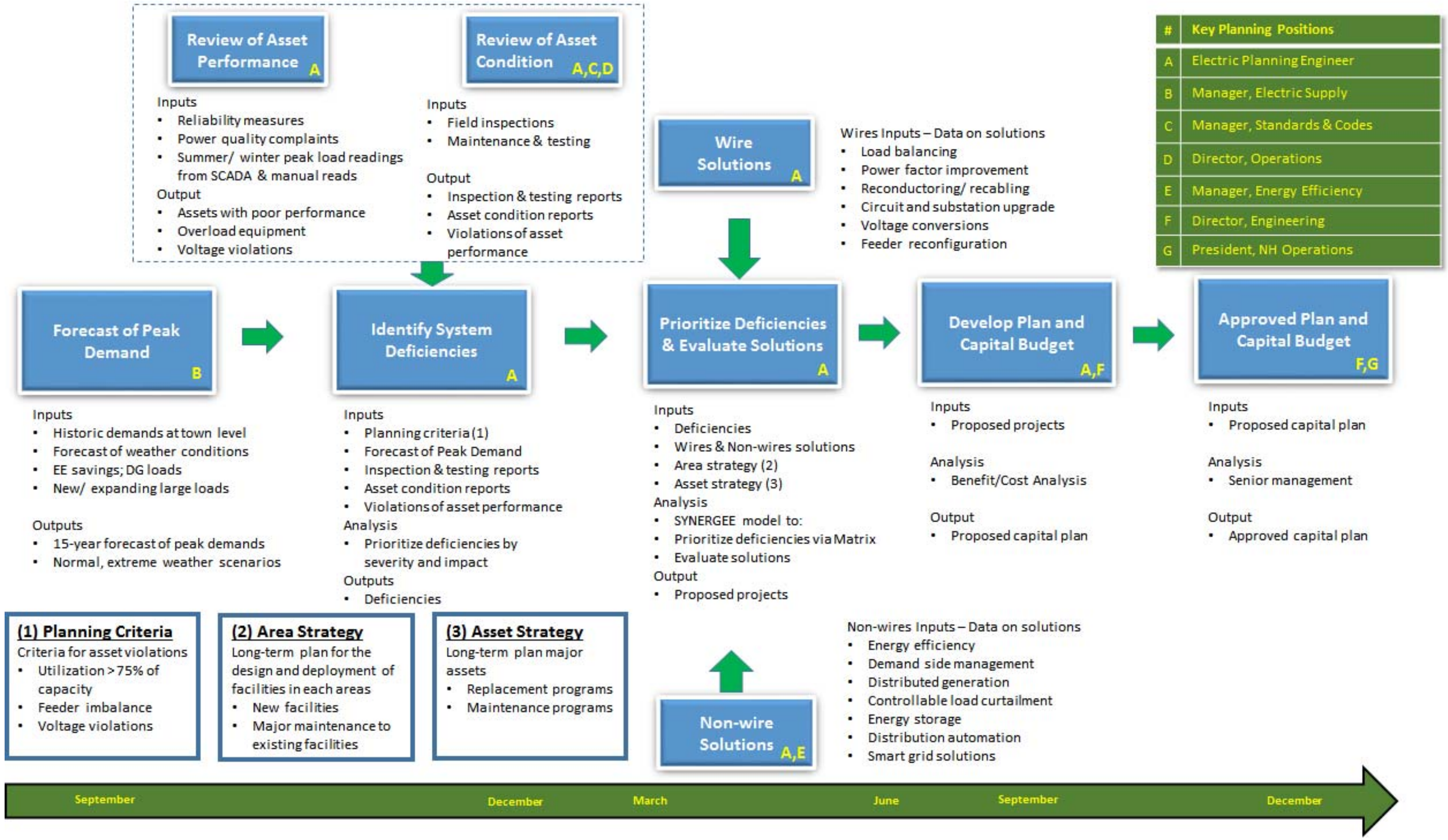
Rockingham and Grafton Economic Variables

year	Employment	Households	Ratio Employment	Ratio Households	emp_hh
2000	187.907035	136.67992	0.920630285	0.890251731	0.908479
2001	190.213308	138.994921	0.931929622	0.905330271	0.92129
2002	188.792416	141.139531	0.924968114	0.919298985	0.9227
2003	188.116395	142.7048	0.921656022	0.929494217	0.924791
2004	192.795558	144.091146	0.944581077	0.93852405	0.942158
2005	195.961972	145.783314	0.960094582	0.949545826	0.955875
2006	199.001481	147.631915	0.974986329	0.961586514	0.969626
2007	200.826942	148.693788	0.983929978	0.968502924	0.977759
2008	200.737984	150.063565	0.983494138	0.977424836	0.981066
2009	194.560295	150.820776	0.953227216	0.982356859	0.964879
2010	195.343011	151.627674	0.957062049	0.987612512	0.969282
2011	197.024053	151.825071	0.965298133	0.988898239	0.974738
2012	199.328096	152.626136	0.976586544	0.9941159	0.983598
2013	201.23947	153.175113	0.985951115	0.99769161	0.990647
2014	204.106945	153.529519	1	1	1
2015	208.568515	154.575235	1.021858982	1.006811172	1.01584
2016	212.760828	155.736281	1.042398768	1.014373536	1.031189
2017	215.26408	156.863478	1.054663182	1.021715427	1.041484
2018	216.525787	157.928542	1.060844779	1.02865262	1.047968
2019	217.550317	158.974593	1.065864354	1.035465974	1.053705
2020	218.847603	160.012894	1.072220267	1.04222885	1.060224
2021	220.484682	161.037051	1.080240959	1.0488996	1.067704
2022	221.987483	162.080835	1.087603771	1.055698188	1.074842
2023	223.397776	163.17224	1.094513349	1.062806951	1.081831
2024	224.597318	164.144965	1.100390376	1.069142703	1.087891
2025	225.737448	165.124695	1.10597632	1.075524082	1.093795
2026	226.792275	166.073529	1.111144332	1.081704223	1.099368
2027	227.775758	166.90446	1.115962801	1.087116413	1.104424
2028	228.761927	167.756316	1.12079443	1.092664897	1.109543
2029	229.615563	168.6358	1.124976727	1.098393332	1.114343
2030	230.537068	169.541138	1.129491542	1.104290166	1.119411
2031	231.455754	170.397771	1.133992545	1.109869764	1.124343

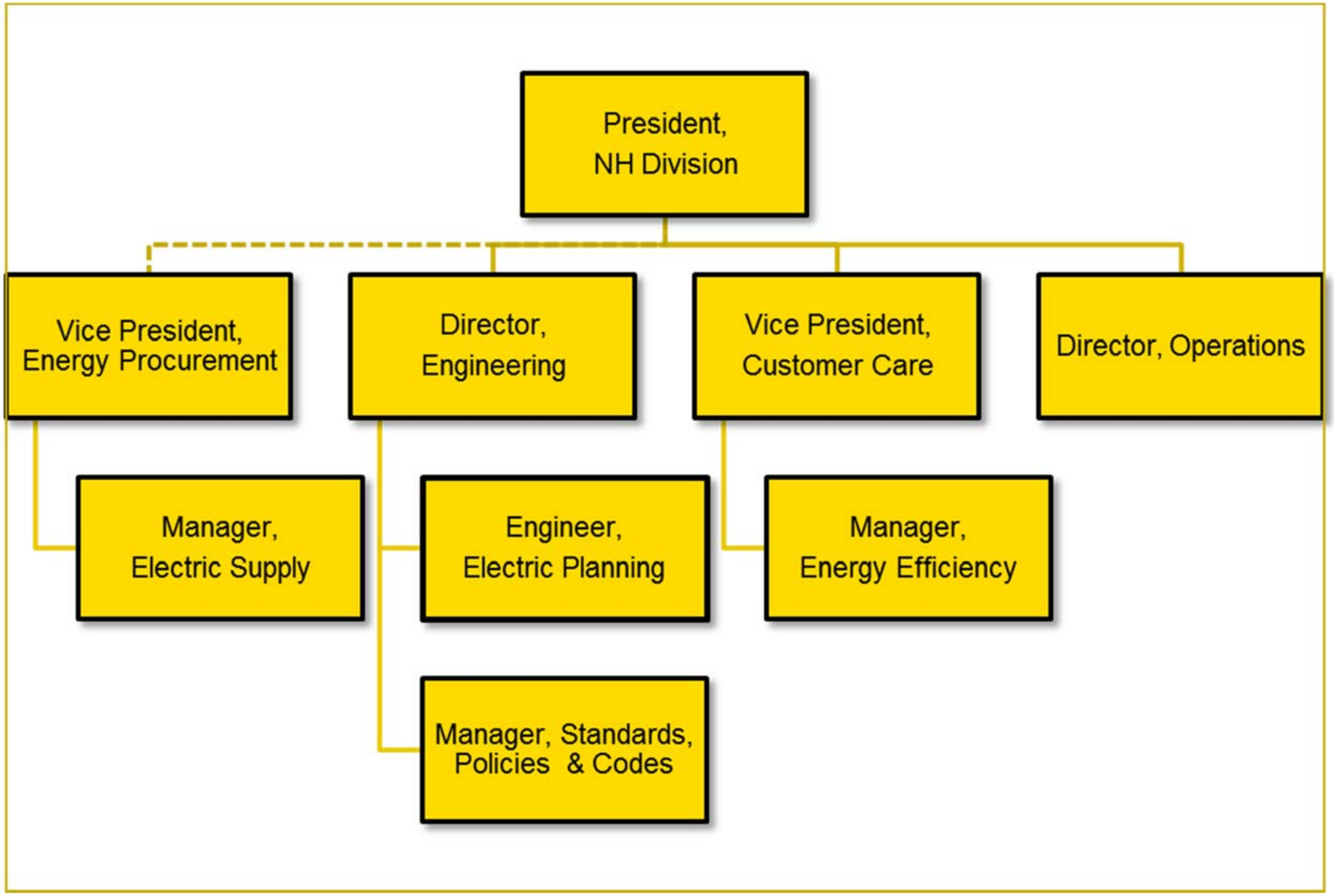
Table 8

year	month	day	hour	system mw	psa total	mw_e	mw_w	Eastern %	Western %
2014	3	3	19	144.09	144.088	66.7299	77.3576	46.312%	53.688%
2014	4	15	14	122.63	122.625	50.2352	72.3902	40.966%	59.034%
2014	5	12	16	133.566	133.565	57.9524	75.613	43.389%	56.611%
2014	6	30	17	172.905	156.836	69.5198	87.3159	44.327%	55.673%
2014	7	23	16	193.21	193.213	96.3262	96.8868	49.855%	50.145%
2014	8	27	16	175.731	175.731	87.1339	88.5967	49.584%	50.416%
2014	9	2	15	177.966	177.966	87.8959	90.07	49.389%	50.611%
2014	10	16	12	134.995	134.995	54.5696	80.4256	40.423%	59.577%
2014	11	18	18	135.778	135.892	62.2174	73.6748	45.784%	54.216%
2014	12	8	18	143.234	143.321	68.0705	75.2504	47.495%	52.505%
2015	1	8	18	148.541	148.451	69.6552	78.7954	46.921%	53.079%
2015	2	16	19	144.885	144.833	68.6982	76.1348	47.433%	52.567%
2015	3	5	19	137.502	137.502	63.046	74.4561	45.851%	54.149%
2015	4	2	11	123.717	123.717	53.1958	70.5207	42.998%	57.002%
2015	5	27	16	159.605	173.241	80.9305	92.3104	46.716%	53.284%
2015	6	23	17	149.229	163.897	76.974	86.9234	46.965%	53.035%

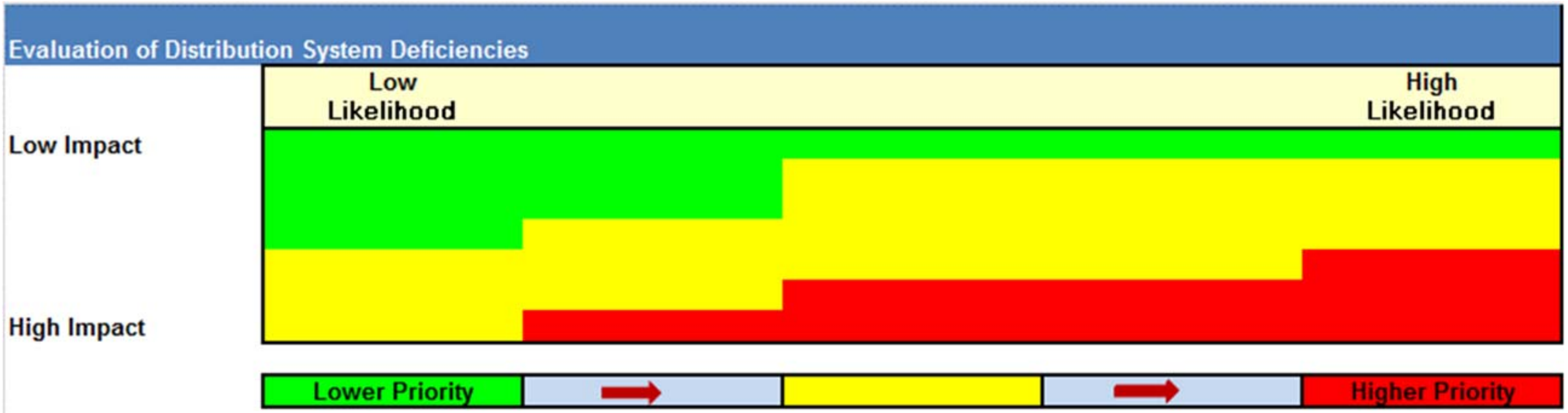
Appendix C. Distribution Planning Process Map and Timeline



Appendix C. Distribution Planning Organizational Chart and Key Positions



Appendix C. Prioritization of System Deficiencies



Impact Measures	Customers Affected	MW Affected	Loadings (% of Rated Capacity)	Safety and Environment	Overall Impact
Low Impact	Low	Low	<75%	Low $ Consequence	Low Impact
	↓	↓	↓	↓	↓
High Impact	High	High	>120%	High $ Consequence	High Impact

Likelihood Measures	1 in 100 Years	Each Year
Likelihood	Low Likelihood	High Likelihood

THIS PAGE INTENTIONALLY LEFT BLANK

Appendix D - Distribution Planning Criteria Summary

1.0 Introduction

This document summarizes the Distribution Planning Criteria and Strategy that will be used by the Engineering Department of Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities ("Liberty" or the "Company") to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA").

2.0 Equipment Ratings

Thermal limits are recognized for all system elements in conducting planning studies. The current in equipment and lines are limited so that voltage drops are held to reasonable values; so that conductors will not be severely annealed or damaged; so that switches, connectors, etc. will not be overloaded and that clearances are not exceeded. Several factors are taken into account, including: 1) ambient temperatures, 2) load cycles, 3) wind velocities, and 4) potential loss of life of equipment.

Liberty's Distribution Planning Department maintains equipment ratings for all major equipment, including transformers, overhead lines, and underground cables. Overcurrent protection system settings are also taken into account where applicable.

Figure D-1 summarizes the Equipment Rating criteria:

Figure D-1. Equipment Rating Criteria Summary

	Overhead Conductors		Underground Cables		Transformers	
Condition	Duration	Design Criteria	Duration	Design Criteria	Duration	Design Criteria
Normal	Continuous	• The maximum value for normal peak loads on all new and rebuilt feeders • Temperature limit for 100% ampacity for normal operating conductor is 176°F/80°C for bare conductors and 167°F/75°C for spacer cable, tree wire, & covered conductors	Continuous	• Maximum loading that does not cause the conductor temperature to exceed its design value at any time during a 24-hour load cycle • Normal cable ampacities are based on a 90° insulation operating temperature.	Continuous	• Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or • The Top Oil Temperature exceeds 110 °C, or • The Hot Spot Copper temperature exceeds 180 °C
LTE	24 Hours	• The absolute maximum ampacity allowed for a given conductor and should not be exceeded at any time. • Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for both bare and spacer cable, tree wire, & covered conductors	100 - 300 Hours	• Maximum loading that does not cause the conductor temperature to exceed its design value over several consecutive 24-hour load cycles. • Emergency cable ampacities are based on 130° insulation operating temperature.	1 - 300 Hours	• Level for the peak hour with the emergency load added in the 24-hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer life, or • the Top Oil Temperature exceeds 130 °C, or • the Hot Spot Copper temperature exceeds 180 °C
STE	As Needed	• Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department	1 - 24 Hours	• Maximum loading that does not cause the conductor temperature to exceed its allowable emergency value at any time during a 24-hour load cycle. • Emergency cable ampacities are based on 130° insulation operating temperature.	15 minutes	• The one hour operation of the transformer at that level for the peak hour in the 24 hour load cycle causes a cumulative (24 hour) 3.0% loss of Transformer Life, or • a hot spot copper temperature exceeding 180°C. • Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).

3.0 Planning Criteria

For normal loading conditions on distribution feeders and transformers, the planning criteria is based on facilities to remain within 75% of normal ratings at all times. For sub-transmission lines, facilities are to remain within 90% of normal ratings.

For N-1 contingency situations, the planning criteria is based on interrupted load returning to service within a reasonable time via system reconfiguration through switching, installation of temporary equipment, such as mobile transformers or generators, and/or by repair of a failed device. Where practical, switching flexibility is integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Figure D-2 shall guide loading and contingency planning on the distribution system:

Figure D-2. Distribution System Planning Criteria Summary

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

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 device. Therefore it is expected that the Load Relief budgets will increase from historic 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 D-3:

Figure D-3. Estimated Capital Costs of New Criteria

	$Millions
Total Substation Scope	$13.5
Other Distribution Line Scope	$3
Total Cost over 15 Years	$16.5

Liberty has refined the distribution planning criteria to better fit Liberty's strategy and scale of facilities. The Figure D-4 below provides a summary of the changes to Liberty's new criteria from the previous criteria under National Grid.

Figure D-4. Summary of Planning Criteria Changes

New Criteria	Previous Criteria	Reason for Change
During normal operation, all distribution feeders to remain within 75% of normal ratings.	During normal operation, all distribution feeders to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all sub-transmission lines to remain within 90% of normal ratings.	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
During normal operation, all transformers to remain within 75% of normal ratings.	During normal operation, all transformers to remain within 100% of normal ratings.	Reflects Liberty's strategy to proactively plan for sufficient capacity to meet changes in demand.
For the loss of a distribution feeder, if more than 16MWhrs of load at risk results for a single feeder fault evaluate alternatives to mitigate.	No Change.	Existing targets are adequate given size of a typical Liberty distribution feeder.
For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 20MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 1.5MW combined. If more than 36MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
For the loss of a transformer, the quantity of load at risk of being out of service following post contingency switching should be limited to 10MW combined. If more than 240MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	For the loss of a sub-transmission supply line, the quantity of load at risk of being out of service following post contingency switching should be limited to 2.5MW combined. If more than 60MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.	Reflects Liberty's strategy and scale of facilities.
Every effort must be made to return the failed sub-transmission line to service within 12 hours.	Every effort must be made to return the failed sub-transmission line to service within 24 hours.	Reducing normal loading to 90% for sub-transmission lines allows for adequate capacity on adjacent lines to restore load post-contingency.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Establishes a new limit for repairing feeder faults on Liberty's distribution feeders.

4.0 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of NH and within the limits of ANSI C84.1-2006.

These upper and lower voltage ANSI limits, as measured at the customer's meter, are listed below in Figure D-5:

Figure D-5. Voltage Requirements for Liberty Utilities

For 120 V – 600 V Systems				
Nominal Voltage (V)	Service Voltage (V)			
	Range A		Range B	
	Max	Min	Max	Min
120	126	114	127	110
240	252	228	254	220
480	504	456	508	440

Source: ANSI

Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage on the feeders is controlled by the station load tap changer or station regulators on feeders, the application of distribution capacitor banks, and the application of pole or pad mounted line regulators.

5.0 Distribution Circuit Phase Imbalance Criteria

This criterion is established to limit the load imbalance among the three phases of a primary distribution circuit. These criteria call for the correction of phase imbalances of existing and new distribution circuits. Phase imbalance is defined on the basis of connected KVA (CKVA) load for that circuit as:

$$\%imbalance = \frac{(phase\ load - average\ phase\ load)}{average\ phase\ load} X\ 100$$

Two criteria should be met for the circuit to be considered for corrective action:

1. The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting.
2. The loading between the low and high phase should not exceed 100A.

6.0 <u>Environmental Review of Planning Activities</u>

This procedure describes how environmental considerations are incorporated into the planning and design of distribution facilities to ensure that all Distribution activities are in compliance with environmental laws and regulations.

All Engineers attend an Environmental Training Program provided by the Environmental Engineer on a regular basis. The training includes a section on identifying environmental considerations related to project and work order preparation.

It is the responsibility of the Engineering Department to identify and address during the planning, design or estimating stages any environmental considerations related to project or work order activities. At a minimum, the environmental evaluation will assess the following conditions through discussion with the property owner, review of site plans and/or field observations:

- Location of any rivers or streams within 200 feet of the proposed work
- Location of flood plains in the vicinity of the proposed work

- Bodies of water or potential indications of wetlands (such as wet, soft soil or low lying land; or areas naturally devoid of trees with vegetation primarily no taller than shrub height) within 100 feet of the proposed work
- Areas on the property that are contaminated with oil or other hazardous materials
- The total square footage/ acreage disturbed
- The potential for asbestos containing material to be removed or disturbed
- Any waste that will be generated by the proposed work activities

The Engineering Department will address environmental considerations in one or more of the following ways:

- Where practical, choose an alternative that has less environmental impact.
- Consult with the Environmental Engineer to determine if permitting or regulatory requirements exist. If there are permitting or regulatory requirements, work with the Environmental Engineer to ensure that the appropriate permits are obtained and that any regulatory requirements are followed.
- Confirm that property developers have included electric utilities in their environmental filings. It is the responsibility of the property developer to obtain permits and licenses for work on private property.

Appendix E. Hypothetical Case Study: Evaluation of Non-Wires Solution

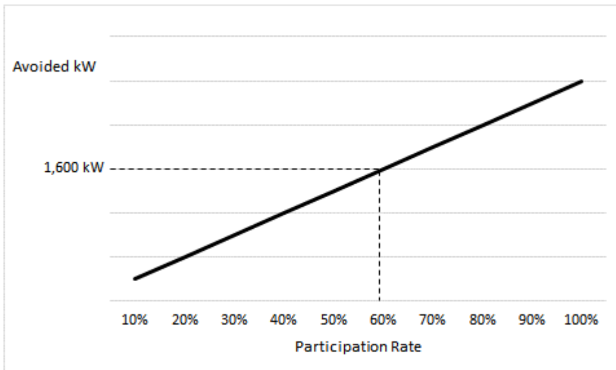
Background

To illustrate how the Company's planning process will evaluate and, as feasible, implement a non-wires solution, the Company prepared the following hypothetical case study. The case study consists of five phases that describes the planning process, beginning with a description of a hypothetical situation, the approach to evaluate a non-wires solution, and the potential action steps.

The case study identifies important information that is needed to evaluate the potential benefits and costs of non-wires solutions.

Planning Phase	Description
Hypothetical Situation	The Company needs to install one new feeder to address an anticipated distribution system deficiency of approximately 1,600 kW in serving a targeted area (i.e., section of a community) within the next five years. The deficiency was identified through an annual planning process that identifies distribution system deficiencies based on certain planning criteria. The engineering study includes a forecast of peak demands as well as a review of asset performance and conditions. The estimated investment in the new feeder is $5.0 million (in $2015) and the system deficiency represents approximately 13 percent of the total capacity in the targeted area.
Market Profile of Targeted Area	The targeted area consists of approximately 2,200 customers; Feeder 1 serves 1,900 customers (75% of which are residential), while Feeder 2 serves 300 customers (75% of which are small commercial). Feeder 1 has a current capacity of 7,100 kW and Feeder 2 has a current capacity of 5,500 kW. The targeted area also consists of eleven large commercial customers who represent approximately 40 percent of the total load in the targeted area.
Opportunity	The Company believes there is an opportunity to implement a non-wires solution that would defer installation of the new feeders for several years through demand (kW) reductions in the targeted area since the planned investment meets the Company's screening criteria for consideration of a non-wires solution. Potential non-wires solutions include programs that complement and improve the operations of the existing distribution system and that individually or collectively could defer the need for a wires solution, including: (a) targeted energy efficiency; (b) targeted demand response; (c) targeted load controls; and/or (d) Distributed Generation ("DG"). See Figure 1 for a comprehensive list of non-wires programs that could be considered. Most of the non-wires solutions require some level of customer participation to reduce demand (kW) in the targeted area. The graph below illustrates the

<table>
<tr><th>Planning Phase</th><th>Description</th></tr>
<tr><td></td><td>expected relationship between customer participation and reduced demand (kW) in the targeted area.



An example of the relationship between customer participation in a non-wires program and reduction in demand (kW) is a Direct Load Controls ("DLC") program. Based on the results of a national study by E-Source, the average load reduction of residential customers participating in an air conditioning DLC program is 1.12 kW per residential participant. To achieve a reduction in demand (kW) of 1,600 kW based on the E-Source average of 1.12 kW per residential participant, approximately 1,400 residential customers would need to participate. However, there are only 1,500 residential customers in the target area; thus, almost all residential customers in the target area would need to participate in the DLC program. This is unlikely since the E-Source survey shows that only 13.3 percent of eligible residential customers participate in a DLC program. To better evaluate potential savings and customer participate rates, the Company needs perform a comprehensive evaluation of customer demographics and behavior in the targeted area in order to get a full understanding of the expected participation, corresponding load reduction, benefits, and costs from these potential NWA programs.</td></tr>
<tr><td>Challenges</td><td>The Company notes that there are several challenges to a successful evaluation and implementation of a non-wires solution, including:
Insufficient data to evaluate the potential benefits and costs of a non-wires solution, including: (a) current saturation levels of targeted equipment and associated peak demands; and (b) consumer interest and likelihood of installing the proposed measures based on a range of incentive offerings. This can be addressed through a market assessment of customers and equipment in the targeted area.
Insufficient data to estimate the potential costs of designing, developing, implementing, and administrating non-wires programs. This can be addressed through research and evaluation of similar programs designed and implemented in other companies.</td></tr>
</table>

Planning Phase	Description
	• Little operating experience with such non-wires programs, including load control and DG programs. This can be addressed by retaining experienced firms to train Liberty employees and/or administer the programs. • No mechanism(s) to recover the cost of evaluating, designing, developing, implementing and administering non-wires programs. This can be addressed through regulatory approval of a cost recovery mechanism. • No mechanism(s) to recover the lost revenues associated with non-wires programs, since such programs reduce the sales that fund recovery of the Company's fixed costs. This can be addressed through regulatory approval of a cost recovery mechanism. • No mechanism(s) to recover potential investments in non-wires programs, such as distributed generation. This can be addressed through regulatory approval of a cost recovery mechanism. The Company believes that it is important to address such challenges in order to ensure that non-wires solutions can be treated on equal footing as traditional T&D wires solutions.
Evaluation	The Company's evaluation of the hypothetical situation would be based on a cost effectiveness test performed consistent with the energy efficiency benefit-cost test approved by the New Hampshire Public Utilities Commission (the "Commission"). The cost effectiveness test is based on: (a) data that quantifies the demand savings (in kW) of the non-wires solutions; (b) data that quantifies the costs of the non-wires solutions; (c) data that quantifies the benefits of deferring investment in the new feeders; and (d) a risk assessment of the wires vs. non-wires solutions. Specifically, a non-wires solution would enable the Company to defer a wires solution if the following conditions were met: • The demand savings of the non-wires solutions are sufficient to address the distribution system deficiency. The demand savings can be estimated through a market assessment. • The costs associated with design, development, implementation, and administration of the non-wires solution is less than or equal to the benefits of deferring investment in the new feeders. The costs can be estimated through research and analysis of similar programs. • If the Company's risk assessment of the non-wires solution does not result in a risk sufficiently greater, in the Company's opinion, than the wires solution. Such risk assessment is based on a number of factors, including size, complexity, and Company control over the non-wires solution. In simplistic terms, if the carrying cost associated with the hypothetical wires solution of $5 million is 15%, then a non-wires solution could be cost effective if

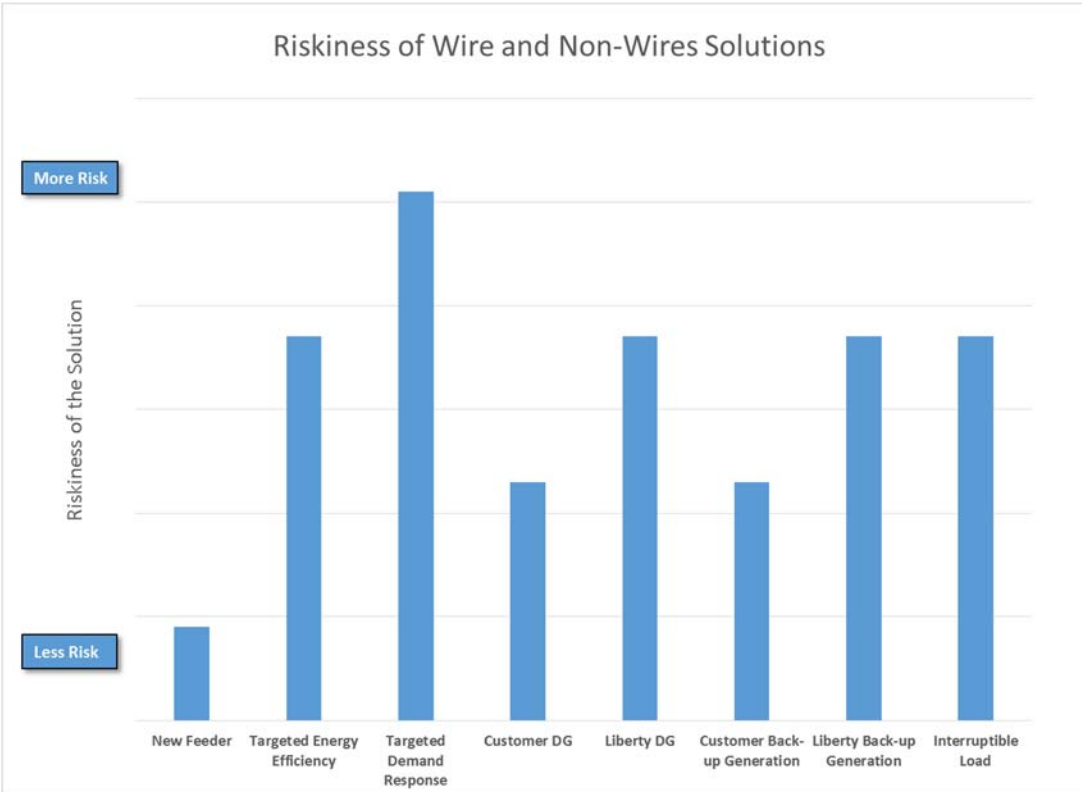
Planning Phase	Description
	it was sufficient to address the distribution system deficiency, cost annually less than $750,000, and represented a risk that was not sufficiently greater, in the Company's opinion, than the wires solution. Figure 2 illustrates the Company's approach to measure such risk of non-wires and wires solutions.
Actions/ Next Steps	In this final phase of this hypothetical case study, the Company would be responsible for implementing the non-wires program. Other than its current Energy Efficiency program, the Company has little experience operating and administrating non-wires programs, and thus would seek to retain experienced firms to assist in the development, implementation, and administration of the program, in particular for a load controls program. **<u>Next Steps</u>** As described above, there are a number of challenges that need to be addressed before the Company can implement a non-wires alternative program, some of which require regulatory action in order to move forward. An important first step is to perform the evaluation study to gather the necessary data, for which cost recovery is needed. Once the evaluation study has been completed, programs that pass the cost effectiveness screening can move forward to the implementation phase.

Figure 1. Summary of Potential NWA Programs

Sector	*Program*	*Description*
Residential	**Direct Load Control (A/C Cycling)**	Programs offer financial incentives for allowing the utility to cycle customer's A/C during peak demand times
Residential	**Programmable Communicating or Wi-Fi Enabled Thermostat**	Programs offer a free thermostat (Direct installation), or a rebate (bring-your-own-thermostat) that enables the utility to cycle the A/C or change the thermostat setpoint
Residential	**Electric Heat Programs**	Multiple programs aimed at electrically heated homes, including special rates for allowing the heating system to be controlled, special rates for having a backup heating system so the electric heat can be interrupted
Residential	**Water Heater Programs**	Programs offer financial incentives for allowing the utility to cycle customer's electric water heater.
Residential	**Pool Pump Programs**	Programs offer financial incentives for allowing the utility to interrupt power to customer's pool pumps
Residential	**Peak-Time Rebate (PTR) Dynamic Pricing Programs**	Programs offer a bill credit for customers who save energy during DR events
Residential	**Critical Peak Pricing (CPP) Dynamic Pricing Programs**	Programs have significantly higher rates for energy used during critical times
Small Business	**Direct Load Control (A/C Cycling)**	Programs offer financial incentives for allowing the utility to cycle customer's A/C during peak demand times
Small Business	**Programmable Communicating or Wi-Fi Enabled Thermostat**	Programs offer a free thermostat (Direct installation), or a rebate (bring-your-own-thermostat) that enables the utility to cycle the A/C or change the thermostat setpoint
Medium to Large Business	**Critical Peak Pricing Programs**	Programs have significantly higher rates for energy used during critical times
Medium to Large Business	**Base Interruptible Programs**	Programs offer an incentive to reduce customer's load to or below a level that is pre-selected by the customer, and has a penalty when that level is not met
Medium to Large Business	**Demand Bidding Programs**	Programs offer an incentive to reduce customer's load with no penalty for failing to reduce load
Medium to Large Business	**Scheduled Load Reduction Programs**	Programs offer an incentive to reduce load during pre-selected time periods
Medium to Large Business	**Agricultural/Pumping Interruptible Programs**	Programs offer a year-round credit when customers allow utility to temporarily interrupt service
Medium to Large Business	**Automated DR**	Programs offer incentives for installing technologies that automatically reduce load during events

Source: E-Source

Figure 2: Hypothetical Evaluation Matrix



Risk Matrix Measures the riskiness of the solution	Size	Number of Lead Elements	Internal Complexity	Construction Time (in Years)	Total Time (in Years)	Success Risk Factor	Customer Involvement	Regulatory Approvals	Total Risk
Risk Factors	Percentage of target area load; non-wires solutions considered only if <20%	Project steps prior to completion (e.g., design, permitting)	Internal complexity	Length of time to Complete Construction	Length of time to design, permit and build project	Experience w/ successful implementation of similar projects	Customer involvement to achieve expected outcome	Complexity of regulatory approvals to achieve expected outcome	Riskiness of the Project
	Each Category is rated on a 10-point scale that measures the impact of each category on overall risk: 1 = Less risk, 10= More risk								
Riskiness of Solutions									
New Feeder	5	2	2	2	2	2	2	2	19
Targeted Energy Efficiency	5	6	6	6	6	6	6	6	47
Targeted Demand Response	5	8	8	8	8	8	8	8	61
Customer DG	5	4	4	4	4	4	4	4	33
Liberty DG	5	6	6	6	6	6	6	6	47
Customer Back-up Generation	5	4	4	4	4	4	4	4	33
Liberty Back-up Generation	5	6	6	6	6	6	6	6	47
Interruptible Load	5	6	6	6	6	6	6	6	47