1 **Appendix A. LCIRP Statutory Requirements**

2 **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
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; Section 5
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 ("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 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] The Commission has suspended the docket as it decides on Eversource's Motion for Reconsideration and/or Clarification filed in response to the Commission's Order No. 26,358 whereby the Commission supported Staff's position in their recommendation filed on February 12, 2019. As described in Section 4, Liberty is proposing a Least Cost Integrated Resource Plan with Grid Modernization Plan elements based on assessment of Smart Grid technologies working with CMG Consulting. This Plan will significantly improve Liberty's ability to integrate Distributed Energy Resources (DERs) and manage the grid more efficiently, reducing the growth in centralized transmission and generation resources (See Section 5 and Appendix E) for details on the costs and benefits of this Plan. Therefore, this LCIRP is consistent with the

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.

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 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 20-092, the Commission's EERS proceeding. As of the date of this filing, the Settlement Agreement filed in the docket has not been approved. As described in Section 6.5, Liberty supports the creation of an EERS and believes, if structured correctly, there can be significant benefits to businesses, residents and communities in increasing energy efficiency and helping further reduce overall energy usage and demand.

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

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 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.

8 *Ibid*., at 47.

9 *Ibid*., at iv.

Liberty Utilities New Hampshire

Final Seasonal Peak Forecasts 2021-2037

Prepared By

Business Economic Analysis and Research

November 2020

Summary of Results

The weather adjusted actual seasonal peaks appear in Table 1 below for Liberty Utilities New Hampshire (LUNH). Note that the peak load series reflects the historic impacts of both energy efficiency programs and distributed generation activities in the LUNH 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
2006	7	186.75		1	153.612	
2007	7	187.414	0.36%	12	152.502	-0.72%
2008	7	195.127	4.12%	12	146.214	-4.12%
2009	7	190.418	1.60%	12	153.703	0.79%
2010	7	188.743	-0.88%	12	148.501	-3.38%
2011	8	201.095	6.54%	12	151.458	1.99%
2012	8	189.013	-6.01%	1	153.171	1.13%
2013	7	194.107	2.70%	12	155.101	1.26%
2014	7	200.922	3.51%	1	158.777	2.37%
2015	7	184.679	-8.08%	1	148.348	-6.57%
2016	7	187.276	1.41%	1	145.011	-2.25%
2017	8	185.292	-1.06%	1	143.535	-1.02%
2018	8	187.317	1.09%	1	150.948	5.16%
2019	7	194.069	3.60%	1	145.559	-3.57%
2020	7	188.48	-2.88%	1	140.297	-3.62%
2016-2020 Avg			0.43%			-1.06%

The summer peak increased .43% per year from 2016 through 2020 compared to the winter peak declining 1.06% annually over the same period.

Table 2 displays the LUNH 2021-2037 seasonal peak forecasts under normal peak day weather conditions. The forecasted peak values are split between the regression model forecast and expected electric vehicle charging station load and distributed generation activity not accounted for in the peak regression analysis. The 2021 growth is based on the 2020 weather adjusted actual shown in Table 1.

Table 2
Forecasted Peaks Normal Weather

year	Summer month	Model Peak	PV and EV Peak	Peak Mw	Growth	Winter month	Model Peak	PV and EV Peak	Peak Mw	Growth
2021	7	192.548	-0.089	192.459	2.11%	1	148.685	0.385	149.070	6.25%
2022	7	192.934	0.242	193.176	0.37%	1	148.738	0.692	149.430	0.24%
2023	7	193.387	0.557	193.944	0.40%	1	148.894	0.923	149.817	0.26%
2024	7	193.871	0.796	194.667	0.37%	1	149.087	1.154	150.241	0.28%
2025	7	194.365	0.955	195.320	0.34%	1	149.302	1.461	150.763	0.35%
2026	7	194.851	1.194	196.045	0.37%	1	149.517	1.769	151.286	0.35%
2027	7	195.326	1.353	196.679	0.32%	1	149.718	1.999	151.717	0.29%
2028	7	195.787	1.592	197.379	0.36%	1	149.908	2.230	152.138	0.28%
2029	7	196.237	1.672	197.909	0.27%	1	150.084	2.384	152.468	0.22%
2030	7	196.679	1.831	198.510	0.30%	1	150.252	2.615	152.867	0.26%
2031	7	197.11	1.990	199.100	0.30%	1	150.41	2.922	153.332	0.30%
2032	7	197.526	2.229	199.755	0.33%	1	150.556	3.153	153.709	0.25%
2033	7	197.929	2.388	200.317	0.28%	1	150.685	3.384	154.069	0.23%
2034	7	198.317	2.547	200.864	0.27%	1	150.805	3.614	154.419	0.23%
2035	7	198.695	2.786	201.481	0.31%	1	150.906	3.922	154.828	0.26%
2036	7	199.071	2.945	202.016	0.27%	1	151.004	4.153	155.157	0.21%
2037	7	199.435	3.184	202.619	0.30%	1	151.099	4.383	155.482	0.21%
2022-2026 Avg					0.37%					0.30%

The average annual summer growth rate in peak for 2022-2026 is 327% while the winter average annual growth rate is .30% over the same period.

Table 3 provides the LUNH 2021-2037 seasonal peak forecasts under extreme weather. The extreme weather was computes by averaging the two highest weather conditions by month over the 20 year historic period which means a 1 in 10 year weather event. Although the summer peaks are higher, the annual growth rates for 2022-2026 are just less than the summer growth rate using normal weather.

Table 3
Forecasted Peaks Extreme Weather

year	Summer month	Model Peak	PV and EV Peak	Peak Mw	Growth	Winter month	Model Peak	PV and EV Peak	Peak Mw	Growth
2021	7	207.083	-0.089	206.994	9.82%	1	151.821	0.385	152.206	8.49%
2022	7	207.481	0.242	207.723	0.35%	1	151.874	0.692	152.566	0.24%
2023	7	207.946	0.557	208.503	0.38%	1	152.029	0.923	152.952	0.25%
2024	7	208.441	0.796	209.237	0.35%	1	152.222	1.154	153.376	0.28%
2025	7	208.947	0.955	209.902	0.32%	1	152.437	1.461	153.898	0.34%
2026	7	209.445	1.194	210.639	0.35%	1	152.653	1.769	154.422	0.34%
2027	7	209.931	1.353	211.284	0.31%	1	152.853	1.999	154.852	0.28%
2028	7	210.404	1.592	211.996	0.34%	1	153.044	2.230	155.274	0.27%
2029	7	210.865	1.672	212.537	0.26%	1	153.22	2.384	155.604	0.21%
2030	7	211.318	1.831	213.149	0.29%	1	153.387	2.615	156.002	0.26%
2031	7	211.761	1.990	213.751	0.28%	1	153.545	2.922	156.467	0.30%
2032	7	212.188	2.229	214.417	0.31%	1	153.691	3.153	156.844	0.24%
2033	7	212.603	2.388	214.991	0.27%	1	153.821	3.384	157.205	0.23%
2034	7	213.003	2.547	215.550	0.26%	1	153.94	3.614	157.554	0.22%
2035	7	213.393	2.786	216.179	0.29%	1	154.041	3.922	157.963	0.26%
2036	7	213.78	2.945	216.725	0.25%	1	154.14	4.153	158.293	0.21%
2037	7	214.156	3.184	217.340	0.28%	1	154.234	4.383	158.617	0.21%
2022-2026 Avg					0.35%					0.29%

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, LUNH system hourly data was the only source of historic peak day analysis. Once the LUNH system seasonal peak day forecasts were developed in this analysis, Eastern PSA and Western PSA forecasts were derived by using the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2020 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2020. 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
2021	7	97.9616		1	70.6589	
2022	7	98.3267	0.37%	1	70.8299	0.24%
2023	7	98.7176	0.40%	1	71.0131	0.26%
2024	7	99.0855	0.37%	1	71.2139	0.28%
2025	7	99.418	0.34%	1	71.4617	0.35%
2026	7	99.7869	0.37%	1	71.7094	0.35%
2027	7	100.1097	0.32%	1	71.914	0.29%
2028	7	100.4659	0.36%	1	72.1135	0.28%
2029	7	100.7354	0.27%	1	72.2699	0.22%
2030	7	101.0414	0.30%	1	72.4588	0.26%
2031	7	101.3419	0.30%	1	72.6794	0.30%
2032	7	101.6752	0.33%	1	72.8581	0.25%
2033	7	101.9614	0.28%	1	73.0286	0.23%
2034	7	102.2399	0.27%	1	73.1947	0.23%
2035	7	102.5538	0.31%	1	73.3884	0.26%
2036	7	102.8262	0.27%	1	73.5442	0.21%
2037	7	103.1331	0.30%	1	73.6986	0.21%
2022-2026 Avg			0.37%			0.30%

Table 5 lists the Western PSA seasonal forecasts under normal weather conditions. The Eastern PSA numbers are slightly higher than the Western peak day values in the summer but somewhat lower in the winter months.

Table 5
Western PSA Peaks Normal Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2021	7	94.4973		1	78.4105	
2022	7	94.8495	0.37%	1	78.6001	0.24%
2023	7	95.2265	0.40%	1	78.8036	0.26%
2024	7	95.5815	0.37%	1	79.0264	0.28%
2025	7	95.9025	0.34%	1	79.3013	0.35%
2026	7	96.2583	0.37%	1	79.5762	0.35%
2027	7	96.5696	0.32%	1	79.8034	0.29%
2028	7	96.9131	0.36%	1	80.0247	0.28%
2029	7	97.1731	0.27%	1	80.1982	0.22%
2030	7	97.4683	0.30%	1	80.4079	0.26%
2031	7	97.7579	0.30%	1	80.6527	0.30%
2032	7	98.0795	0.33%	1	80.8509	0.25%
2033	7	98.3556	0.28%	1	81.0401	0.23%
2034	7	98.6243	0.27%	1	81.2247	0.23%
2035	7	98.9272	0.31%	1	81.4392	0.26%
2036	7	99.19	0.27%	1	81.6125	0.21%
2037	7	99.4859	0.30%	1	81.7838	0.21%
2022-2026 Avg			0.37%			0.30%

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 Eastern PSA values are higher than the Western PSA numbers in the summer but lower during the winter period.

Table 6
Eastern PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2021	7	105.3599		1	72.1455	
2022	7	105.7312	0.35%	1	72.3163	0.24%
2023	7	106.128	0.38%	1	72.4991	0.25%
2024	7	106.5017	0.35%	1	72.6999	0.28%
2025	7	106.8403	0.32%	1	72.9477	0.34%
2026	7	107.2153	0.35%	1	73.1958	0.34%
2027	7	107.5437	0.31%	1	73.4	0.28%
2028	7	107.906	0.34%	1	73.5998	0.27%
2029	7	108.1812	0.26%	1	73.7563	0.21%
2030	7	108.4927	0.29%	1	73.9448	0.26%
2031	7	108.7992	0.28%	1	74.1655	0.30%
2032	7	109.1382	0.31%	1	74.344	0.24%
2033	7	109.4303	0.27%	1	74.515	0.23%
2034	7	109.7151	0.26%	1	74.6807	0.22%
2035	7	110.0352	0.29%	1	74.8745	0.26%
2036	7	110.313	0.25%	1	75.0307	0.21%
2037	7	110.626	0.28%	1	75.1847	0.21%
2022-2026 Avg			0.35%			0.29%

Table 7
Western PSA Peaks Extreme Weather

year	Summer month	Peak Mw	Growth	Winter month	Peak Mw	Growth
2021	7	101.6339		1	80.06	
2022	7	101.9922	0.35%	1	80.2499	0.24%
2023	7	102.3753	0.38%	1	80.4527	0.25%
2024	7	102.7352	0.35%	1	80.6754	0.28%
2025	7	103.0619	0.32%	1	80.9502	0.34%
2026	7	103.4238	0.35%	1	81.2258	0.34%
2027	7	103.7406	0.31%	1	81.4523	0.28%
2028	7	104.0899	0.34%	1	81.6743	0.27%
2029	7	104.3555	0.26%	1	81.8476	0.21%
2030	7	104.6562	0.29%	1	82.057	0.26%
2031	7	104.9518	0.28%	1	82.3018	0.30%
2032	7	105.2788	0.31%	1	82.4998	0.24%
2033	7	105.5605	0.27%	1	82.6897	0.23%
2034	7	105.8354	0.26%	1	82.8736	0.22%
2035	7	106.1438	0.29%	1	83.0885	0.26%
2036	7	106.4119	0.25%	1	83.2621	0.21%
2037	7	106.7143	0.28%	1	83.4327	0.20%
2022-2026 Avg			0.35%			0.29%

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

Introduction

This report presents the Liberty Utilities New Hampshire (LUNH) seasonal peak forecasts for 2021-2037 under both normal and extreme weather. Regression analysis was used to estimate the LUNH 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 LUNH system level. Additional peak load due to electric vehicle charging station growth and distributed generation activity not accounted for in the regression analysis was added in to create the LUNH final system seasonal peak forecast which was displayed in summary Table 2. The LUNH final system seasonal peak forecasts were then split into Eastern and Western jurisdictions using LUNH township sales information as well the average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2020 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2020.

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 2021-2037 seasonal forecast process is detailed.

Data

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

Hourly system load for LUNH from October 2000 through April 2014 was supplied by National Grid while historic system loads from May 2014 through September 2020 was provided by LUNH staff. LUNH also supplied hourly Eastern and Western PSA loads for March 2014 through September 2020. 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 2014-2019 township volumes came from LUNH. The 2014-2019 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 September 2020 was identified as the dependent variable (LUNH staff requested not using 2002-2003 peak day values). A total of 216 months of peaks are used in the peak day analysis. Each of the 19 townships has 24 years of annual sales in the annual usage analysis. Appendix A contains the historic monthly peak values for LUNH.

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. Household values were summed across the two counties. The annual household values 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 households for Rockingham and Grafton counties from 2000 to 2037.

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 September 2020. 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 21 in year 2020) 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 number of households (HH) variable discussed in the previous section of this report. It is expected that a positive relationship exists between peak day use and the value of household count. 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 LUNH peak day model expressed in mathematical terms is as follows:

$$\begin{aligned} \text{PeakDay Mw} = {} & a + b * WTHI + c * WTHI\_SUMMER + d * WTHI\_SUMMER\_T \\ & + e * HDD + f * HH + g * FEB + h * MAR + i * APR + j * MAY \\ & + k * JUN + l * JUL + m * AUG + n * SEP + o * OCT + p * NOV \\ & + q * DEC \end{aligned}$$

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 twenty four in 2019. 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 2019 and a negative value if township sales declined from 1996 through 2019. 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 LUNH 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 .8795 which means that almost 88% of the monthly historic peak day variation was explained by the model coefficients. The monthly peak day Mw model coefficients are as follows:

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|
INTERCEPT	59.551	18.94427	3.14	0.0019
WTHI	0.94283	0.1937	4.87	<.0001
WTHI_SUMMER	3.24428	0.44566	7.28	<.0001
WTHI_SUMMER_T	0.0034	0.0026	1.31	0.1913
HDD	1.01251	0.22034	4.6	<.0001
HH	0.15598	0.09767	1.6	0.1118
FEB	-5.01006	2.67624	-1.87	0.0627
MAR	-8.78562	2.99189	-2.94	0.0037
APR	-19.63901	4.14047	-4.74	<.0001
MAY	-5.04123	5.07922	-0.99	0.3221
JUN	-246.54621	34.38385	-7.17	<.0001
JUL	-241.41378	35.04311	-6.89	<.0001
AUG	-241.44013	34.64611	-6.97	<.0001
SEP	-248.70372	33.6111	-7.4	<.0001
OCT	-14.96771	4.51406	-3.32	0.0011
NOV	-6.12208	3.6267	-1.69	0.093
DEC	1.64547	2.76843	0.59	0.5529

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 HH term has an expected positive coefficient sign. Only the DEC monthly term is 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	0.1679
INTERCEPT	-1279931	1840789	-0.7	0.4945		
TIME	637717	356240	1.79	0.0879		
CDD	2000.91489	1862.709	1.07	0.2949		
Town=Pelham					R-Square	0.8577
INTERCEPT	24744202	6578248	3.76	0.0011		
TIME	12751658	1273060	10.02	<.0001		
CDD	15078	6656.58	2.27	0.0342		
Town=Salem, NH					R-Square	0.3666
Intercept	260951547	16287406	16.02	<.0001		
TIME	4562942	3119623	1.46	0.1591		
CDD	23205	16645	1.39	0.1786		
YEAR 2005	27915615	10087868	2.77	0.0119		
Town=Windham					R-Square	0.7971
INTERCEPT	8381833	1156563	7.25	<.0001		
TIME	1784238	223825	7.97	<.0001		
CDD	2448.15397	1170.335	2.09	0.0488		

Note that the Salem Township had a year 2005 indicator variable added to capture a spike in annual usage for that year. Except for Derry and Salem, all the CDD terms were significant at the 95% confidence level which is very good for a twenty four 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 and Monroe Township had inserted a year 2015 indicator variable to capture a sharp decline in usage for that year.

Western Township Regression Results #1

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Acworth					R-Square	0.2976
INTERCEPT	1142518	38034	30.04	<.0001		
TIME	49656	15149	3.28	0.0034		
Town=Alstead					R-Square	0.2718
INTERCEPT	9946377	260081	38.24	<.0001		
TIME	320743	103591	3.1	0.0053		
Town=Bath					R-Square	0.6427
INTERCEPT	-21098	16105	-1.31	0.2043		
TIME	15982	3116.811	5.13	<.0001		
CDD	32.28344	16.2972	1.98	0.0608		
Town=Canaan					R-Square	0.4529
INTERCEPT	10966620	457457	23.97	<.0001		
TIME	815720	182206	4.48	0.0002		
Town=Charlestown, NH					R-Square	0.6943
INTERCEPT	380656	6884436	0.06	0.9564		
TIME	8621472	1332315	6.47	<.0001		
CDD	6381.56103	6966.414	0.92	0.37		
Town=Cornish					R-Square	0.2298
INTERCEPT	745301	114821	6.49	<.0001		
TIME	49806	22221	2.24	0.0359		
CDD	117.05325	116.1882	1.01	0.3252		

Western Township Regression Results #2

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Enfield					R-Square	0.69
INTERCEPT	14887600	1073080	13.87	<.0001		
TIME	1342705	207668	6.47	<.0001		
CDD	855.72201	1085.858	0.79	0.4395		
Town=Grafton, NH					R-Square	0.2637
INTERCEPT	61114	6001.554	10.18	<.0001		
TIME	478.93278	2374.284	0.2	0.8421		
YEAR 2002	25830	8079.306	3.2	0.0043		
Town=Hanover, NH					R-Square	0.7725
INTERCEPT	73300569	9499372	7.72	<.0001		
TIME	14526699	1838372	7.9	<.0001		
CDD	9912.18954	9612.488	1.03	0.3142		
Town=Lebanon					R-Square	0.8237
INTERCEPT	83967167	23835611	3.52	0.002		
TIME	40755582	4612802	8.84	<.0001		
CDD	48183	24119	2	0.0589		
Town=Marlow					R-Square	0.214
INTERCEPT	26029	6478.657	4.02	0.0006		
TIME	3024.65533	1253.786	2.41	0.0251		
CDD	3.77432	6.5558	0.58	0.5709		

Western Township Regression Results #3

Variable	Parameter Estimate	Standard Error	t Value	Pr > |t|		
Town=Monroe, NH					R-Square	0.0481
INTERCEPT	1745683	47913	36.43	<.0001		
TIME	12279	19282	0.64	0.5311		
YEAR 2015	-114951	65615	-1.75	0.0944		
Town=Plainfield					R-Square	0.5314
INTERCEPT	4812703	504132	9.55	<.0001		
TIME	428829	97563	4.4	0.0003		
CDD	588.75076	510.1354	1.15	0.2614		
Town=Surry					R-Square	0.5845
INTERCEPT	129054	42264	3.05	0.006		
TIME	43289	8179.17	5.29	<.0001		
CDD	17.86532	42.76728	0.42	0.6804		
Town=Walpole					R-Square	0.4587
INTERCEPT	22258777	1349940	16.49	<.0001		
TIME	1049120	261248	4.02	0.0006		
CDD	946.45162	1366.015	0.69	0.496		

Except for Grafton and Monroe, 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 65% 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 2021-2037

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 2021 through 2037. As mentioned in the summary and introduction, additional peak load due to electric vehicle charging station growth and distributed generation activity not accounted for in the peak regression analysis was added in to create the LUNH final system seasonal peak forecast. The electric vehicle charging station growth portion used the NE-ISO forecast for New Hampshire and the LUNH proportion of the winter and summer New Hampshire non-coincident peaks in 2020. The distributed generation activity not accounted for in the peak regression analysis used both historic LUNH distributed generation capacity and NE-ISO forecast of distributed generation for New Hampshire. A regression model was estimated as a function of time of the historic LUNH distributed generation capacity by LUNH staff and a forecast from 2021-2037 was developed. That forecast was compared to the NE-ISO distributed generation capacity for LUNH to capture the NE_ISO distributed generation forecast not accounted for by the peak regression model.

The normal monthly WTHI and HDD values were computed by taking the average values for those terms during the October 2001 through September 2020 LUNH system monthly peak days. The extreme monthly WTHI and HDD values were extracted by taking the average of the maximum two values for those monthly terms during the October 2001 through September 2020 LUNH 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	30.0403	22.1275	35.085	45.55
February	34.3413	27.9425	29.605	37.85
March	39.6418	31.185	22.395	32.3
April	61.4713	77.35	5.7	20.9
May	75.941	81.205	0	0
June	80.2715	84.5175	0	0
July	81.912	85.3225	0	0
August	80.98	84.565	0	0
September	77.978	82.0725	0	0
October	67.549	74.4975	1.305	10
November	47.1588	37.4675	13.435	25.75
December	37.221	26	26.18	41

The normal and extreme LUNH 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 average summer coincident peak Eastern and Western PSA percent contributions for 2014 through 2020 and the average winter coincident peak Eastern and Western PSA percent contributions for 2015 through 2020. The summer Eastern coincident peak proportion was 50.90% while the Western proportion was 49.10%. The winter Eastern coincident peak contribution was 47.4% compared to the Western value of 52.6%. Appendix C lists the Eastern and Western coincident peak contributions for March 2014 through September 2020.

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 1072 and the extreme CDD took the value of 1286 which were computed based upon 2005 through 2019 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 2022-2026 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
2021	0.72		0.5193		0.8665		0.5934	
2022	0.7271	0.99%	0.5237	0.85%	0.874	0.87%	0.5978	0.74%
2023	0.7342	0.98%	0.5281	0.84%	0.8815	0.86%	0.6022	0.74%
2024	0.741	0.93%	0.5325	0.83%	0.8888	0.83%	0.6067	0.75%
2025	0.7474	0.86%	0.5372	0.88%	0.8956	0.77%	0.6115	0.79%
2026	0.754	0.88%	0.5418	0.86%	0.9026	0.78%	0.6162	0.77%
2027	0.7601	0.81%	0.546	0.78%	0.9091	0.72%	0.6205	0.70%
2028	0.7664	0.83%	0.5501	0.75%	0.9158	0.74%	0.6246	0.66%
2029	0.7719	0.72%	0.5538	0.67%	0.9217	0.64%	0.6284	0.61%
2030	0.7776	0.74%	0.5577	0.70%	0.9277	0.65%	0.6323	0.62%
2031	0.7832	0.72%	0.5617	0.72%	0.9337	0.65%	0.6365	0.66%
2032	0.789	0.74%	0.5654	0.66%	0.9399	0.66%	0.6402	0.58%
2033	0.7944	0.68%	0.569	0.64%	0.9455	0.60%	0.6439	0.58%
2034	0.7996	0.65%	0.5724	0.60%	0.9511	0.59%	0.6474	0.54%
2035	0.805	0.68%	0.5761	0.65%	0.9569	0.61%	0.6511	0.57%
2036	0.81	0.62%	0.5794	0.57%	0.9622	0.55%	0.6545	0.52%
2037	0.8153	0.65%	0.5826	0.55%	0.9678	0.58%	0.6578	0.50%
2022-2026 Avg		0.93%		0.85%		0.82%		0.76%

The Pelham township results are provided next. The 2022-2026 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
2021	20.1274		14.5177		21.9915		15.0587	
2022	20.2793	0.75%	14.6082	0.62%	22.1492	0.72%	15.1493	0.60%
2023	20.4341	0.76%	14.6994	0.62%	22.3098	0.73%	15.2405	0.60%
2024	20.582	0.72%	14.7926	0.63%	22.4632	0.69%	15.3338	0.61%
2025	20.7205	0.67%	14.8939	0.68%	22.6071	0.64%	15.4355	0.66%
2026	20.8646	0.70%	14.9939	0.67%	22.7566	0.66%	15.5359	0.65%
2027	20.9973	0.64%	15.0835	0.60%	22.8943	0.61%	15.6256	0.58%
2028	21.1353	0.66%	15.1707	0.58%	23.0374	0.63%	15.7132	0.56%
2029	21.2534	0.56%	15.2477	0.51%	23.1602	0.53%	15.7903	0.49%
2030	21.3777	0.58%	15.3304	0.54%	23.2892	0.56%	15.8731	0.52%
2031	21.4994	0.57%	15.4187	0.58%	23.4155	0.54%	15.9617	0.56%
2032	21.6267	0.59%	15.4972	0.51%	23.5475	0.56%	16.0403	0.49%
2033	21.7427	0.54%	15.5729	0.49%	23.668	0.51%	16.1164	0.47%
2034	21.8558	0.52%	15.6468	0.47%	23.7856	0.50%	16.1904	0.46%
2035	21.9754	0.55%	15.7258	0.50%	23.9097	0.52%	16.2696	0.49%
2036	22.085	0.50%	15.7958	0.45%	24.0234	0.48%	16.3398	0.43%
2037	22.2009	0.52%	15.8647	0.44%	24.1437	0.50%	16.4088	0.42%
2022-2026 Avg		0.72%		0.65%		0.69%		0.63%

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
2021	73.016		52.6659		78.0581		53.4505	
2022	73.1984	0.25%	52.7287	0.12%	78.2397	0.23%	53.5131	0.12%
2023	73.4028	0.28%	52.8028	0.14%	78.4431	0.26%	53.5867	0.14%
2024	73.5926	0.26%	52.8919	0.17%	78.632	0.24%	53.6756	0.17%
2025	73.7586	0.23%	53.0177	0.24%	78.7976	0.21%	53.8009	0.23%
2026	73.9538	0.26%	53.1451	0.24%	78.9924	0.25%	53.9281	0.24%
2027	74.117	0.22%	53.2421	0.18%	79.1551	0.21%	54.0245	0.18%
2028	74.3069	0.26%	53.3368	0.18%	79.3449	0.24%	54.1191	0.18%
2029	74.4346	0.17%	53.401	0.12%	79.4726	0.16%	54.1832	0.12%
2030	74.591	0.21%	53.4906	0.17%	79.6289	0.20%	54.2722	0.16%
2031	74.745	0.21%	53.6049	0.21%	79.7833	0.19%	54.3861	0.21%
2032	74.9248	0.24%	53.6893	0.16%	79.9631	0.23%	54.4702	0.15%
2033	75.0713	0.20%	53.7689	0.15%	80.1102	0.18%	54.5498	0.15%
2034	75.2137	0.19%	53.8464	0.14%	80.2533	0.18%	54.6267	0.14%
2035	75.3834	0.23%	53.945	0.18%	80.4237	0.21%	54.7251	0.18%
2036	75.5239	0.19%	54.0168	0.13%	80.5647	0.18%	54.797	0.13%
2037	75.6909	0.22%	54.0885	0.13%	80.7325	0.21%	54.8681	0.13%
2022-2026 Avg		0.26%		0.18%		0.24%		0.18%

The last Eastern PSA township, Windham, forecasts are displayed next. The annual growth rate in peaks for Windham from 2022-2026 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
2021	4.0982		2.956		4.4438		3.0429	
2022	4.1219	0.58%	2.9693	0.45%	4.4683	0.55%	3.0561	0.43%
2023	4.1465	0.60%	2.9828	0.45%	4.4936	0.57%	3.0697	0.45%
2024	4.1699	0.56%	2.9969	0.47%	4.5177	0.54%	3.0838	0.46%
2025	4.1915	0.52%	3.0129	0.53%	4.54	0.49%	3.0998	0.52%
2026	4.2145	0.55%	3.0286	0.52%	4.5637	0.52%	3.1156	0.51%
2027	4.2353	0.49%	3.0424	0.46%	4.5852	0.47%	3.1294	0.44%
2028	4.2573	0.52%	3.0559	0.44%	4.6079	0.50%	3.1429	0.43%
2029	4.2755	0.43%	3.0674	0.38%	4.6267	0.41%	3.1544	0.37%
2030	4.2951	0.46%	3.0801	0.41%	4.6469	0.44%	3.1672	0.41%
2031	4.3143	0.45%	3.0941	0.45%	4.6667	0.43%	3.1812	0.44%
2032	4.3347	0.47%	3.1062	0.39%	4.6877	0.45%	3.1933	0.38%
2033	4.353	0.42%	3.1178	0.37%	4.7066	0.40%	3.2049	0.36%
2034	4.3708	0.41%	3.1291	0.36%	4.7251	0.39%	3.2162	0.35%
2035	4.39	0.44%	3.1415	0.40%	4.7449	0.42%	3.2287	0.39%
2036	4.4073	0.39%	3.1522	0.34%	4.7627	0.38%	3.2394	0.33%
2037	4.426	0.42%	3.1628	0.34%	4.782	0.41%	3.25	0.33%
2022-2026 Avg		0.56%		0.49%		0.53%		0.47%

The Western Township forecasts are shown next starting with Acworth. The Acworth annual growth rates are much lower than the overall system for 2021-2025.

Acworth Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2021	0.2372		0.1968		0.2482		0.1955	
2022	0.2372	0.00%	0.1966	-0.10%	0.2483	0.04%	0.1954	-0.05%
2023	0.2374	0.08%	0.1965	-0.05%	0.2485	0.08%	0.1953	-0.05%
2024	0.2376	0.08%	0.1964	-0.05%	0.2486	0.04%	0.1952	-0.05%
2025	0.2377	0.04%	0.1965	0.05%	0.2487	0.04%	0.1953	0.05%
2026	0.2379	0.08%	0.1966	0.05%	0.2489	0.08%	0.1954	0.05%
2027	0.238	0.04%	0.1967	0.05%	0.249	0.04%	0.1955	0.05%
2028	0.2382	0.08%	0.1967	0.00%	0.2491	0.04%	0.1955	0.00%
2029	0.2382	0.00%	0.1966	-0.05%	0.2492	0.04%	0.1954	-0.05%
2030	0.2383	0.04%	0.1966	0.00%	0.2493	0.04%	0.1955	0.05%
2031	0.2385	0.08%	0.1967	0.05%	0.2494	0.04%	0.1956	0.05%
2032	0.2387	0.08%	0.1968	0.05%	0.2496	0.08%	0.1956	0.00%
2033	0.2388	0.04%	0.1968	0.00%	0.2497	0.04%	0.1956	0.00%
2034	0.2389	0.04%	0.1968	0.00%	0.2499	0.08%	0.1957	0.05%
2035	0.2392	0.13%	0.1969	0.05%	0.2501	0.08%	0.1958	0.05%
2036	0.2393	0.04%	0.1969	0.00%	0.2502	0.04%	0.1958	0.00%
2037	0.2395	0.08%	0.1969	0.00%	0.2504	0.08%	0.1958	0.00%
2022-2026 Avg		0.06%		-0.02%		0.06%		-0.01%

Alstead township forecast appears next. As the case with Acworth, Alstead annual growth in peak is much 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
2021	1.9979		1.6578		2.0911		1.6473	
2022	1.998	0.01%	1.6557	-0.13%	2.0911	0.00%	1.6453	-0.12%
2023	1.9988	0.04%	1.6541	-0.10%	2.0918	0.03%	1.6438	-0.09%
2024	1.9995	0.04%	1.6532	-0.05%	2.0922	0.02%	1.643	-0.05%
2025	1.9997	0.01%	1.6535	0.02%	2.0923	0.00%	1.6434	0.02%
2026	2.0008	0.06%	1.654	0.03%	2.0933	0.05%	1.644	0.04%
2027	2.0012	0.02%	1.6537	-0.02%	2.0935	0.01%	1.6437	-0.02%
2028	2.0024	0.06%	1.6535	-0.01%	2.0946	0.05%	1.6436	-0.01%
2029	2.0021	-0.01%	1.6523	-0.07%	2.0942	-0.02%	1.6425	-0.07%
2030	2.0027	0.03%	1.6521	-0.01%	2.0947	0.02%	1.6424	-0.01%
2031	2.0033	0.03%	1.6528	0.04%	2.0953	0.03%	1.6431	0.04%
2032	2.0047	0.07%	1.6526	-0.01%	2.0966	0.06%	1.6429	-0.01%
2033	2.0054	0.03%	1.6523	-0.02%	2.0971	0.02%	1.6427	-0.01%
2034	2.006	0.03%	1.6521	-0.01%	2.0976	0.02%	1.6425	-0.01%
2035	2.0074	0.07%	1.6525	0.02%	2.099	0.07%	1.6431	0.04%
2036	2.0081	0.03%	1.6523	-0.01%	2.0996	0.03%	1.6429	-0.01%
2037	2.0096	0.07%	1.6521	-0.01%	2.1011	0.07%	1.6427	-0.01%
2022-2026 Avg		0.03%		-0.05%		0.02%		-0.04%

The Bath township forecasts are displayed below. The annual growth in the Bath peaks from 2022-2026 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
2021	0.012		0.01		0.0139		0.0109	
2022	0.0121	0.83%	0.01	0.00%	0.014	0.72%	0.011	0.92%
2023	0.0122	0.83%	0.0101	1.00%	0.0141	0.71%	0.0111	0.91%
2024	0.0123	0.82%	0.0102	0.99%	0.0142	0.71%	0.0111	0.00%
2025	0.0124	0.81%	0.0102	0.00%	0.0143	0.70%	0.0112	0.90%
2026	0.0125	0.81%	0.0103	0.98%	0.0143	0.00%	0.0113	0.89%
2027	0.0125	0.00%	0.0104	0.97%	0.0144	0.70%	0.0113	0.00%
2028	0.0126	0.80%	0.0104	0.00%	0.0145	0.69%	0.0114	0.88%
2029	0.0127	0.79%	0.0105	0.96%	0.0146	0.69%	0.0114	0.00%
2030	0.0128	0.79%	0.0105	0.00%	0.0147	0.68%	0.0115	0.88%
2031	0.0128	0.00%	0.0106	0.95%	0.0147	0.00%	0.0116	0.87%
2032	0.0129	0.78%	0.0107	0.94%	0.0148	0.68%	0.0116	0.00%
2033	0.013	0.78%	0.0107	0.00%	0.0149	0.68%	0.0117	0.86%
2034	0.0131	0.77%	0.0108	0.93%	0.015	0.67%	0.0117	0.00%
2035	0.0131	0.00%	0.0108	0.00%	0.015	0.00%	0.0118	0.85%
2036	0.0132	0.76%	0.0109	0.93%	0.0151	0.67%	0.0118	0.00%
2037	0.0133	0.76%	0.0109	0.00%	0.0152	0.66%	0.0119	0.85%
2022-2026 Avg		0.82%		0.59%		0.57%		0.72%

Forecasts for the Canaan Township appear below. The annual growth rate in Canaan is less than the system average during the 2022-2026 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
2021	2.4793		2.0573		2.5951		2.0442	
2022	2.4822	0.12%	2.057	-0.01%	2.5978	0.10%	2.044	-0.01%
2023	2.4859	0.15%	2.0572	0.01%	2.6015	0.14%	2.0444	0.02%
2024	2.4893	0.14%	2.0581	0.04%	2.6048	0.13%	2.0455	0.05%
2025	2.492	0.11%	2.0606	0.12%	2.6074	0.10%	2.048	0.12%
2026	2.4957	0.15%	2.0632	0.13%	2.6111	0.14%	2.0507	0.13%
2027	2.4985	0.11%	2.0648	0.08%	2.6139	0.11%	2.0523	0.08%
2028	2.5023	0.15%	2.0663	0.07%	2.6176	0.14%	2.0539	0.08%
2029	2.5041	0.07%	2.0667	0.02%	2.6194	0.07%	2.0544	0.02%
2030	2.507	0.12%	2.0682	0.07%	2.6222	0.11%	2.056	0.08%
2031	2.5098	0.11%	2.0706	0.12%	2.625	0.11%	2.0585	0.12%
2032	2.5136	0.15%	2.072	0.07%	2.6287	0.14%	2.0599	0.07%
2033	2.5163	0.11%	2.0733	0.06%	2.6314	0.10%	2.0613	0.07%
2034	2.519	0.11%	2.0746	0.06%	2.6341	0.10%	2.0626	0.06%
2035	2.5226	0.14%	2.0767	0.10%	2.6377	0.14%	2.0647	0.10%
2036	2.5253	0.11%	2.0778	0.05%	2.6404	0.10%	2.0659	0.06%
2037	2.529	0.15%	2.079	0.06%	2.644	0.14%	2.0672	0.06%
2022-2026 Avg		0.13%		0.06%		0.12%		0.06%

The Charlestown township forecasts are shown next below. The annual growth rate in peak forecasts is higher than the system average during the 2022-2026 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
2021	6.4705		5.369		7.032		5.5393	
2022	6.5208	0.78%	5.4037	0.65%	7.0838	0.74%	5.5737	0.62%
2023	6.5718	0.78%	5.4384	0.64%	7.1364	0.74%	5.6082	0.62%
2024	6.6204	0.74%	5.4737	0.65%	7.1864	0.70%	5.6433	0.63%
2025	6.6658	0.69%	5.5119	0.70%	7.2332	0.65%	5.6814	0.68%
2026	6.7129	0.71%	5.5495	0.68%	7.2818	0.67%	5.7189	0.66%
2027	6.7562	0.65%	5.5832	0.61%	7.3264	0.61%	5.7523	0.58%
2028	6.8011	0.66%	5.6159	0.59%	7.3726	0.63%	5.7849	0.57%
2029	6.8395	0.56%	5.6447	0.51%	7.4122	0.54%	5.8135	0.49%
2030	6.8797	0.59%	5.6755	0.55%	7.4537	0.56%	5.8442	0.53%
2031	6.9191	0.57%	5.7084	0.58%	7.4943	0.54%	5.8769	0.56%
2032	6.9601	0.59%	5.7375	0.51%	7.5366	0.56%	5.9059	0.49%
2033	6.9975	0.54%	5.7656	0.49%	7.5751	0.51%	5.9339	0.47%
2034	7.0338	0.52%	5.7929	0.47%	7.6127	0.50%	5.9611	0.46%
2035	7.0722	0.55%	5.822	0.50%	7.6522	0.52%	5.9901	0.49%
2036	7.1073	0.50%	5.8478	0.44%	7.6884	0.47%	6.0158	0.43%
2037	7.1444	0.52%	5.8732	0.43%	7.7267	0.50%	6.041	0.42%
2022-2026 Avg		0.74%		0.66%		0.70%		0.64%

The Cornish township forecast numbers are displayed next. The annual growth in Cornish peaks is less than the 2022-2026 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
2021	0.1879		0.1559		0.2014		0.1587	
2022	0.188	0.05%	0.1558	-0.06%	0.2016	0.10%	0.1586	-0.06%
2023	0.1883	0.16%	0.1558	0.00%	0.2018	0.10%	0.1586	0.00%
2024	0.1884	0.05%	0.1558	0.00%	0.2019	0.05%	0.1586	0.00%
2025	0.1886	0.11%	0.1559	0.06%	0.202	0.05%	0.1587	0.06%
2026	0.1888	0.11%	0.1561	0.13%	0.2023	0.15%	0.1588	0.06%
2027	0.1889	0.05%	0.1561	0.00%	0.2024	0.05%	0.1589	0.06%
2028	0.1892	0.16%	0.1562	0.06%	0.2026	0.10%	0.159	0.06%
2029	0.1892	0.00%	0.1562	0.00%	0.2027	0.05%	0.159	0.00%
2030	0.1894	0.11%	0.1562	0.00%	0.2028	0.05%	0.159	0.00%
2031	0.1895	0.05%	0.1564	0.13%	0.203	0.10%	0.1592	0.13%
2032	0.1898	0.16%	0.1564	0.00%	0.2032	0.10%	0.1592	0.00%
2033	0.1899	0.05%	0.1565	0.06%	0.2033	0.05%	0.1593	0.06%
2034	0.1901	0.11%	0.1565	0.00%	0.2035	0.10%	0.1593	0.00%
2035	0.1903	0.11%	0.1566	0.06%	0.2037	0.10%	0.1594	0.06%
2036	0.1904	0.05%	0.1567	0.06%	0.2038	0.05%	0.1595	0.06%
2037	0.1907	0.16%	0.1567	0.00%	0.2041	0.15%	0.1595	0.00%
2022-2026 Avg		0.10%		0.03%		0.09%		0.01%

Enfield Township seasonal peak forecasts are listed next. Much like Cornish, the annual 2022-2026 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
2021	3.6732		3.0479		3.8794		3.0559	
2022	3.6783	0.14%	3.0481	0.01%	3.8844	0.13%	3.0564	0.02%
2023	3.6847	0.17%	3.0492	0.04%	3.8907	0.16%	3.0576	0.04%
2024	3.6905	0.16%	3.0513	0.07%	3.8964	0.15%	3.0598	0.07%
2025	3.6953	0.13%	3.0556	0.14%	3.9011	0.12%	3.0641	0.14%
2026	3.7016	0.17%	3.0601	0.15%	3.9074	0.16%	3.0688	0.15%
2027	3.7065	0.13%	3.063	0.09%	3.9122	0.12%	3.0717	0.09%
2028	3.7128	0.17%	3.0658	0.09%	3.9185	0.16%	3.0747	0.10%
2029	3.7162	0.09%	3.067	0.04%	3.9218	0.08%	3.0759	0.04%
2030	3.7211	0.13%	3.0698	0.09%	3.9267	0.12%	3.0787	0.09%
2031	3.7259	0.13%	3.074	0.14%	3.9315	0.12%	3.083	0.14%
2032	3.7322	0.17%	3.0766	0.08%	3.9377	0.16%	3.0857	0.09%
2033	3.7368	0.12%	3.079	0.08%	3.9423	0.12%	3.0882	0.08%
2034	3.7414	0.12%	3.0813	0.07%	3.9469	0.12%	3.0906	0.08%
2035	3.7474	0.16%	3.0849	0.12%	3.9528	0.15%	3.0942	0.12%
2036	3.752	0.12%	3.0871	0.07%	3.9574	0.12%	3.0965	0.07%
2037	3.7579	0.16%	3.0893	0.07%	3.9634	0.15%	3.0987	0.07%
2022-2026 Avg		0.15%		0.08%		0.14%		0.08%

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
2021	0.0114		0.0094		0.0119		0.0094	
2022	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0094	0.00%
2023	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0094	0.00%
2024	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	-1.06%
2025	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2026	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2027	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2028	0.0114	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2029	0.0113	-0.88%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2030	0.0113	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2031	0.0113	0.00%	0.0094	0.00%	0.0119	0.00%	0.0093	0.00%
2032	0.0113	0.00%	0.0093	-1.06%	0.0119	0.00%	0.0093	0.00%
2033	0.0113	0.00%	0.0093	0.00%	0.0119	0.00%	0.0093	0.00%
2034	0.0113	0.00%	0.0093	0.00%	0.0119	0.00%	0.0093	0.00%
2035	0.0113	0.00%	0.0093	0.00%	0.0119	0.00%	0.0093	0.00%
2036	0.0113	0.00%	0.0093	0.00%	0.0119	0.00%	0.0093	0.00%
2037	0.0113	0.00%	0.0093	0.00%	0.0119	0.00%	0.0093	0.00%
2022-2026 Avg		0.00%		0.00%		0.00%		-0.21%

The Hanover township forecasts appear next. As one of the larger Western PSA townships, the Hanover annual growth rate from 2022-2026 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
2021	23.9316		19.8576		25.4516		20.049	
2022	24.0029	0.30%	19.8908	0.17%	25.524	0.28%	20.0828	0.17%
2023	24.0812	0.33%	19.9281	0.19%	25.6031	0.31%	20.1205	0.19%
2024	24.1545	0.30%	19.9709	0.21%	25.6773	0.29%	20.1637	0.21%
2025	24.2198	0.27%	20.0273	0.28%	25.7435	0.26%	20.2203	0.28%
2026	24.2944	0.31%	20.0841	0.28%	25.819	0.29%	20.2775	0.28%
2027	24.3583	0.26%	20.1292	0.22%	25.8838	0.25%	20.3228	0.22%
2028	24.4307	0.30%	20.1733	0.22%	25.9572	0.28%	20.3673	0.22%
2029	24.4825	0.21%	20.2057	0.16%	26.01	0.20%	20.4001	0.16%
2030	24.5436	0.25%	20.2476	0.21%	26.072	0.24%	20.4421	0.21%
2031	24.6037	0.24%	20.2986	0.25%	26.1332	0.23%	20.4933	0.25%
2032	24.6721	0.28%	20.3382	0.20%	26.2024	0.26%	20.5331	0.19%
2033	24.7294	0.23%	20.3758	0.18%	26.2608	0.22%	20.5711	0.19%
2034	24.7852	0.23%	20.4125	0.18%	26.3177	0.22%	20.6079	0.18%
2035	24.8499	0.26%	20.4571	0.22%	26.3833	0.25%	20.6526	0.22%
2036	24.9048	0.22%	20.4914	0.17%	26.4391	0.21%	20.6873	0.17%
2037	24.9683	0.25%	20.5255	0.17%	26.5036	0.24%	20.7214	0.16%
2022-2026 Avg		0.30%		0.23%		0.29%		0.23%

Lebanon township seasonal peak forecasts are listed next. As the largest Western PSA township, Lebanon peak growth from 2022-2026 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
2021	49.0133		40.6695		53.2604		41.9548	
2022	49.2321	0.45%	40.7978	0.32%	53.4833	0.42%	42.0819	0.30%
2023	49.4624	0.47%	40.932	0.33%	53.7179	0.44%	42.2148	0.32%
2024	49.68	0.44%	41.0753	0.35%	53.9394	0.41%	42.3573	0.34%
2025	49.8787	0.40%	41.2446	0.41%	54.1422	0.38%	42.5262	0.40%
2026	50.0947	0.43%	41.4131	0.41%	54.3624	0.41%	42.6945	0.40%
2027	50.2865	0.38%	41.5559	0.34%	54.558	0.36%	42.8364	0.33%
2028	50.4941	0.41%	41.6948	0.33%	54.7698	0.39%	42.9751	0.32%
2029	50.6574	0.32%	41.8082	0.27%	54.9366	0.30%	43.0877	0.26%
2030	50.8382	0.36%	41.9397	0.31%	55.1212	0.34%	43.2184	0.30%
2031	51.0154	0.35%	42.0889	0.36%	55.3023	0.33%	43.3673	0.34%
2032	51.2084	0.38%	42.2131	0.30%	55.4993	0.36%	43.4911	0.29%
2033	51.3771	0.33%	42.3321	0.28%	55.6718	0.31%	43.6099	0.27%
2034	51.5412	0.32%	42.4481	0.27%	55.8399	0.30%	43.7251	0.26%
2035	51.7226	0.35%	42.5794	0.31%	56.0254	0.33%	43.8562	0.30%
2036	51.8825	0.31%	42.6883	0.26%	56.189	0.29%	43.9649	0.25%
2037	52.0592	0.34%	42.796	0.25%	56.3698	0.32%	44.0719	0.24%
2022-2026 Avg		0.44%		0.36%		0.41%		0.35%

Marlow township forecast values are shown next. The Marlow growth is lower than the system average during the 2022-2026 years especially in the winter season.

Marlow Township Peaks

year	Summer Normal Peak Mw	Growth	Winter Normal Peak Mw	Growth	Summer Extreme Peak Mw	Growth	Winter Extreme Peak Mw	Growth
2021	0.0073		0.006		0.0078		0.0061	
2022	0.0073	0.00%	0.006	0.00%	0.0078	0.00%	0.0061	0.00%
2023	0.0073	0.00%	0.006	0.00%	0.0078	0.00%	0.0061	0.00%
2024	0.0073	0.00%	0.006	0.00%	0.0078	0.00%	0.0061	0.00%
2025	0.0073	0.00%	0.0061	1.67%	0.0078	0.00%	0.0061	0.00%
2026	0.0073	0.00%	0.0061	0.00%	0.0078	0.00%	0.0061	0.00%
2027	0.0073	0.00%	0.0061	0.00%	0.0078	0.00%	0.0062	1.64%
2028	0.0074	1.37%	0.0061	0.00%	0.0079	1.28%	0.0062	0.00%
2029	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2030	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2031	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2032	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2033	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2034	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2035	0.0074	0.00%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2036	0.0075	1.35%	0.0061	0.00%	0.0079	0.00%	0.0062	0.00%
2037	0.0075	0.00%	0.0061	0.00%	0.008	1.27%	0.0062	0.00%
2022-2026 Avg		0.00%		0.33%		0.00%		0.00%

Monroe township peak forecasts are shown below. The annual growth in Monroe Township is smaller than the system average during the 2022-2026 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
2021	0.3243		0.2691		0.3394		0.2674	
2022	0.3241	-0.06%	0.2685	-0.22%	0.3392	-0.06%	0.2669	-0.19%
2023	0.3239	-0.06%	0.2681	-0.15%	0.339	-0.06%	0.2664	-0.19%
2024	0.3238	-0.03%	0.2677	-0.15%	0.3388	-0.06%	0.2661	-0.11%
2025	0.3236	-0.06%	0.2676	-0.04%	0.3386	-0.06%	0.2659	-0.08%
2026	0.3236	0.00%	0.2675	-0.04%	0.3385	-0.03%	0.2659	0.00%
2027	0.3234	-0.06%	0.2672	-0.11%	0.3383	-0.06%	0.2656	-0.11%
2028	0.3234	0.00%	0.267	-0.07%	0.3383	0.00%	0.2654	-0.08%
2029	0.3231	-0.09%	0.2667	-0.11%	0.338	-0.09%	0.2651	-0.11%
2030	0.323	-0.03%	0.2665	-0.07%	0.3379	-0.03%	0.2649	-0.08%
2031	0.3229	-0.03%	0.2664	-0.04%	0.3377	-0.06%	0.2649	0.00%
2032	0.323	0.03%	0.2662	-0.08%	0.3378	0.03%	0.2647	-0.08%
2033	0.3229	-0.03%	0.266	-0.08%	0.3377	-0.03%	0.2645	-0.08%
2034	0.3228	-0.03%	0.2659	-0.04%	0.3376	-0.03%	0.2643	-0.08%
2035	0.3229	0.03%	0.2658	-0.04%	0.3376	0.00%	0.2643	0.00%
2036	0.3228	-0.03%	0.2656	-0.08%	0.3375	-0.03%	0.2641	-0.08%
2037	0.3229	0.03%	0.2654	-0.08%	0.3376	0.03%	0.2639	-0.08%
2022-2026 Avg		-0.04%		-0.12%		-0.05%		-0.11%

Plainfield township forecasts appear next. The Plainfield growth rate is peak from 2022-2026 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
2021	1.2451		1.0331		1.3271		1.0454	
2022	1.2466	0.12%	1.033	-0.01%	1.3286	0.11%	1.0454	0.00%
2023	1.2486	0.16%	1.0333	0.03%	1.3306	0.15%	1.0456	0.02%
2024	1.2504	0.14%	1.0338	0.05%	1.3323	0.13%	1.0462	0.06%
2025	1.2519	0.12%	1.0352	0.14%	1.3337	0.11%	1.0476	0.13%
2026	1.2539	0.16%	1.0366	0.14%	1.3357	0.15%	1.049	0.13%
2027	1.2554	0.12%	1.0374	0.08%	1.3372	0.11%	1.0499	0.09%
2028	1.2574	0.16%	1.0383	0.09%	1.3391	0.14%	1.0508	0.09%
2029	1.2584	0.08%	1.0386	0.03%	1.3401	0.07%	1.0511	0.03%
2030	1.2599	0.12%	1.0394	0.08%	1.3416	0.11%	1.0519	0.08%
2031	1.2614	0.12%	1.0407	0.13%	1.3431	0.11%	1.0532	0.12%
2032	1.2634	0.16%	1.0415	0.08%	1.3451	0.15%	1.054	0.08%
2033	1.2649	0.12%	1.0422	0.07%	1.3465	0.10%	1.0548	0.08%
2034	1.2663	0.11%	1.0429	0.07%	1.3479	0.10%	1.0555	0.07%
2035	1.2682	0.15%	1.044	0.11%	1.3498	0.14%	1.0566	0.10%
2036	1.2697	0.12%	1.0447	0.07%	1.3512	0.10%	1.0573	0.07%
2037	1.2716	0.15%	1.0453	0.06%	1.3532	0.15%	1.0579	0.06%
2022-2026 Avg		0.14%		0.07%		0.13%		0.07%

Surry Township forecast values are listed next. The annual growth in the Surry peak from 2022-2026 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
2021	0.0528		0.0438		0.056		0.0441	
2022	0.053	0.38%	0.044	0.46%	0.0562	0.36%	0.0443	0.45%
2023	0.0533	0.57%	0.0441	0.23%	0.0565	0.53%	0.0444	0.23%
2024	0.0535	0.38%	0.0443	0.45%	0.0567	0.35%	0.0445	0.23%
2025	0.0537	0.37%	0.0444	0.23%	0.0569	0.35%	0.0447	0.45%
2026	0.054	0.56%	0.0446	0.45%	0.0572	0.53%	0.0449	0.45%
2027	0.0542	0.37%	0.0448	0.45%	0.0574	0.35%	0.0451	0.45%
2028	0.0544	0.37%	0.0449	0.22%	0.0576	0.35%	0.0452	0.22%
2029	0.0546	0.37%	0.045	0.22%	0.0578	0.35%	0.0453	0.22%
2030	0.0547	0.18%	0.0452	0.44%	0.058	0.35%	0.0455	0.44%
2031	0.0549	0.37%	0.0453	0.22%	0.0582	0.34%	0.0456	0.22%
2032	0.0551	0.36%	0.0455	0.44%	0.0584	0.34%	0.0458	0.44%
2033	0.0553	0.36%	0.0456	0.22%	0.0586	0.34%	0.0459	0.22%
2034	0.0555	0.36%	0.0457	0.22%	0.0588	0.34%	0.046	0.22%
2035	0.0557	0.36%	0.0458	0.22%	0.0589	0.17%	0.0461	0.22%
2036	0.0559	0.36%	0.046	0.44%	0.0591	0.34%	0.0463	0.43%
2037	0.056	0.18%	0.0461	0.22%	0.0593	0.34%	0.0464	0.22%
2022-2026 Avg		0.45%		0.36%		0.42%		0.36%

The final township, Walpole forecasts of peak appear below. The Walpole average annual growth is less than the system average for the 2022-2026 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
2021	4.8535		4.0273		5.1186		4.032	
2022	4.8555	0.04%	4.0237	-0.09%	5.1202	0.03%	4.0287	-0.08%
2023	4.8593	0.08%	4.0213	-0.06%	5.1237	0.07%	4.0265	-0.05%
2024	4.8626	0.07%	4.0203	-0.02%	5.1265	0.05%	4.0257	-0.02%
2025	4.8646	0.04%	4.0225	0.05%	5.1283	0.04%	4.028	0.06%
2026	4.8688	0.09%	4.025	0.06%	5.1322	0.08%	4.0307	0.07%
2027	4.8713	0.05%	4.0255	0.01%	5.1344	0.04%	4.0313	0.01%
2028	4.8757	0.09%	4.0261	0.01%	5.1386	0.08%	4.032	0.02%
2029	4.8764	0.01%	4.0245	-0.04%	5.1391	0.01%	4.0307	-0.03%
2030	4.8792	0.06%	4.0251	0.01%	5.1416	0.05%	4.0314	0.02%
2031	4.882	0.06%	4.0278	0.07%	5.1443	0.05%	4.0341	0.07%
2032	4.8868	0.10%	4.0284	0.01%	5.1488	0.09%	4.0348	0.02%
2033	4.8896	0.06%	4.0288	0.01%	5.1515	0.05%	4.0353	0.01%
2034	4.8923	0.06%	4.0292	0.01%	5.154	0.05%	4.0358	0.01%
2035	4.897	0.10%	4.0313	0.05%	5.1585	0.09%	4.0381	0.06%
2036	4.8999	0.06%	4.0316	0.01%	5.1613	0.05%	4.0385	0.01%
2037	4.9047	0.10%	4.032	0.01%	5.166	0.09%	4.0389	0.01%
2022-2026 Avg		0.06%		-0.01%		0.05%		-0.01%

APPENDIX A

	LUNH 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
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
2015	7	30	14	184.893
2015	8	18	14	186.141
2015	9	9	16	187.326
2015	10	13	19	153.086
2015	11	30	18	131.008
2015	12	29	18	133.603
2016	1	9	18	142.592
2016	2	15	18	142.576
2016	3	3	19	129.165
2016	4	4	12	125.539
2016	5	31	16	152.579

2016	6	20	16	167.76
2016	7	28	15	185.985
2016	8	12	16	193.151
2016	9	9	16	176.143
2016	10	17	19	125.149
2016	11	21	18	128.994
2016	12	19	18	143.2
2017	1	9	18	143.485
2017	2	7	19	134.572
2017	3	4	19	127.668
2017	4	11	16	124.478
2017	5	18	16	162.931
2017	6	12	17	181.34
2017	7	20	15	179.727
2017	8	22	17	179.089
2017	9	25	16	172.378
2017	10	9	19	136
2017	11	28	18	129.146
2017	12	28	18	150.426
2018	1	2	18	154.265
2018	2	7	18	135.615
2018	3	7	18	127.866
2018	4	16	12	121.766
2018	5	31	18	145.275
2018	6	18	16	170.718
2018	7	3	14	194.416
2018	8	29	15	197.82
2018	9	5	16	185.689
2018	10	10	16	141.038
2018	11	15	18	131.335
2018	12	18	18	139.289
2019	1	21	18	150.382
2019	2	12	18	138.559
2019	3	6	19	133.735
2019	4	9	11	118.91
2019	5	20	18	132.493
2019	6	28	16	161.997
2019	7	30	15	193.95
2019	8	19	15	182.172
2019	9	23	15	150.777
2019	10	2	11	126.246
2019	11	13	18	133.621
2019	12	19	18	141.462

2020	1	20	18	137.577
2020	2	14	19	130.986
2020	3	17	12	121.805
2020	4	27	13	112.267
2020	5	27	18	155.706
2020	6	23	17	179.551
2020	7	27	15	191.186
2020	8	11	16	191.383
2020	9	8	17	158.588

Appendix B

Economic Variable

Year	Households
2000	136.932
2001	138.431
2002	140.450
2003	142.297
2004	143.843
2005	145.913
2006	147.547
2007	148.609
2008	150.018
2009	150.621
2010	151.204
2011	152.925
2012	154.434
2013	155.826
2014	157.037
2015	157.585
2016	158.811
2017	159.666
2018	160.213
2019	160.870
2020	162.096
2021	162.379
2022	163.355
2023	164.578
2024	165.958
2025	167.346
2026	168.638
2027	169.867
2028	171.000
2029	172.077
2030	173.097
2031	174.043
2032	174.879
2033	175.652
2034	176.303
2035	176.936
2036	177.549
2037	178.061

Appendix C

year	month	day	hour	system mw	psa total	mw_e	mw_w	Eastern %	Western %
2014	3	3	19	144.09	144.0875	66.7299	77.3576	46.31%	53.69%
2014	4	15	14	122.63	122.6254	50.2352	72.3902	40.96%	59.04%
2014	5	12	16	133.566	133.5654	57.9524	75.613	43.39%	56.61%
2014	6	30	17	172.905	156.8357	69.5198	87.3159	40.21%	59.79%
2014	7	23	16	193.213	193.2128	96.326	96.8868	49.85%	50.15%
2014	8	27	16	175.731	175.7307	87.134	88.5967	49.58%	50.42%
2014	9	2	15	177.966	177.966	87.896	90.07	49.39%	50.61%
2014	10	16	12	134.995	134.9956	54.57	80.4256	40.42%	59.58%
2014	11	18	18	135.892	135.8918	62.217	73.6748	45.78%	54.22%
2014	12	8	18	143.321	143.3214	68.071	75.2504	47.50%	52.50%
2015	1	8	18	148.451	148.4504	69.655	78.7954	46.92%	53.08%
2015	2	16	19	144.833	144.8328	68.698	76.1348	47.43%	52.57%
2015	3	5	19	137.502	137.5021	63.046	74.4561	45.85%	54.15%
2015	4	2	11	123.717	123.7167	53.196	70.5207	43.00%	57.00%
2015	5	27	16	173.241	173.2414	80.931	92.3104	46.72%	53.28%
2015	6	23	17	163.897	163.8974	76.974	86.9234	46.96%	53.04%
2015	7	30	14	185.508	185.5081	88.65	96.8581	47.79%	52.21%
2015	8	18	14	186.141	186.141	90.612	95.529	48.68%	51.32%
2015	9	9	16	187.326	187.3256	90.746	96.5796	48.44%	51.56%
2015	10	13	19	126.066	126.0657	54.757	71.3087	43.44%	56.56%
2015	11	30	18	131.179	131.1792	61.125	70.0542	46.60%	53.40%
2015	12	29	18	135.02	135.0195	64.717	70.3025	47.93%	52.07%
2016	1	19	18	142.656	142.6563	66.52	76.1363	46.63%	53.37%
2016	2	15	18	142.576	142.576	66.849	75.727	46.89%	53.11%
2016	3	3	19	129.165	129.1652	58.534	70.6312	45.32%	54.68%
2016	4	4	12	125.627	125.6264	55.789	69.8374	44.41%	55.59%
2016	5	31	16	152.932	152.9326	72.016	80.9166	47.09%	52.91%
2016	6	20	16	168.23	168.2302	80.188	88.0422	47.67%	52.33%
2016	7	28	15	187.268	187.268	92.677	94.591	49.49%	50.51%
2016	8	12	16	193.773	193.7728	101.455	92.3178	52.36%	47.64%
2016	9	9	16	176.143	176.1425	88.094	88.0485	50.01%	49.99%
2016	10	17	19	125.149	125.1491	54.943	70.2061	43.90%	56.10%
2016	11	21	18	128.994	128.9941	59.783	69.2111	46.35%	53.65%
2016	12	19	18	143.2	143.2006	68.277	74.9236	47.68%	52.32%

2017	1	9	18	143.485	143.4859	67	76.4859	46.69%	53.31%
2017	2	7	19	134.572	134.5725	62.075	72.4975	46.13%	53.87%
2017	3	4	19	127.668	127.6675	59.331	68.3365	46.47%	53.53%
2017	4	11	16	124.478	124.4777	53.157	71.3207	42.70%	57.30%
2017	5	18	16	162.931	162.9316	80.043	82.8886	49.13%	50.87%
2017	6	12	17	181.34	181.3401	93.591	87.7491	51.61%	48.39%
2017	7	20	15	179.727	179.7268	89.606	90.1208	49.86%	50.14%
2017	8	22	17	179.089	179.0891	88.946	90.1431	49.67%	50.33%
2017	9	25	16	172.378	172.378	80.833	91.545	46.89%	53.11%
2017	10	9	19	136	136.0002	59.58	76.4202	43.81%	56.19%
2017	11	28	18	129.146	129.1464	60.506	68.6404	46.85%	53.15%
2017	12	28	18	150.426	150.4257	73.259	77.1667	48.70%	51.30%
2018	1	2	18	154.265	154.265	73.013	81.252	47.33%	52.67%
2018	2	7	18	135.615	135.6153	62.193	73.4223	45.86%	54.14%
2018	3	7	18	127.866	127.8662	58.701	69.1652	45.91%	54.09%
2018	4	16	12	121.766	121.7653	54.945	66.8203	45.12%	54.88%
2018	5	31	18	145.275	145.2743	67.507	77.7673	46.47%	53.53%
2018	6	18	16	170.718	170.718	83.684	87.034	49.02%	50.98%
2018	7	3	14	194.416	194.4155	95.599	98.8165	49.17%	50.83%
2018	8	29	15	197.82	197.8195	100.733	97.0865	50.92%	49.08%
2018	9	5	16	185.689	185.6899	90.481	95.2089	48.73%	51.27%
2018	10	10	16	141.038	141.0376	62.74	78.2976	44.48%	55.52%
2018	11	15	18	131.335	131.3347	60.068	71.2667	45.74%	54.26%
2018	12	18	18	139.289	139.289	64.837	74.452	46.55%	53.45%
2019	1	21	18	150.382	150.382	72.05	78.332	47.91%	52.09%
2019	2	12	18	138.559	138.5583	63.554	75.0043	45.87%	54.13%
2019	3	6	19	133.735	133.7351	61.373	72.3621	45.89%	54.11%
2019	4	9	11	118.91	118.9103	51.345	67.5653	43.18%	56.82%
2019	5	20	18	132.493	132.4932	60.393	72.1002	45.58%	54.42%
2019	6	28	16	161.997	161.9967	81.176	80.8207	50.11%	49.89%
2019	7	30	15	193.95	193.9498	98.721	95.2288	50.90%	49.10%
2019	8	19	15	182.172	182.1724	92.449	89.7234	50.75%	49.25%
2019	9	23	15	150.777	150.777	72.09	78.687	47.81%	52.19%

2019	10	2	11	126.246	126.2455	53.012	73.2335	41.99%	58.01%
2019	11	13	18	133.621	133.6203	61.034	72.5863	45.68%	54.32%
2019	12	19	18	141.462	141.4616	67.074	74.3876	47.41%	52.59%
2020	1	20	18	137.577	137.5764	63.125	74.4514	45.88%	54.12%
2020	2	14	19	130.986	130.9863	59.614	71.3723	45.51%	54.49%
2020	3	17	12	121.805	121.8043	53.852	67.9523	44.21%	55.79%
2020	4	27	13	112.267	112.2671	50.427	61.8401	44.92%	55.08%
2020	5	27	18	155.706	155.7056	76.29	79.4156	49.00%	51.00%
2020	6	23	17	179.551	179.5516	92.256	87.2956	51.38%	48.62%
2020	7	27	15	191.186	191.1854	99.621	91.5644	52.11%	47.89%
2020	8	11	16	191.383	191.3825	99.966	91.4165	52.23%	47.77%
2020	9	8	17	158.588	158.5873	79.027	79.5603	49.83%	50.17%

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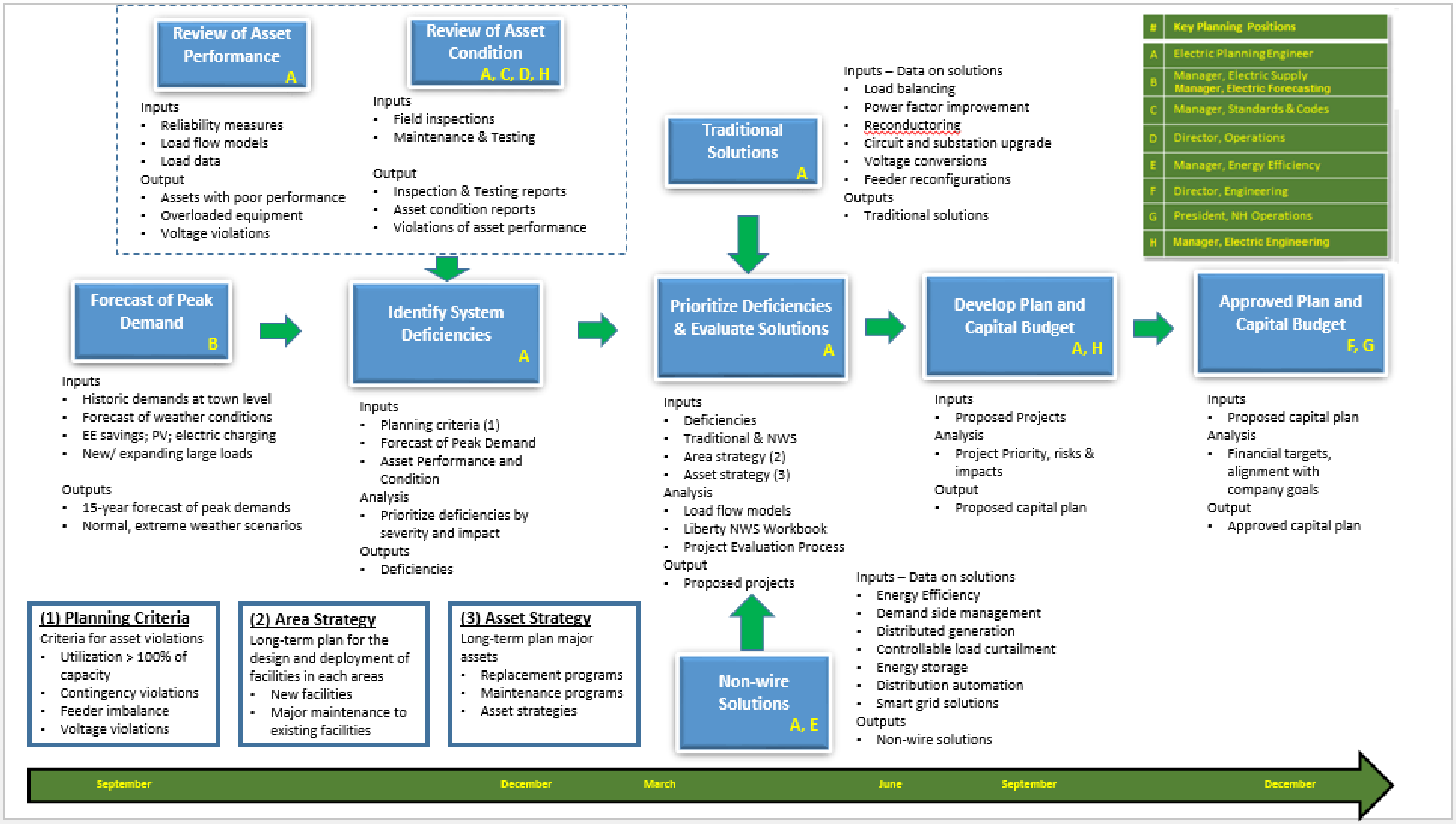
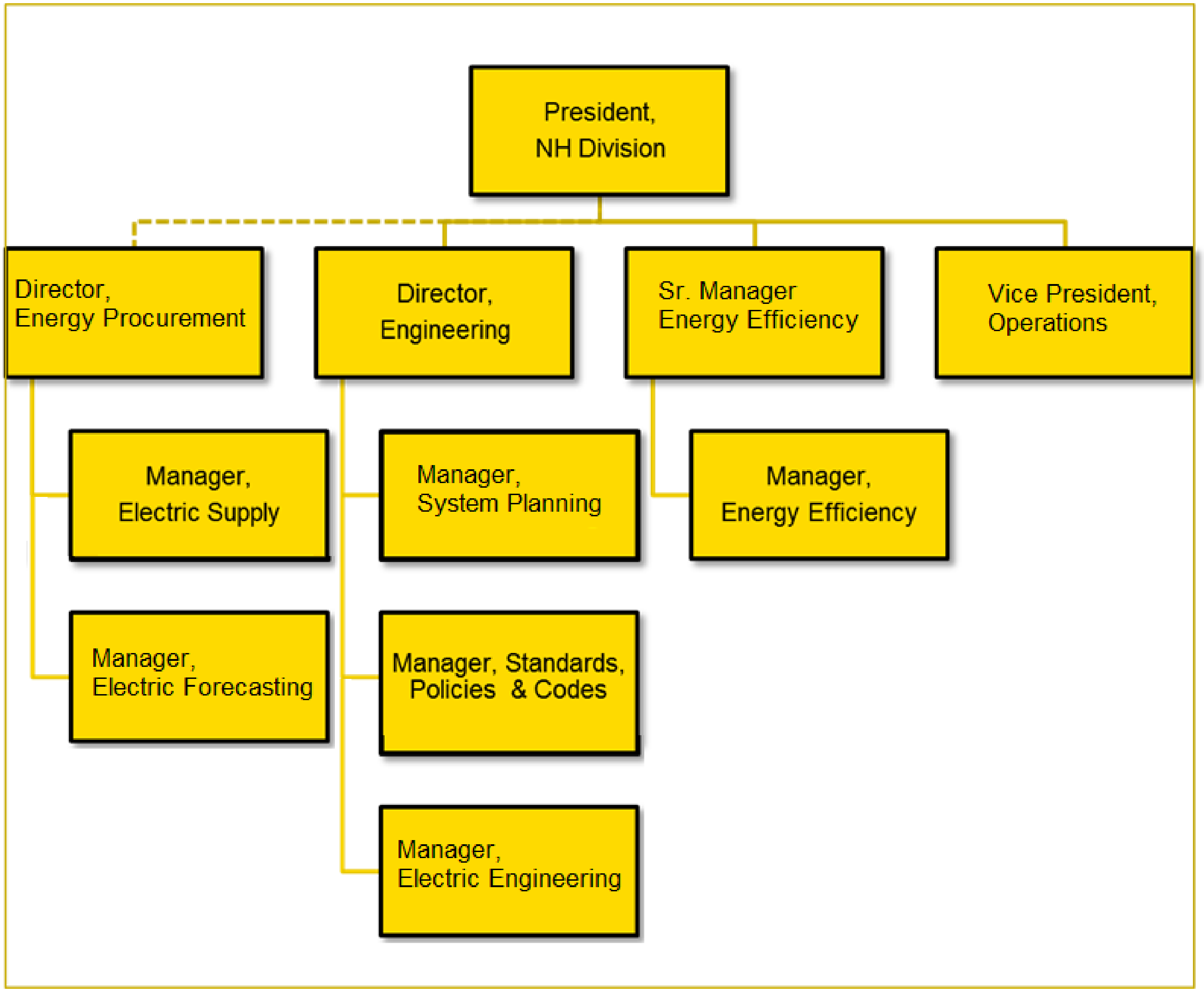
Appendix C. Distribution Planning Process Map and Timeline



Appendix C. Distribution Planning Organizational Chart and Key Positions



Appendix C. Prioritization of System Deficiencies

Evaluation of Distribution System Deficiencies

	Low Likelihood	High Likelihood
Low Impact		
High Impact		

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

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1.0 INTRODUCTION

This document describes the Distribution Planning Criteria and Strategy that will be used by the Liberty Utilities Engineering Department to review and evaluate the performance of its distribution system for each Planning Study Area ("PSA"). A PSA is a group of distribution facilities, including substations, feeders, transformers, and sub-transmission lines, within a specific geographic area that are interconnected and are studied as a group. There are four PSAs in Liberty's service territory: Salem, Lebanon, Bellows Falls, and Monroe. See Attachment A for Liberty Utilities Planning Study Area Map. The review and evaluation of each PSA is to be documented in a report ("Distribution PSA Study") that describes the assumptions, procedures, economic comparison, conclusions, and recommendations for the PSA. Liberty will conduct a PSA Study periodically, or when conditions within the PSA change, such as: changes in overall PSA demand forecast; changes in how load is distributed within the PSA; significant load additions; and/or other changes in conditions that warrant a PSA Study.

When preparing a PSA Study, Liberty will consider wires and non-wires alternatives to address system needs, such as those listed in Table 1 below.

Table 1. Distribution System Planning Alternatives

Wires Alternatives	Non-Wires Alternatives
• Load Balancing • Power Factor Improvement • Reconductoring/Recabling • Circuit and Substation Equipment Upgrades • Voltage Conversions (e.g. 4kV to 13.2kV) • Feeder reconfigurations	• Distributed Generation • Controllable Load Curtailment • Energy Efficiency • Energy Storage Devices • Demand Side Management • Distribution Automation • Smart Grid Solutions (Ex: Dynamic Ratings, Real Time Load Transfers and Capacitor Activation, etc.)

1.1 Objective

The goal of these planning criteria is to provide adequate capacity for safe, reliable, and economic service to customers with minimal impact on the environment. To achieve that goal, the distribution system is planned, measured, and operated with the objective of providing electric service to customers under system intact conditions (i.e., "normal") and first contingency conditions ("N-1").

1.2 Planning Criteria

Since the purchase of the New Hampshire electric assets from National Grid in 2012, Liberty Utilities has refined the distribution planning criteria to better fit Liberty's strategy of having sufficient capacity available to meet changes in demand, including new customer demand, to improve operations during emergency conditions, and to allow more time for the planning, analysis, and construction, as needed, of new facilities.

In addition, the refinements reflect the operating parameters of Liberty's smaller distribution footprint and resource base.

The criteria shall be reviewed and refined further, as needed, to reflect any major changes in standards or operating criteria.

2.0 PLANNING CRITERIA SUMMARY

The planning criteria are used to review and evaluate the performance of Liberty's distribution system for each Planning Study Area ("PSA"). The planning criteria are a critical input to identifying system deficiencies in Liberty's distribution planning process. See Figure 1 for the planning process. The planning criteria described in this document provide the framework to identify normal and emergency conditions, the acceptable equipment ratings under these conditions, and the corrective action required when the criteria are exceeded. Planning Criteria are distinguished from Planning Guidelines. Planning Guidelines are broader goals which should be met over time in the pursuit of achieving a reliable, economic distribution system, but may not necessitate immediate action.

For normal loading conditions, the planning criteria are based on feeders, supply lines, and transformers to remain within 100% of normal ratings at all times.

For N-1 contingency situations, the planning criteria are based on interrupted load returning to service 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, at least three feeder ties are planned for each feeder for switching flexibility and are integrated into the system design to minimize the duration of customer outages to meet reliability objectives.

The following criteria summarized in Table 2 shall guide planning on the distribution system:

Table 2. Distribution System Design Criteria Summary

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.

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 are expected to be made within 24 hours Evaluate alternatives if more than 120 MWhr of load at risk results post contingency switching.	Load must be transferred to nearby transformer to within their LTE rating. Repairs or installation of Mobile Transformer expected to take place within 24 hours. For transformers larger than 10 MVA nameplate, evaluate alternatives if more than 180 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 24 hours.
N-1 Contingency, which results in facilities operating above their Short Term Emergency (STE) rating	As Needed – Typically 15 min 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 15 min for OH conductors and 1-24 hours for UG cables.

3.0 DESCRIPTION OF THE DISTRIBUTION SYSTEM

Liberty's distribution system consists of lines and equipment operated at a voltage at or below 23 kilovolts ("kV"). The components of the distribution system include distribution substations, sub-transmission lines, and distribution circuits or feeders.

3.1 Distribution Substations

The distribution substations within Liberty Utilities are a mixture of stations with one, two, or three or more transformers. A typical substation consists of 23/13 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders. Some distribution substations are supplied by the 115 kV circuits and are jointly owned by Liberty Utilities and National Grid. Liberty Utilities and National Grid maintain approximately 16 distribution substations containing approximately 26 power transformers in the Liberty Utilities service territory. Liberty Utilities anticipates that the distribution planning criteria will, in general, be applied to both Liberty and New England Power assets serving Liberty customers. However all existing 115kV transformers serving Liberty customers are owned and maintained by National Grid. System Non-Wires and Wires solution alternatives will be developed along the lines of these criteria recognizing, however, the unique nature of transmission supply contingencies on the distribution system.

3.2 Sub-Transmission System

The sub-transmission system provides supply to distribution substations as well as large three phase customers. It consists of those parts of the system that are considered neither bulk transmission nor distribution. The voltages for Liberty's sub transmission system include 23 kV and 13.8 kV. The voltages for the National Grid sub transmission system includes 46 kV. The sub-transmission system is designed in an open loop or "radial" system and, generally provides a redundant supply for distribution substations. The sub-transmission system is presently designed with conductors ranging from 336.4 ACSR to 1113 thousand circular mils ("kcmil") overhead conductors, and from 500 to parallel 1000 kcmil copper underground conductor. There are eight sub-transmission lines that are maintained by Liberty Utilities.

3.3 Distribution Feeders

The distribution feeders from each substation are in a "radial" configuration with provisions for manual or automatic transfer of load between feeders, including feeders from adjacent substations. Distribution feeders originate at circuit breakers connected within the distribution substations. Feeders are generally comprised of 477 or 336 kcmil aluminum mainline overhead conductors and 1/0 AWG aluminum branch line conductors. Some feeders have underground getaway cables exiting from the substation with 500 to 1000 kcmil aluminum or copper conductors. Protections for faults on the feeders consist of relays at the circuit breaker, automatic circuit reclosers at points on the mainline, and fuses and trip savers on the branch circuits. The Liberty Utilities distribution system is comprised of approximately 41 feeders ranging from 2.4kV to 13.2kV.

4.0 EQUIPMENT RATINGS

Thermal limits are recognized for all system elements in conducting planning studies. 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 so 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.

4.1 Overhead Conductors

The current carrying capacity (also known as, "ampacity") of an overhead conductor may be limited either by conductor clearances or maximum allowable operating temperature under a predefined set of reasonably severe summer or winter ambient conditions. The Company's Overhead Construction Standards book lists maximum ratings not to be exceeded for each conductor for normal and emergency operation.

As part of system operation, standard conductor sizes for overhead distribution construction of #2 AAAC, 1/0 AAAC and 477 AAAC or equivalent tree wire have been selected by Liberty Utilities.

The following general guidelines were developed for 13.2 kV overhead distribution lines:

- New single-phase overhead distribution lines should be constructed with #1/0 AAAC, and new single-phase underground distribution lines should be constructed with #2 AWG AL for loads less than 500kW.
- The single-phase lines should be reconductored to three-phase wherever needed based on operating conditions, phase imbalance, and voltage drop.
- New three-phase overhead distribution lines and/or future distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:
    - For loads less than 3,000 kW: 1/0 AAAC
    - For loads greater than 3,000 kW: 477 AAAC
- The single-phase and three phase lines should be reconductored with covered tree conductor or spacer cable wherever needed, based on operating conditions in tree prone areas.

The maximum ampacity of an overhead conductor is estimated for Normal (continuous) and Long-Time Emergency (LTE) operations for summer and winter conditions.

4.1.1 Normal Capability

The Normal rating shall be interpreted as the maximum value for normal peak loads on all new and rebuilt feeders. The 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, and covered conductors.

4.1.2 Long-Time Emergency Capabilities (24 hours)

The LTE rating shall be interpreted as the absolute maximum ampacity allowed for a given conductor. This ampacity should not be exceeded at any time unless an appropriate engineering review has been conducted. The temperature limit for LTE for 100% ampacity for operating conductor at an elevated temperature during emergency conditions limited to a 24 hour period is 194°F/90°C for bare and spacer cable, tree wire, and covered conductors. Higher temperatures for bare conductors may be considered as field conditions permit following approval by the Manager of Engineering - Standards, Policies, and Programs.

4.1.3 Short-Time Emergency Capability (As needed)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. Loads must be reduced within 15 minutes to operate within the LTE rating. Ratings for other short time emergency durations are approved and provided by the

Engineering department on a case by case basis after an appropriate engineering review has been conducted.

4.2 Underground Cables

Underground distribution line ratings were derived from the October 1957 AIEE paper titled, "The Calculation of the Temperature Rise and Load Capability of Cable System," by J.H. Neher and M.H. McGrath. These calculations integrate all aspects of the cable system design such as conductor material, conductor size, insulation, properties, insulation thickness, cable type, shield connections, load characteristics, installation conditions, and environment. Cable ampacities are based on normal and emergency operating conditions. Normal cable ampacities are based on a 90° insulation operating temperature, while emergency cable ampacities are based on 130° insulation operating temperature. The Company's underground construction standards book provides estimates of cable ampacity for common sizes and configuration of main line cables. Given the many different aspects of a cable system, specific cable ratings are typically derived using computer software such as Synergee Electric or PC Amp.

New three-phase underground distribution lines or future three-phase underground distribution line upgrades should be constructed with the specified conductors at the initial load given as follows:

- For loads less than 2000 kW: #2 AWG AL
- For loads greater than 2000 kW: #4/0 AWG CU
- For loads greater than 3500 KW or part of a feeder mainline: 500 MCM CU
- For feeder cable getaways: 1000 MCM CU

Ampacities are defined for underground cables as follows:

4.2.1 Normal Ampacity (Continuous)

This is the maximum loading on the cable that does not cause the conductor temperature to exceed its design value at any time.

4.2.2 100-300 Hour Ampacity (LTE)

This is the maximum emergency loading on the cable that does not cause the conductor temperature to exceed its applicable emergency value over a period of several consecutive 24-hour load cycles. At the end of the emergency time period, the load on the cable must be reduced to a value within its normal ampacity.

4.2.3 One-Hour to 24-Hour Emergency Ampacities (STE)

Other short duration ratings, such as Short Time Emergency (STE) if required for maintenance or construction, are estimated conservatively using seasonal ambient data along with circuit specific information by the engineering department. These are the maximum emergency loadings on the cable that do not cause the conductor temperature to exceed its allowable emergency value at any time during the period. At the end of the emergency time period, the load on the cable must be reduced so that the peak load in the next load cycle does not exceed the LTE ampacity (defined above).

4.3 Transformers

Distribution substation transformers are rated for loading according to the American National Standards Institute ("ANSI") standards for maximum internal hot spot and top oil temperatures. This is detailed in the Institute of Electrical and Electronics Engineers ("IEEE") Guide for Loading Mineral-Oil-Immersed Power Transformers up to and including 100 MVA with 55°C or 65°C winding temperature rise (ANSI/IEEE C57.91 latest version). The manufacturer's factory test data and the experienced 24-hour loading curve data are used in an iterative computer program that calculates allowable loading levels.

The transformer's "ratings" for the Normal ("N"), Long Term Emergency ("LTE"), and Short Term Emergency ("STE") load levels are identified based upon maximum internal temperatures and selected values for the loss of the transformer's life caused by its operation at the criteria temperatures for a specified duration, and on a defined load curve. Three categories of transformer capabilities are defined below:

4.3.1 Normal Capability

Winter normal and summer normal capabilities are based on a normal daily load cycle and on the maximum 24-hour average ambient temperature for the period involved. The maximum load for Normal operation of the transformer is determined and set when the operation of the transformer at that 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. Conditions above any of these limitations will result in a shortening of the transformer service life beyond prescribed design levels and/or physical damage to the equipment.

4.3.2 Long-Time Emergency Capabilities (1 hour to 300 hours)

These capabilities are based on a normal daily load cycle, with the emergency load increment added. The maximum 24-hour average ambient temperature is used for the appropriate season. The LTE rating of a substation transformer is determined and set when the 24 hour operation of the transformer, with that additional load in each of the hours in the 24 hour load cycle curve, causes a cumulative (24 hour) 3.0% loss of transformer life, or the Top Oil temperature to exceed 130 °C, or the hot spot copper temperature to exceed 180 °C.

4.3.3 Short-Time Emergency Capability (15 minutes or less)

The STE rating of a transformer is determined and set when 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. However, the maximum STE rating is limited to a value equal to twice the transformer's "nameplate" rating (i.e., 200%).

4.4 Other Equipment

In addition to the items above, normal and emergency capabilities are reviewed for switches, circuit breakers, voltage regulators, and instrument transformers. Emergency capabilities usually involve elevated temperatures with some potential loss of equipment life. However, any circuit rating may be limited by other circuit equipment such as circuit breakers, disconnects, regulators, et cetera. These ratings are generally based on the allowable maximum temperature of the equipment. The facility (feeder, sub transmission line, and/or transformer) rating is determined by identifying the "limiting device" and applying the rating criteria for that device or equipment.

4.4.1 Distribution Overhead Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
145%	180%	160%	200%

4.4.2 Distribution Single Phase Padmount Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
140%	160%	140%	160%

4.4.3 Distribution Three Phase Padmount Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
120%	140%	120%	140%

4.4.4 Distribution Step-Down Transformers

The following generic ratings in % of nameplate are used:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
110%	110%	110%	110%

4.4.5 Circuit Breakers / Reclosers

The following generic ratings in % of nameplate are used: NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
107%	123%	115%	130%

4.4.6 Voltage Regulators

The following generic regulator ratings in % of nameplate for 10% regulation are used:

55ºC INSULATION SYSTEM				**65ºC INSULATION SYSTEM**			
NORMAL		EMERGENCY		NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
125%	148%	125%	148%	141%	160%	141%	160%

4.4.7 Disconnect Switches

The following generic air switches ratings in % of nameplate:

NORMAL		EMERGENCY	
Summer	Winter	Summer	Winter
113%	134%	139%	147%

4.5 Equipment Rating Criteria Summary

The major equipment ratings to be used by planning engineers relate to transformers, overhead lines, and underground cables. The normal and LTE rating limits for feeders, sub transmission lines, and transformers may be applied for the time associated with each rating. Table 3 summarizes the durations for emergency loading that system operators must be aware of, including the limiting factor involved in any contingency. There is also a short time emergency (STE) rating that is mainly used for transformers and must not exceed

200% of nameplate rating. Table 4 summarizes the Equipment Rating criteria, as described in more detail above.

Table 3. Facility Rating Durations

Equipment	Normal	LTE	STE
Feeders	Continuous	24 Hours	As Needed, Typically 15 Minutes
Sub Transmission lines	Continuous	24 Hours	As Needed, Typically 15 Minutes
Transformer	Continuous	1 - 300 Hours	15 Minutes

Table 4. 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.	24 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%).

5.0 DISTRIBUTION SUBSTATION TRANSFORMER LOADING CRITERIA

The ratings of transformers are calculated from their thermal heat transfer characteristics and the expected electric loading experience over a 24-hour cycle. All distribution substation transformer bank ratings are evaluated seasonally for their summer and winter values.

5.1 Normal Operation Design Criteria

Normal operation is the condition under which all electric infrastructure equipment is fully functional. A substation transformer will not be loaded above 100% of its Normal rating during non-contingency operating periods.

5.2 First Contingency Emergency Design Criteria

First contingency operation is the condition under which a single element (distribution substation transformer) is out of service. For first contingency emergency conditions involving the loss of one distribution substation transformer larger than 10 MVA, the following system design criteria applies:

- In cases where a first contingency situation causes the LTE rating of the remaining transformer to be exceeded, all load above the LTE rating of the remaining transformers must be transferred to neighboring facilities or shed 15 minutes without exceeding the LTE rating of the substation transformers or distribution circuits receiving the load.
- In cases where a first contingency situation will cause the STE rating of a remaining transformer to be exceeded, load must be immediately reduced (dropped/shed) to a level within the STE. All load between the LTE and STE ratings, and any load that was initially shed to get the remaining transformer below its STE rating, must be transferred to peripheral facilities without exceeding the LTE rating of the substation transformers or the distribution circuits receiving the load.
- Repairs or the installation of mobile equipment are expected to be made within 24 hours.
- The quantity of load at risk of being out of service following post contingency switching should be limited to 180 MWhrs. If more than 180 MWhrs of load is at risk at peak load periods for a transformer or substation bus fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.

5.3 Automatic Transfer of Load

Locations with two or more transformers at a substation utilize automatic bus transfers. Based on the loading limitations of Section 5.2, it may be necessary to block the automatic transfer on either the main bus tie or one of the feeder bus tie breakers to avoid exceeding the STE limit during a first contingency. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

6.0 DISTRIBUTION CIRCUIT LOADING CRITERIA

6.1 Normal Operation Design Criteria

A feeder circuit should be loaded to no more than 100% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent feeders during first contingency N-1 conditions and/or provides capacity to serve new business or commercial applications in a timely manner.

6.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a distribution circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. For the loss of a distribution feeder, the following criteria apply:

- After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. All adjoining tie feeders can be loaded to their maximum LTE rating.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.

6.3 First Contingency Emergency Design Guidelines

The following guidelines shall apply to distribution feeders:

- If more than 16 MWh of load is at risk at peak load periods for a single feeder fault, alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2,000kVA of load between disconnecting devices.
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload adjoining feeders.
- For a typical Liberty owned 10 MW feeder, approximately 8 MW would need to be restored via switching within one hour. The remaining 2 MW would be restored after

repairs within 4 hours. Where longer repair times are needed, such as for a cable getaway fault, the load out of service should be reduced to 1 MW.

6.4 Automatic transfer on feeders

In some cases it will be necessary to adjust a feeder rating to below normal summer or winter thermal rating due to automatic backup or Second Feeder Service commitments to certain customers or due to automatic reclosing loop schemes in the distribution lines.

6.5 Primary Circuit Voltage Criteria

The normal and emergency voltage to all customers shall be in line with limits specified by the state of New Hampshire and within the limits of ANSI C84.1-2016.

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

Table 5. Voltage Requirements for LU

For 120 V – 600 V Systems				
Nominal Voltage (V)	**Service Voltage (V)**			
	Range A		**Range B**	
	Max	Min	Max	Min
120	126	114	127.2	104.4
240	252	228	254.4	208.9
480	504	456	508.8	417.6

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.

Voltage regulation of the feeders and supply lines must be adequate to ensure the voltage requirements in Table 5 above are maintained. The ultimate goal is to keep all customers' service voltages within accepted limits. From a supply point of view, the acceptability of voltage regulation is determined at the distribution substation buses. At substations with feeder or bus regulating equipment, the regulation (the extreme range of voltages expressed as a percentage of normal peak load voltage) should be no greater than 10 percent for normal and 15 percent for emergency conditions on the source side of the regulating equipment. Most substation regulating equipment has a range of 20 percent. Under normal conditions, therefore, half the regulator range can compensate for variations in supply voltage, leaving the other half available for voltage drops on the distribution feeders. The substation transformer taps are chosen to allow this control.

6.6 Distribution Circuit Phase Imbalance Criteria

Adding new customer loads to the distribution circuit must be done in the manner to minimize phase imbalance on the distribution system. These criteria are established to limit the load imbalance among the three phases of a primary distribution circuit. Such an imbalance gives rise to return current through the neutral conductor which contributes towards additional losses and voltage drop. Heavily loaded phases overstress the conductors reducing their life and can also lead to their eventual burn down or connector overheating, even at low loadings of the circuit. A high imbalance could also lead to the ground relay operating on the feeder breaker. 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.

Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified. Any new load addition to a circuit should adhere to these criteria.

For all new single phase load additions, the new installation is connected to the phase with the least connected KVA, if it is available, to maintain a balanced circuit.

7.0 SUB-TRANSMISSION LINE LOADING CRITERIA

7.1 Normal Operation Design Criterion

A sub transmission line should be loaded to no more than 100% of capacity during normal conditions. This loading level provides reserve capacity that can be used to carry the load of adjacent supply lines during first contingency N-1 conditions.

7.2 First Contingency Emergency Design Criteria

For first contingency emergency conditions on a supply circuit, the worst of which is the loss of the circuit's getaway cable or circuit breaker. After transfers, all resultant components must be below the emergency ratings as defined by the appropriate loading guides. For the loss of a supply line, the following criteria apply:

- The initial load increase at the remaining sub-transmission supply lines within the area must not exceed the summer or winter LTE rating.
- Every effort must be made to return the failed sub-transmission line to service within 24 hours (12 hour for overhead, 24 hours for underground).
- Feeder ties and cascading of load within the area can be utilized to the emergency limits of feeders to offload a sub-transmission line.
- For a typical Liberty-owned sub-transmission supply line consisting of either 13.8 kV or 23 kV, the quantity of load at risk of being out of service following post contingency switching should be limited to 120MWhr of load at risk at peak load periods for a single fault. Alternatives to eliminate or significantly reduce this risk shall be evaluated and prioritized considering the load at risk, reliability impacts, and the cost to mitigate.
- In the case of parallel underground conductors, depending on the protection and operating scheme, N-1 contingency analysis may include the initial loss of both parallel phases. However, when determining repair and restoration times for contingency analysis, operating capabilities such as the ability to isolate paralleled cables using disconnects and partially restoring one of two cables will be considered.

7.3 Automatic Transfer of Load

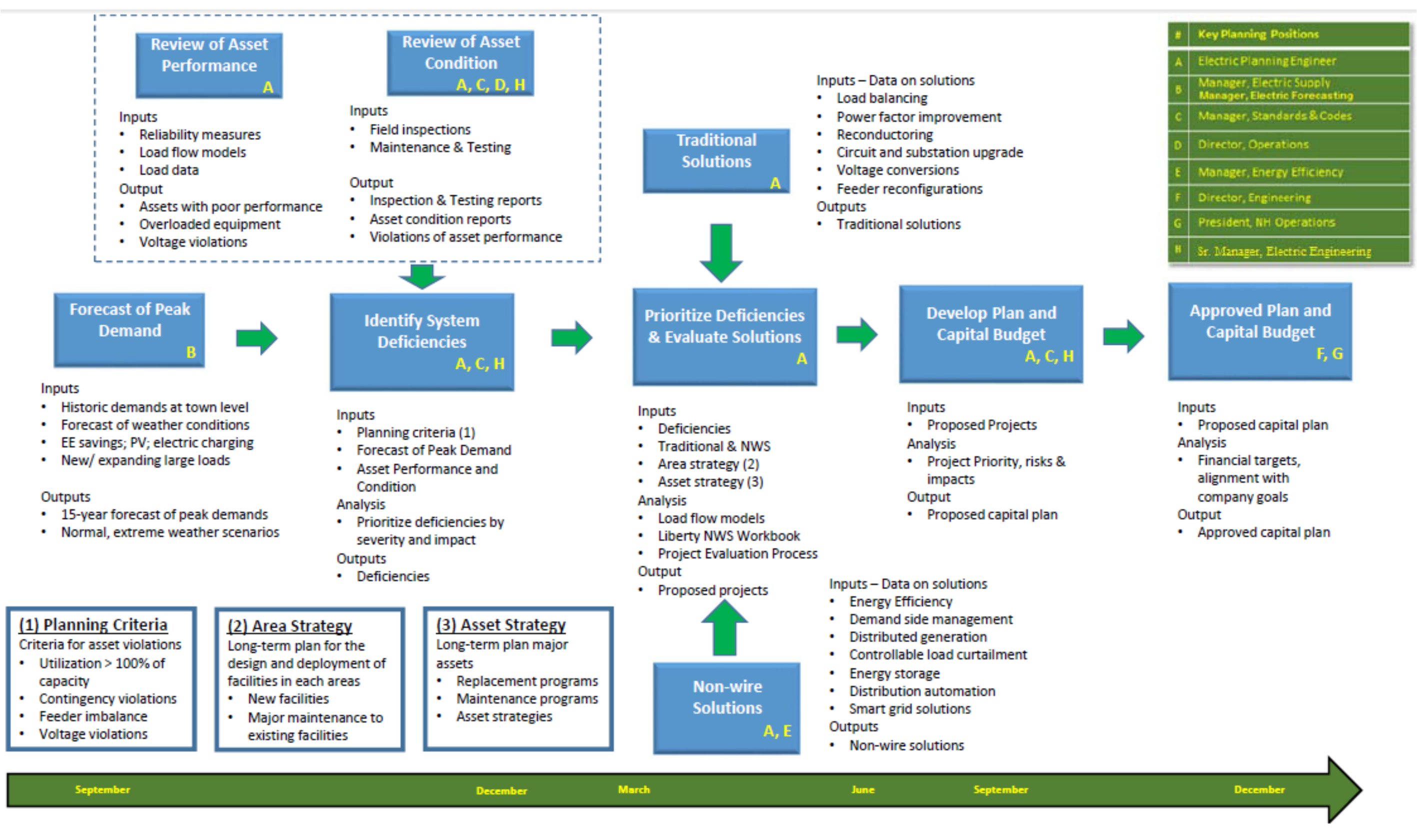
Auto transfer of load on the sub-transmission may be employed, but may not exceed the LTE ratings of the remaining supply lines. When available, SCADA control of sub-transmission lines will be utilized to block auto transfers and avoid overloading of lines as needed. Cases where automatic restoration is disabled will be communicated with Electric Control as part of an annual summer preparedness review. Disabling of automatic bus transfer schemes will not be considered as a permanent solution to a criteria violation.

8.0 PLANNING STUDIES

A planning study area ("PSA") within Liberty Utilities is a grouping of distribution substations, feeders, transformers, and sub-transmission lines within a specific geographic area that are interconnected and can be studied as a group. PSA's in Liberty's service territory are totally independent from each other. A listing of the planning study areas that exist in the Liberty service territory are presented in Attachment A.

Liberty conducts an annual capacity planning process covering a 5 year period with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints, ensure adequate delivery voltage, and assess the capability of the system to respond to contingencies that might occur. The distribution planning process is illustrated in Figure 1 below:

Figure 1. Distribution Planning Process Map and Timeline



8.1 Electric System Planning Criteria and Methodology

8.1.1 Modeling Guidelines

As shown in Figure 1 above, the planning process for designing the Distribution System begins with the load forecast. The PSA load forecast is updated annually. The load forecast at the system level is based on econometric models, and is developed on both a weather-normalized and weather-probabilistic basis. Currently, the Liberty distribution system is modeled for a "peak hour" load level that has a 10% probability of occurrence such that those weather conditions are expected to occur once in 10 years. Specific major known or planned load additions are factored into the load forecast. Historical DSM and DG along with specific DSM/DG installations are also factored into the forecast. The resultant load forecasts are utilized in two types of planning studies which assess the ability of the distribution system to meet future customer load requirements. These studies include (1) Area Studies and (2) Interconnection Studies, and are described below.

Load flow analyses are used to determine expected circuit overloads and to evaluate alternatives for system reinforcements. Liberty utilizes the Synergee computer application to model load flows in the distribution system.

Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

Area studies

Area studies are generally 15-year forecast time frames and address specific load areas, including the area supply system, substations, and distribution feeders.

Interconnection studies

System interconnection studies are designed to determine the interconnection facilities and system reinforcements required for specific generation and distribution growth projects to enable them to be effective over the life of the project.

9.0 SYSTEM RELIABILITY

The supply and distribution system in the Liberty system are designed to limit the interruption of energy delivery for a loss of any single element.

The indices of service reliability are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). The SAIDI measures the total duration of an interruption for the average customer during a given time period. The SAIFI measures the average number of times that a customer experiences an outage during a given time period.

The supply and distribution systems shall be designed so that the annual SAIDI and SAIFI do not exceed the five-year rolling averages, excluding severe weather related events, and support a nominal improving five-year reliability trend. When an exceedance does occur, efforts shall be made in the subsequent year(s) to further improve reliability performance to an improving trend level.

10.0 OTHER CONSIDERATIONS

The planning engineer must consider the effect of each plan on all aspects of system design. These include:

- Protection: Protection or Coordination studies are performed when it is needed to adjust relay settings at substations to increase rating of the facility. Settings are carefully selected to avoid mis-coordination and trips due to load imbalance.
- Operation and Maintenance ("O&M"): O&M is taken into account when ranking different project alternatives.
- System Power Factor: Liberty will strive to maintain a 98% power factor at the substations to provide quality power to its customers and limit system losses via the addition of new capacitor banks. In addition, annual Surveys for system power factor will allow Liberty to properly manage reactive support by adjusting settings from capacitor bank controls.
- Short Circuit Duty: Substation circuit breakers are modeled using their rated interrupting capability in the ASPEN™ short circuit analysis computer program. Any breaker that meets or exceeds its rated interrupting capability is targeted for replacement.

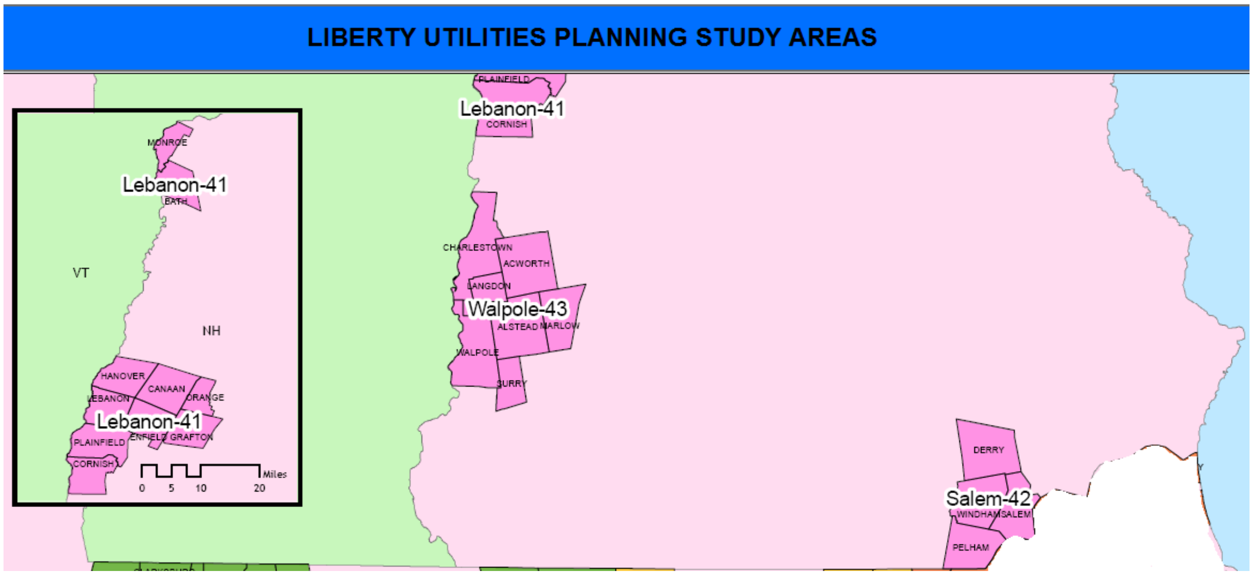
11.0 BENEFITS OF PLANNING CRITERIA STRATEGY

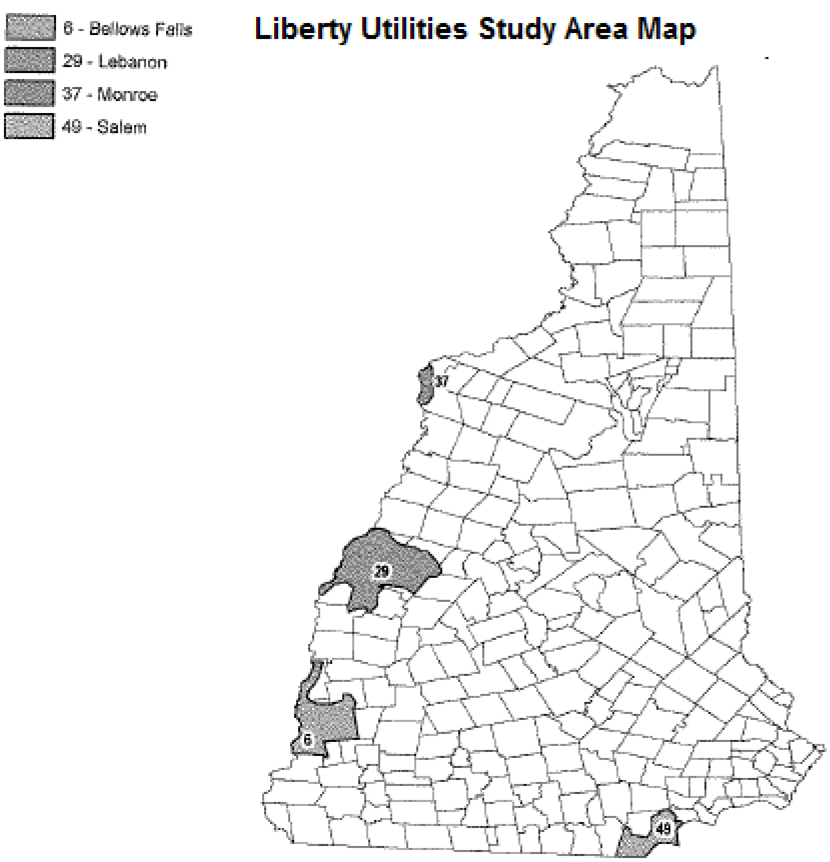
The most recent changes to these planning criteria are to move Liberty's criteria closer to that of the other utilities in the region. This planning strategy provides a documented approach to managing the Liberty system consistent with the approach of other local utilities, a goal of the New Hampshire regulator. This will better support the investment plans needed to implement the loading guidelines outlined in the strategy.

The planning strategy provides a consistent approach for feeder/substation/supply line and PSA loading analysis across Liberty. All studies being conducted under one set of criteria will make way for a consistent reference for ranking studies as part of the budgeting process. This will result in a more efficient organization and a streamlined flow of information from the planning study results into the budgeting process.

	Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description: Electric Distribution Planning Criteria	Revision #:	3.0	Page 22 of 24

Attachment A – Liberty Utilities Planning Study Area Map





Attachment B – Summary of Planning Criteria Changes

2016 Criteria	2020 Criteria	National Grid Criteria
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.**	During normal operation, all distribution feeders to remain within 100% of normal ratings.
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.**	During normal operation, all sub-transmission lines to remain within 100% of normal ratings.
During normal operation, all transformers to remain within 75% of normal ratings.	**During normal operation, all transformers to remain within 100% of normal ratings.**	During normal operation, all transformers to remain within 100% of normal ratings.
No Change	**Part of a Planning Design Guideline**	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.
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.	**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 120 Mwhr. If more than 120 MWhrs 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 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 transformer, 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.	**For the loss of a transformer above 10 MVA, the quantity of load at risk of being out of service following post contingency switching should be limited to 180 MWhr. If more than 180 MWhrs of load at risk results for a single line fault evaluate alternatives to mitigate.**	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.

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 12 hours for OH wires and 24 hours for UG cables.**	Every effort must be made to return the failed sub-transmission line to service within 24 hours.
N/A	Every effort must be made to return the failed distribution feeder to service within 24 hours.	Every effort must be made to return the failed distribution feeder to service within 24 hours.

Approved by: ______________________________________ Date: ____________________

Charles Rodrigues
Director of Engineering
Liberty Utilities

DAS-001 Distribution Line Overarching Strategy
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Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
3	6/18/2019	Revision of Strategy for Liberty-NH.	Joel Rivera Manager Electric System Planning	Charles Rodrigues Director of Engineer
2	07/02/2008	Deleted Strategy Statement (redundant) Deleted Substation references due to separate strategy document Updated Section 2 (AM Objectives) to align with updated OSP objectives Updated Section 3 (AM Strategy Framework) with graphic and revised text Updated Section 4 (Existing Asset Strategy) with summary of approved documents Updated Section 5 (AM Tools) with progress on inspection program and SubT flyover. General editing for terminology, company/department name changes and data table updating	Jeffrey H. Smith Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Jeffrey H. Smith – Asset Strategy Dev. John M. Teixeira – Asset Strategy Dev. Anthony J. McGrail – Sub. Eng. Services	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This paper outlines Liberty Utilities NH Electric Distribution strategy objectives and processes. This paper is meant to be revised as the company's strategies, processes, and organization evolve over time.

This document is subject to review and continuous improvement and is a controlled document. This document is approved and endorsed by the Engineering department.

It is the intent that this strategy be:

- Consistent with the company's organizational plan,
- Consistent with all organizational policies,
- Provide the framework for developing and enabling specific asset management strategies, and
- Be consistent with the company's overall risk management objectives.

The purpose of this document is not to lay strategies for individual asset classes. This is done in the individual asset management strategies. This document details the overall asset management strategy and philosophy within which the individual asset class strategies lie.

This document describes how Liberty Utilities NH will meet stated levels of service, reliability and business performance through the efficient and effective management of its electric distribution assets within the framework of responsible corporate governance and the regulatory environment.

The distribution substation overarching strategy is covered under a separate document due to the more specific nature of the assets.

2.0 Asset Management Objectives

Liberty Utilities NH has set specific asset management objectives in four areas. These objectives are subject to review and change on a continuing basis. The current objectives are:

- **Safety**
  - Achieve zero injuries every day
  - Continue to work on processes, systems and designs that improve safety, and to reinvigorate our safety culture to bring fresh effort to improving performance
  - Design for safety
- **Reliability**
  - Meet service quality requirements for frequency and duration of outages to our distribution system (SAIDI/SAIFI) using NH PUC regulatory criteria of 5 year rolling averages.
  - Achieving this objective, and making it sustainable, will require investments in the replacement of our aging infrastructure.
  - Building relationships with our regulatory bodies is required to achieve mutual understanding for the need to support long-term investment in a sustainable distribution network

- **Customer Service**
  - Achieve targeted customer service and satisfaction levels measured by a 3rd party survey company to evaluate how our customers feel about our services.

- **Efficiency**
  - Look for opportunities to invest capital in our distribution system, whether through the development of new projects, new technologies or commitment to support growth in our communities.
  - Liberty Utilities NH will constantly strive to be more efficient in the service we provide to our customers by improving annual O&M cost efficiency and improving capital efficiency.

2.1 Sustainable Network

In addition to meeting the specific and general objectives in the broad areas listed above, asset management strategies are specifically intended to create and maintain a sustainable network. A sustainable network is one which receives the attention necessary to meet stated network performance targets (reliability, safety, stakeholder expectations, etc.) both at present and into the foreseeable future.

Management of a sustainable network requires an understanding of the health, reliability, lifecycle and capability of the assets to perform their function within the network. Investment decisions (maintenance, repair, replace etc.) must be supported by appropriate data and capable of robust defense.

It should be noted explicitly that a sustainable network requires investment to allow both:
- reactive response to environmental pressures (be they weather, regulatory or statutory) , and
- proactive preparation of the network for the future (load growth, new technology, etc.).

2.2 Adjacent Assets

Adjacent assets are not a core driver in the asset management process but play a role when specific assets or asset groups are reviewed. Adjacent assets must be considered as part of a holistic approach to asset management which will address both the asset itself and the role of the asset in the network. Adjacency is one differentiator between otherwise similarly scored assets.

2.3 Individual Asset Strategy Objectives

Liberty Utilities NH asset strategies deal with the management of physical distribution assets throughout their lifecycle. The management of physical assets is inextricably linked to the management of all other aspects of the electric distribution business. These other aspects of the business are only considered when they have a direct impact on the management of the physical infrastructure assets.

Individual asset strategies are developed in order to meet overall business objectives and address risk in the following broad areas:
- Safety and Environmental
- Reliability
- Customer/Regulatory/Reputation
- Efficiency

3.0 Asset Management Strategy Framework

The Asset Management process is what links asset management across the business segments of Liberty Utilities. This process allows for the uniform analysis of assets with respect to performance, costs, business risks and initiative benefits. The process develops, optimizes and implements the whole life asset management plans for all assets and asset systems. The process also reflects the requirement of business and strategic planning, resource allocation and on-going program management.

3.1 Asset Strategy Types

In general, most asset strategies will fit in one of two classifications, those focused on reliability performance and those focused on sustainability (long term reliability). A smaller number of strategies will fall under other types; for example, those designed to address specific safety, environmental, reputation, or other issues. Many strategies, while primarily addressing one specific area, have elements that address other areas. All strategies consider the company's business objectives as outlined above.

3.2 Reliability Focused Strategies

These strategies are designed to improve the overall reliability performance. Their main focus is on SAIDI and SAIFI improvements but also address CAIDI. These strategies are in place to manage the company's reliability objectives stated above.

Examples of reliability focused strategies are listed below. These are not the only strategies that address reliability. As the company's asset management evolves and the company's goals change, it can be expected that additional strategies will be developed.

- Distribution Feeder Hardening Strategy (In Development)
- Distribution Automation Strategy
- Reliability Enhancement Program
- Recloser Application Strategy

3.3 Sustainability Focused Strategies

These strategies are designed to create a sustainable distribution system to serve our customers. These strategies call for the appropriate level of investment (maintenance and/or replacement) to meet the stated network performance targets and assure sustainability. In general, these strategies are condition-based replacement strategies. Where condition data is lacking or insufficient, age data is sometimes used.

The following is a partial list of typical sustainability focused strategies.

- Pole Strategy (In Development)
- Distribution Line Transformer Strategy
- Distribution Line Capacitor Strategy
- URD Cable Strategy
- Stepdown Transformer Strategy
- Voltage Regulator Strategy
- Overhead Secondary Strategy

3.4 Other Asset Strategy Types

Several strategies address other areas such as safety and customer service. The following are examples of those:

- Pockets of Poor Performance Strategy
- Poor Performing Feeder Program

- Small Wire Replacement (Amerductor Replacement) Program
- Low Voltage Mitigation

4.0 Asset Strategy

Currently documentation and approval of specific asset strategies has completed its first cycle in July 2019. Distribution line asset strategies have been developed for Liberty Utilities NH. These strategies are fully developed and received approval in July 2019. There are other strategies that are currently being developed or updated and require further data collection and analysis prior to acceptance as fully developed strategies. A communication plan is being developed to inform the appropriate groups within the organization.

In practice, most distribution asset strategies involve fix or repair on failure scenarios. It is important to note, however, that relatively few distribution assets actually run to failure. The majority of distribution assets are replaced before failure due to a number of reasons including, load growth, circuit re-configuration, road re-building, etc.

5.0 Asset Management Tools

Based on the review and input from appropriate stakeholders, additional detail will be added to support the execution of the recommendations. In most cases the recommendations will be incorporated into data collection projects under development as part of the Grid Modernization Effort.

5.1 Asset Inspection Programs

Overhead and Underground

The existing overhead and underground inspection program (described in EOP D004 and UG006) has been updated with the following goals:

- Improve the consistency of the equipment condition reporting

- Inspect all assets across the system on a cycle based program.

- Identify and address all problems found based on the following priority system:
  - Priority 1 – One week to replace
  - Priority 2 – Six months to replace
  - Priority 3 – Two years to replace
  - Priority 4 – Information Only, replace based on engineering judgment and budget

- Link to work management system (under development) for streamlined work order creation, execution, completion, closeout and tracking

Enhanced pole inspection is included in the program which includes both a visual and rudimentary structural (using a hammer and screwdriver) review of all poles.

The visual overhead and underground inspections cover both the distribution system and the subtransmission system.

In addition to the overhead and underground visual inspections, a number of other inspections are conducted on the overhead and underground system. These inspections include such things as:

- Infrared inspections of overhead lines,
- Infrared inspections of certain underground work (EOP UG001),

- Elevated/Stray voltage inspections of the overhead and underground system (EOP G016) are performed as part of power quality investigations.

Future Recommendations – Inspections

Asset inspection programs are a vital tool in accumulating asset condition data. In the absence of credible condition data, age data can serve as a substitute.

The following specific recommendations will be considered as Liberty's asset management program matures:

➢ **Pole inspections**

The company will evaluate a pole inspection program that goes beyond a simple visual inspection and evaluates the structural integrity and the required strength for each specific pole. This type of inspection is common in the industry.

5.2 Asset Register Systems

ArcFM GIS

The principal asset register system for distribution lines is the ArcFM GIS. All distribution overhead and underground equipment, along with limited substation data, is contained in the GIS. Subtransmission equipment data (overhead and underground) is also contained in ArcFM GIS.

The accuracy of the data within the ArcFM GIS is integral to the asset management process. An ongoing effort is underway to upgrade the company's GIS system and integrate with an ADMS platform. This requires to update the existing equipment data and add key data (mainly equipment settings and linking of customer service locations).

5.3 Reliability Data

Responder

The Responder application stores reliability data for the company. This system has been in place in New Hampshire since 2014. Reliability data prior to 2014 is maintained in other spreadsheets and databases.

Presently, data is fed to the Responder Archive application from the Responder outage management system.

Future Recommendations – Reliability Reporting

➢ **ADMS (under development)**

As more technology is deployed in the field, the outage data collection may soon be taking place in the truck repairing the outage. A simplified, interactive form provides an opportunity to capture the outage data more accurately. An ADMS platform will further automate outage restoration and optimize the performance of the distribution system. This will lead to the improved ability to analyze the data and create effective reliability strategies.

5.4 Asset Condition Data

Asset condition data is typically stored in a number of places including several independent databases. In order to maximize the lifetime value of existing assets the Company's Grid Modernization Plan under development will include an asset management system. This will enable an increase in asset effectiveness by consolidating multiple work and asset management solutions into a single platform and database.

5.5 Risk Assessment

The Company currently assesses risk and priority using a combination of the likelihood of event occurrence and the potential consequence to create a matrix of risk scores. These tools also consider multiple factors (e.g., economic, safety, reputation, reliability, environmental, etc.).

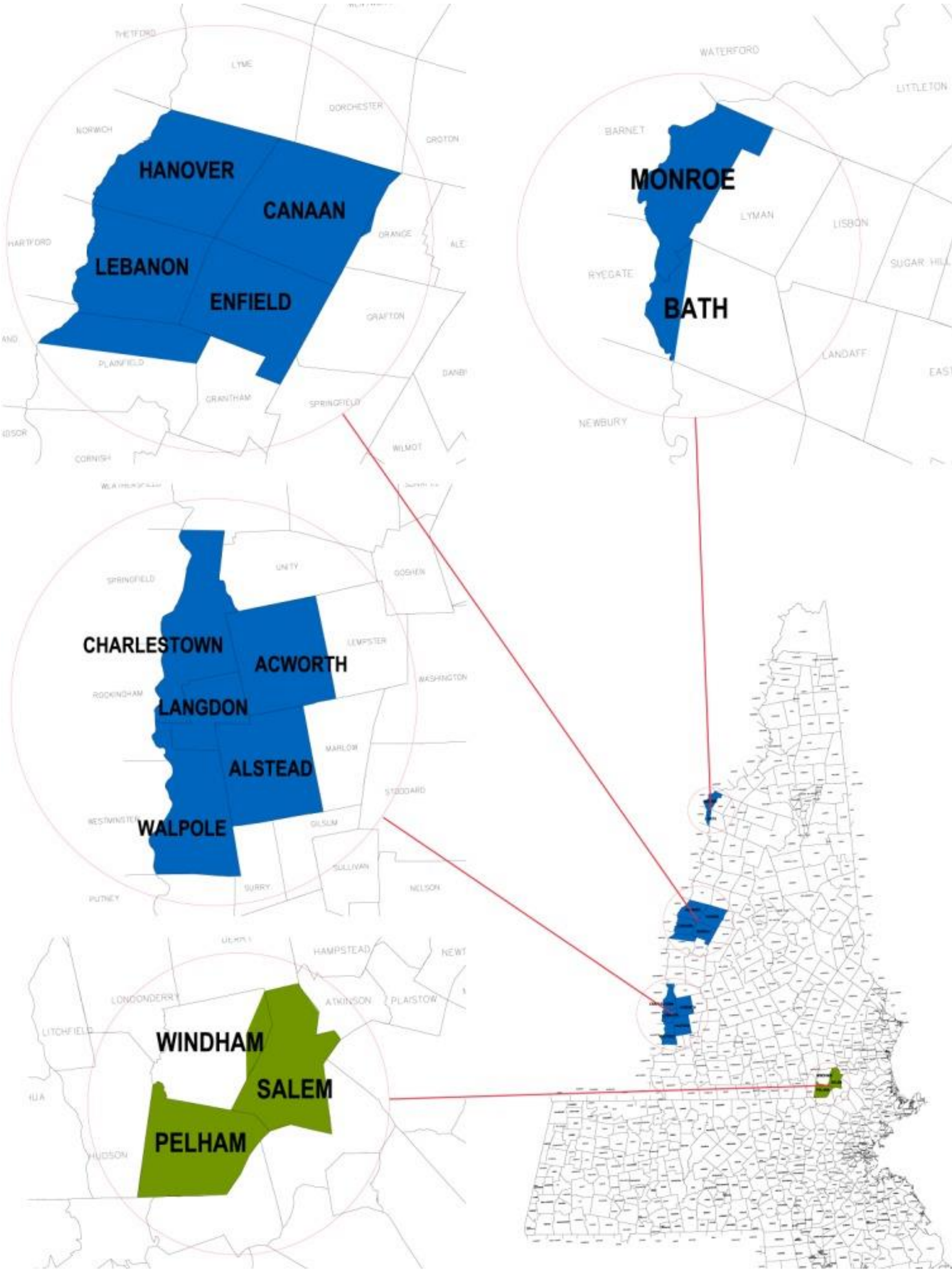
6.0 State of the System

6.1 Assets

Liberty NH distribution serves approximately 44,600 customers in 21 towns. A breakdown of assets is listed in the following table:

Liberty Utilities Electric Distribution/Subtransmission Line and Service Area Statistics	
Square Miles	740
Cities and Towns	21
Customers	44,600
Poles	38,000
Manholes	300
Distribution Feeders	40
Overhead Distribution Circuit Miles	905
Underground Distribution Circuit Miles	234
Distribution Transformers	9,360
Subtransmission Lines, <69kV	10
Overhead Substransmission Miles, <69kV	23
Underground Subtransmission Miles, <69kV	5
Substations	14
Power Transformers	13
Circuit Breakers	61
These numbers represent the approximate quantities (+/- 10%) of each item making up the subtransmission/distribution system in the Liberty NH service territory	

6.2 Service Territory Graphics



6.3 Load Data

The current mix of customers served by the system as a whole as calculated by percent of total energy delivered and customer count is estimated below:

Company	Residential		Commercial		Industrial	
	% KWH	% Customers	% KWH	% Customers	% KWH	% Customers
Liberty - NH	32.4	83.7	53.8	15.7	13.8	0.6

The coincident peak load data for the last two calendar years for summer is as follows:

Company	Summer 2019 (MW)	Summer 2020 (MW)
Liberty - NH	194	191

DAS-002 Distribution Automation (DA) Strategy
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Strategy Statement

The objectives for using distribution automation (DA) are to improve reliability performance and power quality, increase power system efficiency by automating processes for data preparation, optimal decision making and control of distribution operations.

This DA strategy will encompass distribution automation and also supervisory control and data acquisition (SCADA) of reclosers, fault locators, switches; the interface of DA enabled line devices with the substation feeder breaker along with communication of these devices back to central Operations centers and database warehouses; and other related issues.

Grid Modernization is an initiative that encompasses DA along with other issues such as load control, switched capacitor control and automated voltage profiling, and advanced metering infrastructure (AMI).

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
1	12/01/2019	Initial Issue	Anthony Strabone, Jeff Matthews, Kayle Scott, Kyle Slagle, Joel Rivera	Under Review

Strategy Justification

1.0 Purpose and Scope

The purposes for using distribution automation (DA) are to improve reliability performance, increase ease of operation, and to provide more and better data for optimal decision making and control of distribution operations. This strategy supports the reliability improvement objectives of the Company.

2.0 Strategy Description

2.1 Background

Distribution Automation (DA) has progressed in the industry to a level of maturity that provides confidence in equipment quality and availability sufficient to support a sustainable automation enhancement to the distribution system. In addition several competing forms of communication mediums, protocols, methods, etc. have now been vetted by the industry to a point that allows a reasonable understanding of their advantages and disadvantages.

Such as the use of various communication media including MDS licensed and unlicensed radio, CDMA digital cellular phone, 900 MHz licensed radio, and spread spectrum 900 MHz radio for team communication and reach back to our existing back haul communication back bone composed of fiber optic cable, microwave, and some leased line.

2.2 Coordination with Advanced Distribution Management System (ADMS)

With the implementation of Advanced Distribution Management System (ADMS) for the company, DA technologies such as Fault Location Isolation and Service Restoration (FLISR), Volt/VAR Control, Advanced Metering Systems (AMI), Intelligent Electronic Devices (IEDs) and others, best practices will be formulated to optimize the use of equipment for all of these initiatives.

2.3 What is encompassed by DA

This DA strategy encompasses distribution automation and supervisory control and data acquisition (SCADA) of reclosers, fault locators, switches; the interface of DA enabled feeder devices with the substation feeder breaker along with communication of these devices back to central Operations centers and database warehouses; and other related issues such as where to place the intelligence for DA, i.e. distributed or centralized.

3.0 Benefits

DA will allow for the system to automatically respond to interruptions faster than human intervention, either through manual or supervisory control, can accomplish. This improvement in responsiveness will allow the duration of customers impacted by a permanent interruption to be diminished. In addition DA will provide additional data beyond the substation which will help in monitoring system health in a more targeted fashion. Both faster response for system reconfiguration and additional data for further analysis will help in meeting reliability performance targets and power quality, thus contributing to a sustainable and resilient system.

3.1 Safety & Environmental

DA is expected to be benefit neutral relative to safety and environmental issues.

3.2 Reliability

3.2.1. Distribution

SAIFI improvements from DA result mainly from the ability to rapidly reroute power to line sections downstream of a fault so that these customers do not experience a permanent interruption, only a momentary interruption. SAIFI is expected to improve by 20% to 30%.

SAIDI improvements from DA result mainly from the ability to shorten outages by deploying field crews to outage repairs more quickly & efficiently due to 1) knowing where the problem is, 2) not needing these resources to restore power to downstream load blocks first via manual switching, and 3) faster restoration of the faulted load block after repairs are completed using remote switching. SAIDI is expected to improve by 10% to 20%.

3.3 Regulatory

Regulator's observations of the Company and their subsequent perception of it will significantly impact their actions relative to the Company. Regulators will form a more positive impression of the Company when they see it engaging in serious DA pilots that can improve reliability and customer service.

3.4 Customer

Customers want to see a more modern power system that can respond quicker to problems and isolate them to smaller portion of the system, thus further reducing customer impacts. To the extent they see the Company moving in this direction they will be encouraged. However, true customer satisfaction will not be achieved until results they can understand are demonstrated and explained to them as well as seen in their daily experience.

4.0 Estimated Costs

Estimated cost will vary considerably by distribution feeder. This is due to factors such as the number of tie points available, number of main line automated switches or reclosers needed to segment the load, and where the nearest uplink point for communication to Control Centers is relative to the devices. However, based on estimates for the current DA pilot an average cost per automated device which includes associated support infrastructure such as repeater radios and uplink points at substations has been developed. Also an average per distribution feeder has been developed. Deployment costs are expected to range between $200k and $300k or more per circuit.

average cost **per DA controlled location** =	total	$65,000
(includes cost of standard recloser)	material	$45,000
	labor	$3,000
	contingency	$11,000

	misc	$6,000
ave cost per **DA controlled fdr or ckt** =	total	$250,000
(includes cost of standard recloser)	material	$177,000
	labor	$11,000
	contingency	$40,000
	misc	$22,000

5.0 Implementation

While many of the DA applications apply to a broad range of systems, the distribution systems for each area may have different characteristics. This will require each area to develop and design its own DA system that brings positive value to their system. It is recommended that all new and large projects such as substations, feeders and expansions be evaluated by the Planning Departments for DA implementation.

In general DA is implemented incrementally rather than all at once. This allows each utility to develop its DA System at a rate that fits its resource capabilities and its financial constraints. At a conceptual level, the following table illustrates the suggested development process.

	Development Stage	Resources Committed	Timeline
1	Concept and Approach	Very small	Year 1
2	Small scale Test	Small	Year 2
3	Field Verification Test	Modest	Year 3
4	System Wide Deployment	Very large	Year 3 +

Applications related to distribution automation are listed by application area in the table below. Within each area, the applications have been sorted in approximate stage of development, with the first application.

Application Area	Benefits	Applications
SCADA Applications	RTU, Detailed monitoring, Fault Location. Improves fault response and repair times	Substation SCADA, Feeder SCADA, Volt/Var SCADA
Advanced monitoring applications	Intelligent electronic devices (IEDs): relays, reclosers, capacitor controls, fault location, equipment diagnostics, sensors	Integration of data into common database platform. Fault Location, power quality identification, equipment diagnostics, asset management

Automatic system reconfiguration	Improved efficiency, reduced losses, prevent overloading, etc.	Automated switching for isolating faults during contingency, Automated switching for dynamic reconfiguration
Volt/Var Control and PQ Systems	Monitoring and control of cap banks and regulators for improved voltage control and minimize losses.	Remote switching of capacitors, regulators and load tap changers. Coordination with VAR compensation from DG.
AMI	Demand Response, load control systems, CIS, voltage reduction	Voltage reduction based on sensors, cap banks, regulators, customer facilities
Integration of DER	DG and storage	

6.0 Selection of feeders / circuits for application of DA

The selection and prioritization of feeders for application of DA is based on reliability performance and the feasibility of implementing DA at a given location. After addressing poor performing circuits, circuits performing acceptably but with high risk of failure may be targeted. For example, risk of failure due to deteriorated equipment, risk due to lightning, risk from tree exposure and pockets of poor performance may be targeted.

The following table lists the candidates in NH for implementation of DA and shows expected year of installation, estimated costs and study area:

DA Candidates	Area	Estimate	Year
16L1 - 6L3 Goodfellow Rd	Lebanon	$1,200,000	2023
7L1 - 7L2 Lockehaven Rd	Lebanon	$1,400,000	2024
16L1 - 16L3 Rt 120	Lebanon	$225,000	2022
16L2 - 16L5 Mt Support Rd	Lebanon	$225,000	2022
6L2 - 16L5 College St	Lebanon	$150,000	2025
11L1 - 11L2 S Main St	Lebanon	$225,000	2024
11L2 -39L2 S Main St	Lebanon	$225,000	2024
39L1 - 39L2 Airport Swgr	Lebanon	$125,000	2024
1L1 APD Swgr	Lebanon	$200,000	2025
16L1 -16L5 - 1L3 DA	Lebanon	$50,000	2021
12L1 - 12L2 Rt 12	Bellows Falls	$225,000	2022
12L1 - 40L3 Rt 12	Bellows Falls	$170,000	2022
40L1 - 40L3 Sullivan St	Bellows Falls	$150,000	2022
9L3 - 13L2 Range Rd	Salem	$25,000	2023
14L4 - 18L4 DA	Salem	$25,000	2023
21L4 New Feeder	Salem	$550,000	2025

13L1 - 19L4 DA	Salem	$200,000	2024
13L3 - 18L2 DA	Salem	$75,000	2023
13L3 - 19L6 DA	Salem	$150,000	2022
14L2 - 14L3 DA	Salem	$25,000	2023
14L5 New Feeder	Salem	$1,300,000	2025
19L8 - 13L3 DA	Salem	$225,000	2022
1L2-1L3 Rt 120 Tie	Lebanon	$1,400,000	2025

7.0 Risk Assessment

7.1 Changing Technology

Development of automation technologies is fluid. While benefit can be derived now and equipment is expected to be usable without risk of stranding costs, it is expected that adjustments will be made to this strategy over time to take advantage of new opportunities as they mature. For this reason this strategy should be reviewed periodically.

7.2 Regulatory

Maintaining a favorable relationship with state regulators is important to the Company's future success. Poor performance as measured by state reliability goals and customer complaints to the regulator stresses this relationship and results in reduced credibility. Creating a process for DA use on a program basis can help improve perception.

7.3 Customer

Poor reliability performance will result in diminished customer satisfaction. This diminished satisfaction impacts the Company's reputation through negative press, word of mouth between customers, and increased complaints to the regulator. Unsatisfied customers are less likely to cooperate with Company plans. A satisfied customer is less vocal during routine interruptions and this can prevent a negative climate from forming around politicians, regulators, news media, and fellow customers.

8.0 Data Requirements

The intelligent electronic devices (IED) and communication systems required for DA will provide a wealth of new data. This information will be used first by system operators for decision making during events. Secondly the data will be used by planning engineers analyzing the system to optimize its performance and economics. To do this the data available from DA enabled devices needs to be brought into control centers in a fashion that will not overload operators with too much data but allow them to quickly grasp what is happening and what actions they should be taking. The data must also be stored in a data warehouse for general use after the fact. To maximize the use of the vast amount of new data which will be available, a system or process for its storage and maintenance should be evaluated by IT departments.

8.1 Existing/Interim/Proposed:

8.1.1. DA Generated Data

Existing data is obtained from EMS at the substation level and controlled devices at the distribution level. The information is used by Operators and some of it is stored in the OMS system and PI for future use and analysis. In the future, storage of data will be handled by a parallel ADMS system.

9.0 References

Smart Grid and Advanced Distribution Automation, Richard F. Day, November 2013
Value of Distribution Automation Applications, Energy and Environmental Economics, Inc., EPRI Solutions, Inc, April 2007
Distribution Management Systems Planning Guide, Electric Power Research Institute, B. Deaver, March 2013
Guidelines for Implementing Advanced Distribution Management Systems, Jianhui Wang, Xiaonan Lu and Chen Chen, August 2015

DAS-003 Distribution Line Capacitors
Asset Management Strategy

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Strategy Statement

Currently, the asset condition of distribution line capacitors does not, in general, significantly impact the company's performance from safety, environmental, reliability and regulatory standpoints. Identification of capacitor plant requiring maintenance or replacement should be made through the annual capacitor inspection and the overhead inspection and maintenance program. Recommendations for installation of new capacitors and/or removal of existing capacitor plant should be made as a result of planning studies performed by the Electric System Planning department.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	6/19/2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager – Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Brian Hayduk Distribution Field Engineering	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

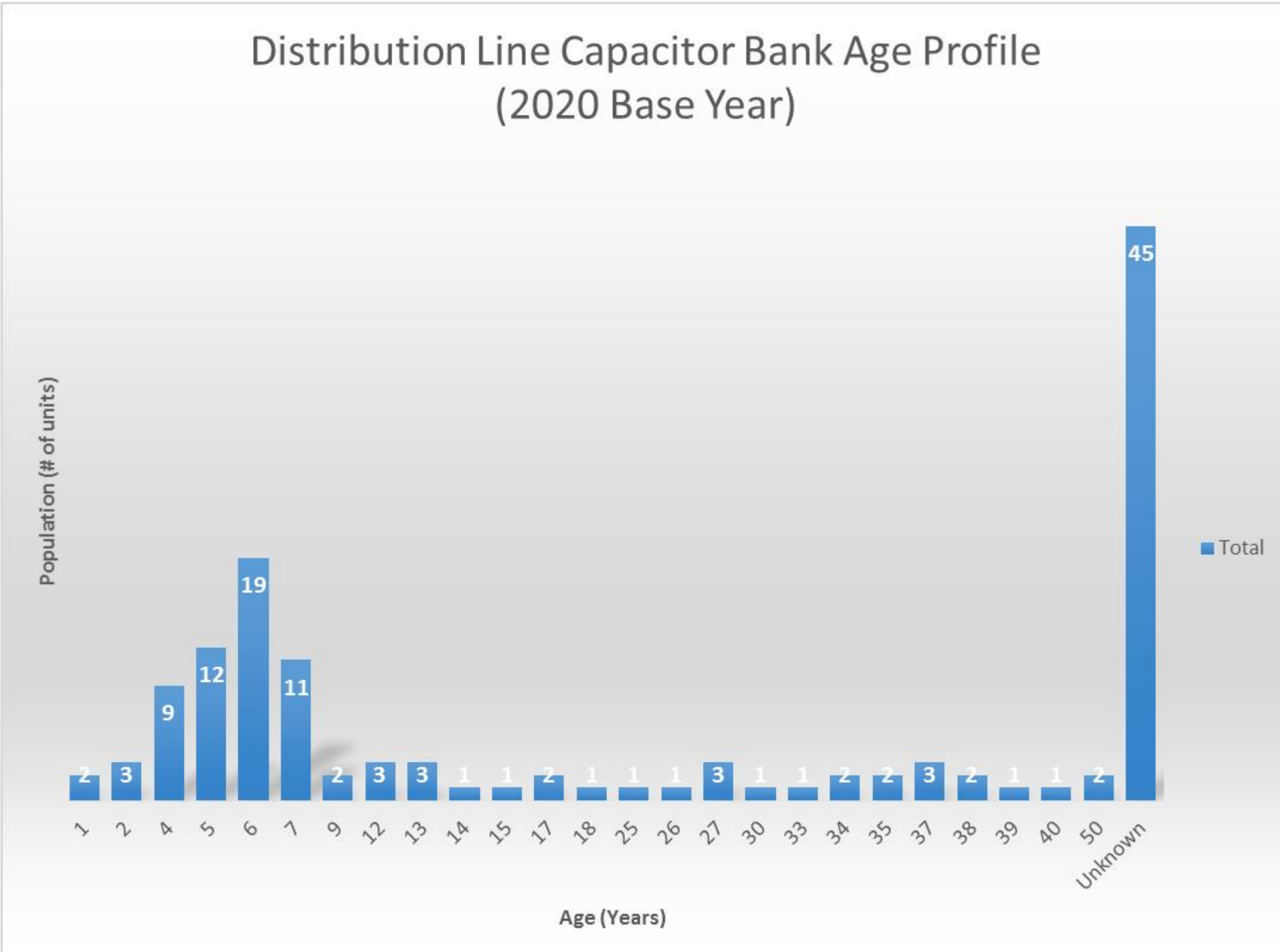
1.0 Purpose and Scope

This policy sets forth the asset management philosophy for distribution line capacitors with the intent of maximizing system performance while minimizing safety, environmental, reliability and regulatory impacts to the company.

2.0 Strategy Description

2.1 Background

Based on data obtained from the ArcFM GIS system including the year each capacitor bank was installed, 84% of the distribution capacitor plant in New Hampshire is under 30 years of age, with the average age being approximately 13 years. Age data for 45 Capacitor Banks could not be readily obtained. The total number of distribution line capacitor bank installations in New Hampshire is approximately 134; providing 110,500 kVAr of reactive power. The age profile for distribution line capacitors across the system is shown in the graphs below in both population by age and percent of total population.


Distribution Line Capacitor Bank Age Profile
(2020 Base Year)
Population (# of units)
Age (Years)
Total
2
3
9
12
19
11
2
3
3
1
1
2
1
1
1
3
1
1
2
2
3
2
1
1
2
45
1
2
4
5
6
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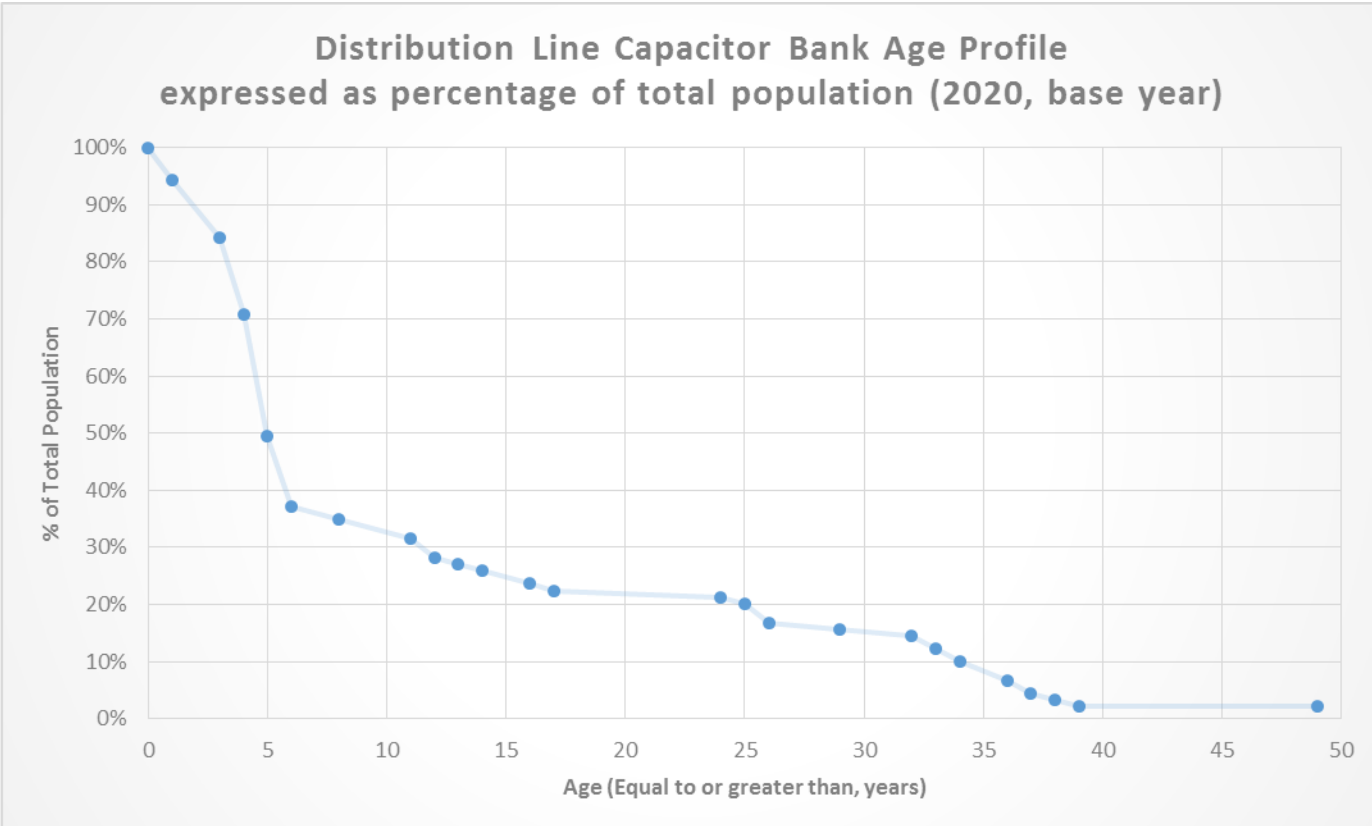


The relatively large population of units installed beginning seven years ago to present is due to the effort to bring power factor at its delivery points into compliance with NEPOOL Operating Procedures.

Accurate determination of capacitor bank age is somewhat difficult to ascertain due to the manner in which banks are assembled and maintained; they are made up of a number of smaller components—individual capacitor units, switches, racks, junction boxes, controls, etc—which are replaced as needed. It is not uncommon for a capacitor bank to be removed from service for maintenance and subsequently re-installed at a different location, the result of which is that a used capacitor bank is given a new installation date in the GIS system. Additionally, a small number of “new” capacitor banks are assembled using components which were removed from previously in-service banks. In these ways it is difficult to accurately determine the age of a given capacitor bank, and ultimately to use age as an indicator for bank replacement.

New capacitor banks have typically been installed to compensate for additional reactive demand attributed to load growth on the distribution system or to satisfy new reactive demand requirements from circuit reconfigurations.

2.2 Strategy

The operability and general condition of distribution line capacitors will be evaluated and maintenance performed when needed as part of the annual capacitor inspection program as well as a formal Overhead Inspection and Maintenance Program. In some cases where maintenance cannot practically be performed in the field, the entire bank will be replaced.

Recommendations for new banks or modifications to existing will be determined from reactive compensation reviews conducted as part of capacity planning studies performed by the electric system planning department.

3.0 Benefits

Benefit of this distribution line capacitor strategy is that asset utilization will be maximized by maintaining banks in service until such point that replacement is required as identified through visual and operational inspection or testing, recognizing that these assets have minimal overall impact to the company in terms of safety, environmental, reliability and regulatory performance.

3.1 Safety & Environmental

There is currently minimal impact related to safety and environmental drivers attributed to distribution line capacitor failures. The total population of capacitor banks is significantly smaller than other types of equipment—such as distribution transformers for example—and the volume of dielectric fluid contained in these units is small.

3.2 Reliability

Distribution line capacitors represent a relatively minor potential reliability impact to the company. The total population of capacitor banks is significantly smaller than other types of equipment—such as distribution transformers for example—and failure or misoperation of a bank typically results in blowing of one or more of its protective fuses which isolate it from the feeder.

3.3 Regulatory

Capacitors are used to maintain system voltages and correct power factor to levels within mandated ranges. This strategy requires that feeder voltage and reactive compensation studies be performed to identify areas where more/less reactive support is needed.

3.4 Customer

Voltage rise due to capacitor switching and steady-state system voltage are taken into account when capacity planning studies are performed as specified in this strategy to ensure that they are within acceptable ranges.

4.0 Estimated Costs

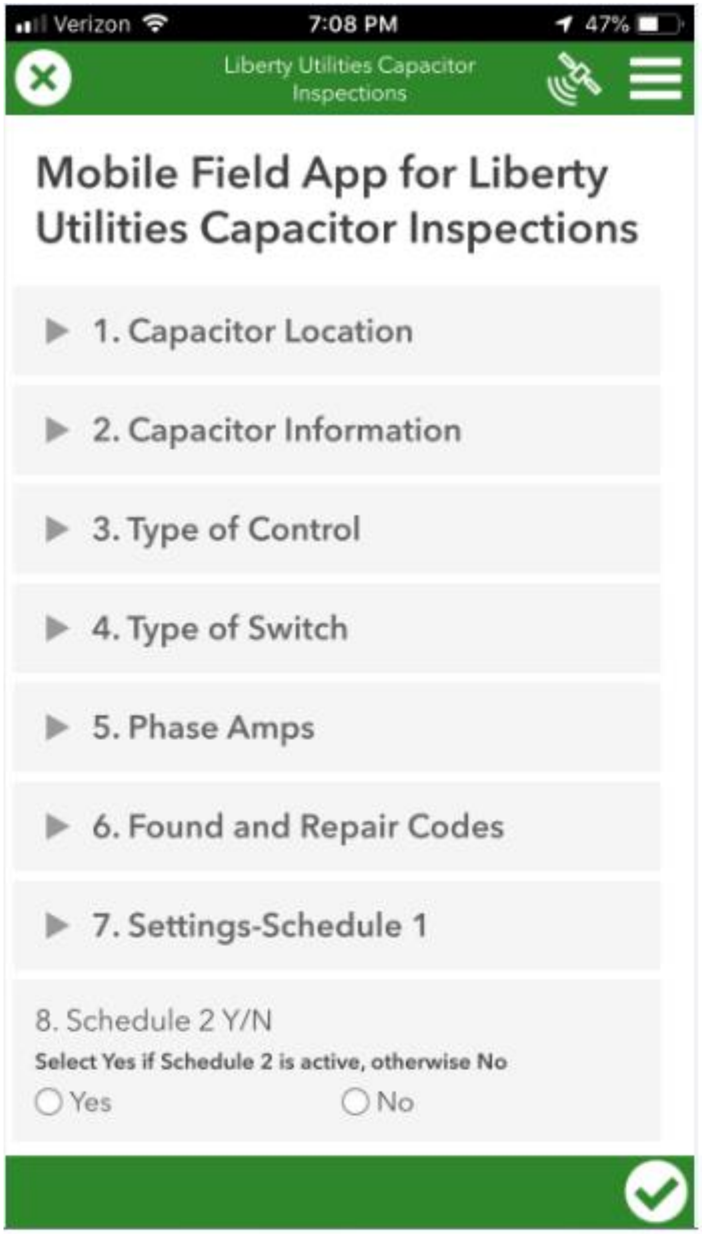
The installed cost (2020 dollars) for a complete distribution line capacitor bank is approximately $15,000. Maintenance costs associated with replacement of controls, vacuum switches, or individual capacitor units range from approximately $1,500 to $5,000 per bank. The following allocations to the transformer/capacitor blankets are estimated and are associated with distribution line capacitor maintenance and installation as well as compensation for additional reactive demand and losses associated with annual system load growth:

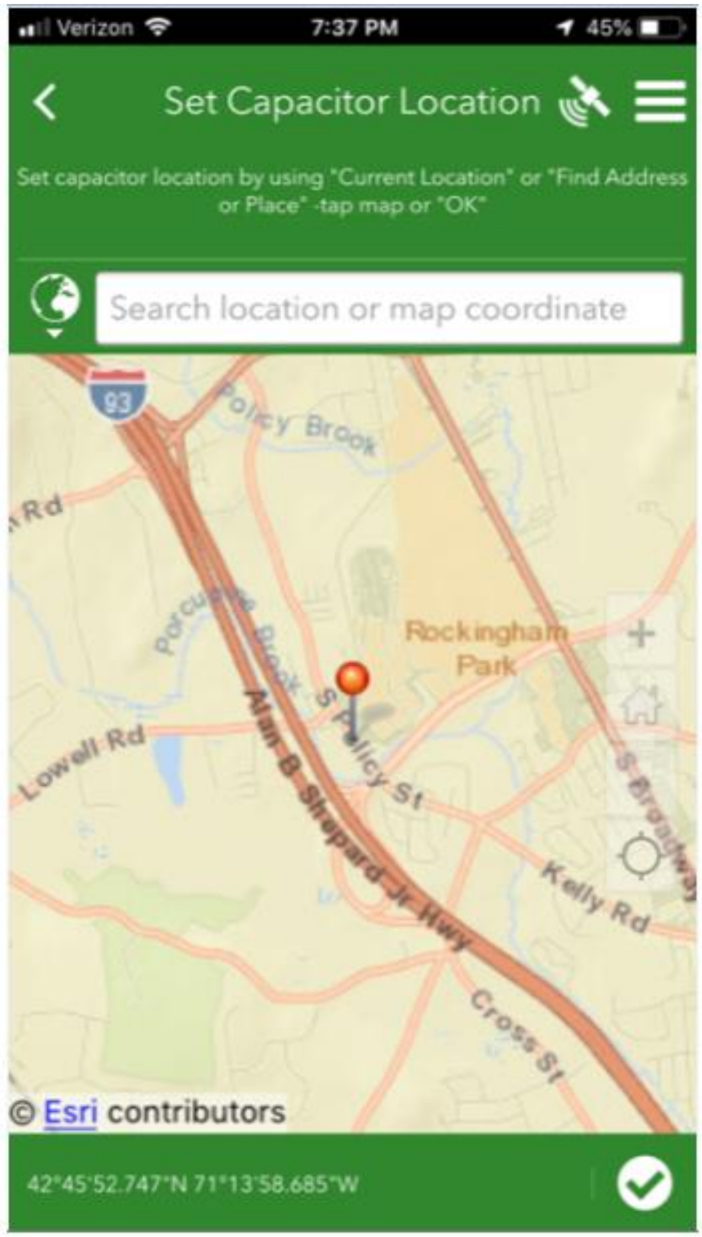
	CAPITAL	O&M	REMOVAL	TOTAL
Existing banks—Inspection & Maintenance	$75,000	$8,000	$8,000	$91,000

New banks—Load Growth	45,000	5,000	5,000	55,000
TOTAL	$120,000	$13,000	$13,000	$146,000

5.0 Implementation

- Inspection of distribution line capacitors by local Divisional Operations personnel will be performed per the applicable Standard.
- Recommendations for new capacitor banks as a result of under-compensated existing load or load growth will be made as a result of reactive compensation reviews conducted within System Planning Studies. This analysis is typically performed on an annual basis.
- Results from the inspections will be captured using ESRI Survey 123 mobile application —which facilitates capacitor inspections, reporting of capacitor bank locations/properties by feeder, and also is structured to accept all available setting parameters used in our standard capacitor control unit. See sample below of the ESRI Survey 123 mobile application:





6.0 Risk Assessment

Primary drivers of this strategy are to mitigate risks associated with customer and regulatory impact attributed to power quality by ensuring that adequate reactive support exists on our distribution feeders to maintain acceptable system voltage. Routine inspection and maintenance will ensure existing capacitor plant is in good working order and recurring studies will recommend adjustments to existing capacitor plant based on dynamic system requirements.

7.0 Data Requirements

7.1 Existing:

- ArcFM/GIS
- Capacitor database
- Oasis Historian
- ESRI Survey 123

7.2 Proposed:

- Same

8. References

- EOP D-004 – "Distribution Line Patrol and Maintenance"
- Liberty Utilities Distribution Construction Standards CS2860 – "Field Inspection and Testing of Capacitors"
- Liberty-NH Distribution Asset Manager's Notebook, DAM-007 – "Reactive Compensation for Distribution Systems" (Under Development)
- NEPOOL Operating Procedure 17 – "Load Power Factor (OP17)"

DAS-004 Distribution Line Step-Down Transformers Asset Management Strategy

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Strategy Statement

Currently, the performance of distribution line step-down transformers does not represent a major impact to the company's performance from, safety, environmental, reliability, or regulatory standpoints, although potential significant risk does exist if this asset class is not maintained. To ensure the continued level of performance and sustainable network, a proactive load-based replacement program for these assets beyond what is already being performed during new customer service investigations and system improvement projects is recommended at this time. In addition, the condition of these assets will be evaluated and replaced as needed as part of the formal Overhead Inspection and Maintenance Programs.

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
2	06/19/2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Brian Hayduk Distribution Field Engineering	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This policy sets forth the asset management philosophy for distribution line step-down transformers with the intent of maximizing asset performance while maintaining existing performance in the way of safety, environmental, reliability and regulatory impacts to the company.

2.0 Strategy Description

2.1 Background

In general, conditions of distribution line step-down transformers are evaluated and replaced as needed as part of the formal Overhead Inspection and Maintenance Programs. Typically, no maintenance is performed on these assets as their per-unit cost is relatively small. Historically each Division takes spot load field readings in an attempt to identify overloaded distribution line step-down transformers. Upgrades are performed based on available funds, however funds are typically not dedicated for step-down transformer replacement, therefore the ability of operations to replace overloaded units varies by Division and by year. The impact of distribution step-down transformer failures on overall system reliability has historically been small.

Maximum allowable loading for step-down transformers is specified in the current Distribution Construction Standard. Currently, no source for step-down transformer load data exists. Load readings at each step-down are taken manually during heavy loading periods (summer) by field personnel. In some cases, resource constraints result in readings not being taken at all, or only on a portion of the population. As a result of the inconsistent practices, we do not have good data to quantify the total number of overloaded step-down transformers.

2.2 Strategy

Using GIS data and customer demand information from the CIS system, modeling software can be used to estimate peak loading for each step-down transformer. Based on the output of this analysis, the number and magnitude of potential overloaded step-down transformers can be estimated. Replacement can then be prioritized based on magnitude of overload, and field load readings taken to verify the calculations. Upgrade of overloaded units/banks will be made to bring loading to levels below the limit specified in the Construction Standards. In cases where larger step-down transformers are overloaded (167 kVA and 250 kVA units/banks), partial or complete conversion to the higher voltage may be required. Primary voltage conversion is not within the scope of this strategy as the quantity and magnitude of this type of work cannot be quantified with the limited data available at this time.

The general condition of distribution line step-down transformers will be evaluated as part of the formal Overhead Inspection and Maintenance Programs. Replacements will be made as determined by these inspections when they are found to be in sub-standard condition.

There are approximately 80 step-down transformers in the system of which 96% of them are single phase installations. Date of installation is mostly not available as this information has not been documented in the GIS. It is estimated that 3 step-down transformers will have to be installed annually including those due to damage/failure, upgrade due to overload and new installations typically associated with feeder voltage conversions.

3.0 Benefits

Benefit of this distribution line step-down transformer strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through loading reviews or visual and operational inspection, recognizing that transformer life expectancy is predominantly affected by loading and environmental factors rather than age. Implementation of this strategy will ensure the sustainability of this asset class over time and maintain its relatively minor impact on overall system reliability.

3.1 Safety and Environmental

There is currently minimal impact related to safety and environmental drivers attributed to distribution line step-down transformer failures. This strategy will minimize instances where dielectric fluid releases occur as a result of step-down transformer failure due to overload or poor condition.

3.2 Reliability

The impact of distribution line step-down transformer failures on overall system reliability has historically been small. This strategy will ensure that the reliability performance of this asset class is maintained over time.

3.3 Regulatory

There is minimal impact related to regulatory drivers attributed to distribution line step-down transformer failures.

3.4 Customer

There is minimal impact related to customer drivers attributed to distribution line step-down transformer failures.

4.0 Estimated Costs

After performing visual inspections and measuring load on Step-Down Transformers in July of 2020, the following issues were identified:

- The 6L2 Maple St 167 kVA Step-Down Transformer was found to be overloaded mainly due to phase imbalance. In 2021, it is recommended to perform phase balance in the area to maintain the step-down transformer within ratings.
- The 1L2 Shaker Blvd 100 kVA Step-Down Transformer was identified in need of replacement due to deterioration. In 2020, this transformer will be replaced with a 167 kVA transformer.
- The 6L3 Hemlock Rd 167 kVA Step-Down Transformer was identified in need of replacement due to deterioration. In 2021, this transformer will be replaced.
- The 39L2 Trues Brook Rd 167 kVA Step-Down Transformer was identified in need of replacement due to deterioration. In 2021, this transformer will be replaced.

The installed cost for a complete distribution line step-down transformer ranges from approximately $3,000 to $8,000 per unit/bank. The following allocation to the transformer/capacitor blankets and associated specific funding projects on an annual basis related to distribution line step-down transformer installation is:

	CAPITAL	O&M	REMOVAL	TOTAL
Distribution Line step-down transformers	$15,000	$0	$1,500	$16,500

5.0 Implementation

- Perform load analysis using modeling software which calculates peak loading for each step-down transformer.
- Conduct annual loading reviews of distribution line step-down transformers and replace per the applicable Standard.
- Continue to review step-down transformer loading during investigations for voltage complaints, new customer service and system improvement projects.
- Visually inspect distribution line step-down transformers and replace per the applicable Standard as part of the Overhead Inspection Program.

6.0 Risk Assessment

Primary impact of this strategy is to maintain current risk profile associated with safety/environmental and reliability drivers. There is potentially intermediate risk related to the aforementioned factors if this strategy is not implemented resulting from distribution line step-down transformer failures due to the proximity to the general public, sensitive environmental areas and the relatively large number of customers these units serve on the distribution system.

7.0 Data Requirements

7.1 Existing/Interim:

- ArcFM/GIS
- Synergi Electric

7.2 Proposed:

- ArcGIS Desktop
- Synergi Electric

8.0 References

- Liberty Distribution Construction Standard, 14.8.10 – “Phasing Transformers; Step-Down/Ratio Banks”
- Liberty Electric Operating Procedure, LU-USA EOP D004 – “Distribution Line Patrol and Maintenance”

DAS-005 Distribution Line Voltage Regulators Asset Management Strategy

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Strategy Statement

Currently, the asset condition of distribution line voltage regulators does not, in general, significantly impact the company's performance from safety, environmental, reliability and regulatory standpoints. Identification of voltage regulator plant requiring maintenance or replacement should be made through regular inspections. Recommendations for installation of new voltage regulators and/or removal of existing voltage regulator plant should be made as a result of feeder voltage and capacity studies performed by the Electric System Planning Department.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	6/19/19	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Brian Hayduk Distribution Field Engineering	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

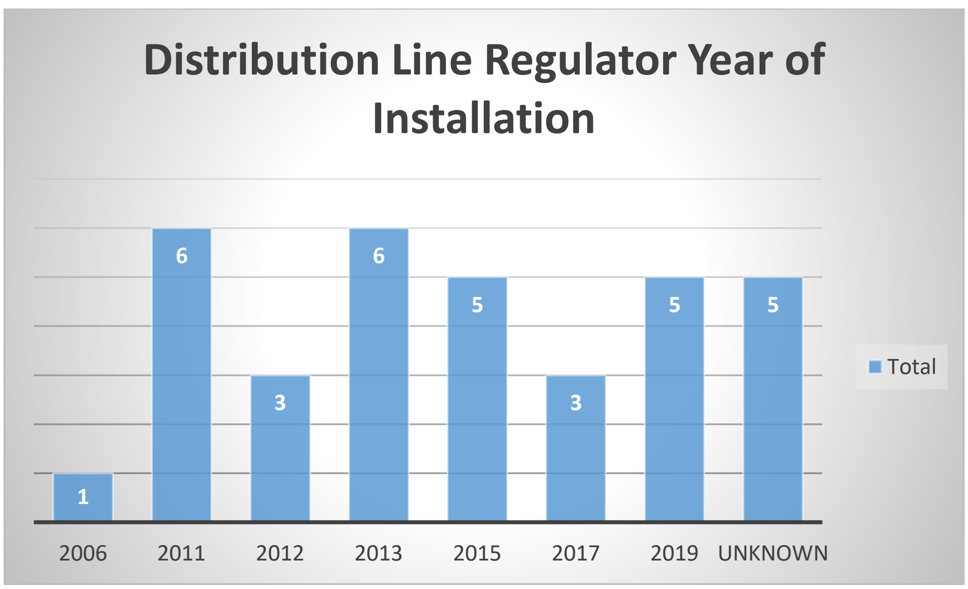
This policy sets forth the asset management philosophy for distribution line voltage regulators with the intent of maximizing system performance while minimizing safety, environmental, reliability and regulatory impacts to the company.

2.0 Strategy Description

2.1 Background

In general, conditions of distribution line voltage regulators are evaluated and maintenance performed if needed as part of a recurring voltage regulator inspection program as well as a formal Overhead Inspection and Maintenance Program. Recommendations for new units, modification to or removal of existing are made as a result of feeder voltage or capacity studies conducted by the Electric System Planning department. There are a total of 38 line regulators installed in the system.

Based on data obtained from the ArcFM GIS system including the year each voltage regulator was installed, the distribution voltage regulator plant in the system is under 15 years of age, making this a very young asset group. The age profile for distribution voltage regulators across the system is shown in the graphs below in population by year installed.



From this graph it is apparent that the total population of voltage regulators—approximately 38 units in total—is significantly smaller than other types of equipment, and therefore represents a relatively minor potential reliability and environmental impact to the company.

2.2 Strategy

The operability and general condition of distribution line regulators will be evaluated and maintenance performed when needed as part of equipment inspection and testing as well as a formal Overhead Inspection and Maintenance Program.

Recommendations for new regulators or modifications to existing will be determined from loading and voltage reviews conducted as part of annual capacity planning studies performed by the Electric System Planning department. Historically New Hampshire has elected to use capacitors instead of regulators to support voltage on the distribution system.

3.0 Benefits

Benefit of this distribution line voltage regulator strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through visual and operational inspection or testing, recognizing that the population of these assets is small and have minimal overall impact to the company in terms of safety, environmental, reliability and regulatory performance.

3.1 Safety & Environmental

There is currently minimal impact related to safety and environmental drivers attributed to distribution line voltage regulator failures.

3.2 Reliability

There is currently minimal reliability related impact attributed to distribution line voltage regulator failures. Equipment age is a less a determinant of a voltage regulator's condition as compared with number of operations and electrical loading. This strategy requires regular inspections and capacity studies to identify units requiring preventative maintenance and/or needing replacement.

3.3 Regulatory

Line voltage regulators are installed in cases where the use of feeder regulators or LTC's located at the substation along with line capacitors cannot maintain voltage across the feeder within mandated ranges. This strategy requires recurring feeder voltage and capacity studies be performed to identify areas where installation, removal or modification of line voltage regulators is needed.

3.4 Customer

Service voltage impacting customers across an entire distribution feeder is reviewed when a feeder voltage study is performed to ensure that it is within acceptable ranges.

4.0 Estimated Costs

The installed cost for a complete distribution line voltage regulator bank is approximately $50,000. Maintenance costs associated with replacement of existing controls or voltage regulator units range from approximately $5,000 to $12,000 per unit. Issues with line regulators will be handled in a timely manner so that delivery voltages are maintained within allowable range.

5.0 Implementation

- Visual and Operational as well as Diagnostic inspections of distribution line voltage regulators are performed by per the applicable Standard.
- Visual inspection of distribution line voltage regulators as part of the overall Overhead Inspection Program is performed per the applicable Standard.
- Feeder voltage and capacity studies are performed on a recurring basis by the Electric System Planning department.

6.0 Risk Assessment

Primary drivers of this strategy are to mitigate risks associated with customer and regulatory drivers attributed to power quality by ensuring that adequate voltage support exists on our distribution feeders to maintain acceptable system voltage across our feeders. Routine inspection and maintenance will ensure existing voltage regulator plant is in good working order and recurring studies will recommend adjustments to existing voltage regulator plant based on dynamic system requirements.

7.0 Data Requirements

7.1 Existing/Interim:

- ArcFM/GIS
- Oasis/SCADA

7.2 Proposed:

- Same

8.0 References

- Liberty Electric Operating Procedure, LU-USA EOP D004 – “Distribution Line Patrol and Maintenance”
- Liberty Substation Maintenance Procedure, SMP 404.01.2 – “Step Voltage Regulator”

DAS-006 Distribution Line Transformer Strategy

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Strategy Statement

Currently, the performance of distribution line transformers does not represent a major impact to the company's performance from, safety, environmental, reliability, or customer standpoints. To ensure this continued level of performance and a sustainable network, a proactive load-based replacement program for these assets beyond what is already being performed during customer service upgrades and system improvement projects is recommended. In addition, the condition of these assets will be evaluated and replaced as needed as part of the formal Overhead and Underground Inspection and Maintenance Programs.

The total population of distribution transformers consists of approximately 9,520 installations with an average age of 27 years (Figure 1). Loading in excess of levels recommended within the Liberty Utilities Standards accounts for the majority of transformer upgrades. Heavily loaded transformers account for approximately 16% (1,534) of the total population based on load information contained within the CIS (Figure 2). Heavily loaded transformers are considered to be loaded to 140% or above their nameplate value. Typically, approximately 0.22% of inspected transformers require replacement due to condition. Applying this percentage across the total population yields a total of 20 installations which require replacement due to condition.

The recommended approach is to reduce this excess loading situation over a 15 year period. Based on the installations identified by the loading review (Figure 2) and factoring in 1% load growth during the program period, approximately 1,650 installations (~ 17% of population) are potentially loaded in excess of the loading guidelines documented in the Construction Standards.

A factor of 0.6 is being applied to the budgetary estimates for transformer replacements. This factor is based on a review of the overloaded transformer investigations which indicates that approximately 40% of the installations are "administrative overloads". These "administrative overloads" are related to incorrect load estimates, incorrect transformer sizes, and/or incorrect customer connections within the GIS (customer connected to the wrong transformer). The Engineering department will evaluate all transformers on the overload list with the expectation that only about 60% of the investigated installations will require replacement.

Based on a 15 year program, 50 installations need to be replaced annually. This includes the annual contribution from the Inspection Program. The following estimated allocation to the transformer blankets and associated specific funding projects on an annual basis for the 15 year program is:

Load Related Replacements	$75,000
Condition Based Replacements	$1,500
Total Annual Program Cost	$76,500

The following performance targets will to be used to measure the successful implementation of this strategy:

- Completing the replacement of identified installations as part of each program year
- Reduction in number of overloaded transformers as reported from the CIS over the 15 year program

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
3	6/19/2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Plannin	Charles Rodrigues Director of Engineering
2	12/20/2008	Added age profile graphic and updated loading graphics Added Section 2.2 Inspection Results Updated Sections 3.0 and 6.0 (Benefits and Risk Assessment) to align with Strategic Business Plan objectives Updated Section 4.0 (Estimated Costs) Added Section 5.1 (Performance Targets) Added State specific sections to address age profile and estimated costs by state	Jeffrey H. Smith Distribution Asset Strategy	John Pettigrew Executive Vice President, Electric Distribution Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Brian Hayduk Distribution Field Engineering	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This policy sets forth the asset management philosophy for distribution line transformers with the intent of maximizing asset performance while maintaining existing performance in the way of safety, environmental, reliability and regulatory impacts to the company. This strategy does not cover stepup/down (ratio) transformers installed on the distribution system.

2.0 Strategy Description

2.1 Background

The total population of distribution transformers consists of approximately 9,520 installations. Transformer unit age data is available, with some gaps and data inconsistencies, and an install date profile is shown in Figure 1. The average transformer age is 27 years, based on units with date information (94% of the population).

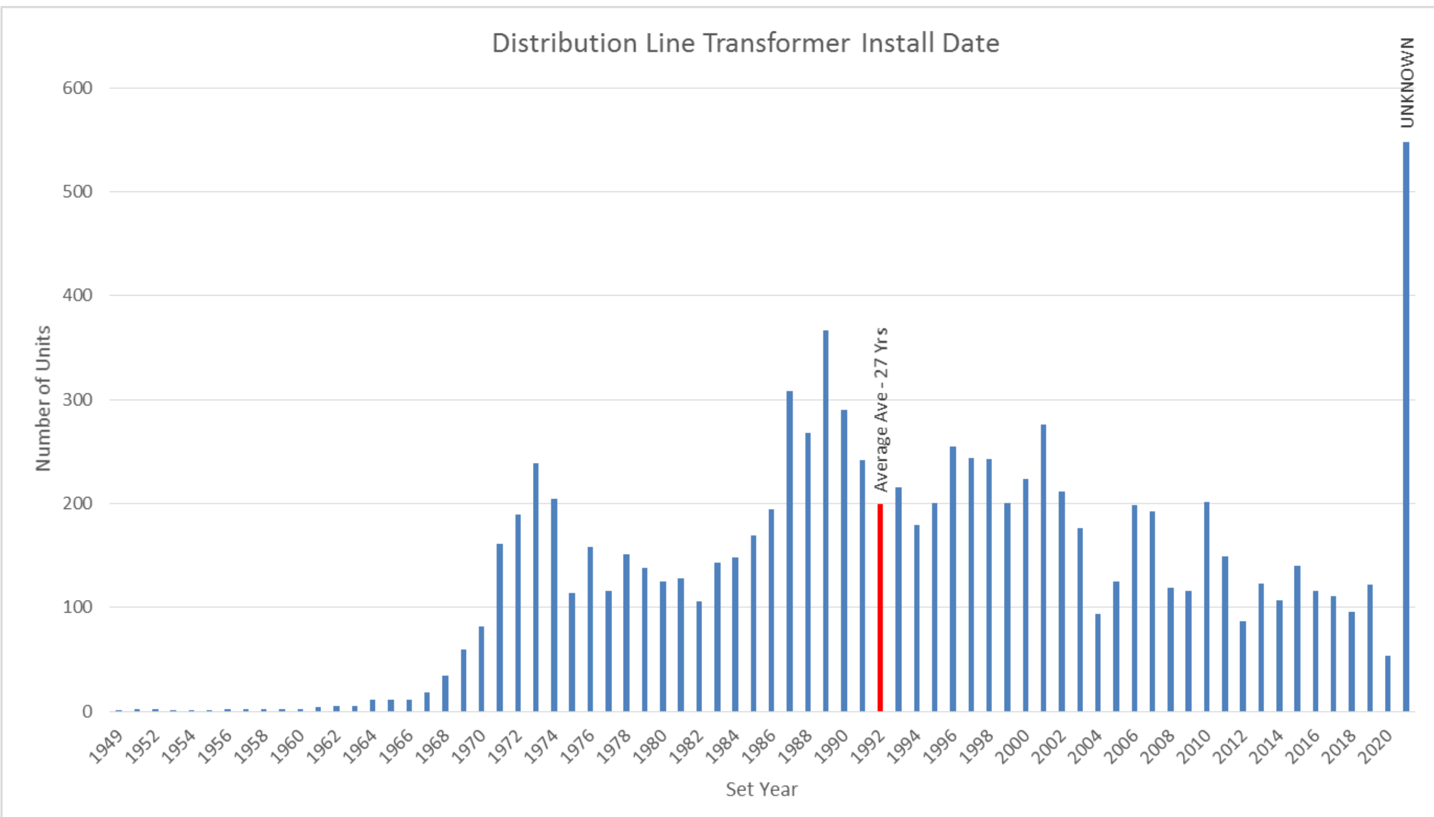

Figure 1

Maximum allowable loading is specified in the Distribution Construction Standards and varies based on type (conventional overhead, padmounted) and configuration (single phase, poly phase, etc). Diversified peak load data for each installation is calculated based on an algorithm which converts kWh energy to demand, or actual peak demand if metered. This diversified peak load data is stored in the GIS for each transformer installation and has been used to create the composite loading distribution for all transformer types in Figure 2.

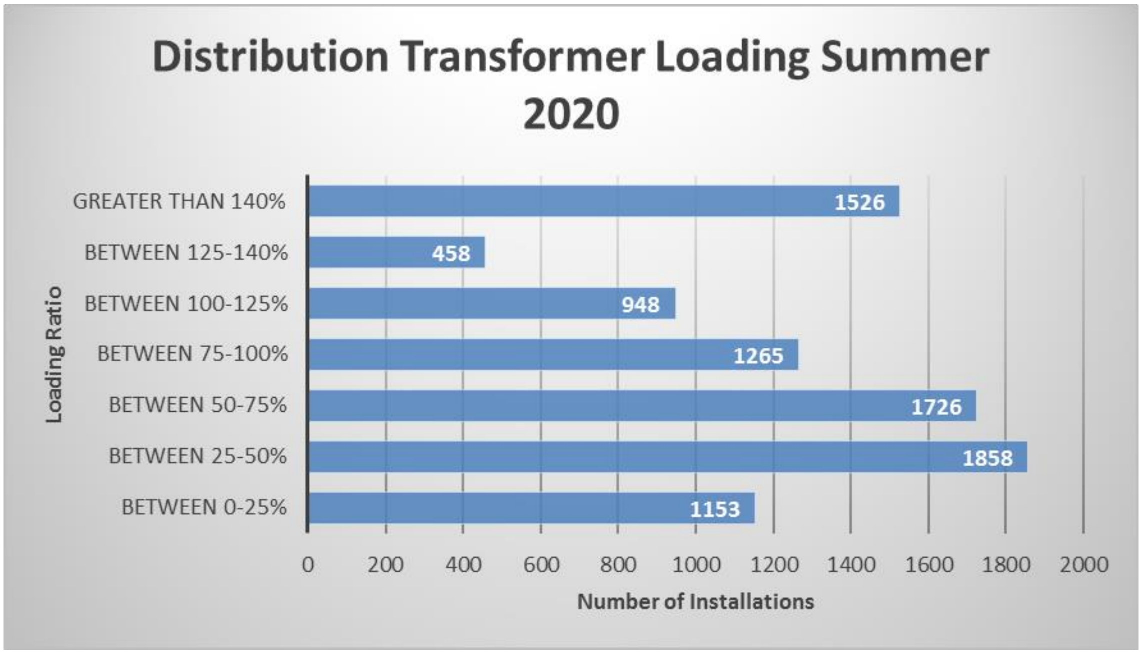

Figure 2

Loading in excess of levels recommended within the Liberty Standards accounts for the majority of transformer upgrades. Heavily loaded transformers account for approximately 16% of the total population based on load information contained within the CIS. Out of the 1,534 heavily loaded transformers, 1,286 are single phase overhead units. .

The average age of heavily loaded transformers is 31 years with an average install year of 1989 based on units with date installation (97% of heavily loaded units). These peak years are consistent with peak installation years as shown in Figure 1.

There are data issues associated with accurately calculating transformer loading. Some transformer installations have obvious data issues with most caused by a lack of load data. These issues are mainly related to correctly linking customer loads to transformers. These errors are most prevalent in areas with underground services or a mix of both underground and overhead services.

The impact of distribution transformer failures on overall system reliability has historically been small; representing less than two minutes on system SAIDI and 0.01 on system SAIFI annually.

2.2 Inspection Results

The condition of distribution line transformers is evaluated as part of the Overhead (EOP D004) and Underground (EOP UG006) Inspection and Maintenance Programs. Typically, no maintenance is performed on these assets as their per-unit cost is relatively small and very little required maintenance can be performed in the field.

2.3 Strategy

Transformer loading will be reviewed annually via reports generated from the transformer loading information within the CIS. Transformers with calculated demands exceeding load limits specified in the applicable Construction Standard will be investigated and any overloaded installations will be replaced with a larger unit or have load relieved via installation of a second transformer (i.e. splitting of secondary crib). The number of installation reviewed annually will be limited by the program budget.

Installations found to have incorrect connectivity within the GIS (customer connected to the wrong transformer) or incorrect transformer size should be corrected by Engineering Department. This is a straight forward process for overhead installations and many underground installations. Correcting these issues will improve our ability to properly identify overloaded transformers and will improve the accuracy of both the outage management and reliability data systems.

Condition-based replacement of distribution transformers is driven by the Inspection Program.
The general condition of distribution line transformers will be evaluated as part of the Overhead and Underground Inspection and Maintenance Programs. Replacements will be made as determined by these inspections when they are found to be in sub-standard condition.

The creation of a model to combine loading, condition, age and wetland data is planned in the future. This model will assist in the selection of the best installations for each program year if all installations cannot be upgraded.

3.0 Benefits

The main benefit of this strategy is that asset utilization will be maximized by maintaining units in service until such point that replacement is required as identified through recurring loading reviews or visual and operational inspection, recognizing that transformer life expectancy is predominantly affected by loading and environmental factors rather than age. Implementation of this strategy will ensure the sustainability of this asset class over time and maintain its relatively minor impact on overall system reliability.

3.1 Safety and Environmental

There is currently minimal impact related to safety and environmental drivers attributed to distribution line transformer failures. This strategy will minimize instances where dielectric fluid releases occur as a result of transformer failure due to overload or poor condition.

3.2 Reliability

The impact of distribution transformer failures on overall system reliability has historically been small; representing less than two minutes on system SAIDI and 0.01 on system SAIFI annually. This strategy will ensure that the reliability performance of this asset class is maintained over time.

3.3 Customer/Regulatory/Reputation

There is minimal impact related to both customer and regulatory drivers attributed to distribution line transformer failures.

3.4 Efficiency

The programmatic replacement of transformers based on loading and condition supports a predictable replacement rate and avoids unexpected changes to replacement in absence of loading and/or condition data. This predictable replacement rate better supports long term budgeting and the packaging of work for internal and/or external crews.

4.0 Estimated Costs

The recommended approach is to reduce this excess loading situation over a 15 year program. Based on the installations identified by the loading review (Figure 2) and factoring in 1% load growth during the program period, approximately 1,660 installations (~ 17% of population) are potentially loaded in excess of the loading guidelines documented in the Construction Standards. The majority of these units are single phase overhead transformers which are typically the least expensive and easiest to address.

Based on past system experience relating calculated to actual transformer overloads, a factor of 0.6 is being applied to the budgetary estimates for transformer replacements. This factor is based on a review of the overloaded transformer investigations which indicated that approximately 40% of the installations are "administrative overloads". These "administrative overloads" are related to incorrect load estimates, incorrect transformer sizes, and/or incorrect customer connections within the GIS (customer connected to the wrong transformer). These issues are corrected within the GIS as they are found to eliminate future "administrative overloads" as part of the review process. The Distribution Design department will evaluate all transformers on the overload list with the expectation that only about 60% of the investigated installations will require replacement.

Based on a 15 year program, 50 installations need to be replaced annually. This includes the annual contribution from the Inspection Program. The installed cost for a complete distribution line transformer ranges is approximately $1,500 per unit. The following estimated allocation to the transformer/capacitor blankets and associated specific funding projects on an annual basis for the 15 year program is:

Load Related Replacements	$75,000
Condition Based Replacements	$1,500

Total Annual Program Cost	$76,500

5.0 Implementation

- Loading reviews of distribution line transformers and subsequent replacements will be performed annually per the applicable Standard. Engineering should record the GIS ID's of the units replaced and investigated to keep track of the installations which have been reviewed. This will reduce the number of repeat requests from year to year.
- Visual inspections of distribution line transformers and subsequent replacements as part of the Overhead and Underground Inspection Programs will be performed per the applicable EOP.
- Continue to review distribution line transformer loading during investigations for new customer service and system improvement projects.
- Investigate the subset of transformer installations loaded in excess of 400% to determine cause. It is not expected that these installations are loaded to this level; either a problem related to the correct transformer size in GIS or inaccurate calculation of loading is suspected.

5.1 Performance Targets

The following performance targets will be used to measure the successful implementation of this strategy:

- Completing the replacement of identified installations as part of each program year
- Reduction in number of overloaded transformers as reported from the GIS over the 15 year program

6.0 Risk Assessment

The primary impact of this strategy is to maintain the current risk profile associated with safety/environmental and reliability drivers. There is potentially significant risk related to the aforementioned factors if this strategy is not implemented resulting from distribution line transformer failures due to the proximity to the general public and sensitive environmental areas given the large population of these units on the distribution system.

6.1 Safety and Environmental

There is currently minimal risk related to safety and environmental drivers attributed to distribution line transformer failures. Failing to implement this strategy will increase the likelihood of dielectric fluid releases occurring as a result of transformer failure due to overload or poor condition.

6.2 Reliability

The impact of distribution transformer failures on overall system reliability has historically been small; representing less than two minutes on system SAIDI and 0.01 on system SAIFI annually. Failing to implement this strategy will put the sustainability of the reliability performance of this asset class at risk.

6.3 Customer/Regulatory/Reputation

There is minimal impact related to both customer and regulatory drivers attributed to distribution line transformer failures.

6.4 Efficiency

The programmatic replacement of transformers based on loading and condition supports a predictable replacement rate and avoids unexpected changes to replacement in absence of loading and/or condition data. Failing to implement this strategy will result in a more reactionary approach to managing this asset class leading to unpredictable replacement rates, possible inventory problems and budgeting inconsistencies.

7.0 Data Requirements

7.1 Existing/Interim

- ArcFM/GIS
- CIS/Cogsdale

7.2 Proposed

- same

7.3 Comments

The creation of a model combining multiple aspects of the line transformer asset class (loading, condition, age, environmental, etc.) is planned to provide a better method to select replacement candidates for each program year.

Investigation of the method used to apply the diversified peak load calculation to the transformer installations should be reviewed as a significant number of transformers (> 10%) have either no load data or suspect load data. This process involves passing data between CSS and Synergi modeling software.

8.0 References

- Liberty Distribution Construction Standards:
  - 10.4 – "Residential Transformer Loading"
  - 10.1.20 – "Commercial or Industrial Secondaries"
  - 40.3.10 – "Sizing and Loading; Single Phase Mini-Pads"
  - 40.3.20 – "Sizing and Loading; Three Phase Padmounts"
- Liberty Electric Operating Procedure, NG-USA EOP D004 – "Distribution Line Patrol and Maintenance"
- Electric Operating Procedures (EOP) UG006 – "Underground Inspection and Maintenance"

DAS-007 Overhead Switch Strategy

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Strategy Statement

The intent of this strategy is to provide an approach to manage our distribution and subtransmission line switches. This strategy is designed to provide for a sustainable distribution system as well as improve employee safety in normal and emergency conditions.

Liberty-NH has approximately 540 distribution and subtransmission switches. A rough age profile can be inferred by switch type. Loadbreak switches were first widely used beginning in the early 1980's. Prior to the use of loadbreak switches, airbreak switches were the standard. Disconnect switches have been used consistently over the entire age profile.

The inspection program will identify and assign a priority code (1-3) to switches in need of replacement. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset prior to the next inspection cycle.

Maintaining or slightly improving our switch age profile is recommended using a condition-based approach supported by the inspection program. This can be achieved by eliminating the airbreak population and installing loadbreak switches where necessary. Disconnect switch replacements will principally come from the inspection program.

Approximately 45 units are in the target population. The replacement cost of the total target population is $450,000. Executing this plan over a ten year period would cost approximately $45,000 annually.

The Distribution Automation strategy may impact the switch selection and the cost per switch. At the present time, this impact is not expected to be large.

The principal benefit/risk of switch replacement is in employee safety.

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
2	6/19/19	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

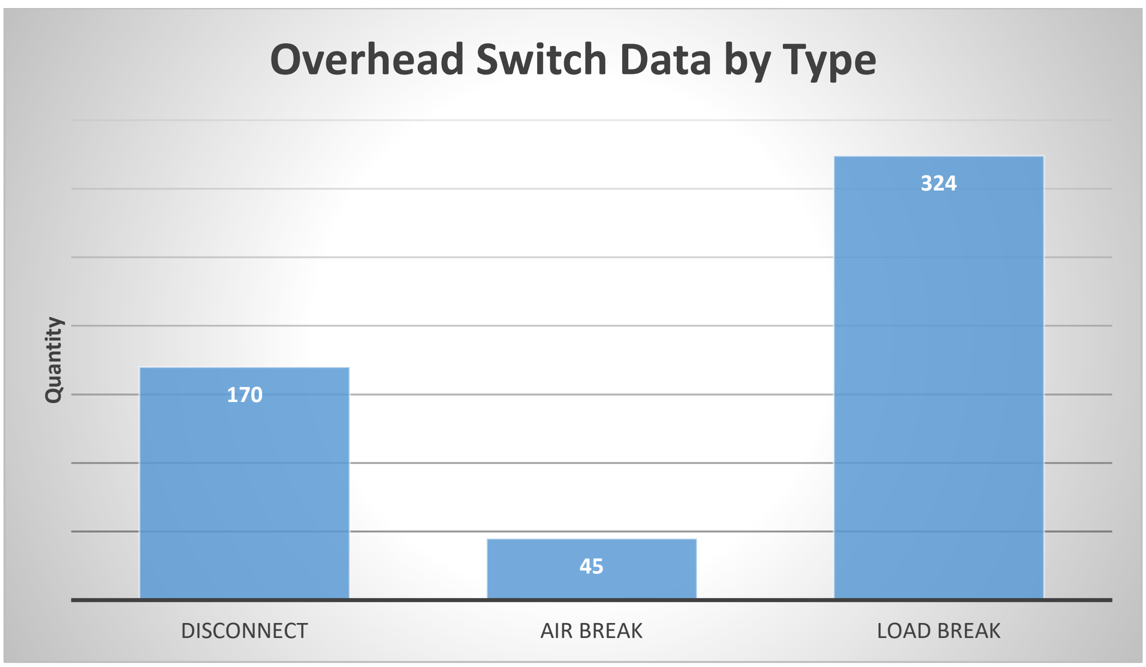
1.0 Purpose and Scope

The intent of this strategy is to provide an approach to manage our distribution and subtransmission line switches. This strategy is designed to provide for a sustainable distribution system as well as improve employee safety in normal and emergency conditions. Substation switches are not covered by this strategy.

2.0 Strategy Description

2.1 Background

Liberty-NH has approximately 540 distribution and subtransmission switches. Reasonable data is available related to switch type, however age related data is not available in sufficient quantity to create an age profile. A rough age profile can be inferred by switch type as loadbreak switches were first widely used beginning in the early 1980's. Prior to the use of loadbreak switches, airbreak switches were the standard. Disconnect switches have been used consistently over the entire age profile.



2.2 Strategy

The existing inspection program is being updated to improve the consistency of the equipment condition reporting. The inspection program will identify and assign a priority code (1-3) to switches in need of replacement. The intention of the program is to provide for the timely replacement of any visibly damaged or deteriorated asset.

Maintaining or slightly improving our switch age profile is recommended using a condition-based approach supported by the inspection program. This can be achieved by eliminating the airbreak and installing loadbreak switches where necessary. A listing of airbreak locations can be easily created to support the proactive review of these locations and the replacement of any required switches. Disconnect switch replacements will principally come from the inspection program.

3.0 Benefits

The principal benefit of switch replacement will be in employee safety.

3.1 Safety & Environmental

Switch replacements prior to failure are beneficial due to improved employee safety during routine and emergency operations.

3.2 Reliability

The reliability benefit associated with switch replacement is negligible. A slight improvement is service restoration time is possible; however this contribution will not be large.

3.3 Regulatory

The regulatory benefit associated with switch replacement is negligible.

3.4 Customer

The customer benefit associated with pole replacement is negligible.

4.0 Estimated Costs

An estimated cost of $~~10~~20,000 capital per loadbreak switch is assumed for this strategy. Approximately 45 units are in the target population (airbreak switches). The replacement cost of the total target population is $~~450~~900,000. Executing this plan over a ten year period would cost approximately $~~45~~90,000 annually.

5.0 Implementation

Target switches on the Airbreak Switch Upgrade Program, Feeder Hardening (under development) and Engineering Reliability Review feeders first followed by inspection program feeders and finally the switch list from ArcFM to fill the annual requirement budget. Additional sources for possible switch replacements are the System Control Center, Problem Identification Worksheets (PIW) and Pockets of Poor Performance analysis.

The Distribution Automation strategy may impact the switch selection and the cost per switch. At the present time, this impact is not expected to be large.

6.0 Risk Assessment

The principal risk of not proactively replacing switches will be in employee safety.

6.1 Safety & Environmental

The risk associated with not proactively replacing switches is the increased possibility of an employee safety related problem during routine or emergency operations.

6.2 Reliability

The reliability risk associated with switches is negligible.

6.3 Regulatory

The regulatory risk associated with switches is negligible.

6.4 Customer

The customer risk associated with switches is negligible.

7.0 Data Requirements

7.1 Existing/Interim:

- ArcFM/GIS – distribution switch data

7.2 Proposed:

- Same

8.0 References

EOP D004 – Distribution Line Patrol and Maintenance
DAM – 012, Engineering Reliability Review Process Guideline
DAM – 016, Problem Identification Worksheet (PIW)
Distribution Automation Strategy
Pockets of Poor Performance Strategy

DAS-008 Small Wire Primary Strategy

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Strategy Statement

The intent of this strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability. This strategy is also referred to as Amerductor Wire Replacement Program as this is the first targeted wire group.

Approximately 76 circuit miles (6%) of the Liberty-NH overhead circuit mileage falls into the category of small wire. The majority of this small wire population is #2 and #6 copper/copperweld/amerductor conductor.

Liberty, formerly National Grid, stopped installing #4 and smaller copper primary wire sometime prior to 1953 (Moved this conductor to maintenance only about this time according to back issues of the construction standards). This makes the small wire population at least 66 years old (some of the oldest overhead energized equipment in service on the distribution system).

Three general strategies were developed to address this small wire population:

1.) Company wide strategy to address three phase installations on a feeder basis
2.) Company wide strategy to address both three phase and non-three phase small wire installations in areas identified as pockets of poor performance.
3.) As part of all future overhead distribution projects.

To expand the scope and increase the speed of replacement, the following incremental strategy is suggested:

- All conductor less than 1/0 aluminum shall not be transferred (except on a single pole change-out basis) or reenergized at a higher voltage as part of a conversion.

Overall these strategies identify a pool of 76 circuit miles (6%) of potential overhead conductor replacement.

The main benefits/risks are safety and reliability.

Amendments Record

Issue	Date	Summary of Changes	Author(s)	Approved By (Inc. Job Title)
2	6/19/19	Revision of Strategy for Liberty-NH	Joel Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

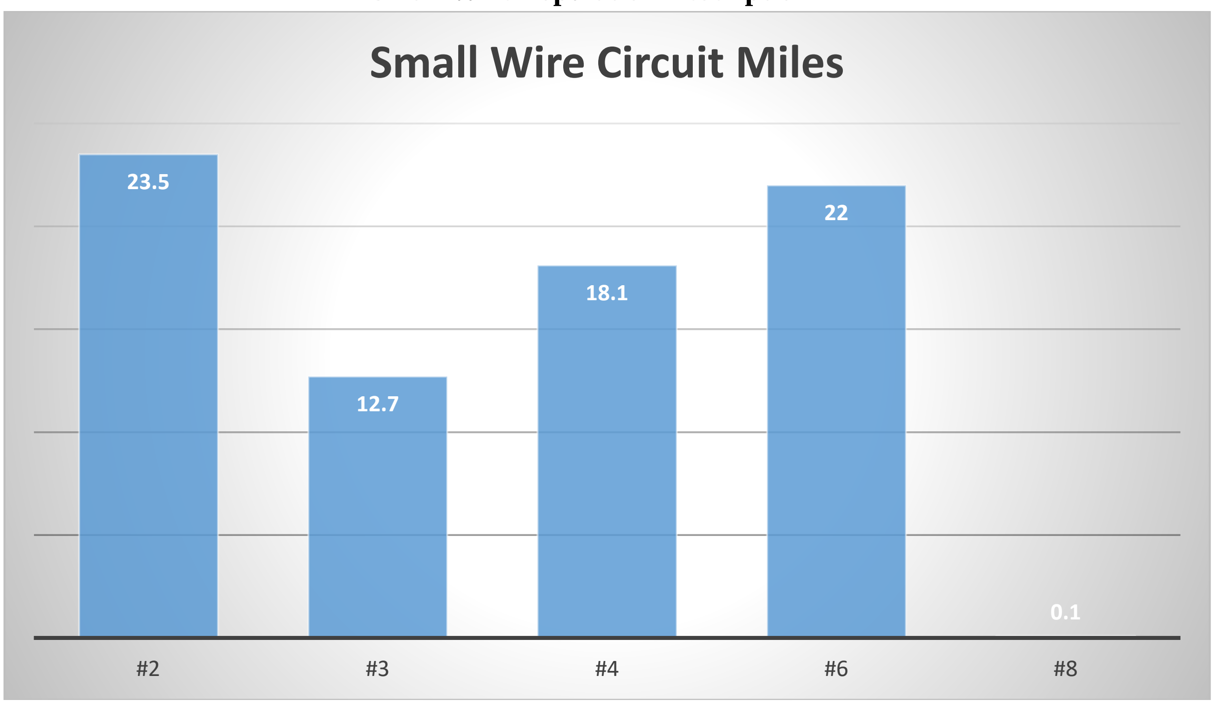
The intent of this strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

2.0 Strategy Description

2.1 Background

For the purposes of this strategy, "small wire" has been defined as any conductor smaller than #2 AWG copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations.

Small Wire Population Description



Approximately 76 circuit miles (6%) of the Liberty-NH overhead circuit mileage falls into the category of small wire. This is approximately 1,635 sections of primary. The majority of this small wire population is #6 and #4 copper/copperweld/amerductor conductor.

Liberty, formerly National Grid, stopped installing #4 and smaller copper primary wire sometime prior to 1953 (Moved this conductor to maintenance only about this time according to back issues of the construction standards). This makes the small wire population at least 66 years old (some of the oldest overhead energized equipment in service on the distribution system). Ever decreasing amounts of small wire continued to be installed after 1953. Recently, reducing splices have been introduced to eliminate the need for this practice.

While age is not the sole determinant of the end of a piece of equipment's useful service life, it is a significant factor due to the harsh environmental conditions to which the conductor is exposed. In the course of this 50+ year service life, the average conductor will have lost some of its tensile strength due to loading conditions and elongation during splicing following emergency service restoration. This loss of tensile strength increases the likelihood of conductor breakage during an interruption which involves physical contact with the conductor. Interruptions involving broken conductors typically result in longer service restoration times. With each successive interruption the ability to restore service quickly is deteriorated. This loss of tensile strength is especially significant during a storm situation where the wind and/or ice/snow loading on the conductor will be higher than during clear conditions. The intention of this policy is to systematically identify and replace the small wire to spread both the cost and the reliability impact across a number of years.

2.2 Strategy

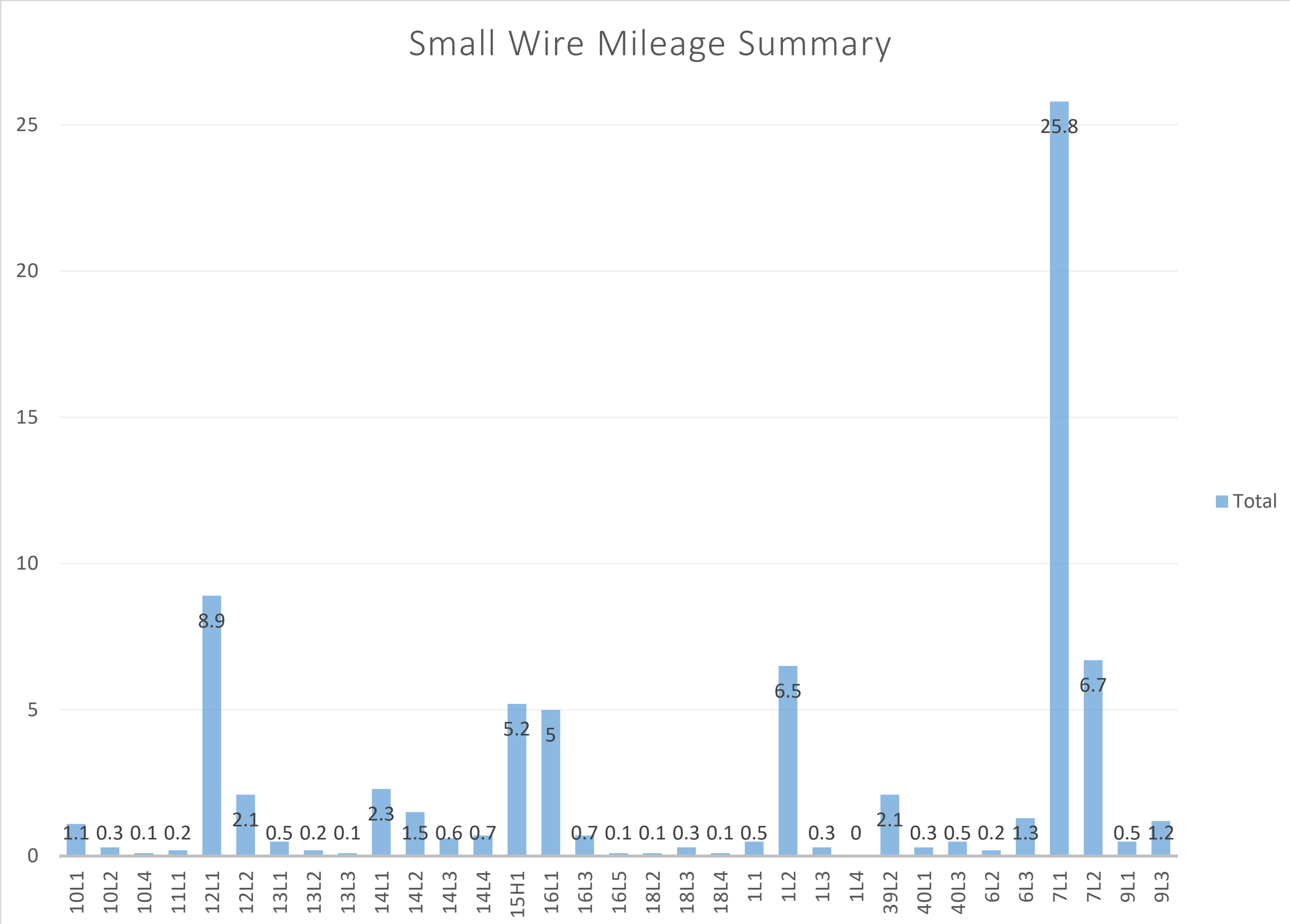
Three strategies are proposed to address the replacement of small wire across the system:

1.) Company wide strategy to address three phase installations on a feeder basis

There are approximately 76 circuit miles of small wire in service across Liberty. The majority of this population is operating a 5 kV with a smaller percentage at 15 kV or more.

Feeders that contain amerductor will be done first. In order to maintain efficiencies of scope and maximize the potential reliability impact, the feeders with the greatest amount of small wire will be prioritized afterwards.

Feeder 7L1 has 34% of the company's small wire circuit miles. Thirteen feeders have slightly less than 0.5 miles of small wire, and a small group of circuits (9) have more than 2 miles of small wire. The distribution is shown below:



During the installation of the new conductor, all associated equipment on the targeted sections of each feeder will be brought up to current standards. This includes poles, crossarms, guys and anchors, cutouts, lightning arresters, and switches/disconnects. Consideration for conversion to 15 kV should be given based on the location of the small wire on the circuit. Things to consider:

- System losses
- Voltage drop
- Stepdown transformer elimination
- Creation of additional feeder ties
- Impact on any ongoing planning studies
- Impact on any ongoing or near term construction such as those projects in the Low Voltage Mitigation program.

477 Al is a standard conductor size for main line distribution feeders. 1/0 Al is a standard conductor size for taps off the main line and main line sections that do not tie to adjacent circuits and serve a small amount of load. Crossarm construction (conductors are covered and in a slightly triangular configuration) is the standard construction where the required clearance from structures and vegetation can be reliably

maintained. Spacer cable construction (conductors are in a diamond configuration) is used in areas with tight clearance requirements and/or significant vegetation problems which prohibit Liberty from maintaining the clearances needed for crossarm construction.

2.) Company wide strategy to address both three phase and non-three phase small wire installations in areas identified as Pockets of Poor Performance

As part of the Pockets of Poor Performance reliability reviews, the replacement of small wire should be considered in non-three phase areas and small three phase areas not already targeted by the three phase strategy. The conductor should be replaced if it is in poor condition (e.g. broken strands, multiple splices, etc.).

The circuit mileage of non-three phase small wire is significantly higher than the three phase installations. All the issues and benefits detailed for the three phase installations apply to the non-three phase installations, the principal difference being the scale of the impact. Three phase installations have the potential to impact a comparatively large portion of a feeder while non-three phase installations will impact a smaller subset of customers on a feeder.

3.) As part of all future overhead distribution projects

Reviewing the suitability of the existing conductor for service in areas being worked by our crews is a third way to locate and replace small sections of small wire. One quarter of the feeders have 0.25 miles or less of small wire. Eliminating the small wire as part of a new project will speed up the removal of the small wire at a fairly small incremental cost (~ $40K) and may better utilize time by not separately engineering and building these small sections.

2.3 Other conductor types

In general, 1/0 aluminum overhead conductor has been the smallest standard conductor used in the system for at least 50 years. Using this as a reference, any overhead copper conductor or aluminum (including ACSR) conductor smaller than 1/0 must be at least 40 years old in New Hampshire. To expand the scope and increase the speed of replacement, the following incremental strategy is suggested:

- All conductor less than 1/0 aluminum shall not be transferred (except on a single pole change-out basis) or reenergized at a higher voltage as part of a conversion.

Not included in this strategy is conductor which is in good condition (minimal splices, no broken strands, no pitting and other signs of wear). This does not apply during emergency operations, however locations should be noted and follow-up projects written to address these areas at a later date.

This additional pool of potential conductor represents approximately 76 circuit miles (6% of the total overhead circuit mileage).

3.0 Benefits

3.1 Safety & Environmental

Replacing the "small wire" population will lead to a safer work environment for our crews due to the expected low tensile strength of this conductor.

3.2 Reliability

This work is expected to reduce the five year average number of customers interrupted (CI) by 3,489 and the five year average customer minutes interrupted (CMI) by 408,465 (Both of these statistics exclude major event days). This improvement is based on a reduction in the number and magnitude of deteriorated equipment, lightning and animal related interruptions in upgraded sections.

3.3 Regulatory

Replacing the "small wire" population will improve Liberty's reliability performance against the state service quality standards. This should have a positive impact on our relationship with the state regulators.

3.4 Customer

Replacing the "small wire" population will improve customer level reliability by reducing the frequency and duration of localized interruptions in Pockets of Poor Performance.

3.5 Additional Benefits

Replacement of the 76 miles of conductor will reduce line losses and improve voltage performance in the impacted areas. This value would be significantly higher on circuits having in excess of 2 miles of conductor and could partially address some existing voltage problems.

4.0 Estimated Costs

Based on study grade estimates from the distribution planning department, an average cost per of $150K per mile was used for these estimates. This estimated cost factors in the mix of different construction as described previously in the document.

Annual Miles Replaced and Estimated Costs for Different Program Lengths

Program Length (Years)	Miles/Year	CAPEX/Year	REM/Year	Total Cost/Year
15	5	$ 760,000	$ 76,000	$ 836,000
20	4	$ 570,000	$ 57,000	$ 627,000
25	3	$ 456,000	$ 45,600	$ 501,600
30	2.5	$ 380,000	$ 38,000	$ 418,000

REM costs are estimated at 10% of the capital costs.

5.0 Implementation

A list of potential locations by feeder will be generated to begin the replacement process. Additionally, Reliability Feeder Statistics, Pockets of Poor Performance, Low Voltage Issues, Problem Identification Worksheets and inspection data from the inspection program should feed into the conductor replacement process.

6.0 Risk Assessment

6.1 Safety & Environmental

Not replacing the “small wire” population will lead to an increasingly unsafe work environment for our crews due to the difficulty associated with working on low tensile strength conductor. Typically the poor condition of the conductor can be determined visually but the risk of missing a hazardous condition still exists.

6.2 Reliability

If this strategy is not adopted the result will be the gradual degradation of reliability (due to equipment failure and deterioration) and customer satisfaction on the circuits with small wire. This impact will be accentuated on feeders with a significant amount of this type of conductor (> 1 mile). This effect will also be more significant during poor weather conditions due to increased wind and/or snow/ice loading on the conductors. At some point, these feeders will become hot spots requiring a significant response to repair the problems as well as regain customer satisfaction. Based on the location and timing to address these hot spots, budgets and schedules could be significantly affected.

6.3 Regulatory

Not proactively replacing "small wire" will lead to a negative regulatory response due to the expected poor reliability performance, customer complaints and potential safety issues.

6.4 Customer

Not proactively replacing "small wire" will lead to increasing customer complaints due to the frequency and duration of interruptions in areas served by this type of conductor. This will be accentuated during storm conditions.

7.0 Data Requirements

7.1 Existing/Interim:

ArcFM GIS – conductor data
Inspection data

7.2 Proposed:

Same

7.3 Comments:

Inspection and survey data is needed to support the location of the small wire.

8.0 References

EOP D004 – Distribution Line Patrol and Maintenance
DAM – 012, Engineering Reliability Review Process Guideline
DAM – 016, Problem Identification Worksheet (PIW) Process for Distribution Lines
Pockets of Poor Performance Strategy

DAS-009 Pockets of Poor Performance Strategy

Strategy Statement

The intent of this strategy is to provide a method to identify subsections of feeders (typically the line fuse level) experiencing measurably more frequent interruptions than the remainder of the feeder. Typically, these pockets of poor performance (P3) will not significantly influence our service quality targets, but the interruptions are very significant to the customers in the pocket. This strategy is designed to support customer-level reliability performance and provide for a sustainable distribution system.

There is no set list of equipment to inspect or replace as part of this strategy. Once these locations have been identified, a reliability review of the area will be conducted by Engineering. The range of potential work could be as simple as solving a coordination problem to performing preventive maintenance (tree trimming, repairing equipment, grounding and bonding) to line reconductoring and/or stepdown conversion.

The current definition used for identifying pockets of poor performance is four or more interruptions in the past twelve months on a device using the output of the Devices with Multiple Outages Report.

The P3 Strategy is intended to identify potential district level reliability "hot-spots" and address them to mitigate future impact on reliability and customer satisfaction.

The principal benefits/risks of this strategy are customer related.

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
3	6/19/19	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
2	03/15/2010	Updated benefit/risk objectives Updated report to reflect new data model Added current five year capital budget Added performance targets Added state specific sections	Jeffrey H. Smith Distribution Asset Strategy	Ellen Smith Chief Operating Officer US Electricity Operations Chairman of DCIG
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

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Strategy Justification

1.0 Purpose and Scope

The purpose of this strategy is to set forth a mechanism to address pockets of poor reliability performance. This strategy is designed to support customer-level reliability performance and provide for a sustainable distribution system.

2.0 Strategy Description

2.1 Background

The Pockets of Poor Performance (P3) Strategy is a reliability-based strategy focused at the customer level rather than the system level. The P3 Strategy is focused on pockets of poor performance, which typically will not significantly influence the service quality targets, but are very significant to the customers in the pocket.

There is no set list of equipment to inspect or replace as part of this strategy. The intention is to provide a method to identify subsections of a feeder (typically at the line fuse level) with outage frequency measurably worse than the remainder of the feeder. Once these locations have been identified, a reliability review of the area will be conducted by Engineering. The range of potential work could be as simple as solving a coordination problem to performing preventive maintenance (tree trimming, repairing equipment, grounding and bonding) to line reconductoring and/or stepdown conversion.

The P3 Strategy is intended to identify potential district level reliability "hot-spots" and address them to mitigate future impact on reliability and customer satisfaction.

2.2 P3 Model Description

The P3 Strategy uses a modified version of the Devices with multiple Outages report from Responder Archive to identify branches experiencing more than a given number of interruptions in a given period of time. Currently these thresholds are set at four or more interruptions in a rolling twelve-month period. A sixteen month period is also considered.

6 pockets were identified serving approximately 176 customers.

3.0 Benefits

The principal benefits of the Pockets of Poor Performance Strategy are customer related.

3.1 Safety & Environmental

This strategy has no direct safety or environmental benefit. As pockets of poor performance are addressed, existing safety and/or environmental issues will be corrected.

3.2 Reliability

This strategy addresses subsections of feeders experiencing measurably more frequent interruptions than the remainder of the feeder. These interruptions represent approximately 176 customers interrupted for Liberty annually. The actual percentage improvement in system reliability will be small, however the impact will be significant for the customers in the areas addressed by the program. Table 2 below lists the areas with frequency of interruptions measurably worse than the remainder of the system:

Device Type	Location	OID	Outages	Customers
Fuse Bank	Old County Rd Plainfield	694	6	17
Fuse Bank	Prospect Hill Rd Walpole	841	4	40
Fuse Bank	Atwood Rd Pelham	2826		42
Fuse Bank	Ibey Rd Canaan	50591	9	25
Fuse Bank	Dogford Rd Hanover	44962	5	31
Fuse Bank	Sawyer Hill Rd Canaan	45774	5	21

Table 2 - Pocket of Poor Performance Reliability History

3.3 Customer/Regulatory/Reputation

This strategy directly addresses subsections of distribution feeders that have reliability problems. Proactively reviewing these areas should maintain customer satisfaction in these locations and minimize reliability “hot-spots” which result in a negative customer experience.

3.4 Efficiency

This is no significant impact on efficiency.

4.0 Estimated Costs

The estimated costs to address individual pockets are not quantifiable at this time due to the range of possible solutions to address the issue(s). As projects are developed to address these pockets, budgetary estimates will be developed for the different solution types. Pockets identified by the Device with Multiple Outage report will be used for work identification. As programs are re-evaluated as part of the annual budget cycle, these estimates may change. Refer to the Liberty Reliability Review document for additional details and estimated costs for targeted pockets of poor performance.

5.0 Implementation

The Device with Multiple Outage report will be used to generate lists of branches to be reviewed by Engineering. Additionally, Problem Identification Worksheets (PIW) will be used to identify possible pockets of poor performance.

6.0 Risk Assessment

The principal risks of the Pockets of Poor Performance Strategy are customer related.

6.1 Safety & Environmental

This strategy has no direct safety or environmental risk.

6.2 Reliability

This strategy has a minimal system reliability impact. The typical reliability impact of these pockets of poor performance is not significant compared to the overall service quality targets.

6.3 Customer/Regulatory/Reputation

Not addressing pockets of poor performance will result in continued poor reliability performance and customer dissatisfaction in these areas. At some point, these pockets may become "hot spots" requiring a response to repair the problems as well as regain customer satisfaction. Based on the location and timing to address these "hot spots", division level budgets and schedules could be impacted. The typical reliability impact of these pockets of poor performance is not significant compared to the overall service quality targets, however the impact is very significant to the customers in the pocket.

6.4 Efficiency

This is no significant impact on efficiency.

7.0 Data Requirements

7.1 Existing/Interim:

- Responder Archive – feeder reliability data

7.2 Proposed:

- Responder Archive – feeder reliability data

8.0 References

DAM – 016, Problem Identification Worksheet (PIW)
Worst Performing Feeder Strategy
Liberty Reliability Review

DAS-010 Poor Performing Feeder Strategy

Strategy Statement

The intent of this strategy is to provide a method to identify poor performing feeders (PPF) (typically the four to six worst performers) experiencing measurably less reliability than the remainder of the feeders. Typically, these poor performing feeders significantly influence our service quality targets, and the interruptions are very significant to the customers on these feeders. This strategy is designed to support system-level reliability performance and provide for a sustainable distribution system.

There is no set list of equipment to inspect or replace as part of this strategy. Once these feeders have been identified, a reliability review of the feeders will be conducted by Engineering. The range of potential work includes added sectionalizing or fusing, preventive maintenance (tree trimming, repairing equipment, grounding and bonding), installation of new ties with adjacent feeders, line reconductoring and/or stepdown conversion.

A Poor Performing Feeder is a feeder that possesses a CKAIDI or CKAIFI value for a reporting year that is among the highest 4-6 of all of Liberty's feeders. CKAIDI measures the average duration of a power outage that a customer connected to a feeder experiences during a year. CKAIFI measures the average number of times that a customer connected to a feeder experiences a power outage during a year.

The poor performing feeders are selected based on exceedance of a target threshold for CKAIDI and CKAIFI. CKAIDI/CKAIFI annual target thresholds are set as the 5 YR average of the CKAIDI and CKAIFI values for all Liberty Feeders plus two standard deviations.

The Poor Performing Feeder strategy is intended to identify potential feeder level reliability deficiencies and address them to mitigate impact on reliability and customer satisfaction.

The principal benefits/risks of this strategy are reliability and customer related.

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	6/19/19	Initial Release of Liberty-NH Strategy	Joel A. Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering

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Strategy Justification

1.0 Purpose and Scope

The purpose of this strategy is to set forth a mechanism to poor performing feeders. This strategy is designed to support system-level reliability performance and provide for a sustainable distribution system.

2.0 Strategy Description

2.1 Background

The Poor Performing Feeder (PPF) Strategy is a reliability-based strategy focused at the system level rather than the customer level. The PPF Strategy is focused on worst performing feeders, which typically significantly influence the service quality targets, and are very significant to the customers in these feeders.

There is no set list of equipment to inspect or replace as part of this strategy. Once these feeders have been identified, a reliability review of the feeders will be conducted by Engineering. The range of potential work includes added sectionalizing or fusing, preventive maintenance (tree trimming, repairing equipment, grounding and bonding), installation of new ties with adjacent feeders, line reconductoring and/or stepdown conversion.

The Poor Performing Feeder strategy is intended to identify potential feeder level reliability deficiencies and address them to mitigate impact on reliability and customer satisfaction.

2.2 PPF Model Description

The PPF Strategy identifies feeders that possess a CKAIDI or CKAIFI value for a reporting year that is among the highest of all of Liberty's feeders and is based on exceedance of a target threshold. CKAIDI/CKAIFI annual target thresholds are set as the 5 YR average of the CKAIDI and CKAIFI values for all Liberty Feeders plus two standard deviations.

Problem Feeders and Chronic Feeders are also tracked. Problem Feeder is a feeder that possesses a CKAIDI or CKAIFI value for a reporting year that is among the 5 highest of all of Liberty's feeders for any two consecutive years. Chronic Feeder is a feeder that possesses a CKAIDI or CKAIFI value for a reporting year that is among the 5 highest of all of Liberty's feeders for any three consecutive years. Currently the Vilas Bridge 12L1, Vilas Bridge 12L2 and Salem Depot 9L3 feeders are problem feeders.

3.0 Benefits

The principal benefits of the Poor Performing Feeder Strategy is system reliability and customer related.

3.1 Safety & Environmental

This strategy has no direct safety or environmental benefit. As poor performing feeders are addressed, existing safety and/or environmental issues will be corrected.

3.2 Reliability

This strategy addresses feeders experiencing measurably less reliability than the remainder of the feeders. Based on 2019 results, the poor performing feeders make up about 34% of the company's SAIFI and about 55% of the company's SAIDI. Refer to the Liberty Reliability Review 2020 document for additional details. This program is used alongside others as an overarching goal to meet the company's 5 year rolling average for SAIDI and SAIFI. The table below lists the reliability performance of the company's poor performing feeders for the past three years.

3.3 Customer/Regulatory/Reputation

This strategy directly addresses distribution feeders that have reliability problems. Proactively reviewing these should maintain customer satisfaction in these locations and help improve system-wide reliability.

3.4 Efficiency

This is no significant impact on efficiency.

4.0 Estimated Costs

Refer to the Liberty Reliability Review 2020 document for details on recommended projects to address poor performing feeders and their estimated costs.

5.0 Implementation

The CKADI and CKAIFI of each feeder will be tracked monthly against the annual company threshold. CKAIDI and CKAIFI annual threshold are set as the 5 year average of the CKAIDI and CKAIFI values for all feeders plus two standard deviations. Projected results are based on year-to-date actual results plus 5-year average results for the remaining months. The table below shows an example of the monthly tracking for poor performing feeders.

2018 Poor Performing Feeders (Worst 5)	CKAIFI			CKAIDI		
	Target	Projected Results*	Problem Feeder	Target	Projected Results*	Problem Feeder
N/A	1.815	N/A	N/A	233.201	N/A	No
MT SUPPORT 16L1	1.815	N/A	N/A	233.201	230.242	No
N/A	1.815	N/A	N/A	233.201	N/A	No
SALEM DEPOT 9L3	1.815	N/A	N/A	233.201	212.832	No
VILAS BRIDGE 12L1	1.815	N/A	No	233.201	430.472	No
VILAS BRIDGE 12L2	1.815	N/A	N/A	233.201	253.540	Yes

Color Codes:

Green	Below Target
Yellow	At Risk of Exceeding Target
Red	Above Target
Blue	Target not scored

Notes:
* Projected results based on YTD actual results plus 5-year average results for the remaining months
* CKA DI measures the average duration of a pow er outage that a customer connected to a feeder experiences during a year.
* CKA FI measures the average number of times that a customer connected to a feeder experiences a pow er outage during a year.
* Poor Performing Feeder is a feeder that possesses a CKA DI or CKAIFI value for a reporting year that is among the highest 5 of all of Liberty's feeders.
* Problem Feeder is a feeder that possesses a CKAIDI or CKA FI value for a reporting year that is among the 5 highest of all of Liberty's feeders for any tw o consecutive years.
* Chronic Feeder is a feeder that possesses a CKA DI or CKA FI value for a reporting year that is among the 5 highest of all of Liberty's feeders for any three consecutive years.
* CKA DI/CKA FI annual targets to be set as the 5 YR average of the CKAIDI and CKAIFI values for all Liberty Feeders plus tw o standard deviations.
* The Vilas Bridge 12L2 w as a chronic feeder in 2018 being among the w orst in three consecutive years.

Table 2 – Poor Performing Feeders

6.0 Risk Assessment

The principal risks of the Poor Performing Feeder Strategy are customer related and system reliability related.

6.1 Safety & Environmental

This strategy has no direct safety or environmental risk.

6.2 Reliability

This strategy has a considerable impact to system reliability. The reliability impact of these poor performing feeders is significant and is estimated at 34% of total SAIFI and 55% of total SAIDI for the company.

6.3 Customer/Regulatory/Reputation

Not addressing poor performing feeders will result in continued poor reliability performance and customer dissatisfaction in these areas. The reliability impact of these poor performing feeders is significant compared to the overall service quality targets set by the state regulators. Not addressing these could result in the company not meeting its objective of meeting the annual target of 5 year rolling averages.

6.4 Efficiency

This is no significant impact on efficiency.

7.0 Data Requirements

7.1 Existing/Interim:

- Responder Archive – feeder reliability data

7.2 Proposed:

- ADMS

8.0 References

DAM – 016, Problem Identification Worksheet (PIW) Process for Distribution Lines
Liberty Reliability Review 2020

DAS-011 Distribution Line Recloser Application Strategy

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Strategy Statement

This intent of this strategy is to set forth the general conditions for the installation of line reclosers on overhead distribution feeders. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance. The strategy should serve as a guide to when, where and why a recloser should be installed on a feeder. It is not intended to cover every possible situation, but provide enough guidance to allow Engineering to make an informed decision.

The line recloser strategy is to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure with a three year average distribution line SAIDI performance greater than the internal Liberty SAIDI goal (estimated at 80 minutes, based on 100 minute goal less 20%). Additionally any circuit identified as a desirable candidate from the Duke Method analysis would be eligible or any location having a $/Delta CMI equal to or less than $1.50. Candidates will compete for inclusion in the budget based on their $/Delta CMI value, the more economic reclosers will be included.

Additionally, some high level reliability and cost projections are presented to gauge the possible range of cost and reliability improvement represented by the strategy. These projections are based on the identification of poor performing feeders indicating the potential for significant reliability performance improvements.

The main benefit/risk of this strategy is reliability.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	6/19/19	Revision of Strategy for Liberty-NH	Joel A. Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This strategy document sets forth the conditions for the installation of line reclosers on overhead distribution feeders. Primarily line reclosers will be installed on 15 kV class distribution feeders with overhead exposure. This is a reliability-focused strategy designed to meet both state regulatory targets and support first quartile reliability performance.

2.0 Strategy Description

2.1 Definitions

The following definitions are being provided to ensure a complete understanding of the issues discussed in the strategy.

Distribution Feeder – Typically distribution feeder voltage levels are between 2.4 kV and 15 kV, however voltages as high as 23 kV are used for distribution at Liberty-NH. Distribution feeders typically supply a large number of customers (hundreds to thousands) using a combination of overhead and underground facilities. Additionally, both three phase and one/two phase sections are present.

Mainline – Any three phase primary location that, if faulted, would operate a three-phase, gang-trip device (reclosing or otherwise). This includes sectionalizers, non-reclosing breakers, etc., but excludes three single phase reclosers on the same or adjacent poles.

Mainline Exposure – Any primary location that, if faulted, would operate a three-phase, gang-trip device (reclosing or otherwise). This includes sectionalizers, non-reclosing breakers, etc., but excludes three single phase reclosers on the same or adjacent poles. Our goal is to have mainline exposure equal mainline through the proper use of line fuses.

Line Recloser – An automatic sectionalizing device capable of interrupting a fault and reclosing afterward to restore service. Both three phase and single phase versions can be installed.

2.2 Strategy

Line reclosers are needed to isolate permanent faults on the distribution system and minimize the scope of the interruption by protecting the feeder breaker. Ideally, reclosers are installed at locations which limit the size of the interruption to the fewest number of customers possible and/or reduce the mainline exposure on the feeder breaker. Reclosers should be installed at natural breakpoints in the distribution primary; bifurcations, long three phase taps, etc. The ideal line recloser location would be on a long three phase tap serving few customers.

Recloser settings should be selected to allow for the installation of a 100K fuse downstream of the recloser. If a larger fuse size will coordinate it is acceptable to install it. If the situation will not allow a 100K fuse to be installed that is also acceptable.

Typically, at least one recloser (near the mid-point of the feeder) can be installed on every 15 kV class overhead radial feeder. Feeders with multiple branches (bifurcations, trifurcations) near the substation can typically support the installation of multiple reclosers. The installation of multiple reclosers in series is permitted providing proper coordination can be maintained and there is a reliability benefit to the installation.

The line recloser strategy is to install at least one recloser on every 15 kV class radial feeder with significant overhead three phase exposure with a three year average distribution line SAIDI performance greater than the internal Liberty SAIDI goal (estimated at 80 minutes, based on 100 minute goal less 20%). Additionally any circuit identified as a desirable candidate from the Duke Method would be eligible or any location having a $/Delta CMI equal to or less than $1.50. Candidates will compete for inclusion in the budget based on their $/Delta CMI value, cost, and relative risk.

2.3 Other Considerations

Loop sectionalizing and preferred/alternate schemes – The installation of LS and P/A schemes is encouraged in areas with enough spare capacity to operate the scheme. The load and settings in areas supplied by these schemes should be reviewed annually to insure the scheme continues to operate properly. Remote recloser control should be present on these schemes so system dispatchers are aware of the current configuration of the system. Future plans for Distribution Automation may impact the operation of these schemes.

Customer reclosers – For a single or small group of large customers a line recloser can be used in place of fused cutouts. This may be necessary when the customer's load exceeds the capability of fused cutouts. The use of older reclosers and/or controls such as Cooper Form 6 is acceptable for these locations if available.

Fast trip settings – The use of a fast trip on line reclosers to prevent downstream fuses from blowing due to temporary faults is open to an engineer's judgment. The use of the fast trip will increase momentary outages. It may or may not prevent a temporary outage from becoming a permanent one. The fast trip setting is designed to save downstream fuses from temporary faults, if there are very few fused taps, the fused taps serve only a few customers, and/or the fused taps are for underground cable installations do not add a fast trip to the recloser. Also, do not use fast trip settings in areas serving principally commercial and/or industrial customers. Residential areas with many fused side taps are good candidates for fast trip settings.

Single phase reclosers – The use of single phase reclosers on long single phase taps is encouraged. The use of three single phase reclosers on three phase taps should be limited to residential areas, with limited three phase customers. If three phase customers are served by three single phase reclosers the transformer size must be below 300 kVA.

3.0 Benefits

The principal benefits of the Recloser Application Strategy are reliability and customer related.

3.1 Safety & Environmental

This strategy has minimal safety or environmental benefit.

3.2 Reliability

The actual reliability improvements will be determined based on the actual recloser locations and feeder configurations.

3.3 Regulatory

This strategy has no direct regulatory impact but the projected reliability improvements will aid in meeting future service quality targets.

3.4 Customer

This strategy will result in an improvement in service quality for all customers. The additional reclosers will limit the size and duration of future distribution interruptions.

4.0 Estimated Costs

An estimated cost of $75,000 per recloser including capital, removal and O&M is assumed for each recloser installation.

5.0 Implementation

The proper application of line reclosers should be reviewed as part of Feeder Hardening and Engineering Reliability Review of distribution feeders. Additionally, the suitability for additional recloser installations should be determined particularly with larger projects such as new feeder installations and feeder reconfigurations. Any location having a $/Delta CMI equal to or less than $1.50 is an eligible candidate. Candidates will compete for inclusion in the budget based on their $/Delta CMI value, cost and relative risk.

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6.0 Risk Assessment

The principal risks of the Recloser Application Strategy are reliability and customer related.

6.1 Safety & Environmental

This strategy has minimal safety or environmental risk.

6.2 Reliability

If this strategy is not adopted, potentially limited interruptions (typically less than 50% of the customers on a feeder) will continue to be lockouts interrupting all customers on the feeder. The duration of the interruption will be more significant on primary sections with significant exposure due to the added time needed to patrol the lines looking for the cause of the interruption. Each individual change per event is potentially significant (typical CMI improvement is 25%) and collectively over time, the effect of proper line recloser applications will be significant at the customer, division and system levels.

6.3 Regulatory

This strategy has no direct regulatory risk. Not installing the additional reclosers will not negatively impact reliability, it just won't improve it.

6.4 Customer

Not implementing this strategy will result in larger and longer interruptions. This will result in continued customer dissatisfaction with their service quality.

7.0 Data Requirements

7.1 Existing/Interim:

- ArcFM/GIS – Feeder asset data
- Responder – Feeder reliability data

7.2 Proposed:

- ArcGIS Desktop – Feeder asset data
- ADMS – Feeder reliability data

7.3 Comments:

- Future plans for Distribution Automation may impact the operation of these schemes.
- Improved data quality in both feeder asset and reliability areas will support the refinement of the modeling process.

8.0 References

DAS-012 Recloser Strategy
DAM-012 Engineering Reliability Review Guidelines

DAS-012 Line Recloser Strategy

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Strategy Statement

The intent of this strategy is to provide an approach to manage distribution and subtransmission line reclosers. This strategy is designed to provide for a sustainable distribution and subtransmission system. Liberty-NH has approximately 95 reclosers in service across the company.

Substation Maintenance Standards/Procedures outline the required maintenance procedures for line reclosers and sectionalizers. These procedures need to be followed consistently across the company to establish a uniform approach for the routine inspection and maintenance of these assets.

The proposed approach for managing line reclosers and controls is condition-based using routine inspection data to determine when a unit should be replaced. A remote application using ESRI Survey 123 has been developed to track and document recloser inspections.

Reclosers and controls will be evaluated separately. If the control is no longer fit for service and cannot be repaired it can be replaced independently assuming the recloser is compatible with recent vintage controls. If the recloser is no longer fit for service and cannot be repaired both the recloser and control will be replaced.

There are no sectionalizers in service at Liberty-NH.

The estimated life expectancy of a line recloser is 35 to 40 years. It is anticipated that after this time the device is technologically obsolete and approaching the end of window for economic maintainability.

At the present time the number of units in need of replacement is unknown. Based on the results of the inspection program an estimate of the number of units approaching their end of life can be collected.

The principal benefits to recloser replacement are improved employee safety and reliability improvements related to recloser inspection and maintenance (not just replacement).

In 2012 Liberty-NH changed its standard recloser to include solid dielectric insulated vacuum fault interrupters, replacing oil-immersed vacuum interrupters. These reclosers and controls provide enhanced features, and given its solid dielectric insulation results in lower maintenance and improved safety and performance. The solid dielectric insulation is an environmental friendly alternative to oil immersed and eliminates oil leaks or spills. The updated recloser also provides the flexibility of three phase or single phase tripping.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	6/19/2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Jeffrey H. Smith Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

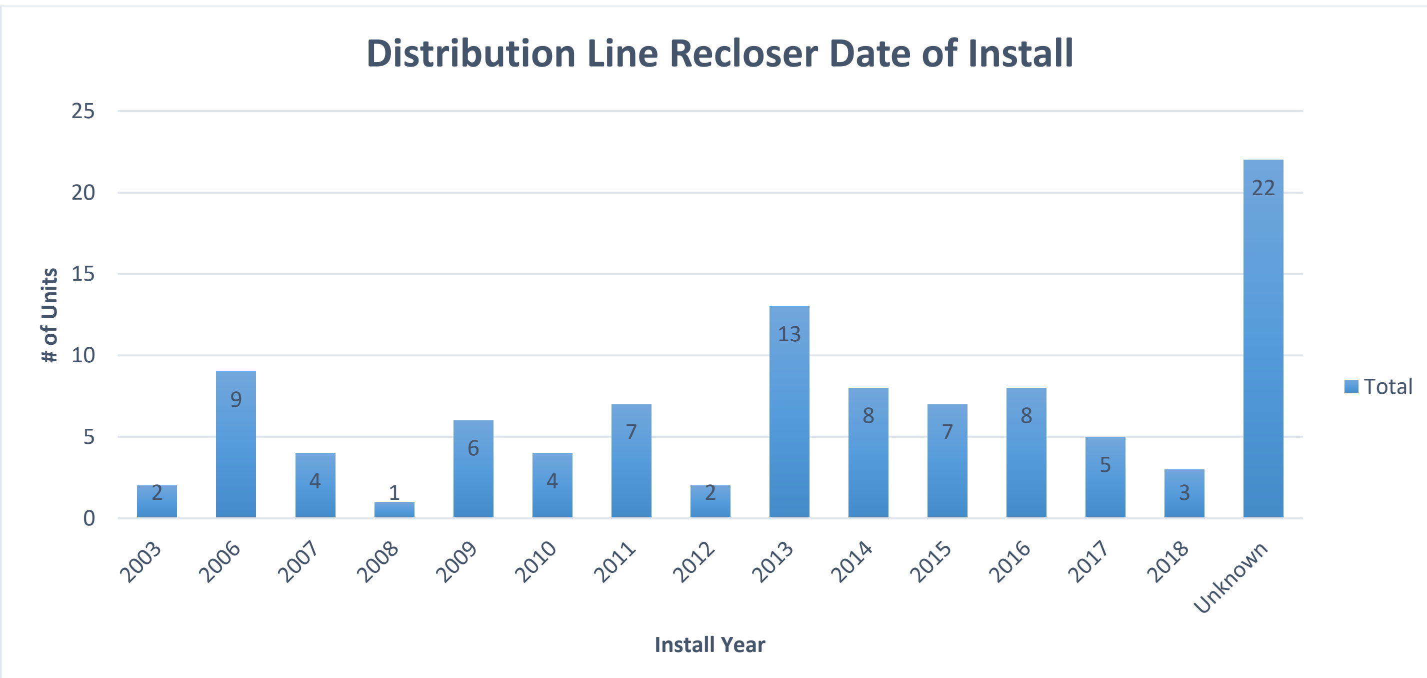
1.0 Purpose and Scope

The intent of this strategy is to provide an approach for managing our distribution and subtransmission line reclosers. This strategy is designed to provide for a sustainable distribution and subtransmission system. Substation reclosers are not covered by this strategy.

2.0 Strategy Description

2.1 Background

Liberty-NH has approximately 95 reclosers in service across the distribution and sub-transmission system. Most of the reclosers were installed after 2003 making this a relatively young asset group. Install date is unknown for 22 units.



From a technology standpoint, the vast majority of the population is Cooper Power System products using either a Form 3, 3A, 4C, 5 or 6 control. The Form 3 and 3A controls are at the end of their service life. All new recloser installations will be Viper-S or ST using a Switzer SEL-651R control with remote status and control. All existing reclosers without communications will be evaluated for implementation of remote status and control capabilities.

2.2 Strategy

Substation Maintenance Standards/Procedures outline the required maintenance procedures for line reclosers and sectionalizers. These procedures need to be followed to establish a uniform approach for the routine inspection and maintenance of these assets. Recloser outages are typically large so an appropriate level of maintenance is needed to offset the higher risk mis-operations and failures represent. During this inspection, if the unit or control is no longer fit for service and spare parts are not available the unit and/or control will be retired and replaced with a new unit.

Reclosers and controls will be evaluated separately. If the control is no longer fit for service and cannot be repaired it can be replaced independently assuming the recloser is compatible with recent vintage controls (SEL-651R). If the recloser is no longer fit for service and cannot be repaired both the recloser and control will be replaced. Serviceable controls of type Form 6, SEL-651R or later will be held as spares.

The estimated life expectancy of a line recloser is 35 to 40 years. It is anticipated that after this time the device is technologically obsolete and approaching the end of window for economic maintainability.

3.0 Benefits

The principal benefits to recloser replacement are improved employee safety and reliability improvements related to recloser inspection and maintenance (not just replacement).

3.1 Safety & Environmental

Recloser replacements prior to failure are beneficial due to improved employee safety during routine and emergency operations. Environmentally friendly solid dielectric insulated design eliminates oil leaks and oil spills.

3.2 Reliability

The reliability benefit associated with recloser replacement is negligible. A slight improvement in service restoration time is expected as new units gain supervisory control capabilities; however this contribution will not be large. Replacing units prior to failure will avoid the potential for the occasional large and extended interruption typically associated with a recloser failure. Greater reliability impact is anticipated from a uniform inspection program which should limit the number of recloser mis-operations due to maintenance issues (dead batteries, faulty controls, etc.).

3.3 Regulatory

The regulatory benefit associated with recloser replacement is negligible.

3.4 Customer

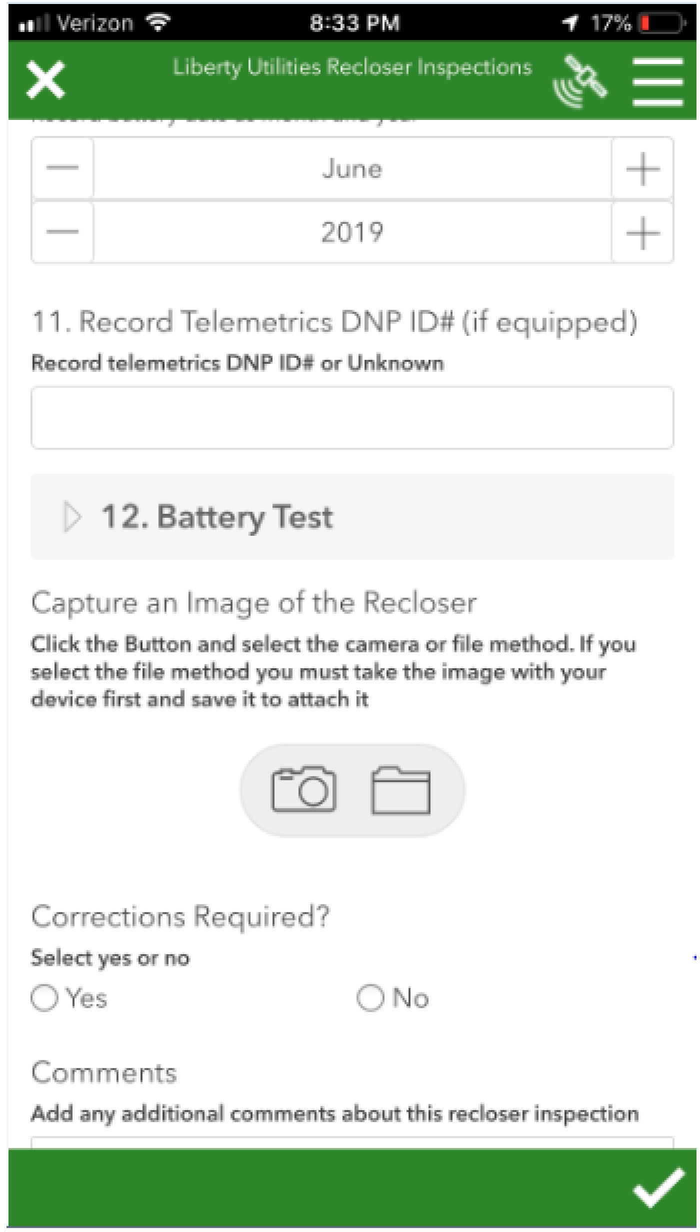
The customer level benefit associated with recloser replacement is negligible. Customers will share in the benefit from the improved reliability expected from the inspection program.

4.0 Estimated Costs

An estimated cost of $75,000 capital per recloser is assumed for this strategy. At the present time the number of units in need of replacement is unknown. Based on the results of the inspection program an estimate of the number of units approaching their end of life can be collected.

5.0 Implementation

Results from the inspections will be collected and reviewed using ESRI Survey 123 mobile application which facilitates recloser inspections, reporting of recloser locations/properties by feeder. After reviewing the available data, a determination of the best place to keep the data will be recommended. See sample below of the ESRI Survey 123 mobile application:



Regardless of the final location of the data, key fields in the GIS have been updated to begin to manage these assets and to incorporate these with planning software and upcoming ADMS systems.

During the next round of inspections, any missing data needed to manage these assets will be collected. This data will be used to update the GIS (or inspection database) so accurate records are available for the future. Devising a process to keep the GIS and real world in synch is critical to making this process work. At a minimum the following pieces of data are required:

- Recloser Manufacturer
- Recloser Type
- Recloser Manufacture Date
- Control Manufacturer
- Control Type
- Control Manufacture Date
- Type of Communications (if any)
- Serial Numbers

The Distribution Automation Strategy may impact the selection and the cost per recloser. At the present time, this impact is not expected to be large.

6.0 Risk Assessment

6.1 Safety & Environmental

The risk associated with not proactively replacing reclosers is the increased possibility of an employee safety related problem during routine or emergency operations. Environmentally friendly solid dielectric insulated design eliminates the risks of hazards associated with oil leaks and oil spills.

6.2 Reliability

The reliability risk associated with reclosers is negligible. Running units to failure will result in the occasional large and extended interruption typically associated with a recloser mis-operation. Not conducting routine inspections represents a greater risk (due to increases mis-operations) than unit failure.

6.3 Regulatory

The regulatory risk associated with reclosers is negligible.

6.4 Customer

The customer risk associated with reclosers is negligible.

7.0 Data Requirements

7.1 Existing:

- ArcFM GIS/ – recloser data
- ESRI Survey 123 – Collection of inspection data

7.2 Proposed:

- ArcGIS Desktop
- ESRI Survey 123 / Terra Spectrum

7.3 Comments:

Improved data quality for the GIS objects will enhance the ability to proactively manage these assets by allowing units to be selected by control type, recloser type, manufacturer, etc.. A review of the work flow used to populate the recloser data fields is recommended. Additional data regarding the settings of the recloser are also being collected in the GIS for future implementation with ADMS and system modeling software.

8.0 References

LU SMP 401.07.2 – Distribution Line Recloser (PTR)
LU EOP D011 – Inspection – Maintenance Reclosers
DAS-012 Recloser Application Strategy
DAS-002 Distribution Automation Strategy

DAS-013 Underground Getaway Cable Strategy

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Strategy Statement

Getaway cables are defined as the underground cables from a substation to the first overhead structure of a predominately overhead or a mixed overhead/underground circuit. Get-away cables are to be replaced based on their individual failure record. In general, cables that are over 50 years of age are targeted for replacement.

Direct Buries Cables

Upon the first failure of a direct buried get-away cable, the cable is to be repaired immediately as an emergency as opposed to being scheduled for future repair. An estimate should be prepared for replacing the get-away and that project should be evaluated with all other proposed projects with the company's existing risk scoring model. A list of cables not replaced should be maintained. Upon the second failure of a direct buried get-away cable, the cable should be repaired as an emergency and the cable should be replaced.

Any replacement of direct buried cables should be with a duct lay cable system in accordance with current company construction standards.

Duct Lay Cables

Upon the first failure of a duct lay get-away cable, the cable is to be repaired immediately as an emergency. Strong consideration should be given to replacing an entire section of cable (manhole-to-manhole or pole-to-pole, etc.) even if the cable could be pieced-out. Upon the second failure of duct lay get-away cable, the entire get-away cable should be replaced except for those sections that had been previously replaced due to earlier failures.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	6/19/19	Revision of Strategy for Liberty-NH	Joel Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	John Teixeira Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

1.0 Purpose and Scope

This paper details the strategy for underground getaway cables. Getaway cables are defined as the underground cables from a substation to the first overhead structure of a predominately overhead or a mixed overhead/underground circuit. This strategy can apply to a circuit that is generally classed as an underground circuit typically found in an urban area.

While not dealt with separately, this strategy is intended to also apply to short sections of mainline underground cable in a predominately overhead or mixed circuit such as found typically at highway or bridge crossings.

This strategy is a reactive strategy based on actual performance of individual underground get-away cables and proactive based on replacement of underground cables that are over 50 years of age.

2.0 Strategy Description

2.1 Background

All distribution circuits in the company have been rated as overhead, underground, or mixed construction circuits; circuits with 75% or more circuit miles of overhead construction have been rated as overhead, circuits with 75% or more circuit miles of underground construction have been rated as underground, and the remainder have been rated as mixed construction. In many cases this results in circuits generally thought of as underground being rated as mixed.

Based on data from the ArcFM GIS system and the working definition of overhead, underground, and mixed construction class, the company has approximately 29 distribution circuits with underground get-aways.

Underground get-aways can be either duct lay or direct buried. The quality of data related to duct lay vs. direct buried is limited in quality. Nonetheless, the strategy for each type of construction is, necessarily, slightly different. Table 1 below lists the total impact from a reliability standpoint that these interruptions had on our Customers.

	5 Year Totals			
	# of Ckts w/Cable Getaway Failure	**Events**	**CI**	**CMI**
NH	4	4	222	34,116

Table 1- 2015-2019 Get-Away Cable Failure- Reliability Data

In the past five years, Liberty has replaced and upgraded underground cable getaways for feeders at Salem Depot, Baron Ave, Pelham and Hanover stations. This has resulted in a decrease in cable faults, having only 4 occurring within the last five years. Liberty has not recorded a cable getaway fault since 2017.

2.2 Direct Buries Cables- Strategy

Upon the first failure of a direct buried get-away cable, the cable is to be repaired immediately as an emergency as opposed to being scheduled for future repair. An estimate should be prepared for replacing the get-away and that project should be evaluated with all other proposed projects with the company's existing risk scoring model. A list of cables not replaced should be maintained. Upon the second failure of a direct buried get-away cable, the cable should be repaired as an emergency and the cable should be replaced.

Any replacement of direct buried cables should be with a duct lay cable system in accordance with current company construction standards.

2.3 Duct Lay Cables- Strategy

Since repair of a duct lay cable fault often requires the replacement of one or more sections of cable, the strategy for duct lay get-away cables differs from that of direct buried cables.

Upon the first failure of a duct lay get-away cable, the cable is the cable is to be repaired immediately as an emergency as opposed to being scheduled for future repair. Strong consideration should be given to replacing an entire section of cable (manhole-to-manhole or pole-to-pole, etc.) even if the cable could be pieced-out. Upon the second failure of duct lay get-away cable, the entire get-away cable (where there is more than one section) should be replaced except for those sections that had been previously replaced due to earlier failures.

2.4 Future

This strategy provides for proactive replacement of get-away cables that are over 50 years of age. Currently the company is investigating condition assessment testing of underground cables. The company will investigate the cost and viability of a proactive testing program and will update this strategy accordingly.

3.0 Benefits

This approach requires that get-away cables be replaced after two failures. After a single failure, the replacement is to be evaluated, along with all other proposed company projects, in the company's risk scoring model. If the replacement evaluates higher than other projects competing for the company's resources, it provides for its replacement. This approach provides a balance between the competitive interests of the reliability and limited resources.

3.1 Safety & Environmental

There are no significant safety or environmental benefits.

3.2 Reliability

Based on the previous five years, Get-away cable failures add approximately 222 customer interruptions and 34,116 customer minutes of interruption to our reliability performance each year. Proactive replacement of underground cables that meets the criteria will result in a slight reliability improvement.

3.3 Regulatory/Reputation

This strategy eliminates the third, and potentially second, get-away cable failure for any circuit. It is the multiple failures that do the greatest damage to the company's reputation and result in the most severe regulatory consequences.

4.0 Estimated Costs

The Company plans to replace the following cables:
- Replace 800 ft direct buried cables 6L2 Maynard St Hanover between 2024 and 2025.
- Replace 500 ft direct buried cables 13L2 Town Farm Rd Salem in 2023.

Some increase in O&M costs may be expected from the requirement that failed cables be repaired immediately, sometimes on overtime, as opposed to being scheduled. This increase is impossible to estimate.

5.0 Implementation

There are no known barriers to immediate implementation of this strategy.

6.0 Risk Assessment

6.1 Safety & Environmental

This strategy has no significant safety or environmental risk.

6.2 Reliability

Currently there is a limited risk that a get-away cable will fail and there will be no capacity to pick up customers on feeder ties or that there will be multiple get-away failures at the same time. This risk is addressed by the company's Distribution System Planning Guidelines.

This strategy makes no significant modifications to this risk.

6.3 Regulatory/Reputation

As with reliability risk, the company's Distribution System Planning Guidelines currently provide guidance on acceptable risk when multiple equipment interruptions occur and when feeder tie capacity is not available. This strategy makes no significant modifications to this risk.

7.0 Data Requirements

7.1 Existing/Interim:

The data used to develop this strategy was derived from the following sources:

- The ArcFM GIS system was used to determine the circuits with underground get-aways (underground primary cables leaving a substation boundary).
- Reliability data was extracted from the Responder system.

7.2 Proposed:

- ArcGIS Desktop
- ADMS

7.3 Comments:

Future consideration will be given to investigating the efficacy of proactive condition assessment methods for get-away cables and the viability of using these methods at Liberty.

8.0 References

Distribution System Planning Guidelines

DAS-014 URD/UCD Cable Strategy Statement

This strategy applies to Underground Residential Development (URD) and Underground Commercial Development (UCD) cables sized #2 and 1/0 and does not apply to mainline or supply cables. It sets forth the approach for replacing or rehabilitating (cable injection) these cables. This strategy supports the current method for handling cable failures by fixing upon failure and offers options for managing cables that have sustained multiple failures. Interruptions on #2 and 1/0 cables do not significantly influence our service quality target but are very important to customer satisfaction. This strategy is designed to support customer-level reliability performance and provide for a sustainable distribution system.

This strategy recommends fix on failure and includes two options for managing failed cables: where possible, cable rehabilitation through insulation injection or cable replacement. Insulation injection is identified as the preferred solution for direct buried Cross Linked Polyethylene (XLPE) cables in a loop fed arrangement. The overall condition of the cable and installation specifics will determine if insulation injection is a viable option. Direct buried cables with corroded neutrals or multiple splices in one section are not good candidates for insulation injection. In these cases, cable replacement is a more suitable solution.

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
3	6/19/2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering
2	11/10/2010	Complete revision of strategy and strategy title to include commercial developments.	Alyne Silva Distribution Asset Strategy	Ellen Smith Chief Operating Officer US Electricity Operations Chairman of DCIG
1	01/03/2008	Initial Issue	John Teixeira Asset Strategy Development	John Pettigrew Executive Vice President, Electric Distribution Operations

Table 1 – Amendment Record

URD/UCD CABLE STRATEGY STATEMENT **1**
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9.0 Appendix A – Replace or Rehabilitate Decision Tree **9**

Strategy Justification

1.0 Purpose and Scope

The intent of this strategy is to provide the approach for replacing or rehabilitating underground residential or commercial development cables, sizes #2 and 1/0, when a cable faults occur.

2.0 Strategy Description

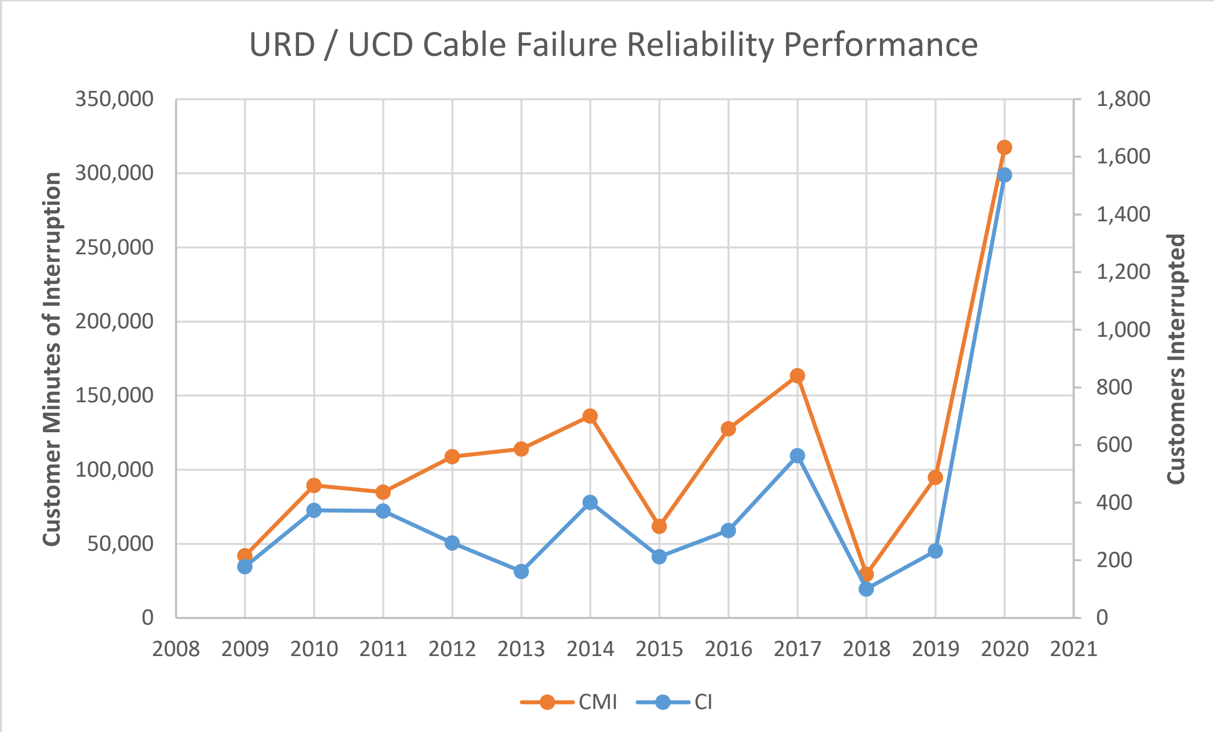
2.1 Background

URDs and UCDs have historically been served by 15kV class, #2 or 1/0, solid dielectric cables. Through the years a number of different insulations have been employed across the company including XLPE, and EPR cables. Likewise these cables have been installed directly buried or in conduit systems.
Direct buried solid dielectric cables installed from the late 1960’s through the late 1980’s have shown the most susceptibility for failure. Failure mechanisms have ranged from improper backfill material during initial installation, damage from third party excavations, and an incomplete understanding of XLPE failure mechanisms by the industry (water trees, electrical trees, CN corrosion, etc) during this period. These cable types have also shown a susceptibility to neutral corrosion. These types of cables tend to be XLPE or PE insulated and are in excess of twenty years of age.

2.2 Data

A URD/UCD may have more than one type of cable as they are typically made up of sections or half loops. The Company maintains a database of all UCD and URD cable faults to document causes and identify locations with repeat interruptions.

The figure below shows the reliability performance for URD and UCD for the Company between 2009 and October 31, 2020. The data shows a worsening trend in reliability with a noticeable spike in 2020. The Company is investigating the recent increase in cable fault incidents supplying residential and commercial developments as well as the impact of increased residential loading from work from home practices.



2.3 Events

When customer interruptions occur, the associated failure data is collected through the Responder reporting system. The data collected includes: time/date, cause, and failure location.

The following Table lists the number of interruptions for the worst performing URDs between 2011 and October 31, 2020:

Year	Blueberry Circle, Pelham	Lancelot Court, Salem	Lancaster Farm Rd, Salem	Hidden Valley - Charlestown	Haskins Development - Enfield
2011		1			1
2012	2			1	
2013			1		
2014		1		1	
2015			2		
2016				1	
2017	2	2			
2018					
2019	1		1		1
2020	3	2	1	1	1
Total	**8**	**6**	**5**	**4**	**3**

Historically, the approach in dealing with these cable faults has been reactive where cables are fixed once they fail. The intention of this strategy is to formalize programs to address such cables that fail multiple times.

Cable injection is recommended in this strategy for loop fed, direct buried XLPE cables that meet the replacement criteria. However, the suitability of a cable for injection is dependent upon its physical condition and number of splices per cable section. This strategy recommends the assessment of these cables splices and neutrals to identify whether cable injection or cable replacement is to be employed to address underground cable sections that have experienced multiple faults.

2.4 URD/UCD Cable Strategy

The URD Cable Strategy recommends that an entire URD or UCD be assessed for cable replacement or cable insulation injection if three failures occur within a three year time frame. Cable sections are also to be replaced or rehabilitated once two cable faults within the same cable section have occurred. This strategy limits the number of repeated interruptions seen by customers within a given URD or UCD. Since URD or UCD cable failures impact a limited number of customers, this strategy has a minor impact on reliability metrics.
These projects will be performed by internal resources for all craft work, outside contractors for all civil work and a mix of resources for design work.
On cable injection projects, each cable section is tested and evaluated prior to injection. Cable sections with greater than two splices or greater than 50% neutral corrosion will not be injected. Cables are pressure tested for ability to contain the pressure applied during the injection process. During injection, some cables are found to be blocked due to splice configuration. If so, these cables are to be replaced. The cable vendor provides the testing resources, records the test results and injects the cable. Internal resources provide the craft work including injection elbows, injection ports on riser terminations, and all switching and tagging.

In general, wherever possible, designs will include installation of additional short runs (up to 500ft) of primary cable to create loop fed arrangements and the installation of fault circuit indicators (FCI) at every padmount transformer. Significant customer satisfaction is gained through the operational flexibility of loop fed URDs/UCDs and the installation of FCIs mitigates the length of restoration time. Surge protectors/lightning arrestors shall be installed at all riser poles and transformers with open point as per Liberty Utilities Construction Standards.

3.0 Benefits

3.1 Safety and Environmental

#2 and 1/0 size underground cables in developments do not present any safety or environmental benefit.

3.2 Reliability

Since cable failures in these developments affect limited number of customers, this strategy will improve reliability at a pocket-level rather than at an overall system reliability level.

3.3 Customer/Regulatory/Reputation

This strategy limits the number of repeated interruptions in a given development. This will generally limit the potential damage to the company’s reputation with the public, state regulators or other governmental authorities.

3.4 Efficiency

Once a development experiences a cable fault, it should be recorded in the Responder Archive allowing for accurate data for future analysis. Response to failure should follow the decision tree shown in Figure 1 permitting for consistency and efficiency.

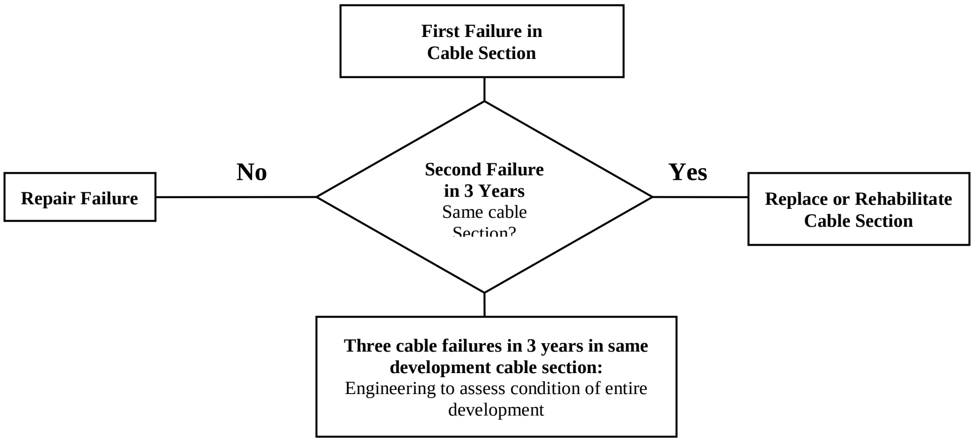


Figure 1 – Response to a URD/UCD Cable Failure (direct buried, loop fed arrangement)

Notes:

1) After any failure, surge protection must be reviewed and brought to current Standards if needed.

2) When cable in a development was installed in phases, judgment must be exercised as to the scope of the replacement or cable injection. See Appendix A for guidance to determine when a replacement or injection is the preferred method of addressing these cable failures.

4.0 Estimated Costs

Cable injection is less expensive and less intrusive on the affected customers than cable replacement and is the preferred method for handling direct buried XLPE cables in loop fed developments. However, in cases where these cables are found to have severely corroded neutrals (with less than 67% intact as determined by diagnostic testing), blocked conductors (through splices or other means) or have experienced more than three faults in the same cable section, cable replacement is recommended. The potential exists for rehabilitation costs to escalate significantly if more injection is required than estimated.

The targeted annual average budget for the next five fiscal years is $1.5M. With an average of $95 per foot of cable replacement, this allows for an annual cable replacement of 3 miles.

The projects listed in the Table below will be included in the 2019-2023 Liberty NH Capital Work Plan.

	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	
$M	**2021**	**2022**	**2023**	**2024**	**2025**	***Total***
Blueberry Cir - Pelham	$0.450	$0.450				$0.900
Replace Subsurface Transformers		$0.300	$0.200	$0.200	$0.200	$0.900
Hidden Valley - Charlestown	$0.550	$0.450				$1.000

Lancaster Farm Rd			$0.250			$0.250
Hidden Acres - Charlestown			$0.450	$0.350		$0.800
Lancelot Court - Salem				$0.250		$0.250
Haskins Development - Enfield			$0.450	$0.350		
Oak Ridge - Lebanon				$0.350	$0.350	$0.700
Total	$1.000	$1.200	$1.350	$1.500	$0.550	$5.600

5.0 Implementation

The criteria for recommending cables to be replaced or injected are as follows:

- If two cable failures occur in the same section of cable within a three year period; replace or rehabilitated individual cable section.
- After three cable failures in the same half loop within a three year period, engineering should assess the condition of the entire development and suggest cable replacement or rehabilitation.

This is outlined in Figure 1.

The following Table lists the recommended mitigation for each URD:

Project Title	Scope
Blueberry Cir – Pelham	Replace 3ph direct buried with new 1ph cable in conduit.
Hidden Valley – Charlestown	Replace 3ph direct buried with 2 separate 1ph loops in conduit.
Lancaster Farm Rd – Salem	Replace repeat faulted sections of cable and perform cable cure.
Hidden Acres – Charlestown	Replace direct buried cable with new 1ph cable in conduit.
Lancelot Court – Salem	Replace repeat faulted sections of cable and perform cable cure.
Oak Ridge – Lebanon	Replace direct buried cable with new 3ph cable in conduit.
Haskins Development – Enfield	Replace direct buried cable with new 1ph cable in conduit and establish loop between Low Rd and Haskins Rd

6.0 Risk Assessment

6.1 Safety and Environmental

Deteriorated underground equipment poses a serious safety risk for utility personnel and the public.

6.2 Reliability

URD/UCD cable failures contribute a relatively small fraction of the overall reliability and affect the customer or group of customers fed by the development. While these interruptions have little impact to the reliability performance of the company, they are very significant to the customers in the development.

6.3 Customer/Regulatory/Reputation

This strategy allows for the implementation of a reactive approach when dealing with URD/UCD cable failures. Proactively reviewing these areas should maintain customer satisfaction in these locations and minimize repeat interruptions which result in a negative customer experience given the typical long restoration times associated with locating and repairing the problem. Improving the condition of the underground cables could reduce the risk of stray voltages and improve the quality of the power being supplied to customers.

6.4 Efficiency

Cable faults present a risk especially for direct buried cables since the only way to get to the fault is to first find it and then excavate to expose the cable. Conduit lay cables can also present a problem due to a collapsed duct or blockage.

7.0 Data Requirements

7.1 Existing/Interim:

The Responder reporting system tracks cable failures.

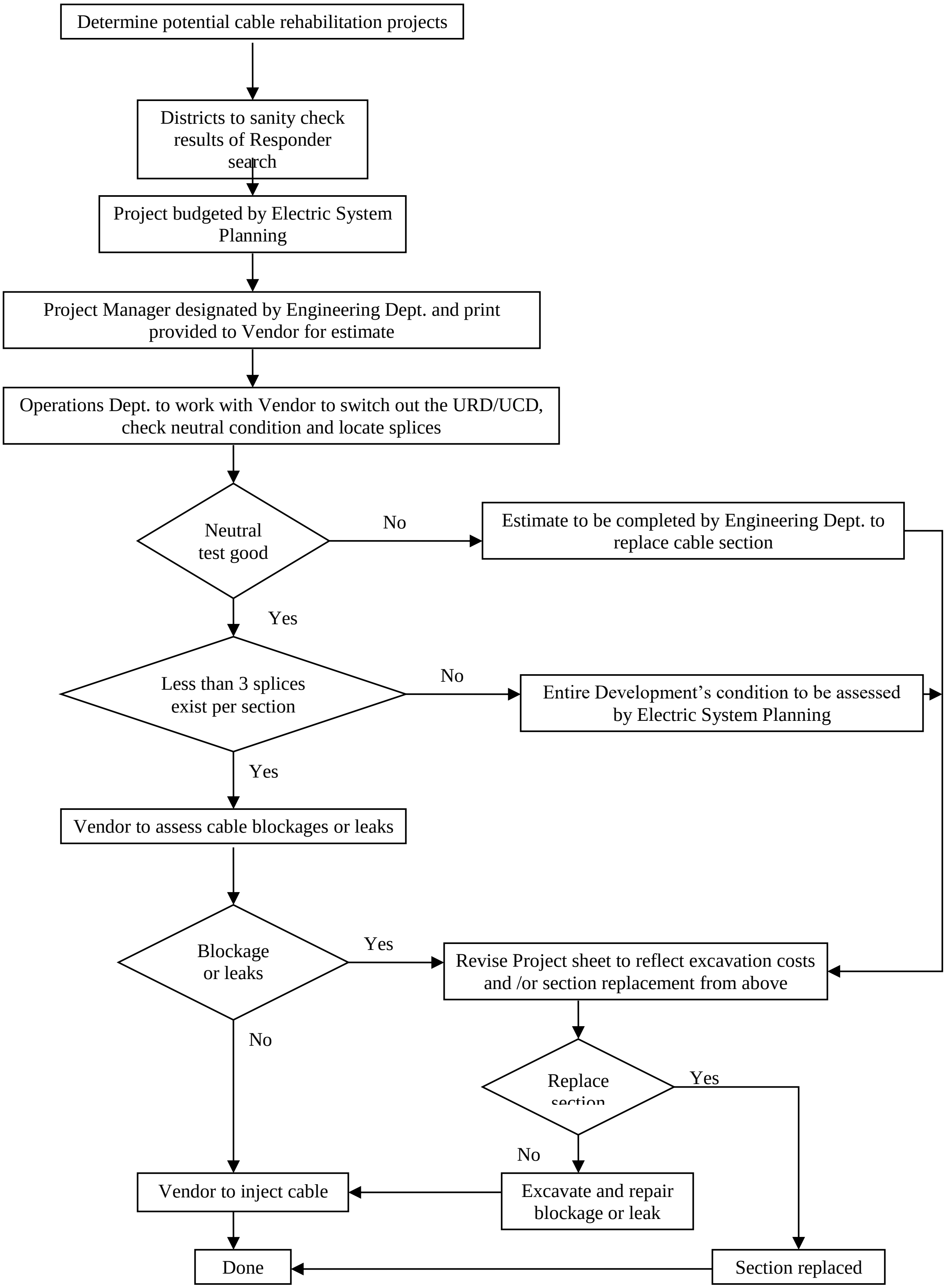
7.2 Proposed:

ArcGIS Desktop / ADMS

8.0 References

None

9.0 Appendix A – Replace or Rehabilitate Decision Tree



DAS-015 Overhead Distribution Fusing Strategy

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Strategy Statement

The intention of the strategy is to provide high level sectionalizing fusing guidelines. To support this strategy all overhead feeders require review over the next five years (2021 – 2025) for proper fuse installations. Based on approximately 40 overhead feeders in New Hampshire and a 5 year cycle, 8 feeders will be targeted for review every year.

Sectionalizing fuses are needed to isolate permanent faults on the distribution system. Ideally, these fuses are installed at locations which limit the size of the interruption to the fewest number of customers possible. Proper sectionalizing fuse application will limit the duration of the interruption by isolating the fault in a small area and reducing the time required to find the fault. This is a reliability-focused strategy designed to meet both regulatory targets and support first quartile reliability performance.

If this strategy is not adopted, potentially small interruptions will continue to be larger due to lack of proper fusing. This effect will be more significant on primary sections with significant exposure due to the added time needed to patrol the lines looking for the cause of the interruption. While each individual change per event is small, collectively over a number of years, the effect of proper sectionalizing fusing will be significant at the customer level and measurable at the system level.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	11/05/2018	Initial Issue	Joel Rivera Manager – Electric System Planning	Charles Rodrigues Director of Engineering

Strategy Justification

1.0 Purpose and Scope

This strategy document sets forth the conditions for the installation of sectionalizing fuses on overhead distribution feeders. In all cases the purpose of sectionalizing fusing is to protect the feeder mainline and/or limit the size of the interruption. This is a reliability-focused strategy designed to meet both regulatory targets and support first quartile reliability performance.

2.0 Strategy Description

2.1 Definitions

The following definitions are being provided to ensure a complete understanding of the issues discussed in the strategy.

Distribution Feeder – Typically distribution feeder voltage levels are between 2.4 kV and 15 kV, however voltages as high as 23 kV are used for distribution at Liberty Utilities NH. Distribution feeders typically supply a large number of customers (hundreds to thousands) using a combination of overhead and underground facilities. Additionally, both three phase and one/two phase sections are present.

Mainline – Any three phase primary location that, if faulted, would operate a three-phase, gang-trip device (reclosing or otherwise). This includes sectionalizers, non-reclosing breakers, etc., but excludes three single phase reclosers on the same or adjacent poles.

Mainline Exposure – Any primary location that, if faulted, would operate a three-phase, gang-trip device (reclosing or otherwise). This includes sectionalizers, non-reclosing breakers, etc., but excludes three single phase reclosers on the same or adjacent poles. Our goal is to have mainline exposure equal mainline through the proper use of line fuses.

Cutout – The fuse holder and fuse combination.

Fuse – The interrupting device within the cutout.

2.2 Strategy

Sectionalizing fuses are needed to isolate permanent faults on the distribution system. Ideally, these fuses are installed at locations which limit the size of the interruption to the fewest number of customers possible. Due to coordination requirements between protective devices, it may not always be possible to install as many sectionalizing fuses as we would prefer. When this becomes the case the following protection priority should be applied:

1. Mainline
2. Three phase taps
3. Two phase taps
4. Single phase taps

Fuses should be installed at natural breakpoints in the distribution primary; bifurcations, taps, changes in number of phases, etc. For side tap installations, the fuse should be installed at the tap location. Possible exceptions to this are pole locations which are difficult to reach for refusing or poles which are too congested to allow the installation of a fuse. In all circumstances the tap fuse must be clearly visible and identifiable from the tap location.

Due to future plans for Distribution Automation and the increasing number of line reclosers being installed, a 100K fuse is typically the largest fuse size which can be installed on most 15 kV feeders. However, if a larger fuse size will coordinate it is acceptable to install.

Series installation of the same size fuse is not permitted; one fuse should be removed or changed to a size which allows for proper coordination.

2.3 URD Fusing

Single span taps to URD's should only be fused in one location (preferably at the riser).

In areas where proper coordination cannot be obtained due to URD riser pole fuses, the installation of a cutout with a solid blade and fault indicator can be installed. Sizing the transformers within the URD (during design) to allow for the installation of a riser pole fuse is a good alternative for new URD's.

2.4 Stepdown Fusing

Fuses should be installed on both the high and low side of stepdown/stepup transformers.

2.5 Other Primary Equipment Fusing

Fuses should be installed on every distribution transformer, including CSP's (completely self-protected) and all capacitor banks.

2.6 Load Growth

As fused tap loading increases due to load growth or circuit rearrangements, it may not be possible to provide protection via fusing. The installation of a line recloser (three-phase or single-phase) should be considered before additional mainline exposure is added to the feeder. If adding mainline exposure is the only alternative, the condition of the primary, any vegetation related issues and sectionalizing fuse applications should be reviewed and addressed as part of the construction. Fuses should not be removed without assessing the impact.

2.7 Mainline Sectionalizing

The installation of a loadbreak switch with fault indicator or three single blade disconnects at three phase locations should be considered to provide a sectionalizing point for fault isolation. Distribution feeders should be limited to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or 2 MVA of load between disconnecting devices or sectors.

2.8 Strategy Application

The intention of the strategy is to provide high level sectionalizing fusing guidelines. To support this strategy all overhead feeders require review on a five year cycle for proper fuse installations. Based on approximately 40 overhead feeders in New Hampshire, 8 feeders require review annually.

3.0 Benefits

The principal benefits of the Fusing Strategy are reliability and customer related.

3.1 Safety & Environmental

This strategy has minimal safety or environmental impact.

3.2 Reliability

It is estimated that approximately 9% of events are mainline. The additional fusing will aid in fault locating by limiting the patrol area to find the problem. This should result in a decrease in the interruption duration thus reducing CAIDI.

3.3 Customer/Regulatory/Reputation

This strategy will result in an improvement in service quality for New Hampshire customers. The additional fusing will limit the size and duration of future distribution interruptions. This strategy has no direct regulatory impact but the projected reliability improvements will aid in meeting future service quality targets.

3.4 Efficiency

This strategy will result in improved trouble crew efficiency during fault location by limiting the size of the patrol area. Trouble crews will be better able to locate faults and restore service to our customers in a timely manner.

4.0 Estimated Costs

An estimated cost of $500 per cutout is assumed for each cutout installation.

Estimated Line Cutout Costs		
Year	Approximate # Cutouts	Total Cost
2021	120	$ 60,000
2022	120	$ 60,000
2023	120	$ 60,000
2024	120	$ 60,000
2025	120	$ 60,000
Total	480	$ 300,000

Table 1 - Estimated Costs

5.0 Implementation

Fusing will be reviewed as part of Engineering Reliability Reviews of distribution feeders. Additionally, a customers interrupted per event list is available to find feeders with high CI/Event numbers and field personnel can aid in identifying potential fuse locations. To support this strategy all New Hampshire overhead feeders require review over a 5 year cycle for proper fuse installations. Synergi Distribution modeling software and ArcFM will be utilized to assist with reviewing fusing and coordination.

Funding for this strategy item will be reviewed and adjusted annually.

6.0 Risk Assessment

The principal risks of this strategy are reliability and customer related.

6.1 Safety & Environmental

This strategy has minimal safety or environmental risk.

6.2 Reliability

If this strategy is not adopted, potentially small interruptions will continue to be larger due to lack of proper fusing. This effect will be more significant on primary sections with significant exposure due to the added time needed to patrol the lines looking for the cause of the interruption. While each individual change per event is small, collectively over a number of years, the effect of proper sectionalizing fusing will be significant at the customer level and measurable at the system level.

6.3 Customer/Regulatory/Reputation

Not implementing this strategy will result in larger and longer interruptions. This will result in continued customer dissatisfaction with their service quality. This strategy has no direct regulatory risk. Not installing the additional fusing in New Hampshire may not negatively impact reliability but it will not improve it.

6.4 Efficiency

Not implementing this strategy will result in continued larger and longer than necessary outages due to extra time spent by trouble crews during fault location.

7.0 Data Requirements

7.1 Existing

- ArcFM – Feeder asset data
- Responder Archive – Feeder reliability data
- Synergi – Planning and Modeling Software

7.2 Proposed

- ArcGIS Desktop
- ADMS
- Synergi

DAS-016
Guidelines for Analysis of Non-Wires Solutions
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Strategy Statement

Liberty Utilities New Hampshire is integrating the identification and analysis of non-wires solutions (NWS) into its distribution system planning process, ensuring that Non-Wires Solutions (NWS) are evaluated on an equal footing with traditional investments as solutions to capacity and reliability issues. This is consistent with the company's commitment to provide safe, reliable and efficient delivery of electricity to its customers.

This integrated distribution planning process considers more than the estimated costs of each potential planning solution, but also compares each option across four risk categories, 1) reliability, 2) feasibility, 3) performance and 4) environmental. This NWS Strategy Document provides a transparent procedure for Liberty Utilities to use going forward in the development of its integrated resource plans.

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	11/26/2020	Integration of Project Evaluation Process to the System Planning Process	Joel A Rivera Manager – Electric System Planning	Charles Rodrigues Director of Engineering

Non-Wires Solutions

1.0 Purpose and Scope

The purpose of this guideline document is to outline a procedure to be used as part of the system planning processes to consider investments in Non-Wires Solutions (NWS) on an equal footing with Traditional investments as possible solutions to capacity and reliability issues.

This document provides guidance for the screening and analysis of Non-Wire Solutions and the comparison of feasible Traditional Alternatives, and a framework within which such comparisons can be made. These guidelines will be updated based on experience in analyzing and implementing NWS projects.

LIBERTY UTILITIES NEW HAMPSHIRE

Distribution Project Evaluation Flow Chart

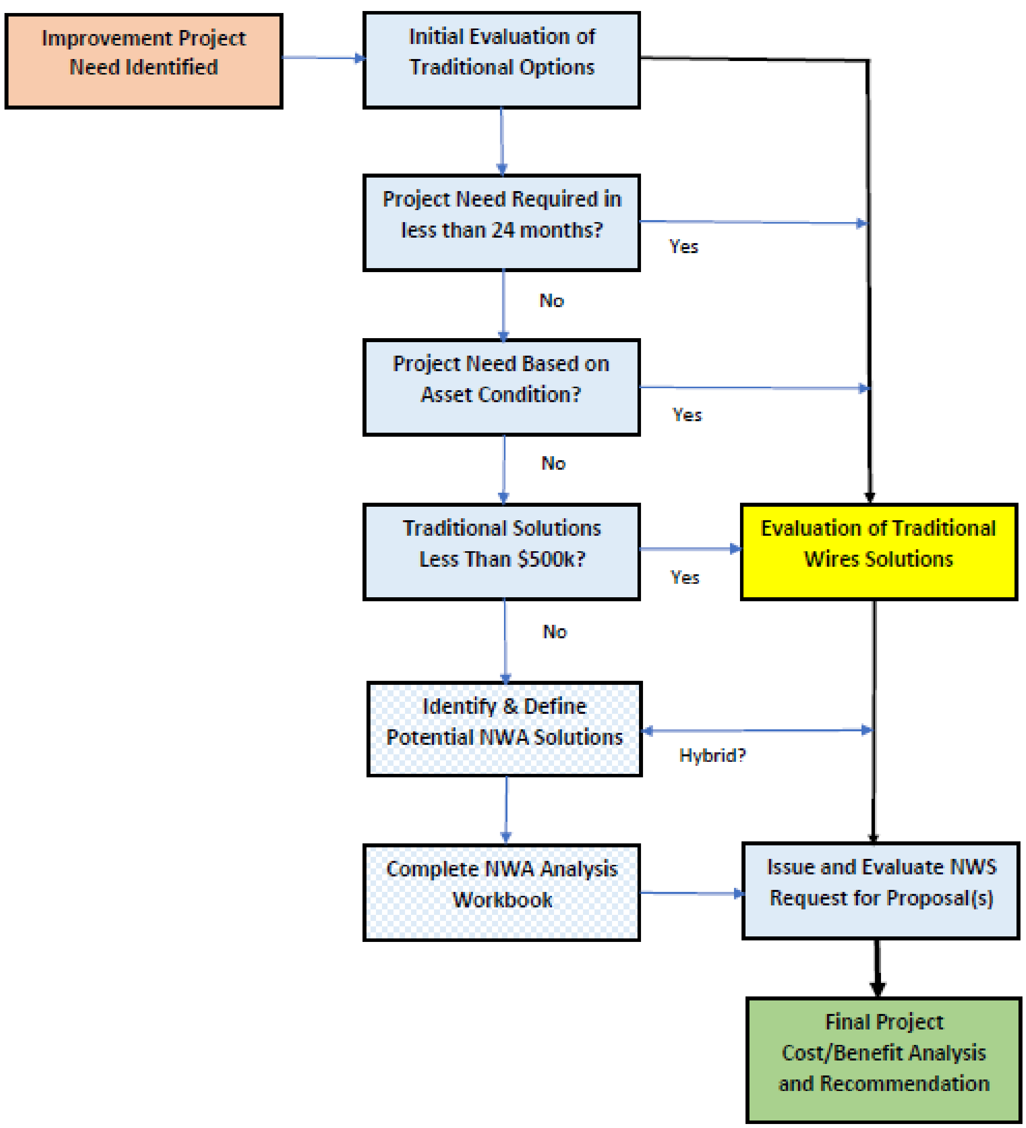

Figure 1: Overview of Project Evaluation Process

Figure 1 provides a high-level overview of the NWS project evaluation process, which is described in more detail in subsequent sections of this document.

2.0 Definitions

2.1. Demand Side Management (DSM): Actions that reduce consumer requirements for electric service, including energy efficiency measures and load control measures.

2.2. Distributed Energy Resources (DER): Distributed Generation and Electric Energy Storage.

2.3. Distributed Generation (DG): An electric power source connected on the customer side of the meter or on the wires company's side of the meter.

2.4. Limiting Element: The element within a feeder, substation, and/or supply line that could constrain transfers or that could be overloaded for design conditions.

2.5. Electric Energy Storage (EES): Use of others forms of energy than electricity, such as chemical, kinetic, or potential energy, to store energy that will later be converted to electricity.

2.6. Non-Wires Solutions (NWS): Demand Side Management programs and Distributed Energy Resources that complement and improve operation of existing systems, and that individually or in combination defer the need for upgrades to the distribution system.

2.7. System Reconfiguration: Switching actions used to reallocate how load is served by existing distribution facilities.

2.8. Traditional Alternatives: The construction or replacement of traditional transmission and distribution facilities (e.g. transmission lines, distribution lines, transformers, System Reconfiguration, and reactive supply equipment) to increase the capability of the system to provide reliable operation of the system.

3.0 Responsibilities

System Planners are responsible for assessing and defining resource needs on the distribution and sub-transmission systems and recommending solutions, including developing and analyzing potential Non-Wires Solutions for consideration.

4.0 Needs Assessment

An initial Needs Assessment is conducted by System Planners to identify conditions and Limiting Elements which require relief or system upgrades. Emerging problems are identified as long in advance as practicable, to allow for a comprehensive consideration of both the Traditional and the Non-Wires Solutions.

a) Planners use modeling software to evaluate the performance of the system within a Study Area under a variety of conditions. The models represent the existing system and consider forecasted changes in load.

b) If the planners identify a need within the Study Area, then it will be flagged and evaluated so that the conditions are understood and appropriate solutions can be applied.

c) Needs are specified in terms of impacted facilities (usually defined by feeder or substation), causal factors, system conditions, and projected solution need dates.

d) Planners identify the characteristics of load-based need, including the magnitude of the overload on the Limiting Element, the shape of the load curve that is impacting the loading on the Limiting Element, whether loading relief needs to occur prior to an event on the system or after an event on the system, and the projected year and season in which a solution is needed.

5.0 Initial Evaluation of Alternatives

An alternatives assessment that identifies potential Traditional Solutions to the issues identified in the Needs Assessment is conducted by System Planners. Traditional solutions will predominately be designed to serve the identified needs. Non-Wires Solutions will predominately be designed to reduce the loading on the Limiting Elements, in order to defer the Traditional solutions.

The advantages and disadvantages of the various alternatives must be considered, along with the risks posed by each option.

6.0 Screening of Non-Wires Solutions

Where an issue has been identified, a Non-Wires Solution may also be considered as an option to defer the Supply or Distribution Traditional solution for a period of time. Considering Non-Wires Solutions to every issue is not practical given the small cost of a large number of potential Traditional solutions, the magnitude of load relief required in certain situations, the time to acquire Non-Wires Solutions (and verify their availability) or instances where the issue is poor operating condition of the asset. It is possible that no Non-Wires Solutions will be considered feasible for a given need. As a result, the following screening criteria are a guide for System Planners to identify when Non-Wires Solutions will be evaluated as an alternative to Traditional solutions:

A. Identified need is at least 24 months in the future to allow time needed to develop a NWS;
B. The need is not based on Asset Condition; and
C. The Traditional solution, based on Engineering judgment, will likely be more than $0.5M.

7.0 Development of Alternatives

Feasible Traditional and Non-Wires Solutions are developed by considering technical, economic, environmental, regulatory, reliability, and scheduling factors. The development process includes the following steps:

a. Develop a range of possible Traditional, Non-Wires and Hybrid Solutions or Options. The Non-Wires Solutions should have sufficient scale and acceptable costs to avoid, defer, economically reduce, or modify the scope and cost of the Traditional Solution. The feasibility of a specific Non-Wires Solution plan depends on the installed and expected mix of end uses and whether the Non-Wires Solution can be operational in time to avoid significant expenses for the Traditional Solution. A hybrid Solution includes both Traditional and Non-Wires Solutions.

b. If applicable, determine the costs associated with the Traditional and Non-Wires Solutions.

c. Define the advantages and disadvantages, both quantitative and qualitative, in terms of benefits and risks for stakeholders.

d. Verify that Non-Wires Alternatives are available when needed, which may be pre- or post-contingency. This may involve determining whether manual or automated controls are necessary.

8.0 Evaluation of Alternatives

The Company has implemented an NWS Analysis Workbook to initially compare and rank potential NWS and Traditional alternatives. Refer to Appendix B for a copy of the NWS Analysis Workbook. A preferred alternative is selected after considering the direct costs and risks as follows:

a) Feasibility of addressing the identified needs including operational complexity and flexibility;
b) Reliability impact of the identified options;
c) Performance Risks; and
d) Environmental Risks.

For each potential traditional and non-wires solution, each of these risk factors is rated on a scale of one to four, then summed to calculate a total project risk score for each Traditional and NWA options.

The Company will prioritize the implementation of feasible NWS projects based on the results of the NWS project evaluation and their value in adding to the Company's understanding of Non-Wires Solutions and supporting Grid Modernization efforts to integrate DER within the distribution system.

If this initial analysis results in a preferred NWS option, then the company will issue a Request for Proposal for this option to obtain the information needed to do a detailed cost/benefit analysis, including initial cost, ongoing O&M costs over the life of the asset, performance guarantees, lifecycle duration, direct benefits, etc.

9.0 Approvals

The preferred and alternative solutions, including the detailed cost/benefit analysis, are presented by the System Planner to Management with a final recommendation for approval of the preferred alternative.

APPENDIX B – NWS Analysis Workbook

NWS EVALUATION SUMMARY

11/2/2020

Identified Problem:

Project Need Year:

Brief Project Description/need:

Project Scope	Option
	1
	2
	3
	4

Scoring Values	
Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Comments
Total Cost	30%	0	0	0	0	
Reliability Risk	20%	0	0	0	0	
Feasibility Risk	20%	0	0	0	0	
Performance Risk	20%	0	0	0	0	
Enviromental Risk	10%	0	0	0	0	
Total Assessment	**100%**	**0.00**	**0.00**	**0.00**	**0.00**	
	Ranking	**1**	**1**	**1**	**1**	

Identified Problem:

11/2/2020

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Comments
Customer Outage Experience	50%					
Automated Restoration	30%					
Power Quality	20%					
Totals	**100%**	**0**	**0**	**0**	**0**	
	Ranking	**1**	**1**	**1**	**1**	

DEFINITIONS

Customer Outage Experience: potential that the solution will decrease customer exposure and/or improve customer outage frequency (SAIFI) or duration (SAIDI)

Automated Restoration: potential that the solution allows or includes automated restoration of service, reducing outage durration (SAIDI)

Power Quality: potential that the solution will positively impact power quality -- voltage, frequency and/or wave form distortion (impact on equipment)

Identified Problem:

11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Comments
Likelihood of Timely Completion	35%					
Predictable Long Term Solution	25%					
Historical Field Experience	10%					
Uncertainty	30%					
Totals	**100%**	**0**	**0**	**0**	**0**	
	Ranking	**1**	**1**	**1**	**1**	

DEFINITIONS

Likelihood of Timely Completion: professional or vendor estimate of time needed to implement each solution to resolve issue

Predictable Long Term Solution: professional or vendor estimate of life cycle experience for each solution. Solution can include vendor guarantees

Historical Field Experience: actual real-world, field experience for the specific program and/or technology used for each solution

Operational Uncertainty: the ability of the utility to integrate the specific program and/or technology into the customer premise and/or utility operating system.

Identified Problem:

11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Comments
Availability	25%					
Operability	20%					
Required Maintenance	10%					
Aligns with Company Goals	15%					
Capacity Provided - Demand	20%					
Capacity Provided - Hosting	10%					
Totals	**100%**	**0**	**0**	**0**	**0**	
	Ranking	**1**	**1**	**1**	**1**	

DEFINITIONS

Availability: historical and preducted availability of each solution to a distribution system need, including vendor guarantees. (Software malfunctions, connectivity issues, resource variability, outages)

Operability: how well the specific option improves operability of the system - flexibility, safety/efficiency, storm response

Required Maintenance: relative assessment of level of maintenance required for each program and/or technology

Alignment: how well does the specific program and/or technological solution aligns with the Company's goals, initiatives or strategies.

Capacity Provided - Demand Growth: reserve MVA capacity gained for the distribution system to serve growth beyond the present capabilities

Capacity Provided - Hosting Capacity: how well the specific option improves the ability of the system to accommodate distributed generation.

PROJECT NAME:

11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Comments
Wetland Impact	25%					
Tree Clearing	25%					
Community Impacts	25%					
Municipal Impacts	25%					
Totals	**100%**	**0**	**0**	**0**	**0**	
	Ranking	**1**	**1**	**1**	**1**	

DEFINITIONS

Wetland Impact: evaluation of the impact of each specific program and/or technology would have on natural "wetlands" in the improvement area

Tree Clearing: to the extent the proposed solution requires "clearing" of trees and other vegetation; does not include vegetation "trimming"

Community Impacts: to the extent that the proposed solutions have a positive or negative impact on the community in the improvement area

Municipal Impacts: to the extent that the proposed solutions have a positive or negative impact on the municipal district(s) in the improvement area

GRID MODERNIZATION

Developing a Pathway for Liberty Utilities

In New Hampshire

Prepared by

CMG Consulting

Prepared for

Liberty Utilities

December 2020

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Executive Summary

Electric utilities have historically extracted as much value and efficiency as possible with manual controls. Today, however, we see a major shift in the thinking within the electric utility industry as it approaches the issue of building the electric infrastructure to ensure reliable and cost-effective electric service given a set of challenges all occurring at the same time:

- A large percentage of skilled labor within the electric utility industry is expected to retire within the next five years, placing stresses on electric utilities to effectively manage systems with a large degree of manual intervention required.
- The Department of Energy (DOE) and industry experts have estimated that losses to the economy due to outages, quality disturbances and other events total in the billions of dollars annually; a DOE report stated that, "the aging of the electric infrastructure...could accelerate turnover of capital assets, including generation, transmission, and distribution facilities."
- Challenging financial times are calling into question how electric utilities can continue to access the capital needed to keep pace with projected load growth given the constraints of today's legacy electric grid.
- Under pressure from environmental groups and foreign governments, federal and state regulators are assigning increasingly stringent emissions regulations – resulting in increasing challenges for electricity generators to supply power.
- Increasing levels of intermittent renewable energy along all levels of the grid and less predictable electric vehicle charging at the edge of the grid are placing new challenges not faced before by electric distribution utilities.
- While the presence of evolving technologies can offer opportunities to explore new approaches to effectively deliver electricity to consumers, electric utilities are often hamstrung by the roadblocks presented by operating grids that are in many ways not designed to integrate with new technical approaches.

This set of issues – all occurring at the same time – presents a form of "perfect storm" that challenges the electric utility industry to identify the optimal approach for delivering cost effective and reliable electricity to customers in the 21st century. The Grid Modernization effort – a way of adding intelligence and new protocols to the electric grid – is seen by many as the way to attack the challenges within the industry.

In support of this effort, Liberty Utilities has engaged CMG Consulting to develop a plan to assess the viability of a Grid Modernization effort, the suitability of certain programs, and to develop a set of short-term and long-term strategies that support all stakeholders.

The result of this effort is the identification of ten dedicated programs in four areas of focus:

- Metering
  - Advanced Metering
  - Connect/Disconnect
- Distribution Automation
  - Fault Detection
  - Conservation Voltage
  - Load Forecasting
  - Asset Management
  - Islanding
- Customer Connections
  - Energy Management
  - Distributed Energy Resources
- Smart City
  - LED Lighting

Liberty Utilities proposes to begin a pursuit of a Grid Modernization effort that incorporates elements of all ten of these programs, with the following as the guide path objectives:

	Program	Value Estimate	Overall Strategy	Five Year Target	Ten Year Target
Metering	Advanced Metering	$ (5,681,208)	Deploy as platform for overall grid modernization effort	Complete deployment	Optimized work processes and data management
	Connect/Disconnect	$ 1,313,376	Implement alongside metering system	Complete deployment	Optimized work processes and data management
Distribution Operations	Fault Detection	$ 1,866,619	Implement alongside metering system	Complete deployment in core fault detection	Implement full isolation recovery scheme
	Conservation Voltage	$ 2,830,220	Implement alongside metering system	Complete deployment	Develop voltage optimization scheme
	Load Forecasting	$ 419,908	Implement alongside metering system	Complete deployment	Optimized work processes and data management
	Asset Management	$ 4,640,406	Implement alongside metering system	Complete deployment	Optimized work processes and data management
	Islanding	$ 6,097,772	Work with customers to explore options	Resolve or defer distribution system deficiency, using NWS	Resolve or defer distribution system deficiency, using NWS
Customer Connections	Energy Management	$ 785,799	Explore options	Initiate pilot and monitor industry developments	Implement initial deployment
	Distributed Energy Resources	$ 1,121,276	Explore options	1% of peak implemented	6% of peak implemented
Smart City	LED Lighting	$ 1,975,128	Pursue opportunities with cities	Two cities completed	Grow LED lighting to other cities and pursue other use cases

Chapter 1: Grid Modernization Trends

The Electric Utility View

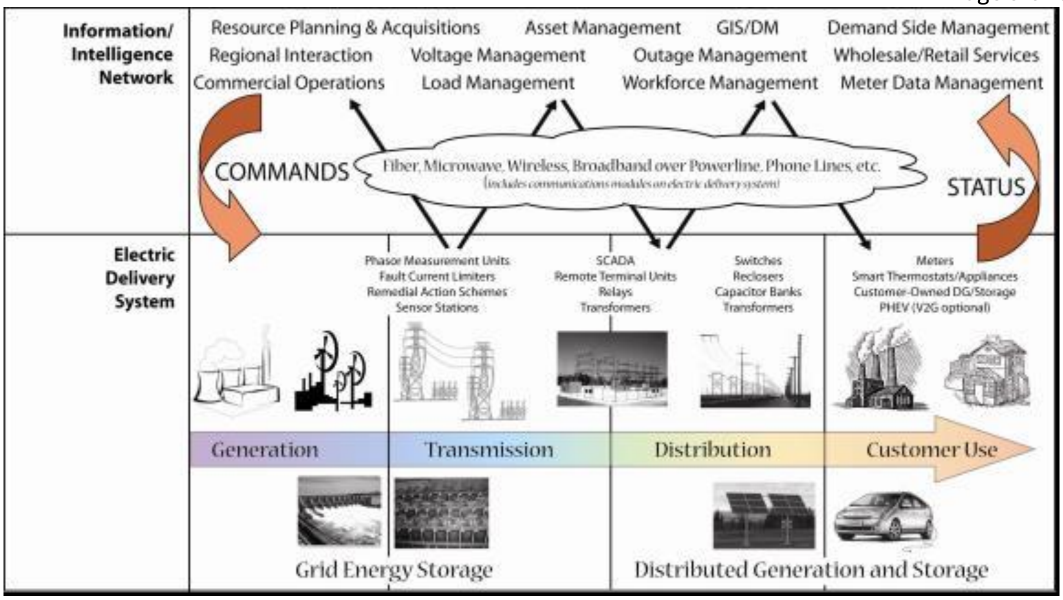
We are witnessing a revolution in the way electric power is transmitted from generators and distributed to end-use consumers. It is a revolution characterized by the convergence of information and electricity delivery technologies.

In the coming years, energy demand is projected to continue to increase due to further electrification (e.g. data centers, electric vehicles), a significant percentage of the industry's skilled workforce is scheduled to retire with job experience and knowledge that cannot be replaced with a 1:1 ratio, and global demand and resource scarcities threaten the stability of energy costs. Regulators favor increased industry competition, information-armed consumer groups are making greater demands about pricing and other issues, and governments at home and abroad are pressing for cleaner, more reliable energy. These dramatic changes in the business environment are encouraging utilities to take advantage of key technologies to improve the efficiency, quality, reliability, resiliency, and cost of supplying services.

The movement toward Grid Modernization involves the deployment of "Intelligent" or "Smart" utility digitized infrastructure that weds the combination of communications, information, hardware, and other technologies into a future "self-healing" grid. As technologies advance, the possibilities for this modernization effort expand as well, not just in having more advanced electric components, but also the consuming devices that get plugged into the grid. Renewables and distributed generation have the potential for adapting utilities to carbon-constrained environments. New storage technologies could save cheap or renewable generation for use in peak periods. Communicating between devices or sensors improves operations, optimizes asset use, increases reliability and safety while providing stakeholders with the information they need to make better decisions. This could mean everything from customers choosing to use electricity differently to utility personnel modifying operating activities. At the end of the day, Grid Modernization will redefine the way in which utilities operate and electricity is consumed.

At a high level, this modernization effort is made up of two parallel networks: the electric grid itself and the intelligence behind it. The electric grid includes the equipment required to generate and distribute electricity as well as the control devices attached to it. The intelligence network consists of the core communications and information management systems as well as the applications that process data from the devices. What makes the grid "Smart" is its ability to communicate seamlessly between these two parallel networks at every level including consumption. Enhanced communications and control capabilities will allow delivery systems to accommodate and support the rapidly evolving needs utilities and their customers have for increased reliability, efficiency, and environmental quality.

To successfully incorporate these technologies, the electric grid will need to support real-time data collection from all end points through a myriad of 'smart devices'; reliable, secure, real-time, high bandwidth communications networks to deliver information and facilitate device automation and remote control; and IT systems including databases, decision support systems, and control applications.



Market Trends

In this environment, utilities will have to pay increasing attention to multiple constraints: aging infrastructure, rising costs, environmental concerns, regulatory compliance, and technological innovations.

The Utility of the Future

From a technology point of view, Grid Modernization is all about applying new technologies to reduce the cost, increase efficiency and improve the quality and reliability, of electric service. The Department of Energy has identified five key technologies that are the essence of the smart grids, and we have adopted this same perspective to elaborate a definition of Grid Modernization.

The five sets of technologies are as follows:

1. Integrated Communications – Connecting all the components of the electric grid, through open architectures, which will provide for real-time

information and control of the grid and thus allowing every component to both 'talk' and 'listen'.

2. Sensing and Measurement – Devices that sense and measure various aspects of grid operation and thus support faster and more accurate response such as remote monitoring of voltage, current, phase angles, etc.

3. Advanced Components – Applying the latest technologies for superconductivity that reduce line losses, storage that allows for the use of off-peak generation to meet peak period requirements, and power electronics and diagnostics that will improve the operation and efficiency of the grid.

4. Advanced Controls – Monitoring essential components in real-time and thus, enabling early detection and rapid diagnosis in order to provide precise solutions appropriate to any event before they can cascade into bigger problems.

5. Improved Interfaces and Decision Support – Improving human decision – making by providing grid operators and managers with the information and ability to enable them to operate as visionaries when it comes to seeing into their systems.

Chapter 2: Use Cases

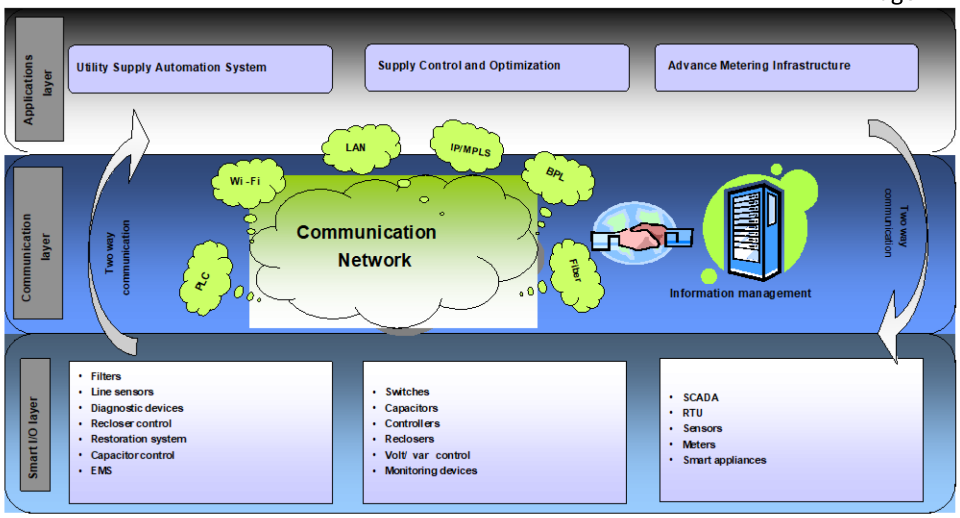
An assessment of the current state of operations at Liberty Utilities was arrived at by engaging with key subject matter experts within Liberty Utilities and by evaluating current industry trends. The following ten use cases within four broad categories of opportunities were evaluated:

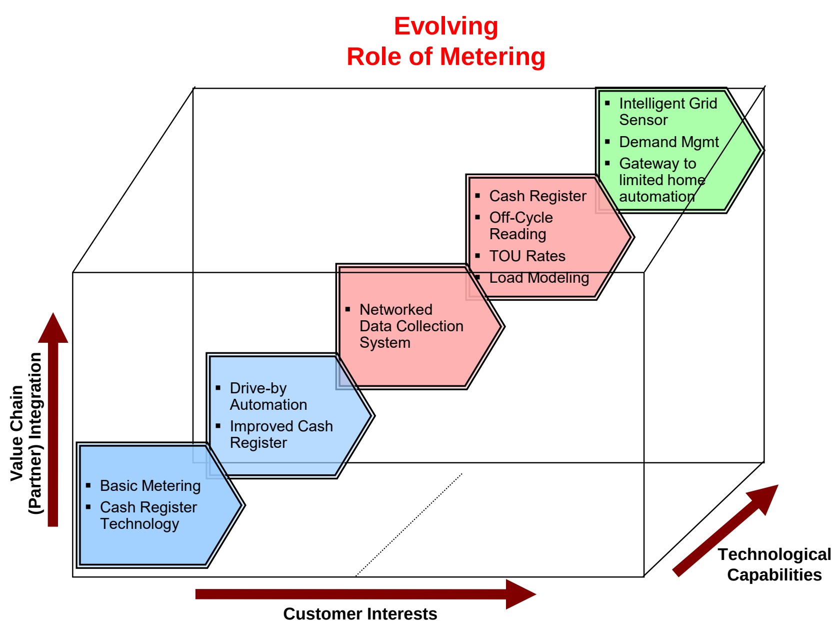
Metering

The first set of benefits involves the advanced metering components of a Grid Modernization effort. The smart meters, and the data they report, create multiple benefits involving labor savings, improved back-office efficiencies, and revenue assurance.

Advanced Metering

The components of a successful AMI deployment include a robust communications channel, some type of MDM software and bidirectional, 15 min interval capable meters (and collectors, if applicable). In addition, the advanced meters deployed across the distribution network also function as grid health monitors by reporting back outages and line conditions related to voltage and current. As a result, the AMI serves as the platform for the entire grid modernization effort.





Prepaid metering programs

Time based rate support

Outage and restoration notification

Self serve customer usage portals

Remote (automated) service connect/disconnect

Advanced distribution management

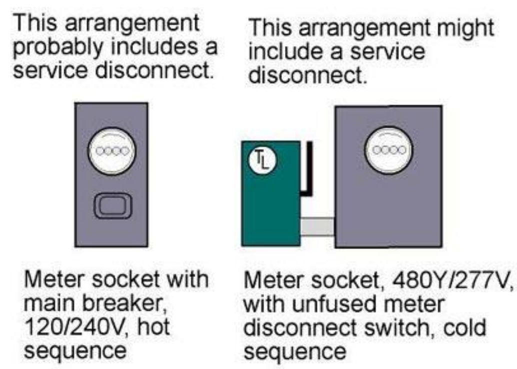
Self healing distribution systems

Load Modeling

Demand Response

Connect/Disconnect

Remote connect/disconnect capabilities are enabled by retrofitting existing meters with a collar or by choosing a remote disconnect capable meter for selected deployments. This equipment generates the cost functions. The ability to remotely disconnect and reconnect energy flow enables both labor savings and revenue assurance and improves service quality. Benefits are made up of revenue improvements and cost reductions.



Distribution Automation

Grid modernization programs create the ability to conduct real-time, condition-based monitoring of core equipment. This would allow continuous analysis of conditions (e.g. temperature, pressure) and operating parameters – which would extend equipment life, prevent major failures, and reduce repair costs. Remote surveillance and control also would enable quicker problem resolution and reduce unplanned events and associated costs.

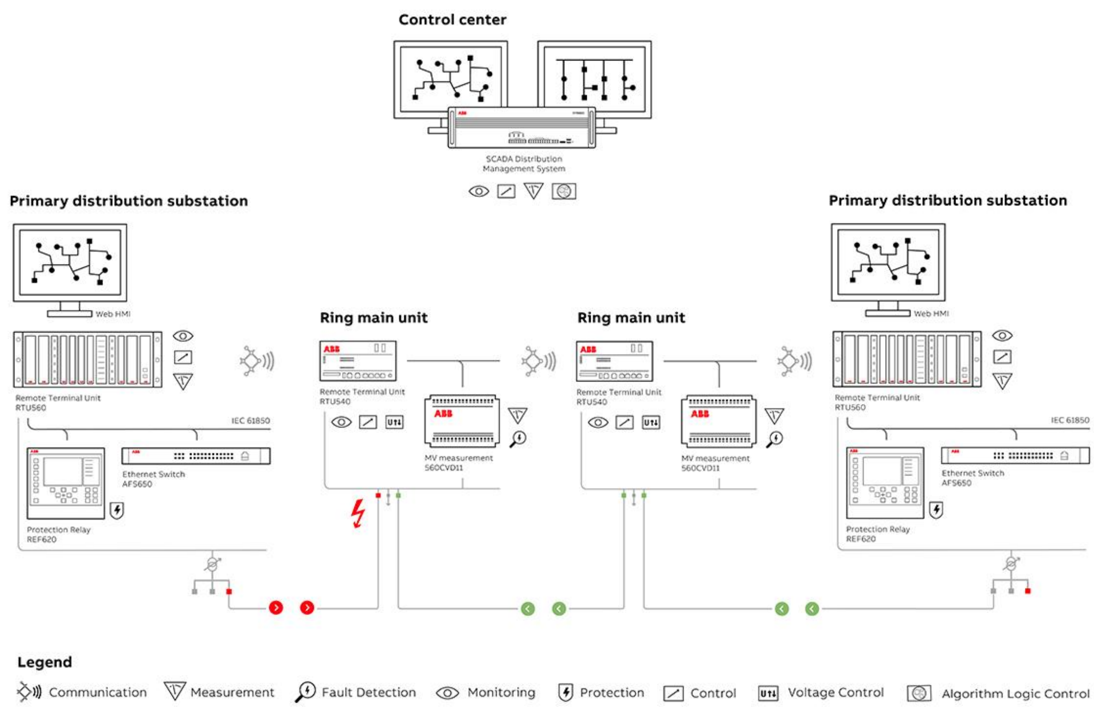
Fault Detection

A significant grouping of benefits involves improved capabilities for responding to electrical faults in the utility's electric delivery system. The automation schemes would provide improved capabilities for activating protective relays (e.g., tripping substation feeder breakers to protect fuses) and instantly switching circuits, as needed, to protect the system. It would provide improved controls for automated balancing, shedding, and transferring of loads; and it would provide advanced decision support systems for human operators.

Power grid faults are defined as physical conditions that cause a circuit element to fail to perform in the required manner. This includes physical short circuits, open circuits, failed devices and overloads. A short circuit is some form of abnormal connection that causes current to flow in some path other that the one intended for proper circuit operation. Short circuit faults may have very low impedance (also known as "bolted faults") or may have some significant amount of fault impedance. In most cases, bolted faults will result in the operation of a protective device, yielding an outage to some utility customers. Faults that have enough impedance to prevent a protective device from operating are known as high impedance faults. Such high impedance faults may not result in outages, but can cause significant power quality issues, and can result in serious utility equipment damage. In the case of downed but still energized lines, high impedance faults also pose a safety hazard.

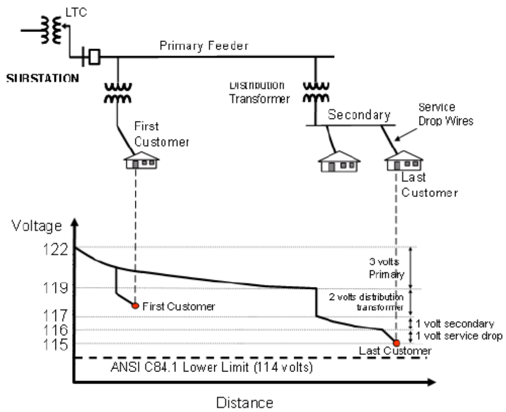
ADMS, AMI and OMS integration allows proactive response to outages rather than waiting for customers to call in, minimizing customer re-calls and eliminating the need to phone customers to verify restoration. Real-time communications links that deliver outage and restoration alarms will send high-priority message when service is out. Fault detection, isolation, and recovery (FDIR) is a subfield of control engineering which concerns itself with monitoring a system, identifying when a fault has occurred, and pinpointing the type of fault and its location.

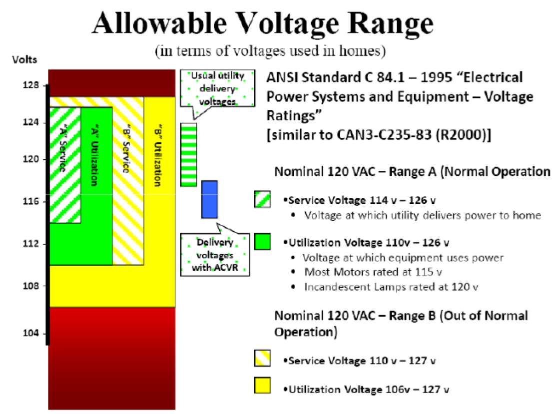
The development of a robust outage management/fault detection program often depends upon the deployment of an advanced distribution management system (ADMS). An ADMS is the software platform that supports the full suite of distribution management and optimization. An ADMS includes functions that automate outage restoration and optimize the performance of the distribution grid. ADMS functions being developed for electric utilities include fault location, isolation and restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction; peak demand management; and support for microgrids and electric vehicles.



Conservation Voltage

Voltage management offers the potential for electric utilities to utilize controls over the voltage levels of the distribution network to enable real operational gains. While utilities typically operate in the upper range of the ANSI voltage band under normal circumstances, voltage can be compressed during key periods in a way that benefits utilities and consumers. Numerous studies have shown that for each 1% drop in voltage levels, mean energy consumption for residential and commercial loads can be reduced by .8%, although this value can vary depending on load mix and distribution system configuration.





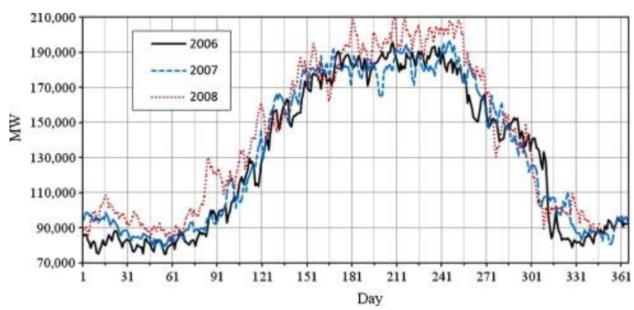
There are a number of deployment options that Liberty Utilities could consider in the ultimate design of its conservation voltage program. Below are three options it may want to consider:

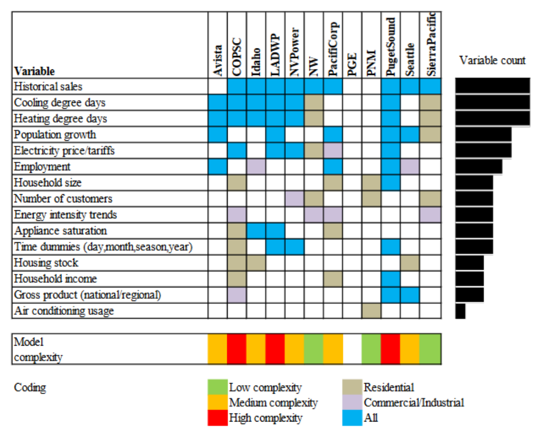
Approach	Concept	Pros	Cons
Standalone	Voltage control managed by individual Volt/VAR regulating devices	Low cost, limited communications requirements, scalable	Not self-monitoring, poor coordination, suboptimal operation
Rule-Based DA Control	Controlled by SCADA with preset rules	Improved efficiency, self-monitoring, override capabilities	Not scalable, not very adaptable to changing rules, limited efficiency gains
Distribution Model Optimization	Coordinated optimal switching for all voltage control devices	Fully coordinated and optimized, flexible, can support feeder reconfiguration	Higher cost, larger deployment required, learning curve required

Load Forecasting

Load forecasting is a vital process in the planning of electricity industry and the operation of electric power systems. Accurate forecasts lead to substantial savings in operating and maintenance costs, increased reliability of power supply and delivery system, and correct decisions for future development. Automated load forecasting tools enable utilities to remove the dependence on purely manual processes from forecasting and planning.

Industry analysts have estimated that load predictions have consistently over-forecast by 1% each year. That implies that a ten-year utility forecast could result in a 10% over-estimation of demand, leading to billions of dollars in unneeded investment. Automating processes with more granular data can support a refinement in load forecast accuracy.

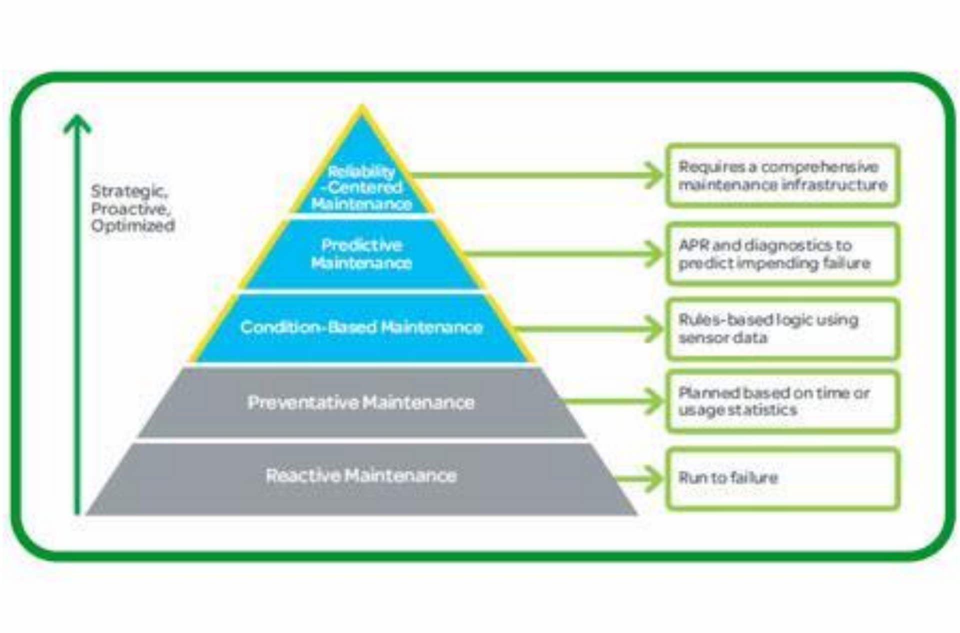




Asset Management

Grid modernization involving automation schemes enable an increase in asset effectiveness by consolidating multiple work and asset management solutions into a single platform and database. These approaches allow for distribution resources to be assessed on a real-time basis to enhance utilization and productivity.

Utility companies frequently struggle with balancing the need to invest in modern equipment and infrastructure with demands to minimize costs for customers. One of the most effective ways to avoid substantial rate hikes is to maximize the lifetime value of every existing asset. Automated asset management tools enable utilities to blend forecasting and business intelligence with traditional enterprise asset management capabilities.

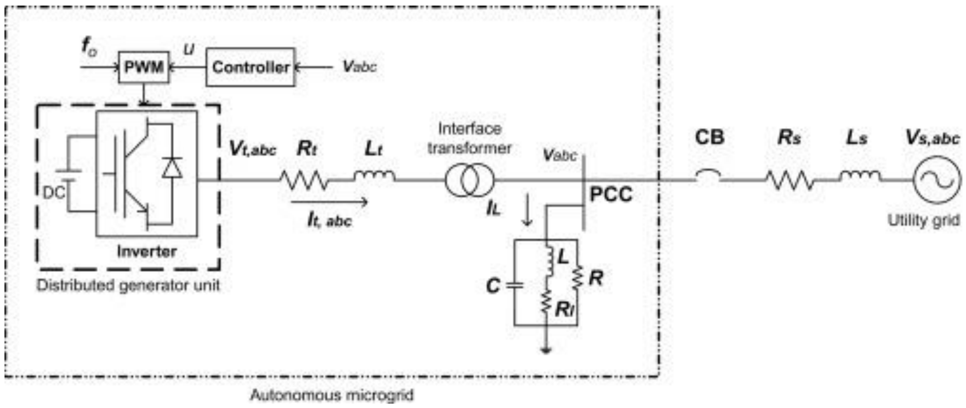


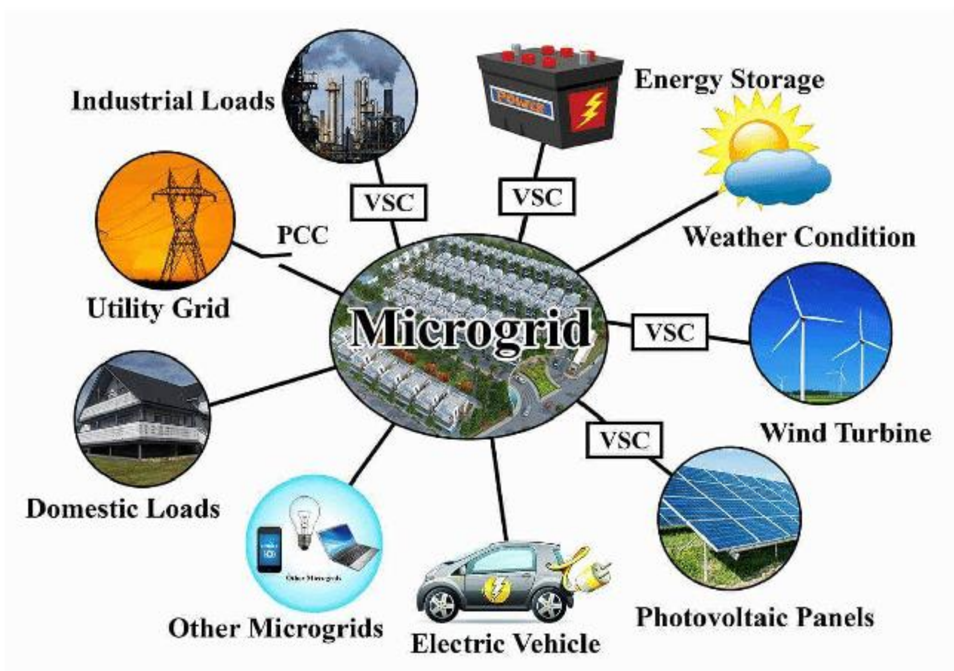
Part of the recommended asset management system would involve automated systems to ensure power quality analysis on a dynamic basis. Power quality analyzers are the most commonly used tools to observe real-time readings and also collect data for downloading to computers for analysis. While historically handheld analyzers have been used to support isolated troubleshooting functions, a real-time dynamic program would feature systems and devices permanently installed in the distribution system.

Islanding

Islanding is the condition in which a distributed generator (DG) continues to power a location even though electrical grid power is no longer present. Strict frequency control is needed to balance between load and generation in the islanded circuit to avoid violations from abnormal frequencies and voltages.

Islanded systems enhance the potential of distributed generation sources to provide power to a portion of the grid absent electric flow from the central generation source. Microgrid designs enable the development of controlled systems that enhance the delivery of distributed resources and can lead to greater efficiencies across the distribution network by localizing generation closer to the site of usage.



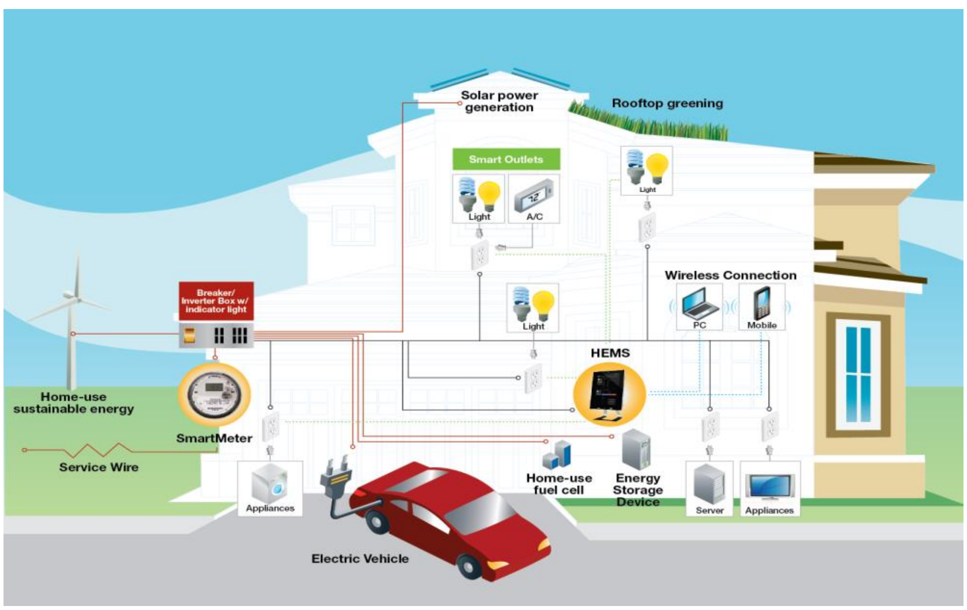


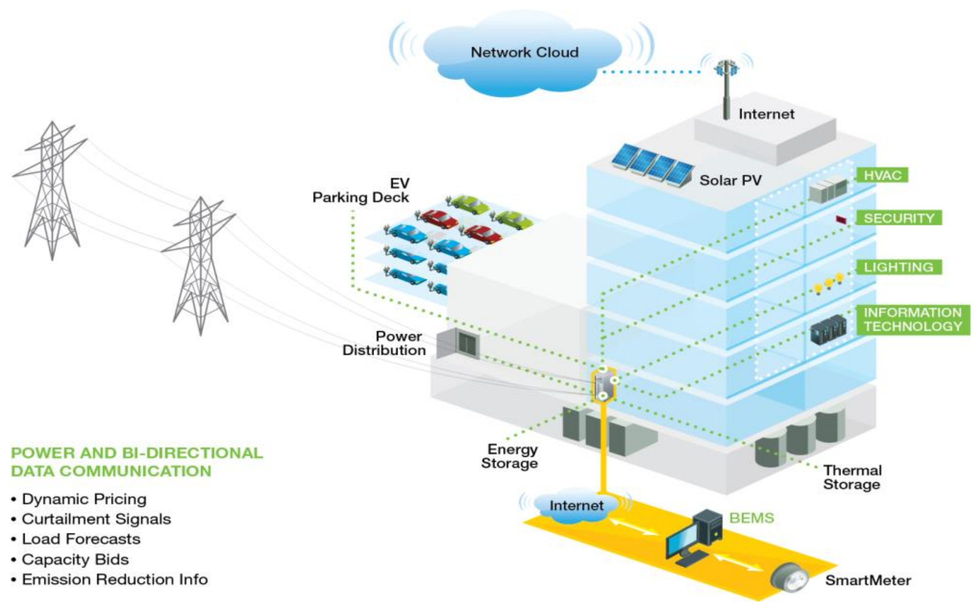
Customer Connections

Grid modernization would allow customers to save in the short-term: (1) by avoiding usage during high-cost periods (those customers who respond by curtailing usage), and (2) by lowering wholesale market prices (those customers who do not respond: when the utility's load drops, it pushes down market clearing prices for all customers). In the long-run, grid modernization would allow the utility to defer investments (on behalf of customers) in new capacity. It also would benefit society at large, if reductions in peak consumption lead to reductions in emissions.

Energy Management

By shifting consumption from peak periods to off-peak periods, the utility and the consumer alike can generate positive value by avoiding consumption during high priced energy periods, reducing market clearing prices, and reducing overall capacity costs. This may be accommodated through the deployment of smart thermostats, electric heat pumps, electric storage, Home Energy Management Systems (HEMS), Building Energy Management Systems (BEMS), and other forms of curtailment.



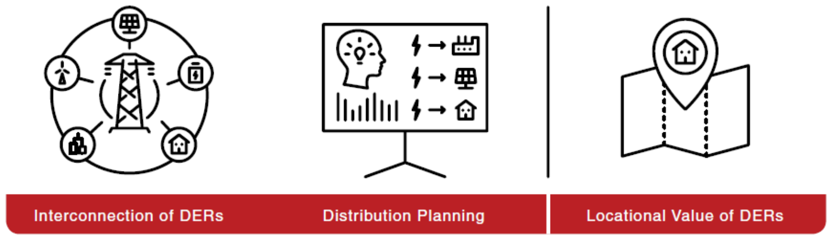


Distributed Energy Resources

There are multiple technologies that enable distributed generation and energy storage applications. Implementing distributed resources offers the opportunity to reduce the amount of energy lost in transmitting electricity because the electricity is generated and delivered close to consumption, perhaps even in the same building. This also improves the management of energy flow on power lines, which could reduce the size and number of power lines that need to be constructed in the future. The graphic below details some of the potential options to generate value:

Application	Description
Generation Deferral	Reduce system peak in order to reduce investments in generation
Wholesale Marketing Resource Call	Reduce system peak in order to provide flexibility in generation requirements during summer peak
Frequency Regulation	Power sources online, on automatic generation control, that can respond rapidly to system-operator requests for up and down movements
Synchronized Reserves	Power sources that can increase output immediately in response to a major generator or transmission outage
Supplemental Reserves	Commitments that can be immediately decreased in response to a major generator or transmission outage
Renewables Integration	Engaging in (a) smoothing, (b) shifting, and (c) shaping renewable energy sources
Energy Arbitrage	Opportunity to purchase energy at off-peak rates and sell at higher peak rates
Blackstart	Process of restoring a power station to operation without relying on the external electric power transmission network
Transmission Deferral	Reduce system peak in order to reduce investments in transmission
Voltage Support	The injection or absorption of reactive power to maintain transmission-system voltages within required ranges
Distribution Deferral	Reduce system peak in order to reduce investments in distribution
Outage Mitigation	Distributed storage capability to bridge gap in power delivery in event of outage
Power Quality	Maintaining electric power that drives an electrical load and the load's ability to function properly with that electric power
Distribution Loss Reduction	Dispersed functions allow existing generation to function more efficiently and improve the overall efficiency of the electric system

One of the considerations for a DER program involves Hosting Capacity Analysis (HCA). The term "hosting capacity" refers to the amount of DERs that can be accommodated on the distribution system at a given time and at a given location under existing grid conditions and operations, without adversely impacting safety, power quality, reliability or other operational criteria, and without requiring significant infrastructure upgrades. HCAs allow utilities, regulators and electric customers to make more efficient and cost-effective choices about deploying DER on the grid. If adopted with intention, HCA may also function as a bridge to span information gaps between developers, customers and utilities, thus enabling more productive grid interactions and more economical grid solutions.



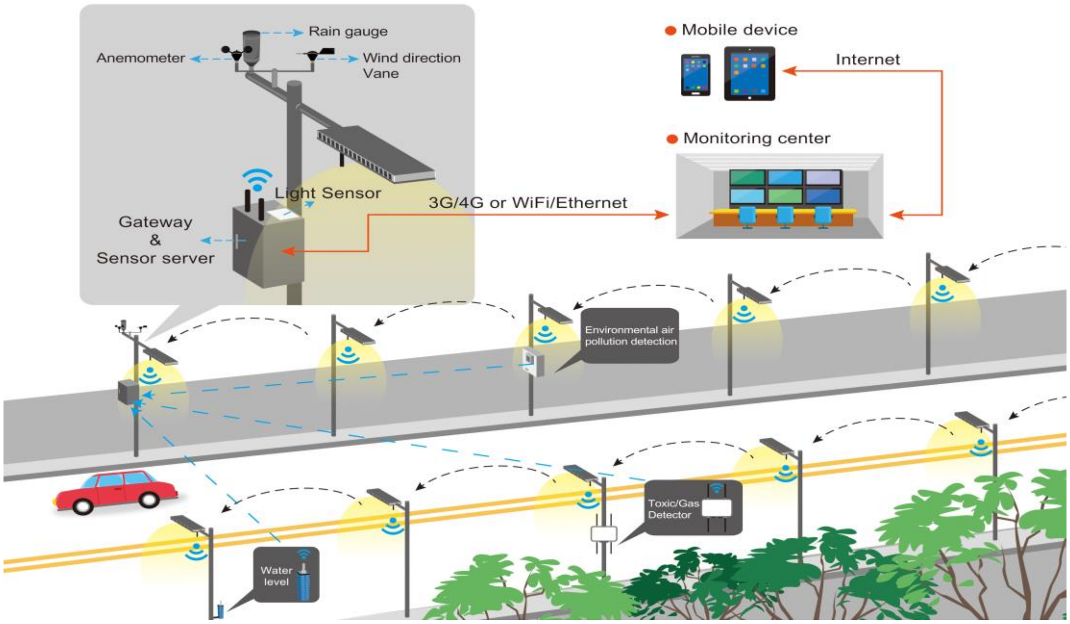
The initial purpose of HCA was to make DER interconnections faster and more efficient. If a utility could know the feeder-level DER penetrations throughout its distribution system, it could immediately approve an application for a new DER installation. Alternatively, it could inform the applicant a distribution system infrastructure upgrade is needed to accommodate new DER. By accommodating HCA on its system, Liberty Utilities will be able to properly plan for distribution resources, including DER.

Smart City

A smart city involves the deployment of technology, primarily using electronic Internet of things (IoT) sensors to collect data and then use these data to manage assets and resources across the city efficiently.

LED Lighting

LED is a highly energy efficient lighting technology and has the potential to fundamentally change the future of lighting in the United States. According to the DOE, widespread use of LED lighting has the greatest potential impact on energy savings in the United States; by 2027 widespread use of LEDs could save about 348 TWh of electricity.


Rain gauge
Anemometer
Wind direction
Vane
Light Sensor
Gateway
&
Sensor server
3G/4G or WiFi/Ethernet
Mobile device
Internet
Monitoring center
Environmental air pollution detection
Toxic/Gas Detector
Water level

Chapter 3: Business Case

Financial models are developed to use customized data to make better business decisions. They can be used to determine what to do or how to do it. The establishment of a business case can assist a utility to determine which grid modernization applications make the most sense. Liberty Utilities has engaged in an effort to evaluate the economics associated with a grid modernization effort. Below are the results of that effort.

Summary

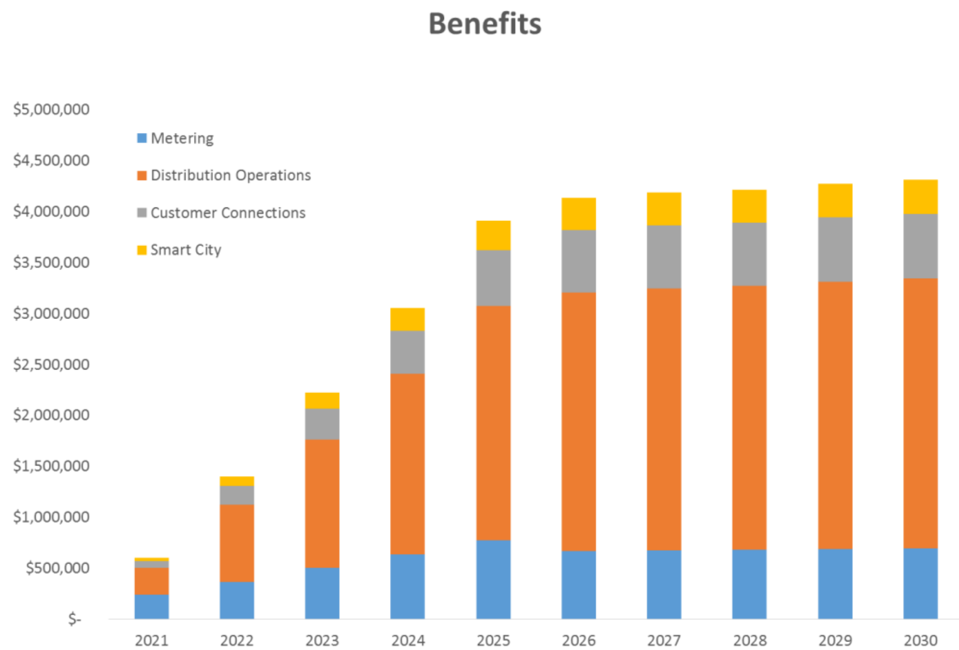
In order to assess the viability of the different grid modernization use cases under consideration, an evaluation of the forecasted economics of each program was evaluated. Included in the analysis were quantifications of the potential benefits for each program, the associated operating expenses and the required capital expenses over a forecasted period of ten years. In addition, an assessment was made regarding the ongoing value of each program beyond the tenth year of operation, referred to as the “terminal value”. Below are the results of the business model for each of the ten use cases, ranked in order to economic viability:

Program Comparison - Ranked

	PV - Benefits	PV - CapEx	PV - OpEx	Terminal Value	NPV	Rank
Islanding	$ 4,674,342	$ 2,702,450	$ 71,745	$ 4,197,624	$ 6,097,772	1
Asset Management	$ 3,501,383	$ 1,225,587	$ 502,214	$ 2,866,825	$ 4,640,406	2
Conservation Voltage	$ 1,828,287	$ 580,151	$ 47,830	$ 1,629,914	$ 2,830,220	3
LED Lighting	$ 1,517,652	$ 729,200	$ 119,575	$ 1,306,250	$ 1,975,128	4
Fault Detection	$ 1,695,304	$ 1,178,087	$ 124,358	$ 1,473,761	$ 1,866,619	5
Connect/Disconnect	$ 841,032	$ 253,269	$ 23,915	$ 749,527	$ 1,313,376	6
Distributed Energy Resources	$ 2,180,530	$ 2,730,556	$ 191,320	$ 1,862,622	$ 1,121,276	7
Energy Management	$ 707,240	$ 486,353	$ 47,830	$ 612,742	$ 785,799	8
Load Forecasting	$ 334,822	$ 141,917	$ 47,830	$ 274,833	$ 419,908	9
AMI	$ 3,011,689	$ 10,137,468	$ 411,337	$ 1,855,908	$ (5,681,208)	10
Total	$ 20,292,282	$ 20,165,038	$ 1,587,954	$ 16,830,006	$ 15,369,296	

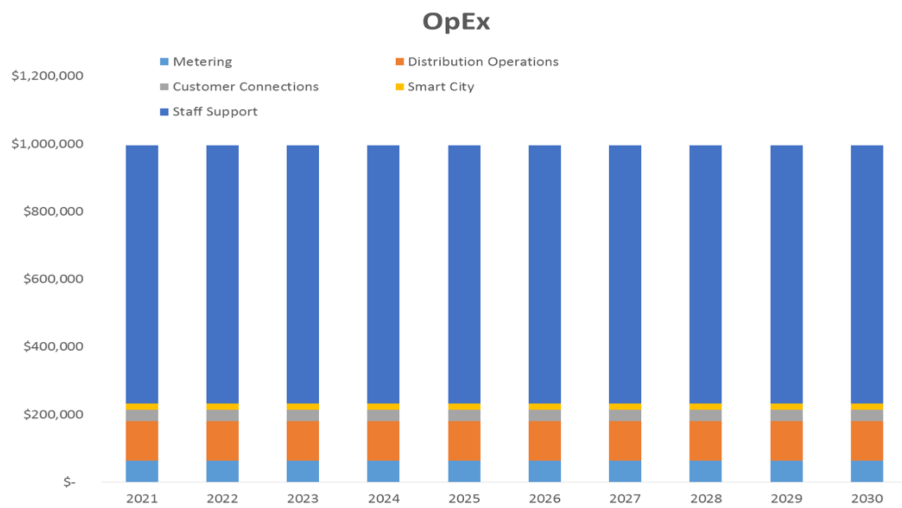
Benefits

The annual benefits that are estimated from a grid modernization campaign are estimated to increase from $600,000 in 2021 to $4.3 million in 2030.



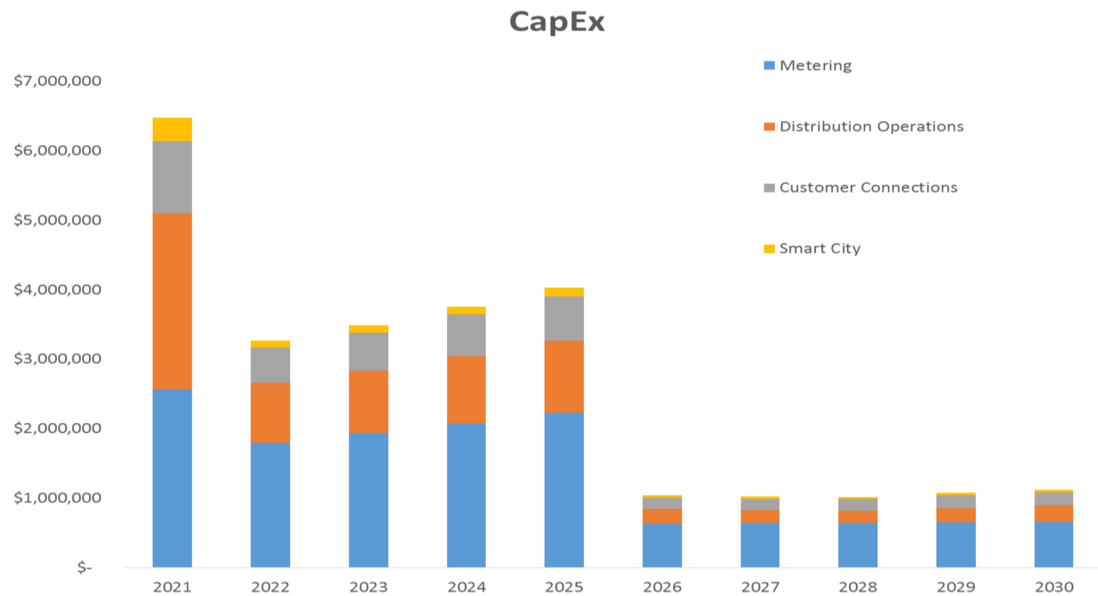
Operating Expense

Annual operating expenses are estimated to be just under $1 million.



Capital Expense

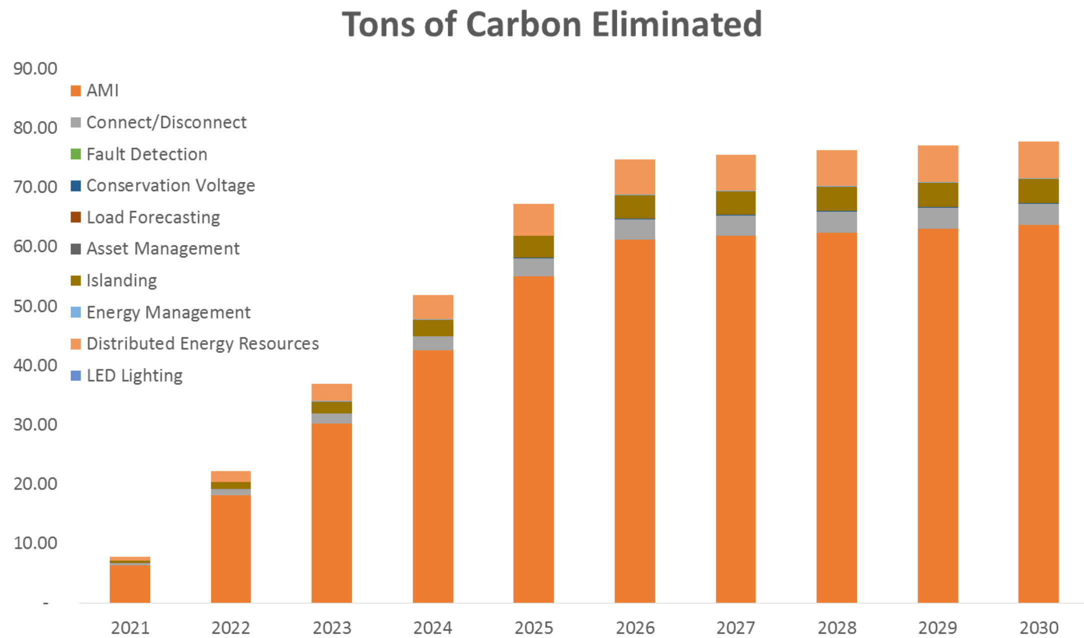
It is estimated that the overall capital budget for a complete grid modernization would run $21 million over a five-year deployment period with an additional $5.3 million over the subsequent five years to cover growth and anticipated replacement.



Non-Financial Benefits

In addition to economic considerations, Liberty Utilities has also had an assessment conducted with the non-financial benefits associated with a grid modernization effort. Specifically, forecasts have been developed with respect to the potential to reduce carbon output as well as the potential to reduce outage minutes experienced by customers. The findings for each are as follows:

- Carbon – It is estimated that a full grid modernization effort would eliminate a total of 567 tons of CO_2 over a period of ten years.
- Outage – It is estimated that a full grid modernization effort would offer the potential to reduce annual outage minutes by 3 million for Liberty's customers. Using NH regulatory criteria, it has a potential to reduce annual outage by 760,000 minutes.


Tons of Carbon Eliminated
90.00
80.00
70.00
60.00
50.00
40.00
30.00
20.00
10.00
-
AMI
Connect/Disconnect
Fault Detection
Conservation Voltage
Load Forecasting
Asset Management
Islanding
Energy Management
Distributed Energy Resources
LED Lighting
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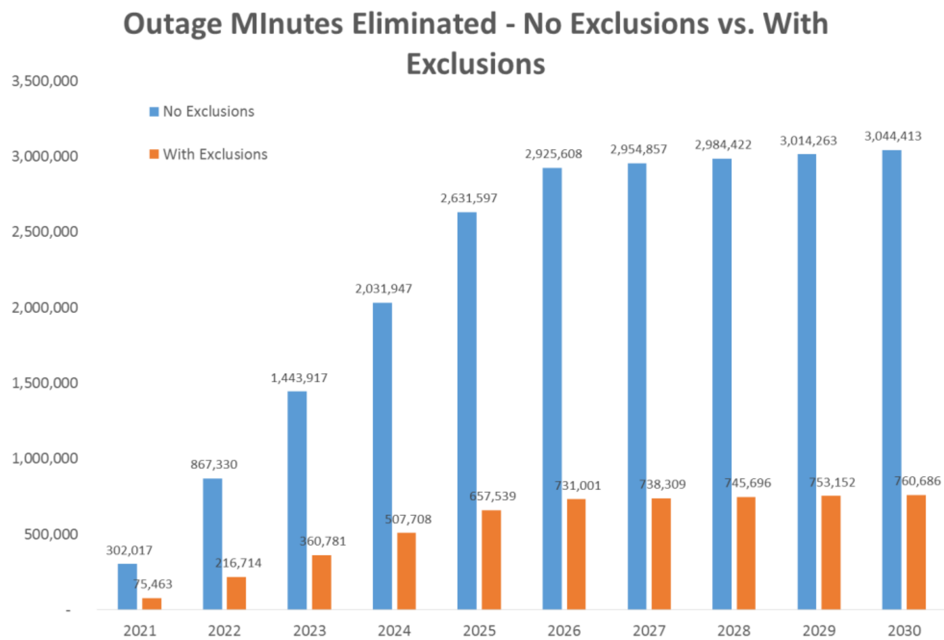


Chapter 4: Migration Strategy

Grid operations incorporates a number of disparate systems, each touching different portions of the electric grid – and in turn requiring different types of supporting infrastructure. In order to evaluate a viable approach for implementation, an assessment of the business case coupled with the state of technology development leads to the development of a recommended migration strategy.

Proposed Pilot Programs

As a next step in the process, a series of budgets have been developed to identify the requisite spending to accomplish the objective of providing a meaningful and prudent test of the viability of each program. The summary of the recommended pilot budgets follows below:

Use Case		Pilot
Connect/Disconnect	$	32,186
DER	$	1,165,000
Islanding	$	599,200
Fault Detection	$	290,410
LED Lighting	$	66,000
Energy Management	$	85,770
Conservation Voltage	$	126,610
Load Forecasting	$	36,800
Asset Management	$	125,000
Total	$	2,526,976

Methodology

The programs that were identified within the assessment phase were flagged as potential programs that could add value to Liberty Utilities and stakeholders. However, these programs will only deliver value to the extent that technologies, systems, and user interfaces work well to enable the capture of the forecasted benefits. Furthermore, it is vital that a determination of the viability of each program be developed with certainty prior to full scale system implementation.

Liberty Utilities has made the decision that it wants to develop a pilot for each program under consideration. The scope and design of each pilot project is based on a number of considerations:

1. In each case, the pilot needs to be large enough to establish a valid test of the program under consideration.

2. At the same time, there is a desire to keep each pilot project to a reasonable size so as not to overcommit resources to an as-yet unproven/unjustified program.

3. Systems have been architected in such a way to make the test as reasonable as possible. For example, the test of advanced meters is based on a targeted meter route, while the test of conservation voltage is based on a feeder design.

4. The plan is that each pilot project will be undertaken, and a forecasted budget has been developed for full-scale deployment for each. However, each program will be reevaluated as the pilot is being conducted to test the updated viability and budget for each. That is, programs that are deemed to not be viable long- term will be delayed or discarded; meanwhile, all programs that are determined to be viable will have updated budgets developed.

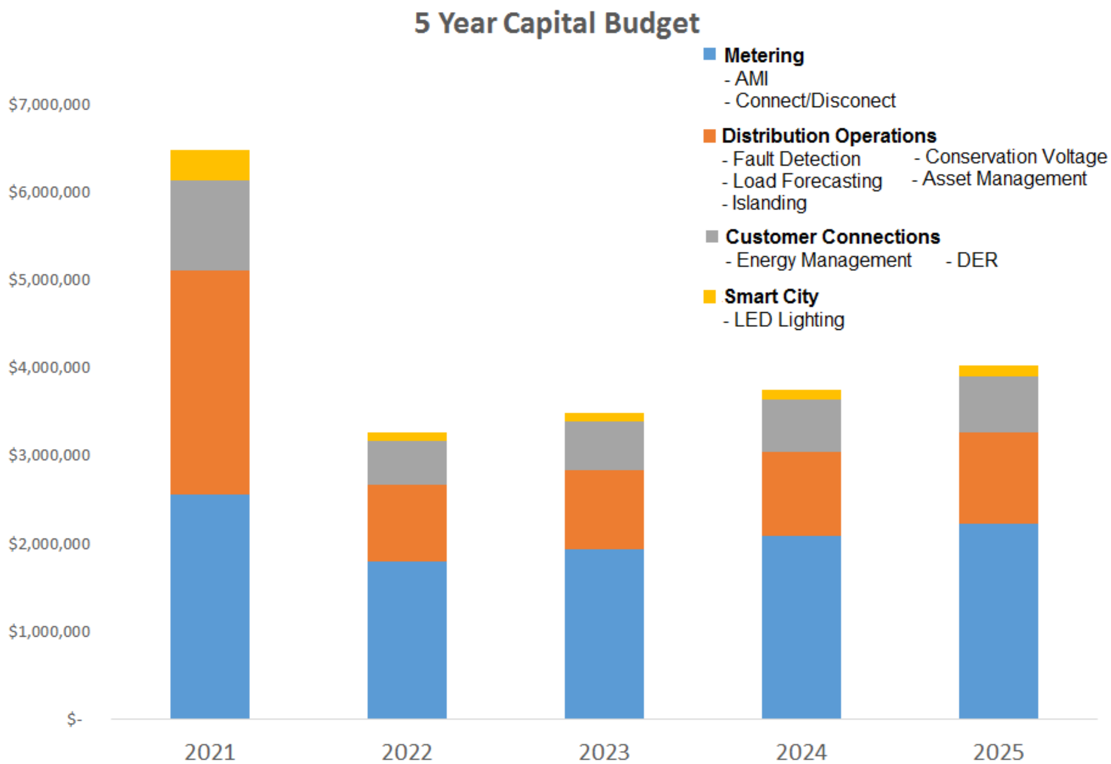
Pilot Budgets

An initial set of plans and associated budgets have been developed to enable Liberty Utilities to prudently test the nine targeted use cases.

For the pilot budgets, below is a listing of the core objective, proposed test focus, and pilot budget for each:

Use Case	Pilot		Post-Pilot Full Deployment		Total Capex Investment	
Connect/Disconnect	$	32,186	$	227,562	$	259,748
DER	$	1,165,000	$	1,674,817	$	2,839,817
Islanding	$	599,200	$	2,250,117	$	2,849,317
Fault Detection	$	290,410	$	1,004,145	$	1,294,555
LED Lighting	$	66,000	$	687,940	$	753,940
Energy Management	$	85,770	$	411,650	$	497,420
Conservation Voltage	$	126,610	$	560,540	$	687,150
Load Forecasting	$	36,800	$	122,200	$	159,000
Asset Management	$	125,000	$	1,188,000	$	1,313,000
Total	$	2,526,976	$	8,126,971	$	10,653,947

1 Assuming that all projects are built out, a five-year budget is detailed below:



CapEx – Annual

	2021	2022	2023	2024	2025
Metering					
AMI	$ 2,477,890	$ 1,755,510	$ 1,894,895	$ 2,036,550	$ 2,179,780
Connect/Disconnect	$ 85,728	$ 38,885	$ 41,811	$ 45,045	$ 48,279
Distribution Operations					
Fault Detection	$ 475,765	$ 183,460	$ 217,460	$ 217,460	$ 200,410
Conservation Voltage	$ 210,050	$ 118,050	$ 112,500	$ 118,050	$ 128,500
Load Forecasting	$ 111,000	$ 12,000	$ 11,000	$ 12,000	$ 13,000
Asset Management	$ 1,095,000	$ 46,000	$ 51,000	$ 60,000	$ 61,000
Islanding	$ 645,711	$ 508,532	$ 500,882	$ 555,302	$ 638,891
Customer Connections					
Energy Management	$ 168,710	$ 73,250	$ 81,060	$ 84,630	$ 89,770
Distributed Energy Resources	$ 868,411	$ 433,382	$ 473,582	$ 515,802	$ 548,641
Smart City					
LED Lighting	$ 335,840	$ 93,425	$ 100,455	$ 108,225	$ 115,995
	$ 6,474,105	$ 3,262,493	$ 3,484,646	$ 3,753,063	$ 4,024,265

For the pilot budgets, below is a listing of the core objective, proposed test focus and pilot budget for each:

6 Automated

	Core Objective	Proposed Test Focus	Pilot Budget
(Connect/Disconnect)	Test viability of advanced metering and connect/disconnect	Route Cycle 01 – 418 meters	$32,186
Distributed Energy Resources	Test viability of bringing distributed energy resources onto the grid	500 kW of DG and 250 kW of energy storage	$1,165,000
Islanding	Test viability of deploying energy storage to facilitate community solar or other islanded systems	500 kW of energy storage	$599,200
Fault Detection	Test ability to use DA system in tandem with fault detection and isolation recovery	New DA Scheme - 6 Automated Switches & 18 Smart Fault Indicators	$290,410
LED Lighting	Test savings potential associated with LED conversions of city lights	100 light poles; location to be determined	$66,000
Energy Management	Test smart thermostat and load control devices to evaluate peak shaving potential	Route Cycle 01 - roughly 10% of meters	$85,770
Conservation Voltage	Test potential of controlling voltage to shave system peak	Spicket River Station - 3 Feeders	$126,610
Load Forecasting	Test viability of systems to manage load across distribution network	Route Cycle 01 - 10 sensors	$36,800
Asset Management	Test potential of using system to extend life of distribution assets	Condition Assessment and defect localization of underground cables	$125,000

Connect/Disconnect

Program objectives include:

- Evaluate functionality of advanced meters being deployed by the Company.
- Test Connect/Disconnect features.
- Assess communication network capabilities.
- Evaluate meter data management capabilities.
- Assess data mapping and workflow with AMI.

Pilot

	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Remote Disconnects	418	$ 77		$	$ 32,186
Total					**32,186**

Conservation Voltage

Program objectives include:

- Test voltage control approach.
- Assess control systems approach – automated vs. manual
- Assess communication network capabilities.
- Evaluate integration between voltage management and AMI systems and/or sensors.

Pilot					
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Regulator Retrofits	9	$ 3,000	3	$ 140	$ 30,780
Sensors	9	$ 2,750	2	$ 140	$ 27,270
Voltage Communication Devices	9	$ 1,750	3	$ 140	$ 19,530
Equipment Controls	9	$ 2,250	3	$ 140	$ 24,030
Voltage Management System	1	$ 25,000			$ 25,000
Total					$ **126,610**

Asset Management

Program Objectives include:

- Evaluate system integration into existing and proposed Company operating systems.
- Assess impact on distribution asset life management.

Pilot					
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Partial Discharge Tool	1	$ 100,000			$ 100,000
Asset Management System	1	$ 25,000			$ 25,000
Total					**125,000**

Load Forecasting

Program Objectives include:

- Evaluate forecasting capabilities of distributed generation and electric vehicle charging.
- Evaluate load forecasting capabilities to manage distribution flows.
- Evaluate system integration into existing and proposed Company operating systems.
- Evaluate opportunities for more granular forecasting capabilities down to a feeder level.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Sensors	10	$ 900	2.00	$ 140	$ 11,800
Load Forecasting System	1	$ 25,000			$ 25,000
Total					$ 36,800

Islanding

Program objectives include:

- Test viability of integrating customer-owned DG resources.
- Test capabilities of energy storage system.
- Assess electrical and operational efficiency rates.
- Defer or mitigate an existing distribution system need or deficiency.
- Evaluate system integration into existing and proposed Company operating systems.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Inverters	6	$ 12,000	3.00	$ 140	$ 74,520
Disconnect Switches	6	$ 3,000	2.00	$ 140	$ 19,680
Storage (per kW)	500	$ 960			$ 480,000
Management System	1	$ 25,000			$ 25,000
Total					$ 599,200

Fault Detection

Program objectives include:

- Evaluate fault detection capabilities
- Evaluate isolation recovery capabilities
- Assess viability of integration with AMI system
- Evaluate system integration into existing and proposed Company Electric Dispatch and Control systems
- Assess communication network capabilities.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Automated Switches	6	$ 30,000	3	$ 140	$ 182,520
Automated Fault Indicators	18	$ 1,620	0.75	$ 140	$ 31,050
Radio Communications Devices	6	$ 3,500	1	$ 140	$ 21,840
Dispatch Integration	1	$ 10,000		$	$ 10,000
Outage Management System	1	$ 10,000		$	$ 10,000
Security System	1	$ 10,000		$	$ 10,000
Distribution Automation System	1	$ 25,000		$	$ 25,000
Total					**$ 290,410**

Energy Management

Program objectives include:

- Test responsiveness of residential customers to utilize smart thermostats
- Test responsiveness of commercial customers to engage with load control devices.
- Test communications and AMI integration
- Evaluate rate mechanisms and other initiatives to incentivize the use of energy management.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Smart Thermostat	209	$ 180	0.50	$ 140	$ 52,250
Load Control Switches	13	$ 350	0.50	$ 140	$ 5,460
Radio Communications Devices	2	$ 1,250	2.00	$ 140	$ 3,060
Smart Thermostat Management Sy	1	$ 12,500			$ 12,500
Load Control Management System	1	$ 12,500			$ 12,500
Total					$ 85,770

Distributed Energy Resources

Program objectives include:

- Test integration of distributed resources onto distribution grid.
- Evaluate Hosting Capacity Analysis capabilities and potential.
- Evaluate capabilities of different distributed generation and energy storage systems.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
DG (per kW)	500	$ 1,800			$ 900,000
Energy Storage (per kW)	250	$ 960			$ 240,000
Central Management System	1	$ 25,000			$ 25,000
Total					$ 1,165,000

LED Lighting

Program objectives include:

- Evaluate capabilities of LED street lights, including control systems.
- Assess economic impacts to stakeholders.
- Evaluate capabilities to support other Smart City functions in the future including electric vehicle charging.

	Pilot				
	Quantity	Unit Cost	Labor Hours	Labor Rate	Total Cost
Controllers	100	$ 150	1.00	$ 140	$ 29,000
Radios	100	$ 50	0.50	$ 140	$ 12,000
Management System	1	$ 25,000			$ 25,000
Total					$ 66,000

Pilot Implementation

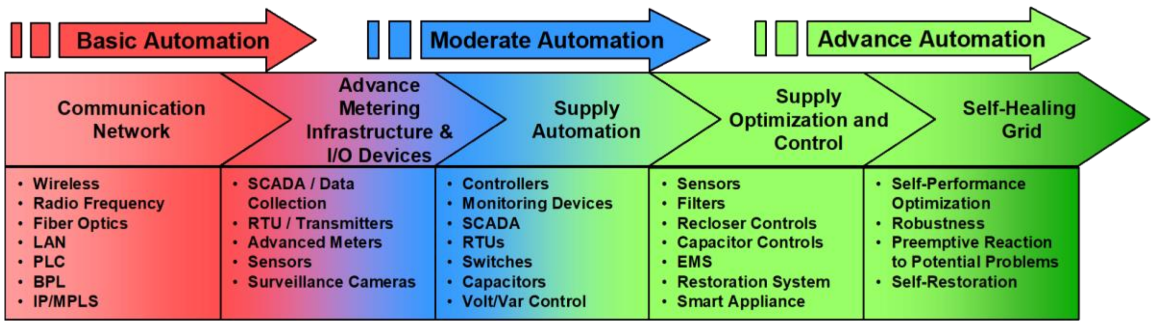
The proposed plan for Liberty Utilities' Grid Modernization pilot test provides for a robust test of each program in a prudent and complete manner. The next steps going forward are:

- Validate the pilot and long-term program approaches with operational staff
- Prepare for the next phases of activity, including:
    - **Requirements** – The requirements phase goes a level deeper into the business and system requirements related to the Grid Modernization effort. In addition, this phase provides the framework and inputs necessary to initiate procurement efforts. The requirements that are developed are then incorporated into the RFP(s) and provide the vendor community with the necessary information to prepare a robust response.
    - **Procurement** – The Procurement phase takes the deliverables from the assessment and requirements phases and uses them as the basis to prepare the RFP documents that are published to solicit proposals from equipment, systems, integration, and/or professional services vendors. Evaluation criteria are developed to ensure an objective evaluation of all proposals submitted.
    - **Pilot Plan Development** – Once the vendors are selected in the procurement phase, the detailed pilot plan development phase can commence taking into account any particulars of the selected vendors' technology and system capabilities/functions. This phase includes the necessary planning and preparation to establish the foundation for project success.
    - **Pilot Deployment –** The underlying purpose of the pilot deployment phase is to enable the selected vendor(s) to prove that the products/equipment will deliver the expected results. In addition, it allows Liberty Utilities to test the necessary interfaces with other systems, and to design, develop and test the future state business processes prior to full deployment.

- **Full Deployment** – Deployment on a large scale begins once the system functionality has been verified and accepted at the end of the pilot phase.

Program Planning and Implementation

The recommended approach for developing a suitable implementation plan is based on the concept of developing core elements that support initial programs while also establishing foundational elements for future aspects of the grid modernization plan. Below is a conceptual approach:



As illustrated above, there are five key stages to the deployment:

- Stage 1 – The establishment of a communications network provides a robust backbone for all grid modernization elements.
- Stage 2 – The AMI network is seen as a key foundational element of the overall design. While AMI will provide demonstrable benefits by itself, it also provides the needed infrastructure for such programs as conservation voltage, fault detection, and load forecasting.
- Stage 3 – Supply automation programs (ADMS) provide for the realization of benefits from those use cases that demonstrate the most viable business cases.
- Stage 4 – Supply optimization and control programs will enable Liberty Utilities to capture further benefits by enhancing distribution operations on a dynamic basis.

- Stage 5 – The ultimate goal is to utilize the grid modernization effort to explore ways to enhance distribution operations with future programs that will be developed over time.

The specific approach for each of the ten use cases is listed below:

	Program	Value Estimate	Overall Strategy	Five Year Target	Ten Year Target
Metering	Advanced Metering	($5,678,839)	Deploy as platform for overall grid modernization effort	Complete deployment	Optimized work processes and data management
	Connect/Disconnect	$1,309,297	Implement alongside metering system	Complete deployment	Optimized work processes and data management
Distribution Operations	Fault Detection	$1,959,248	Implement alongside metering system	Complete deployment in core fault detection	Implement full isolation recovery scheme
	Conservation Voltage	$2,821,247	Implement alongside metering system	Complete deployment	Develop voltage optimization scheme
	Load Forecasting	$418,397	Implement alongside metering system	Complete deployment	Optimized work processes and data management
	Asset Management	$4,624,396	Implement alongside metering system	Complete deployment	Optimized work processes and data management
	Islanding	$6,076,744	Work with customers to explore options	Resolve or defer distribution system deficiency, using NWS	Resolve or defer distribution system deficiency, using NWS
Customer Connections	Energy Management	$782,819	Explore options	Initiate pilot and monitor industry developments	Implement initial deployment
	Distributed Energy Resources	$1,113,852	Explore options	1% of peak implemented	6% of peak implemented
Smart City	LED Lighting	$1,968,298	Pursue opportunities with cities	Two cities completed	Grow LED lighting to other cities and pursue other use cases

In general, the Five Year Target will be driven by the results of the pilot programs. The Ten Year Target will look for opportunities to optimize work processes and data management. Additional projects could be added to the Ten Year Target based on the performance and merits of the programs undertaken in the Five Year Target.

The implementation plan calls for operational efforts leading to deployment over the first twelve months:

	Strategy Development	System Analysis & Design	Project Planning & Preparation	Network Deployment & Testing
Inputs	• Individual Program Plans • Existing Infrastructure • Stakeholder Hierarchy Diagram	• Network Maps • Input from Site Analysis (line crew, vendors, PM, etc.)	• RFP Responses • Installation Duration Estimating • Resource Availability	• Schedule Baseline • Training • Testing Plan
Outputs	• Prioritized List of Technologies • RFP Documentation • List of Vendors	• Approved Design • List of Needed Equipment/Pre-Work • Project Plan	• Inventoried Equipment • Schedule Mgmt Plan • Test Goals & Objectives	• Working Network • Performance Reporting • Lessons Learned
Who	• Smart Network Team • Management	• Project Manager • Line Workers and IT Staff • Vendors	• Project Manager • Purchasing • Line Workers • IT/Telecom Staff • Vendors	• Project Manager • Testing Team • Line Workers • IT/Telecom Staff • Vendors
Duration	2 months	3 months	3 months	4 months
Complexity	◐	●	◔	◕

Short Term Plan

The first five years of the proposed program implementation covers the years 2021-2025. The following steps are planned during this time:

- Advanced Distribution Management System (ADMS) – deployment of the ADMS software, including incorporation of distribution assets in a common GIS database, will provide the software platform for integrating distribution assets and new smart deices into its system.

- Advanced Metering – The deployment of the entire AMI system, including all meters, software, Meter Data Management System (MDMS), communications network, repeaters, and field collection devices. The forecast calls for a complete system installation within five years.

- Connect/Disconnect – All disconnect devices will be installed with the AMI meters under glass and will be deployed within the same timeframe as the AMI network.

- Fault Detection – The core elements of the fault detection system will be deployed, allowing for full capabilities of an outage management system. It is anticipated that the fault detection system will leverage data from the metering system to identify locations of outages.

- Conservation Voltage – The goal is to deploy the conservation voltage system very quickly. In the short term, bellwether meters will be used to report on voltage levels across distribution feeders to ensure compliance with ANSI standards. As the AMI system is deployed across the entire service territory, these bellwether meters will be displaced by AMI meters.

- Load Forecasting – The backend systems supporting the load forecasting system will be deployed in the first year of the project. AMI meters and distribution assets deployed in the field will be utilized to report on load conditions on a real time basis as they are deployed.

- Asset Management – The backend systems supporting the asset management system will be deployed in the first year of the project. AMI meters and distribution assets deployed in the field will be integrated into the system as they are deployed.

- Islanding – The goal in the first phase will be to deploy enough islanded resources in order to defer one or two capital projects currently under budget for fiscal years 2022 and 2023. Currently there are three projects that offer the potential for deferral, including (a) the installation of Lebanon 1L2 Feeder Tie in Plainfield ($1.3 million); (b) the installation of Vilas Bridge 12L1-12L2 Feeder Tie in Charlestown ($1.3 million); and (c) the rebuild of Lockhaven Rd Enfield Phase 1&2 ($1.51 million).

- Energy Management – Liberty Utilities proposes to monitor system development and continue to evaluate the viability of deployment. Within the first five years, Liberty Utilities plans to implement an initial pilot to further test the viability of a dedicated program.

- Distributed Energy Resources – Liberty Utilities is seeking to have a total of 3% of system peak under management of a dedicated DER program by the end of 2024.

- Smart City – The goal is to ensure the complete installation of LED lights for entire public lights for two cities within the service territory.

Long Term Plan

During the first five year of the program, Liberty Utilities will monitor results of each program under management and make adjustments as needed based on actual findings. Based on the information in place today, the plan for the subsequent five years, covering the years 2025-2029 would include the following:

- Advanced Metering – Continue deploying AMI meters in areas of growth within the service territory. In addition, Liberty Utilities will also seek to capture maximum value from the AMI system by looking to optimize the data mapping to ensure that departments can access information in the optimal methodology while also redesigning internal workflows to ensure that work processes are aligned with the new system.

- Connect/Disconnect – Alongside the AMI system, Liberty Utilities will seek to develop learnings from the initial stage of the connect/disconnect program to evaluate how to optimize operations.

- Fault Detection – Liberty Utilities will see to expand the outage management system by incorporating elements of isolation recovery to the fault detection system, enabling automated switching of circuits during major outage events.

- Conservation Voltage – The goal of the long-term conservation voltage program will be to optimize operations by testing and implementing automated voltage management systems.

- Load Forecasting – Liberty Utilities will identify and implement advanced systems to utilize meter and distribution automation data in load forecasting.

- Asset Management – Liberty Utilities will identify and implement advanced systems to utilize meter and distribution automation data in asset management.

- Islanding – The goal in the second phase will be to deploy enough islanded resources in order to defer three to four capital projects by one or more years.

- Energy Management – Liberty Utilities plans to implement an initial deployment involving customers with a mix of smart thermostats and energy management systems.

- Distributed Energy Resources – Liberty Utilities is seeking to have a total of 6% of system peak under management of a dedicated DER program by the end of 2029.

- Smart City – The goal is to ensure the complete installation of LED lights for additional cities within the service territory while also working with communities to evaluate and deploy additional smart city use cases beyond LED lighting controls.

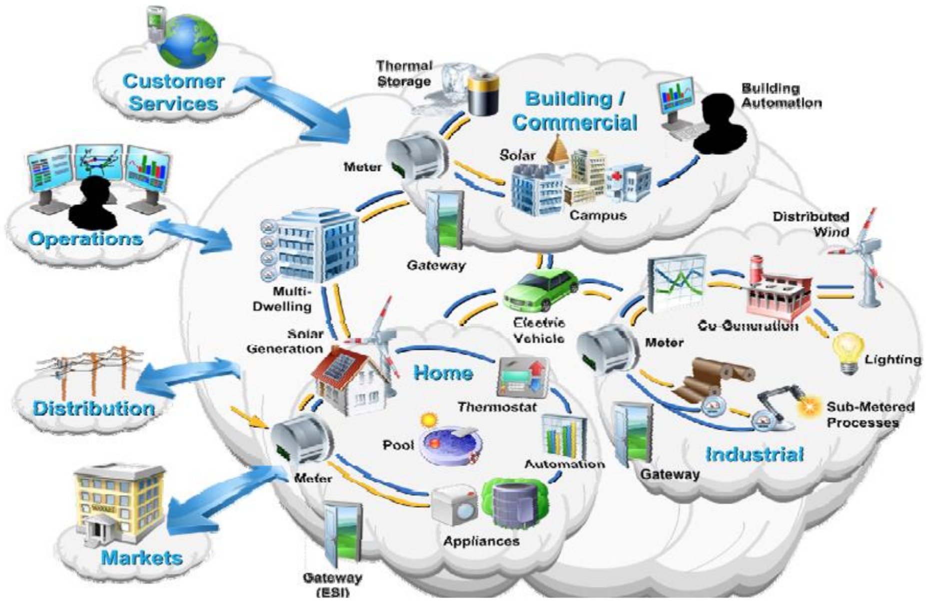
Implementation Approach

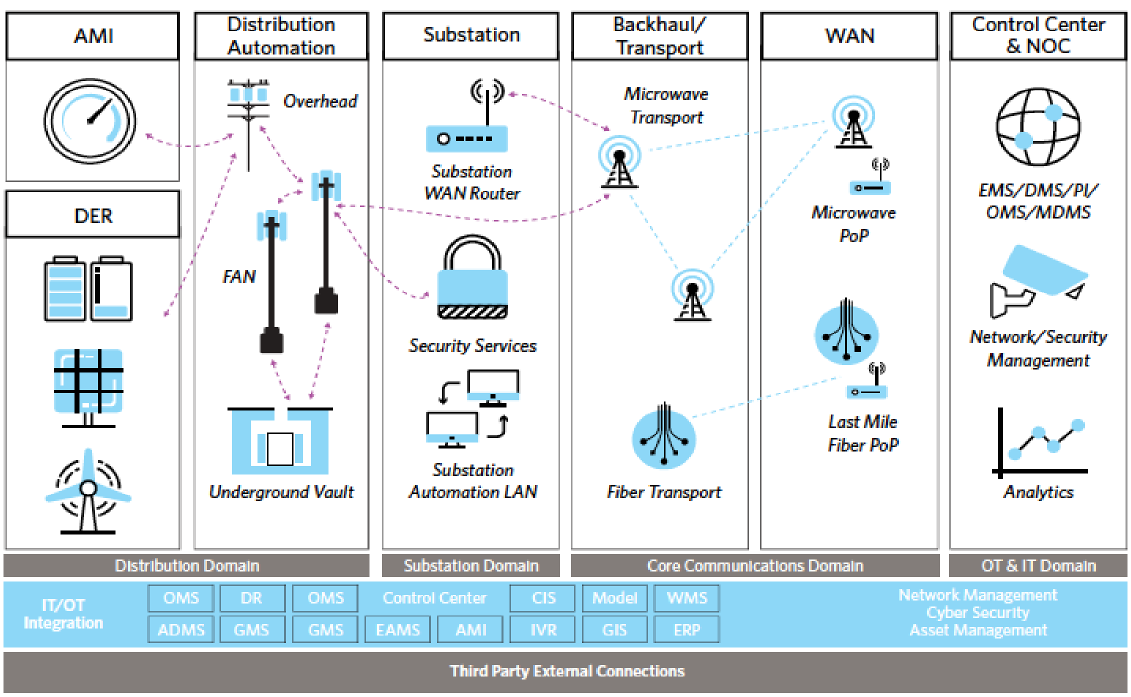
Liberty Utilities seeks to implement programs to enable it to better serve customers and to become more operationally efficient. Grid modernization involves a non-stop, on-demand, re-design journey of the business models, business processes, technologies, organizational structures, and applied human capital to seamlessly leverage existing and new trends into a more profitable, faster growing, and more customer driven utility reality. Liberty Utilities believes that:

- Grid modernization delivers success by committing to pervasive performance management, which helps streamline processes by creating a smart, agile and aligned utility.

- Grid modernization enables the close monitoring of performance, flexible integrated planning, and re-establishes and/or enhances trust with stakeholders.

- Grid modernization also drives insight in divestments and investments, and offers techniques that help in rethinking strategies and managing innovation as a competitive advantage


Customer Services
Operations
Distribution
Markets
Thermal Storage
Building / Commercial
Building Automation
Meter
Solar
Campus
Gateway
Multi-Dwelling
Solar Generation
Distributed Wind
Electric Vehicle
Meter
Co-Generation
Lighting
Home
Thermostat
Pool
Automation
Meter
Appliances
Gateway (ESI)
Gateway
Industrial
Sub-Metered Processes


AMI
DER
Distribution Automation
Overhead
FAN
Underground Vault
Substation
Substation WAN Router
Security Services
Substation Automation LAN
Backhaul/ Transport
Microwave Transport
Fiber Transport
WAN
Microwave PoP
Last Mile Fiber PoP
Control Center & NOC
EMS/DMS/PI/ OMS/MDMS
Network/Security Management
Analytics
Distribution Domain
Substation Domain
Core Communications Domain
OT & IT Domain
IT/OT Integration
OMS
DR
OMS
Control Center
CIS
Model
WMS
ADMS
GMS
GMS
EAMS
AMI
IVR
GIS
ERP
Network Management
Cyber Security
Asset Management
Third Party External Connections

Ultimately, by developing these programs, it will enable the development of a host of new programs that are beneficial for a wide variety of stakeholders. For example, upgrades will be needed to host the inevitable growth in electric vehicles.

Electric vehicles have been discussed for a long time. The promise of achieving mass production of automobiles that could change the fueling paradigm – away from foreign dependence on oil and toward domestic production on electricity – is a promising one that has been championed by virtually all of the relevant stakeholders involved. Almost unanimously, we have heard the voices from the federal government, the automotive industry, and from consumers themselves stating that the time for electric vehicles to reach the market in a meaningful way is upon us. Now that the technology appears to be catching up the hype, there exists considerable optimism that we may be on the verge of the dawning of a new era – the electric vehicle era.

Some of the answers to these questions have been challenging to address for electric vehicle industry. Progress in some of the key areas is well under way and viable solutions appear to be at hand. Certain industry analysts have opined that progress will be slower and more gradual while others are more optimistic. However, one thing that almost no one debates is the ultimate impact of electric vehicles. Simply put, electric vehicles are a "game changer". Consider the following impacts we can realistically expect to see once electric vehicles achieve mainstream status:

- Dependence on foreign oil to fuel our cars will be vastly diminished, thus reshaping foreign relations
- New industries that do not exist today, namely recharging stations and batter developers, will emerge
- Automobile manufacturers will be forced to respond to changing market needs and will need to support the delivery of volumes of electric vehicles not seen today
- Electric utilities will see their load profiles change dramatically – requiring new investments in distribution infrastructure to meet the growing and reshaped loads of the future

- Utilities that pursue smart grid investment may find that the electric vehicle becomes the "killer app" that many have been seeking

- Consumers will develop new relationships with their electric utilities, involving a confluence of smart metering, home automation, distributed energy resources, and electric vehicles

Security

No facet of our society can now afford to ignore the possibility of malicious interference with the normal operations of daily life, and this includes the operations of the utility industry's critical infrastructures. Indeed, the very basic requirements for life are provided by the utility industry: power for heat and light, clean water supply and waste treatment. A secondary level of consideration is energy requirements for the successful functioning of a healthy economy including industrial production, transportation, construction and trade.

For utility companies, when we speak of cyber security we generally are referring to control systems such as DCS or SCADA. Typically Distributed Control Systems (DCS) are used within a single generating plant over a small geographic area while Supervisory Control and Data Systems (SCADA) are used for large, geographically dispersed distribution systems. It is the vitally important function of such systems to control, coordinate and monitor the operations of critical infrastructure including electric lines. In SCADA systems the supervisory control and monitoring station is connected to local control stations through a hard-wired network or through communications networks involving elements such as the Internet, the public switched telephone network, or internal cable or wireless networks. Telecommunications is the intricate nervous system that connects operational assets, providing the means by which control instructions are delivered.

As part of the Grid Modernization effort, we recommend the following practices be instituted:

- ***Internal CI Protection Program Starts at the Top***. A critical infrastructure protection program should be initiated by upper management and included in the annual budget process. High-level leadership facilitates more successful programs. Security initiatives need to be driven from the top of the organization, at the "C" level. There are two reasons for this. First, executive management is in the best position to work with legislators, Federal government contacts, policy makers, and powerful peers. At this level, pertinent information is quickly conveyed. Secondly, an authority within the organization is more likely to see security projects through to a successful conclusion.

- ***Establish Formal Personnel Policies***. Well-defined personnel roles are essential to good security. Another key element of security is personnel policy. When individuals are left in charge of security without specific guidelines, likely results are inconsistency and ineffectiveness. Thus, even good security policies can be rendered ineffective without properly defined personnel roles and responsibilities. Improper training can also impair good security. If employees are properly trained for their roles in the security program, accidental disclosure of sensitive information as well as a host of other security breaches could ensue.

- ***Assess Vulnerabilities***. Knowing weaknesses enables better security strategy. Before utilities can develop a strategy for protecting themselves against attack, they must be able to adequately identify their vulnerabilities. Knowing weak points in the system will enable utilities to provide additional protection where it is needed, rather than throughout the system. Ultimately, this will save valuable resources from being wasted.

- ***Secure SCADA Connections***. The increasing trend towards systems that are more open and allow for more distributed communications environments along with the standardized technology sets that accompany them are leading to increasingly vulnerable systems that can be accessed from anywhere in the world. Because they are so essential to the function of the power grid, it is increasingly important that SCADA networks are appropriately isolated from corporate networks.

- ***Work With Vendors***. There are some grid modernization systems that do not include security features. Using security devices that are provided is a good first step, yet additional security is necessary.

- ***Monitor the Systems***. The ability to quickly detect and eliminate any intrusion into the system will enable the quickest possible recovery of service in an emergency.

- ***Format Disaster Recovery Plans.*** Notification of security incidents is not enough. Utilities should also cultivate disaster recovery plans to cut off any incidents that arise as well as to allow for quick restoration of systems.

- ***Perform Routine Audits.*** In order to ensure that security measures are sufficient for actual protection, the security systems themselves should be audited regularly. Audits will expose weaknesses in security measures, and specifically they will reveal remaining vulnerabilities in the network.

Chapter 5: Summary

Regulatory compliance, support, and funding all have an impact on utility operations. As has been seen in the last few years, new security and environmental regulations are prompting reprioritization of projects and the implementation of new programs and technology. Energy efficiency and net metering are emerging in multiple areas of the country.

Every utility would like to have the fastest and most automated network, but a higher quality network comes at a higher price. That is why Liberty Utilities has developed a detailed business case to examine various factors—including budget—as part of a rigorous planning process to find the best fit for its operational requirements.

1 # Exhibit A – Business Case Assumptions (General)

Growth Rate		
Meters		1.0%
Substations		1.0%
Feeders		1.0%
Meter Counts		
Residential		41,330
Commercial		2,720
Industrial		144
Annual Sales ($MM)		
Residential	$	51.6
Commercial	$	41.2
Industrial	$	7.4
Street Lighting	$	1.2
Electric Delivery (kWh)		
Residential		296,235,488
Commercial		492,762,561
Industrial		126,400,162
Street Lighting		4,168,594
Summer Peak (MW)		
Summer		197.8
Fall		141.0
Winter		154.3
Spring		121.8
Infrastructure		
Mainline Feeders		48
Distribution Transformers		9,340
Substations		15
Substation Transformers		13
Financial Assumptions		
Terminal Value		8
Tax Rate		27.08%
Discount Rate		7.60%
Labor Rate Growth		2.5%
Deployment Period		5
Salary Load Rate		40.0%
Depreciation Period		10

1 Exhibit B – Business Case Assumptions (Benefits)

AMI		
Read-To-Bill		
Days to Acclerate Collection		3
Reduction in Faulty Meters & Loss		
Percentage of Electromechanical Meters		65%
Inaccurate Meter Rate		1.0%
Digital Impact		50%
Special Reads		
Special Read Requests		1,000
Cost per Read	$	95.00
AMI Impact		50%
Vehicle Operations		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		18,000
Cost per Mile	$	0.580
Emissions		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		18,000
CO_2 Reduction per Mile (grams)		455

Connect/Disconnect		
Labor Reduction		
Annual Field Collector Expense	$	65,000
Disconnect Reduction		25%
Bad Debt Reduction		
Annual Bad Debt	$	1,000,000
Loss Reduction		15%
Emissions		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		1,000
CO_2 Reduction per Mile (grams)		455

Fault Detection		
Feeder Outages		
Feeder Related Outages		20
Labor Hours per Feeder Outage		20.0
Labor Reduction Rate		30.0%
Labor Rate	$	140.00
Distribution Element Failure Detection		
Annual Element Failures		10
Failure Detection Rate		25.0%
Replacements Conducted During Overtime		10.0%
Labor Hours per Replacement		20.0
Normal Labor Rate	$	140.00
OT Labor Rate	$	165.00
Transformer Optimization		
Average Transformer Life		40
Transformer Life Extension		20.0%
Transformer Cost	$	6,000
Conductor Repair		
Conductor Failures per Year		75
Cost per Conductor Splice	$	3,140
Reduction Rate		50.0%
Outage Management		
Customer Minutes Out - No Exclusions		17,184,263
Customer Minutes Out - With Exclusions		4,293,710
Diagnosis & Response %		36.9%
Repair %		63.1%
Reduction in Diagnosis & Response Time		20.0%
Reduction in Repair Time		12.0%
Lost Revenue Per Minute	$	0.016
Communications Savings		
Monthly Leased Line Charge per Substation	$	875

Conservation Voltage		
Loss Reduction		
Line Loss Rate		5.5%
Transmission Charge per kW-yr	$	144
Expected Decrease in Loss with Automation		5.0%
Optimization Potential		10.0%
Capacity Reduction		
Peak Impact per Month		0.1%
Cost per Marginal kW	$	685
Hours per Month with Reduced Voltage		30
Average Cost per kWh	$	0.016
Emissions		
Average CO_2 emissions (grams) per kW		606

Load Forecasting

Capacity Reduction		
Peak Impact per Month		0.03%
Transmission Charge per kW-yr	$	144
Emissions		
Average CO_2 emissions (grams) per kW		606

Asset Management

Acquisition and Use		
Annual Capital Budget	$	20,000,000
Efficiency Gain		2.5%
Asset Reliability		
Field Asset Capital Base	$	161,155,443
Average Asset Life		40
Efficiency Gain		5.0%

Islanding

Distribution Loss Reduction		
Impact Rate		15.0%
Line Loss Rate		5.5%
Optimization Potential		10.0%
Distribution Value (per kW-month)	$	12.00
Power Quality		
Impact Rate		15.0%
Outage Value - Supply (per MW-minute)	$	0.10
Outage Mitigation		
Customer Minutes Out		17,184,263
Local Outage Impact		1.0%
Outage Value - Supply	$	0.10
Transmission Savings		
Percentage of System Peak		2.0%
Distribution Value (per kW-month)	$	12.00
Distribution Deferral		
Target Peak Impact		4.0%
Capital Deferral Rate		10.0%
Cost per Marginal kW	$	685
Emissions		
Average CO_2 emissions (grams) per kW		606

Energy Management

Smart Thermostat		
Penetration Rate of Residential Customers		10.0%
Average Impact per Customer		1.0%
Cost per Marginal kW	$	685

Load Control		
Penetration Rate of C&I Customers		10.0%
Average Impact per Customer		1.5%
Cost per Marginal kW	$	685

Emissions		
Average CO_2 emissions (grams) per kW		606

Distributed Energy Resources

Transmssion Savings		
Transmission Charge per kW-yr	$	144
DG Target Peak Under DER		4.0%
Average Capacity Factor		60.0%
Average Electrical Efficiency		60.0%

Capital Efficiency		
DG Target Peak Under DER		6.0%
Average Capacity Factor		60.0%
Average Electrical Efficiency		60.0%
Utilization Rate		5.0%
Value per kW	$	685

Emissions		
Average CO_2 emissions (grams) per kW		606

LED Lighting

Device Charge		
Target Devices		4,000
Annual Service Charge	$	75.00

1 Exhibit C – Business Case Assumptions (Capital)

General

Reinvestment

	Avg. Asset Life
Metering	15
Distribution Operations	20
Customer Connections	15
Smart City	15

Metering

AMI

	Dev: Cust Ratio	Device	Labor	Systems
AMI Meter	100.0%	$ 95	$ 10	
Gateway Devices	2.0%	$ 2,200	$ 75	
Repeaters	8.0%	$ 275	$ 20	
AMI Professional Services				$ 50,000
AMI Software				$ 125,000
PI Services				$ 510,000
MDM Software				$ 175,000

Connect/Disconnect

	Dev: Cust Ratio	Device	Labor	Systems
Remote Disconnect	5.0%	$ 77	$ -	
Management System				$ 50,000

Customer Connections

Energy Management

	Dev: Cust Ratio	Device	Labor	Systems
Smart Thermostat	2.2%	$ 180	$ 20	
Load Control Switches	0.6%	$ 350	$ 20	
Radio Communications Devices	0.1%	$ 1,250	$ 200	
Smart Thermostat Management System				$ 50,000
Load Control Management System				$ 50,000

Distributed Energy Resources

	Dev: Cust Ratio	Device	Labor	Systems
Capacity Cost per kW		$ 1,800	$ 100	
Central Management System				$ 400,000

Smart City

LED Lighting

	Dev: Cust Ratio	Device	Labor	Systems
Controllers	5.0%	$ 150	$ 20	
Radios	5.0%	$ 10	$ 5	
Management System				$ 250,000

Distribution Operations

Fault Detection

	Dev: Cust Ratio	Device	Labor	Systems
Automated Switches	0.1%	$ 30,000	$ 350	
Automated Fault Indicators	0.3%	$ 1,620	$ 75	
Radio Communications Devices	0.1%	$ 3,500	$ 150	
Dispatch Integration				$ 50,000
Outage Management System				$ 150,000
Security System				$ 10,000
Distribution Automation System				$ 50,000

Conservation Voltage

	Dev: Cust Ratio	Device	Labor	Systems
Regulator Retrofits	0.1%	$ 3,000	$ 200	
Automated Fault Indicators	0.1%	$ 2,750	$ 100	
Voltage Communications Devices	0.1%	$ 1,750	$ 200	
Substation Controls	0.1%	$ 2,250	$ 200	
Voltage Management System				$ 100,000

Load Forecasting

	Dev: Cust Ratio	Device	Labor	Systems
Sensors	0.1%	$ 900	$ 100	
Load Forecasting System				$ 100,000

Asset Management

	Dev: Cust Ratio	Device	Labor	Systems
Sensors	0.5%	$ 900	$ 100	
Asset Management System				$ 1,050,000

Islanding

	Dev: Cust Ratio	Device	Labor	Systems
Inverters	0.0%	$ 12,000	$ 200	
Disconnect Switches	0.0%	$ 15,000	$ 100	
Reclosers	0.0%	$ 50,000	$ 750	
Storage (per kW)		$ 1,800	$ 100	
Management System				$ 150,000

1 # Exhibit D – Business Case Assumptions (Operations)

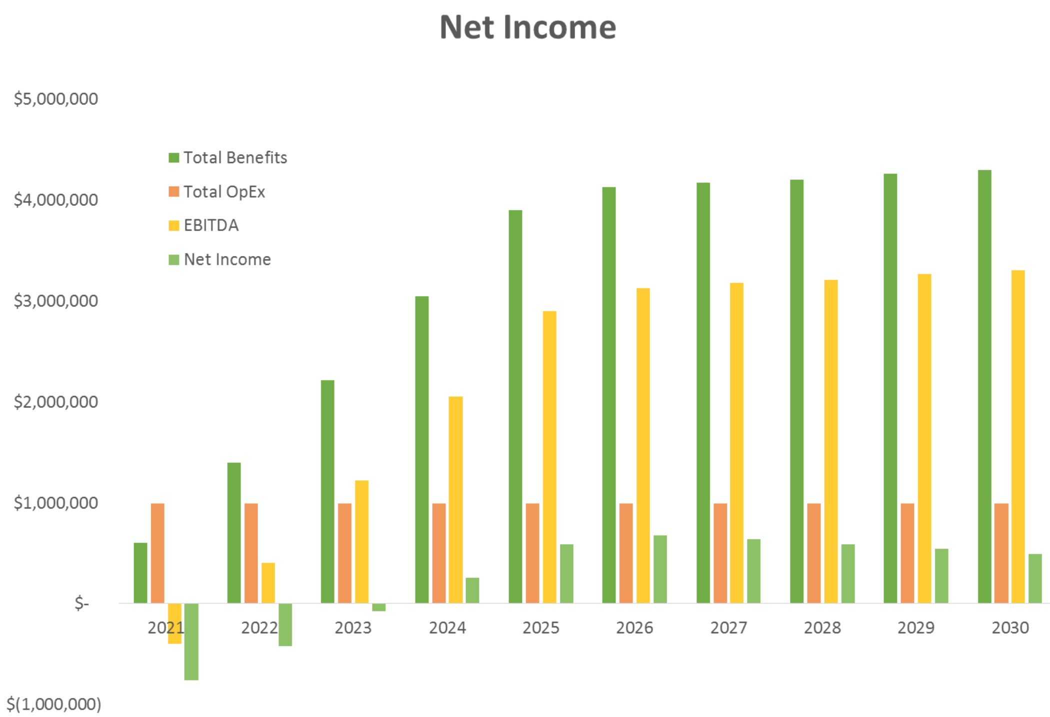
General

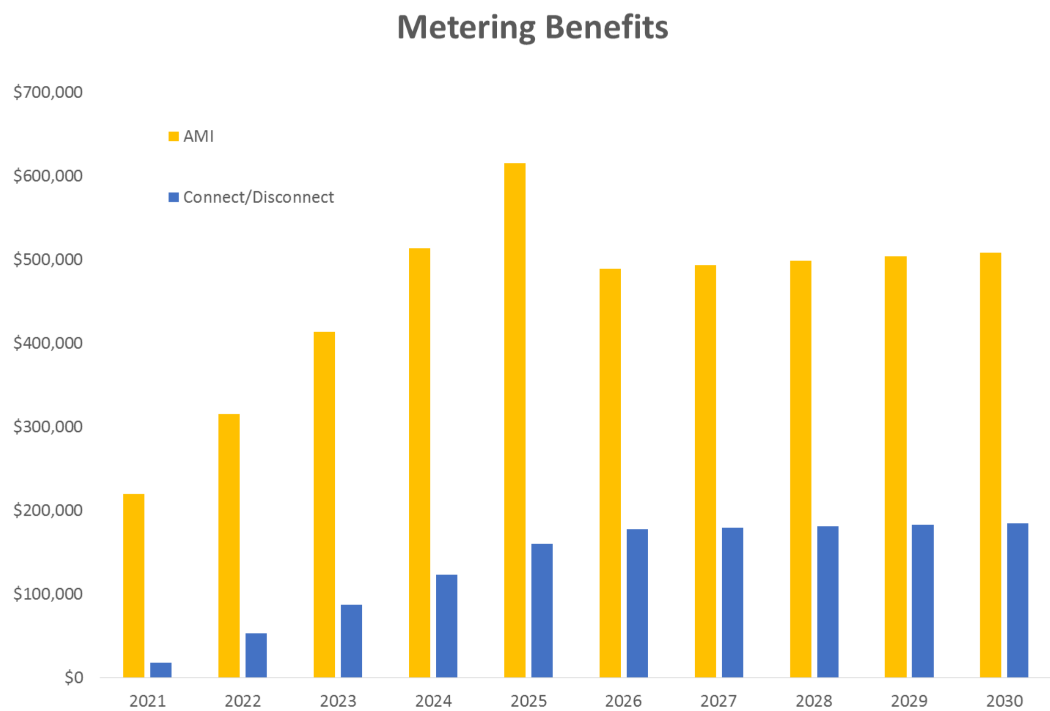
System Maintenance	
Annual System Maintenance	7.0%

Support Staff

	Number	Salary
Communications Design Engineer	1	$ 125,000
Field Support Engineer	1	$ 85,000
Relay and Automation Engineer	1	$ 125,000
System Infrastructure (Servers)	1	$ 85,000
Grid Modernization Engineer	1	$ 125,000

1 # Exhibit E – Additional Graphs




Metering Benefits
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$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
AMI
Connect/Disconnect
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2022
2023
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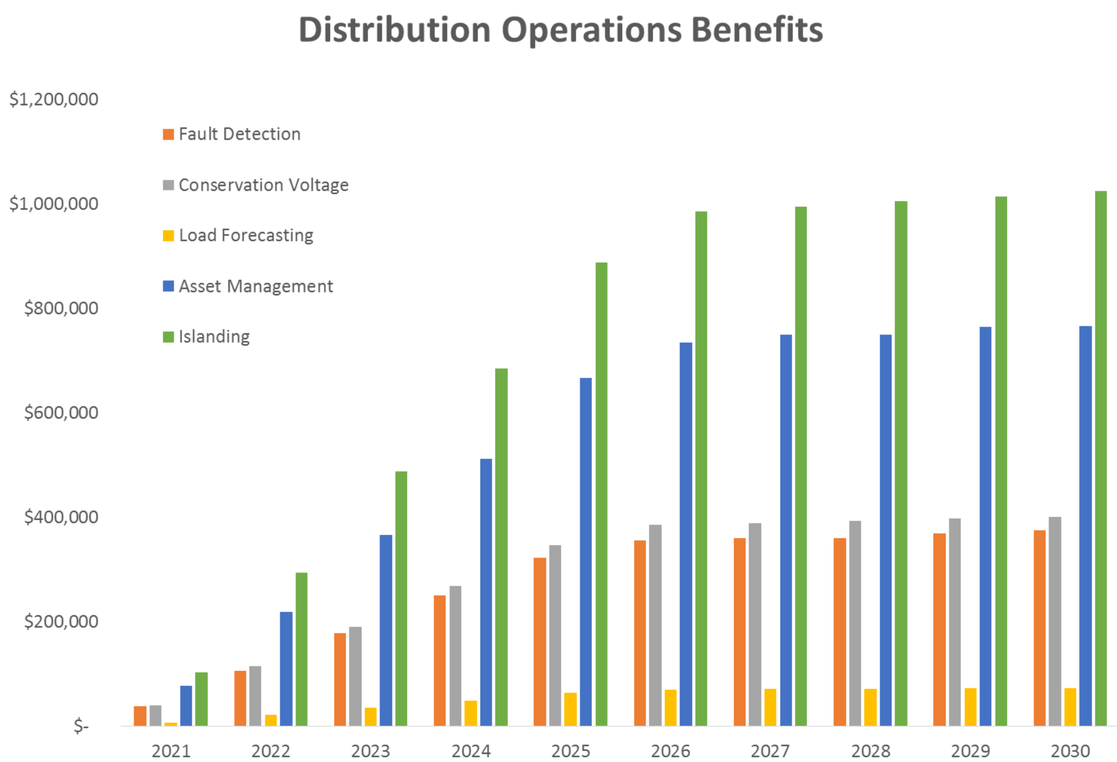
2027
2028
2029
2030


Distribution Operations Benefits
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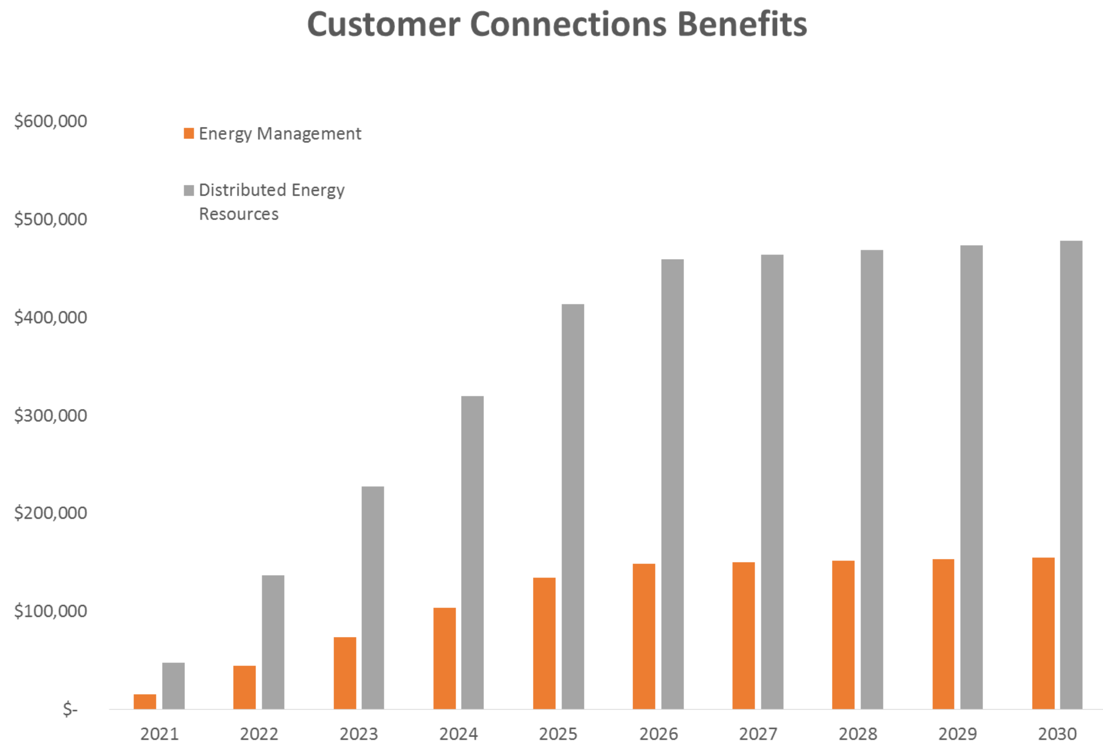
$1,000,000
$800,000
$600,000
$400,000
$200,000
$-
Fault Detection
Conservation Voltage
Load Forecasting
Asset Management
Islanding
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030


Customer Connections Benefits
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$500,000
$400,000
$300,000
$200,000
$100,000
$-
Energy Management
Distributed Energy Resources
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030

Bellows Falls Area

System Planning Summary 2020

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1.0 Executive Summary

Liberty Utilities completed the Bellows Falls Area system planning review for 2020. The revised Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System upgrades required to meet existing and future capacity requirements. The review focused on the distribution requirements needed to resolve deficiencies in system capacity, reliability, power quality or asset condition.

In 2014 the Michael Ave substation was installed to resolve asset conditions and retire the 46/13 kV Charlestown Substation. It was also constructed to supply an expansion from Customer A Engineering, located in Charlestown NH. A new 115kV transmission line, one 115/13 kV transformer and two 13 kV feeders were installed.

The major concern in the Bellows Falls area is poor reliability and the load at risk that results from the inability to supply the Michael Ave substation load during contingency. Maintaining adequate voltages during contingencies is also a challenge given the long distances from the source.

2.0 Introduction

2.1 Purpose

The purpose of this review was to resolve all identified area concerns in the Bellows Falls Area through the 15-year 2020-2036 study horizon. An in-depth review of the area was performed that included the analysis of thermal loading, voltage, reliability, asset condition, power quality, environmental, safety and voltage performance. Both Traditional and NWS were considered to resolve the identified deficiencies presented in this report, using Liberty’s project evaluation guidelines.

2.2 Problem

A study’s initial system assessment is typically based on the needs identified through the problem identification process guided by the Company’s Planning Criteria and Asset Strategies.

3.0 Background

3.1 Geographic Scope

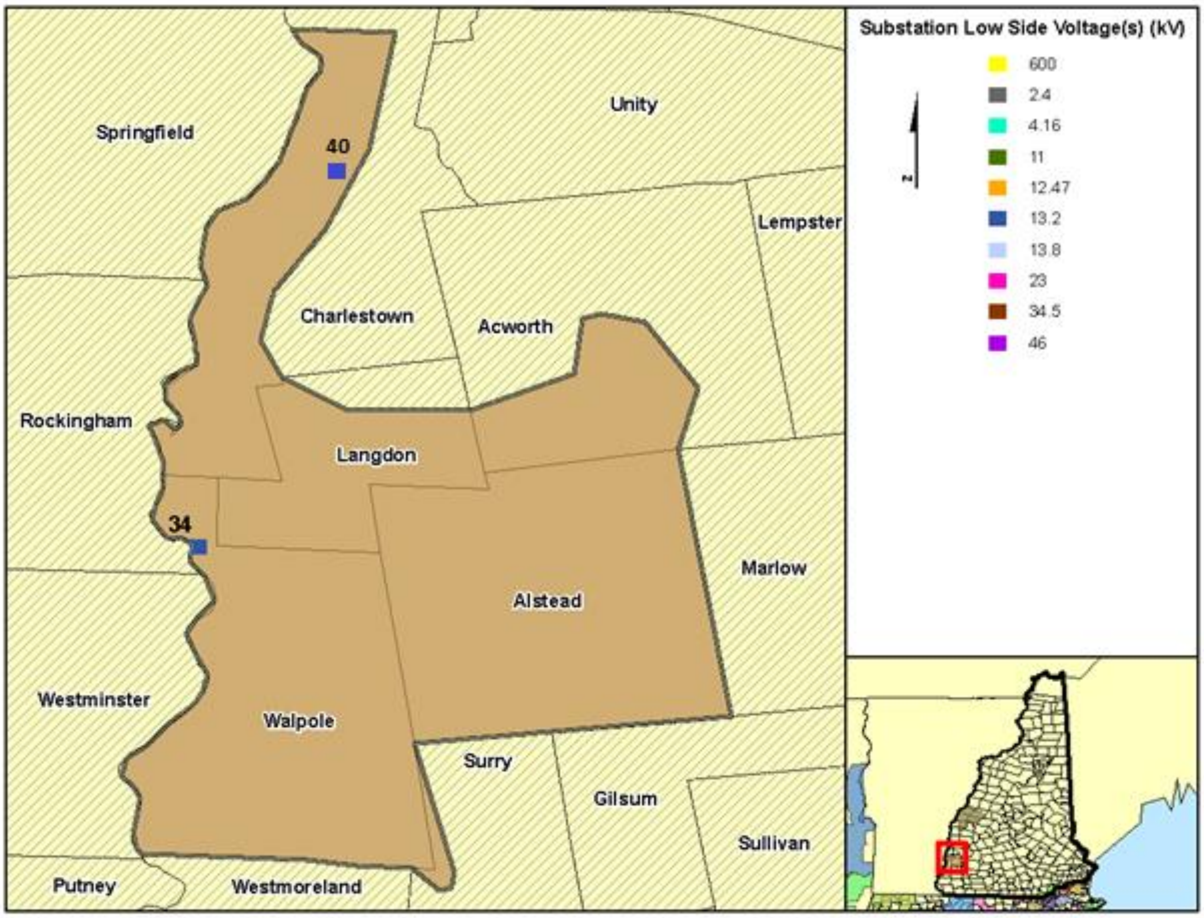
The Bellows Falls area is rural residential with a few small commercial town centers. This area was historically supplied from the hydro generating plant developed at Bellows Falls by New England Power Company. There are two small load centers connected by a long feeder branch running along the Connecticut River. There are two substations in the Bellows Falls area: Michael Ave 40 and Vilas Bridge 34. Vilas Bridge is located in Vermont and is owned and operated by National Grid. Ownership of Michael Ave station is shared between Liberty and National Grid.

Liberty owns and maintains all distribution assets in the substation and National Grid is responsible for the Transformer and Transmission assets. See Figure 1 below.

Supply to the area is from one radial 115 kV transmission line and two radial 46 kV sub transmission lines originating at Bellows Falls. Distribution is at 13.2 kV.

Michael Ave 40 was installed in 2014 to retire the aging Charlestown 8 Substation and to support a major expansion by Customer A.

Figure 1 Bellows Falls Geographical Map



3.2 Electrical Scope

The Bellows Falls Study Area includes one 115 kV transmission supply, two 46 kV supply lines and four 13.2 kV feeders interconnected through two area substations. Supply to Vilas Bridge and Michael Ave is at 46 kV and 115 kV respectively. The Table 1 below summarizes these interconnections:

Table 1: Bellows Falls Area Electric System

Supply	Alternate Supply	Station	Feeder	Customers
W-149S	None	Michael Ave	40L1	509
			40L3	1,244
4402	4401	Vilas Bridge (National Grid)	12L1	2,482
			12L2	1,301

The 115 kV transmission supply to the area originates from Bellows Falls and feeds one transformer at Michael Ave. Appendix A.1, Figure 5 - Bellows Falls 115 kV Transmission System, shows the 115kV supply to the area.

Two 46 kV sub transmission supply lines also originate from Bellows Falls. Table 2 below summarizes these interconnections and Figure 3 in Appendix A.1 – System One Lines shows the 46 kV Supply System.

Table 2: Bellows Falls Area 46 kV Supply System

Circuit	Voltage (kV)	Line Section	
		From	To
4401	46	Bellows Falls (NG)	Vilas Bridge (NG) Tap
4401	46	Vilas Bridge (NG) Tap	Charlestown (NHEC)
4401	46	Charlestown (NHEC)	P.170 (NG)
4402	46	Bellows Falls (NG)	Vilas Bridge (NG) Tap
4402	46	Vilas Bridge (NG) Tap	Charlestown (NHEC)

Liberty Utilities serves 5,536 Customers in the Bellows Falls Area supplied by four 13.2kV distribution feeders. In 2020, the Planning Study Area generated a peak demand of 18 MVA. This area consists of approximately 14 miles of 46 kV three-phase supply line, 66 miles of 13.2 kV three-phase mainline and 164 miles of single-phase 7.62kV distribution. Figure 6, in Appendix A.1 – System One Lines shows the 13.2 kV Distribution System.

3.3 Load and Load Forecast

The Bellows Falls Study Area is a summer peaking area and is limited by summer equipment ratings. The study was conducted using load data beginning with the recorded 2020 peak load; refer to Table 3, below:

Table 3 Bellows Falls Area 2019 Peak Loads

Station	Circuit	2020 Peak Load Amps	Limiting Element	SN Amps	% of SN
MICHAEL AVE	40L1	273	OH Line	530	52%
MICHAEL AVE	40L3	194	OH Line	530	37%
VILAS BRIDGE (NG)	12L1	234	Transformer	336	70%
VILAS BRIDGE (NG)	12L2	224	OH Line	425	53%

The Company developed an econometric model to forecast peak demands through 2036. The forecast model incorporates the impact of weather as well as demographic and local economic conditions on peak demands. The load was escalated through 2036 using the seasonal peak forecast under a 90/10 extreme weather scenario; refer to

, below:

Table 4 LUNH 2020-2036 90/10 Western PSA Growth Rate

Year	% Increase
2020	
2021	11.98%
2022	0.3%
2023	0.3%
2024	0.3%
2025	0.2%
2026	0.2%
2027	0.2%
2028	0.2%
2029	0.2%
2030	0.2%
2031	0.2%
2032	0.2%
2033	0.19%
2034	0.18%
2035	0.17%
2036	0.16%

The forecast model was then adjusted for spot loads to reflect new customer demands larger than 300 kilowatts ("kW"), refer to Table 5 below. There are no known planned customer expansions above 300 kW for the Bellows Falls Area. The Distribution System was modeled and analyzed using the Synergi application to perform the load flow analysis.

Table 5 Bellows Falls Area Spot Loads

Year	Feeder	Location	Load (MW)
None	N/A	N/A	N/A

3.4 Modeling and Criteria

Synergi models were created for the Bellows Falls area 13.2 kV distribution system. Transformers, supply lines, and distribution circuits were evaluated and modeled for each year thru 2036. The peak load and the available tie capacity for each component of the system was determined. Contingencies for the loss of a major component of the electrical system (N-1) were developed, and the system consequences reviewed.

Distribution System Ratings were used to identify any station, supply line, and distribution circuit system capacity and reliability deficiencies, as applicable to Liberty Utilities Planning Criteria which is summarized below.

Table 6 Liberty Utilities Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.
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 are expected to be made within 24 hours. Evaluate alternatives if more than **120 MWhr** of load at risk results following post-contingency switching.	Load must be transferred to nearby transformer to within their LTE rating. Repairs or installation of Mobile Transformer expected to take place within 24 hours. For transformers larger than 10 MVA nameplate, evaluate alternatives if more than **180 MWhr** of load at risk results following post-contingency switching.	Load must be transferred to nearby feeder to within their LTE rating. Repairs expected to be made within 24 hours. Evaluate alternatives if more than **16 MWhr** of load at risk results following post. (Guideline)
N-1 Contingency, which results in facilities operating above their Short-Term Emergency (STE) rating.	As Needed - Typically 15 min 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 15 min for OH conductors and 1-24 hours for UG cables.

4.0 Problem Identification

The goal of system planning is to provide adequate capacity for safe, reliable, and economic service to customers with minimal impact on the environment. System Planning also includes careful management of system assets; addressing asset conditions and protection issues where present to avoid failures, protect the equipment and provide a safe working environment for utility workers.

4.1 Thermal Loading

Analysis results in this section represent the 2020 peak base case. Planning criteria for normal and contingency load serving requirements are applied in concert with the thermal ratings of the facilities to identify capacity violations. Refer to the Company's Distribution Planning Criteria for methodology on rating the equipment. The distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact (normal conditions or "N-0") and N-1 first contingency conditions.

a. Normal Configuration

i. Sub-Transmission System

Analysis under normal conditions resulted in no violations for the Supply System within the Planning Horizon.

Table 7 13.8kV Sub Transmission Loading – Normal Configuration

Circuit	Voltage (kV)	Line Section		Limiting Element	Element Specifics	Rating (MVA)		Actual		Projected Load			
								2020		2025		2036	
		From	To			SN	SE	MVA	%SN	MVA	%SN	MVA	%SN
4401	46	Bellows Falls 14	Vilas Bridge 34 Tap	OH Line	336 ACSR	49.0	52.0	0.0	0%	0.0	0%	0.0	0%
4401	46	Vilas Bridge 34 Tap	Charlestown 32	OH Line	2/0 Cu	29.0	29.0	0.0	0%	0.0	0%	0.0	0%
4401	46	Charlestown	P.170	OH Line	2/0 Cu	29.0	29.0	0.0	0%	0.0	0%	0.0	0%
4402	46	Bellows Falls 14	Vilas Bridge 34 Tap	OH Line	336 ACSR	52.0	52.0	11.3	22%	12.8	25%	13.1	25%
4402	46	Vilas Bridge 34 Tap	Charlestown 32	OH Line	336.4 ACSR	52.0	52.0	0.0	0%	0.0	0%	0.0	0%

ii. Transformers

Analysis under normal conditions resulted in no violations for the Transformers within the Planning Horizon.

Table 8 Transformer Loading – Normal Configuration

Substation	Tranf. ID.	System Voltage (kV)		Maximum	Rating (MVA)		Actual Load			Projected Load					
							2020			2025			2036		
		From	To	Nameplate Rating	SN	SE	MVA	N-1	% SN	MVA	N-1	% SN	MVA	N-1	% SN
MICHAEL AVE	T1	115	13.2	25	31	36	12.0	24.0	39%	13.6	22.4	44%	13.9	22.1	45%
VILAS BRIDGE 34	T1	46	13.2	5.7	7.7	9.6	6.0	3.6	78%	6.8	2.8	89%	7.0	2.6	91%
VILAS BRIDGE 34	T2	46	13.2	8.4	10.05	12.84	5.3	7.6	52%	5.9	6.9	59%	6.1	6.8	60%

iii. Feeders

Analysis under normal conditions resulted in no violations for the Supply System within the Planning Horizon.

Table 9 Feeder Loading – Normal Configuration

Substation	Voltage (kV)	Feeder	Normal Limiting Element	Normal Element Specifics	SN Rating (Amps)	Actual Load			Projected Load					
						2020			2025			2036		
						Amps	N-1	%SN	Amps	N-1	%SN	Amps	N-1	%SN
MICHAEL AVE	13.2	40L1	OH Line	477 Al Spacer	530	284	328	54%	321	291	61%	328	284	62%
MICHAEL AVE	13.2	40L3	OH Line	477 Al Spacer	530	242	370	46%	274	338	52%	280	332	53%
VILAS BRIDGE 34	13.2	12L1	Transformer	1-5.7 MVA	336	264	157	79%	299	122	89%	305	116	91%
VILAS BRIDGE 34	13.2	12L2	OH Line	336 Al Spacer	425	230	246	54%	260	216	61%	266	210	63%

➢ Phase Imbalance

The feeders in the Bellows Falls Planning Study Area were reviewed for phase balance. The peak average phase loading between July20 and August 2020 was selected for each feeder for phase imbalance review.

Liberty utilizes the following criteria for corrective action to phase imbalance:

- The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting;
- The loading between the low and high phase should not exceed 100A.
- Liberty will strive to maintain phase balancing below 10% (guideline).

Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified.

Table 10 below identifies where the imbalance is greater than 10%, and provides recommended mitigation. These recommended mitigation aim to improve the poor voltage conditions that result from a contingency event. The cost to address these is minimal.

Table 10 Feeder Phase Balance above 10%

	Amps						Loading		Criteria			
Source	A	B	C	Avg	Max	N	% Rat	% Imb	Grnd Relay	% Relay	Dif Max / Min	Mitigation
Michael Ave 40L3	242	178	163	194	242	73	52	24	240	30%	79	Transfer 8A from A to B at Fuse 3197 and 14A from A to C at Fuse 2312. Extend 650 ft 3 phase line at Fuse 3201 and transfer 25A from A to C and 14A A to B. Improves % Imb to 3%
Michael Ave 40L1	284	253	283	273	284	31	60.4	7.4	240	13%	31	
Vilas Bridge 12L1	216	221	264	234	264	46	78.6	13.0	200	23%	48	Transfer 12A from C to A at Fuse 2335 and 8A from C to B at Fuse 3049 to improve % Imb to 4.4%
Vilas Bridge 12L2	215	230	226	223	230	13	54.0	3.8	200	7%	15	

b. N-1 Contingency & Load-At-Risk

i. Supply System

Contingency analysis for 46 kV supply lines resulted in no existing violations or predicted violations.

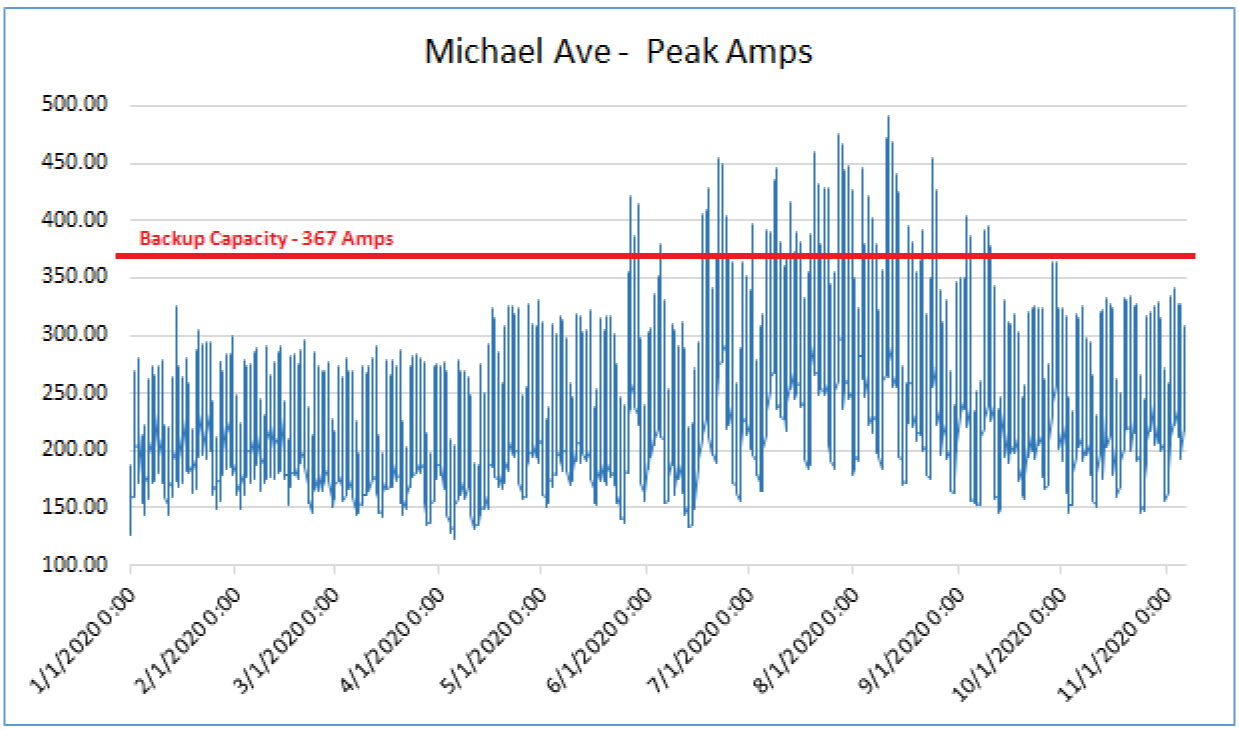
Table 11 13.8kV Sub Transmission Loading – Contingency Configuration

Circuit	Voltage (kV)	Line Section		Limiting Element	Rating (MVA)		Projected Contingency					
							2020		2025		2036	
		From	To		SN	SE	MVA	% SE	MVA	% SE	MVA	% SE
4401	46	Bellows Falls 14	Vilas Bridge 34 Tap	OH Line	49.0	52.0	**12.6**	24%	**14.3**	28%	**14.6**	28%
4401	46	Vilas Bridge 34 Tap	Charlestown 32	OH Line	29.0	29.0		0%		0%		0%
4401	46	Charlestown	P.170	OH Line	29.0	29.0		0%		0%		0%
4402	46	Bellows Falls 14	Vilas Bridge 34 Tap	OH Line	52.0	52.0	**0.0**	0%	**0.0**	0%	**0.0**	0%
4402	46	Vilas Bridge 34 Tap	Charlestown 32	OH Line	52.0	52.0	**0.0**	0%	**0.0**	0%	**0.0**	0%

The Michael Ave transformer is loaded to approximately 12MVA during peak. Contingency analysis for the loss of the single 115 kV supply line feeding Michael Ave identified an existing load at risk of 4.8 MVA. A loss of the 115 kV supply line W-149S results in an interruption to the 40L1 and 40L3 feeders. The Vilas Bridge 12L1 feeder does not have adequate capacity nor can it provide adequate voltage support to supply both 40L1 and 40L3 feeders that are over 8 miles away.

The emergency rating of the Vilas Bridge 12L1 transformer is 9.6 MVA. After transferring most of the 12L1 feeder load to the 12L2 feeder, approximately 8.4 MVA (367 amps) of capacity remains to support the 12 MVA Michael Ave station. A review of the area load between 1/1/2020 and 11/7/2020 found that with the loss of the 115kV Supply Line, the loading for Michael Ave Substation is above 8.4 MVA during 480 hours of the year. The graph below shows the Michael Ave substation peak amps, for this time period.

Figure 2 2020 Michael Ave Coincident Demand (MVA)



An unserved load of 4.8 MVA for 12 hours could result in a load at risk of 58 MWhr. This load at risk is projected to increase to 6.2 MVA and 74 MWhr in 2025 but is not projected to exceed the 120 MWHr limit for Supply Lines. Larger commercial loads would likely be shed to maintain the Vilas Bridge T1 transformer within limits. The Michael Ave substation also provides backup power to the NH Electric Co-Op. Under this contingency scenario, supply to the NHEC cannot not be provided.

ii. Transformers

Contingency analysis identified an existing overload of the Vilas Bridge T1 transformer. The Vilas Bridge 12L2 feeder only ties with the 12L1 feeder. With the loss of the Vilas Bridge T2 transformer, the T1 transformer could be loaded to 118% of emergency rating. To mitigate this condition, load can be transferred to the Michael Ave Substation and maintain the Vilas Bridge T1 Transformer within emergency ratings. This loading is projected to increase to 133% in 2025, and could require shedding customers in the area to maintain the transformer within emergency ratings. This contingency is not projected to violate the Liberty Distribution Planning Criteria for load at risk. The table below shows the actual and projected loading of the area's substation transformers. All transformers are owned, operated and maintained by the New England Power Company.

Table 12 13.8kV Transformer Loading – Contingency Configuration

Substation	Tranf. ID.	System Voltage (kV)		Maximum	Rating (MVA)		Actual		Projected Load			
							2020		2025		2036	
		From	To	Nameplate Rating	SN	SE	MVA	% SE	MVA	% SE	MVA	% SE
MICHAEL AVE	T1	115	13.2	25	31.00	36.00	0.0	0%	0.0	0%	0.0	0%
VILAS BRIDGE 34	T1	46	13.2	5.7	7.70	9.60	11.3	118%	12.8	133%	13.1	136%
VILAS BRIDGE 34	T2	46	13.2	8.4	10.05	12.84	11.3	88%	12.8	99%	13.1	102%

Similar to a loss of the 115kV Transmission Line, a loss of the Michael Ave transformer results in an interruption to the 40L1 and 40L3 feeders. The system constraints described in Section 4.1.2.1 for Supply Lines applies to this contingency as well. However, the loss of the Michael Ave transformer could result in an outage duration of 24 hours and a load at risk of up to 149 MWhr in 2025. This is below the 180 MWhr limit for transformers sized above 10 MVA nameplate.

These MWhr values are determined by multiplying the amount of unserved load in MW with the assumed 24 hour duration and do not take into account the careful planning and restoration steps required between two load areas that are several miles apart.

In 2014 the Michael Ave transformer failed shortly after being placed in service. It took 3-4 days, rather than the assumed 24 hour restoration, to transport and install a mobile transformer. This duration to install a mobile transformer would violate the Liberty Distribution Planning Criteria.

iii. Feeders

A switch plan has been developed for each feeder breaker for both the 2020 and 2025 base case. Detailed results of this analysis can be found in Appendix B.1 – 2020 Switch Plan and Appendix C.1 – 2025 Switch Plan.

The following table summarizes facilities which are expected to be loaded above 100% of emergency limits during the planning horizon. Additional information for each identified problem is provided in Appendix D.1 and E.1.

Table 13 13.8kV Feeder Loading – Contingency Configuration

Dropped Circuit	Year	% Overload	Affected Device	Affected Circuit	Location	Reference
Michael Ave 40L1 / 40L3	2020	159	Power Transformer	12L1	Vilas Bridge Station	Figure 11
Vilas Bridge 12L2	2025	118	Power Transformer	12L1	Vilas Bridge Station	Figure 13
Michael Ave 40L1 / 40L3	2025	190	Power Transformer	12L1	Vilas Bridge Station	Figure 15

4.2 Circuit Analysis

a. Voltage Performance during Normal Operation

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 mounted line regulators. The ultimate goal is to keep all customers' service voltages within accepted limits.

The table below shows the areas where voltage is expected to exceed limits under normal configuration within the planning horizon. Refer to Appendix D.1 for additional details.

Table 14 Voltage Performance – Normal Configuration

Year	Voltage (p.u.)	Affected Circuit	Reference
2020	0.94	12L2	Figure 7
2025	0.92	12L2	Figure 7

b. Voltage Performance during Contingency Operation

The figure below shows the areas where voltage is expected to exceed limits under contingency configuration within the planning horizon. Refer to Appendix E.1 for additional details.

Table 15 Voltage Performance – Contingency Configuration

Dropped Circuit	Year	Voltage (p.u.)	Affected Circuit	Reference
12L2	2020	0.92	12L1	Figure 9
12L1	2020	0.94	12L2	Figure 10
40L1 & 40L3	2020	0.91	12L1	Figure 11
40L1 & 40L3 w/ load shed	2020	0.94	12L1	Figure 12
12L2	2025	0.9	12L1	Figure 13
12L1	2025	0.93	12L2	Figure 14
40L1 & 40L3	2025	0.9	12L2	Figure 15
40L1 & 40L3 w/ load shed	2025	0.9	12L2	Figure 16

With a loss of the Michael Ave Transformer or Transmission supply, load transfers to Vilas Bridge 12L1 will need careful planning to avoid exceeding the emergency rating of two sets of 3-167 kVA line regulators. These regulators require 10% regulation to maintain voltages within ratings.

c. Power Factor

Liberty will strive to maintain a 98% power factor at the substations to provide quality power to its customers and limit system losses via the addition of new capacitor banks. In addition, annual reviews for system power factor will allow Liberty to properly manage reactive support by adjusting settings from capacitor bank controls.

The table below identifies feeders where the power factor is lower than 98% and provides recommended mitigation.

Table 16 Feeder Power Factor below 98%

Source	Amps				Power Factor %				Mitigation
	A	B	C	Avg	A	B	C	Avg	
Michael Ave 40L3	242	178	163	194	97	97	97	97	Placed 1200kVAR capacitor bank CB26 in-service to improve PF to 99%

d. Sector Report

Where practical, Liberty's goal is to limit feeders to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or the load between disconnecting devices does not exceed 2,000kVA.

The Vilas Bridge 12L1 feeder supplies 2,482 customers in the towns of Walpole, Alstead, Langdon, Acworth and Marlow.

Liberty reviewed the load and customers between disconnecting devices to determine areas where these limits are exceeded. The table below summarizes these findings:

Table 17 Sector Report

# Sectors > 2 MVA	# Sectors > 500 Customers	Sector Average MVA	Sector Average Cust. Served
1	2	5.81	568

4.3 Asset Condition

Refer to Liberty Utilities Distribution Asset Strategy in Appendix D for details on the company's plans.

4.4 Reliability

Refer to Liberty Utilities Reliability Report in Appendix H for details on the company's results and plans.

4.5 Protection Analysis

The analysis identified 5 fuse replacements due to overload. With a loss of the Michael Ave Transformer or Transmission supply, load transfers to Vilas Bridge 12L1 will need careful planning to avoid exceeding the relay pickup setting on two reclosers. As part of the Distribution

Automation Program, Liberty will install additional protective devices to facilitate rerouting load in the area after interruptions and to improve outage durations. A protection review will be performed at this time.

5.0 Problem Solutions

The following section provides infrastructure improvement projects to address the deficiencies listed in Section 4, including potential non-wires solutions (NWS) to resolve the problem.

The project costs presented in this section are of investment grade. Project scope and estimates will be refined as part of detailed engineering activities.

5.1 Thermal Loading

a. N-1 Normal Configuration

There are no identified thermal loading problems under Normal Configuration.

b. N-1 Contingency & Load-At-Risk

While none of the contingency issues identified under Section 4.1.2 violate prescribed design limits, there does appear to be a convergence of several issues identified in this study (i.e. long distance from source, potential transformer overloading, voltage fluctuations, forced customer load shedding events) that deserves consideration of a creative NWS involving one or more modular battery storage installation(s) to better control power flows on these feeders and to improve the reliability and power quality issues in this area. Liberty has looked at an initial screening of traditional and Non-Wires solutions to address the deficiencies in the area and has determined that the proposed non-wires solutions should be pursued. For details refer to Appendix D – NWS Project Analysis.

Liberty is committed to working with Commission Staff and other stakeholders to identify a non-wires solution that best fits the needs of our Customers.

Project Cost: TBD

Risk Score: 49

5.2 Circuit Analysis

a. Voltage Performance

The following projects aim to address existing and projected problems during normal and contingency conditions.

b. Vilas Bridge 12L2 - 2022

Feeder 12L2 could experience voltage deficiencies during normal and contingency conditions.

To mitigate, it is recommended to install one 600 kVAR capacitor bank at Prospect Hill Rd Walpole. In addition it is recommended to convert the 2.4 kV step down distribution area of March Hill Rd to 7.62 kV. This conversion is also recommended to improve reliability and to create a feeder tie between the 12L1 feeder at Valley Rd Walpole with the 12L2 feeder at March Hill Rd. For details on the Conversion and tie project refer to the Liberty Reliability Report.

Project Cost: $15,000

Risk Score: 45

c. Vilas Bridge 12L1 - 2022

Feeder 12L1 could experience voltage deficiencies for a loss of Feeder 12L2. To mitigate, it is recommended to install one 900 kVAR capacitor bank at Route 123 and remove 600 kVAR capacitor bank 8938.

Feeder 12L1 could also experience voltage deficiencies for the contingency of loss of Michael Ave Station. This feeder cannot supply the entire Michael Ave substation load and would require shedding load to within the rating of the circuit. To improve voltage conditions during contingency, it is recommended to install one 900 kVAR capacitor bank at Route 12.

Project Cost: $30,000

Risk Score: 45

d. Michael Ave 40L1 - 2022

To improve voltage performance during contingency and overall phase balance of the Michael Ave 40L3 feeder, it is recommended in 2022 to extend a three phase overhead line 650 feet and perform load transfers.

Project Cost: $55,000

Risk Score: 45

e. Power Factor Correction

There are no identified concerns with poor power factor. The Michael Ave feeder 40L3 experienced power factor lower than 98%. Capacitor CB26 was placed in service and is expected to improve the feeder's power factor to 99%.

f. Sector Report

A total of three locations have been identified exceeding number of customers or load between disconnecting devices. These locations will be reviewed for improved sectionalizing opportunities, reliability history and exposure. The scope of work will be to install one disconnect device to limit the exposure to customers and improve restoration times. Liberty expects to address these locations between 2022 and 2023. In general, Liberty assigns a risk score of 34 to these projects.

Project Cost: $60,000

6.0 Non-Wires Solution – Michael Ave

6.1 Grid Needs Assessment

As part of the requirements of the approved Settlement Agreements in Docket Nos. DE 17-136, DE 17-189 and DE 19-120, the Company agreed to provide a grid needs assessment for projects with potential non-wires solutions whereby the wires solutions are $500,000 or greater. Table 18 provides the assessment:

Table 18 Grid Needs Assessment for Potential Non-Wires Solutions

Facility/ Location	System Granularity of Grid Need	Capacity/ Reliability/ Resiliency	Anticipated season or date by which distribution upgrade must be installed	Equipment Rating	Forecasted percentage deficiency above the existing facility/equipment rating 2025	Additional information:	Estimate
14L1 Bridge St, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2023	N/A	N/A		$600,000
14L1 Marsh Rd, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2025	N/A	N/A		$570,000
12L2 Watkins Hill Rd Ph. 3, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A		$550,000
9L3 Range Rd - W Shore Rd, Windham	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A		$590,000
12L1 Rt. 123A, Alstead	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2024	N/A	N/A		$790,000
6L3 S Main St, Hanover	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2024	N/A	N/A		$530,000
1L2 Rt. 120 DA, Plainfield	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability / Resiliency	2025	N/A	N/A		$1,400,000
16L1-6L3 Goodfellow Rd Tie, Hanover	Construct circuit tie 16L1 to 6L3 and implement DA	Reliability / Resiliency	2023	N/A	N/A		$1,200,000
7L1-7L2 Lockehaven Rd Tie, Enfield	Construct circuit tie 7L1 to 7L2 and implement DA	Reliability / Resiliency	2024	N/A	N/A		$1,400,000
21L4 New Feeder, Salem	Construct new 21L4 and implement DA	Reliability / Resiliency	2025	N/A	N/A	Driven by Customer Growth	$550,000
14L5 New Feeder, Salem	Construct new 14L5 and implement DA	Reliability / Resiliency	2025	N/A	N/A		$1,400,000
12L1 Transformer, Walpole	Construct new 40L2 and circuit tie with 12L1 to mitigate contingency loss of 12L2 feeder	Reliability / Resiliency / Capacity	2025	9.6 MVA	133%	Does not violate 16 MWhr guideline. Voltage violations	$8,000,000
12L1 Transformer, Walpole	Add 2nd Transf. and 115 kV T-Line at Michael Ave Sta. to mitigate contingency loss of Michael Ave Transf. #1	Reliability / Resiliency / Capacity	2025	9.6 MVA	190%	Does not violate 180 MWhr criteria / Voltage violations / >24 hr. mobile inst.	Same
11L1 Feeder, West Lebanon	Construct new 39L4 to resolve forecasted overload with new commercial development	Resiliency / Capacity	2025	10.9 MVA	105%	Driven by Customer Growth	$600,000

6.2 Non-Wires Solution Candidate

Traditional Wires Solution

Location: Bellows Fall NH Study Area – Figure 1 on page 5 of this document

Identified Need: A loss of the 115 kV supply line W-149S, owned by National Grid, at Michael Ave substation or the National Grid-owned Transformer could result in an interruption to the Liberty 40L1 and 40L3 feeders, or 1,751 customers including a large industrial customer. The Vilas Bridge #34 substation, also owned by National Grid located in VT, serves the 12L1 Liberty feeder and is the only alternate source for the area and does not have adequate capacity nor can it provide adequate voltage support to supply both 40L1 and 40L3 feeders during loss of supply line or transformer. This loss could result in approximately 4.8 MW of unserved load and could require shedding a large industrial load to maintain equipment within ratings. The expected loss of load in 2025 is 6.2 MW based on growth in the area.

Project Description (Traditional Wires Solution#1):

- Install 2nd 115 kV Transmission Line and 115kV in-line circuit breaker
- Install 2nd 115-13.2 kV 25 MVA Transformer
- Install new 40L2 13.2 kV feeder breaker and associated bus work
- Install new 40L2 circuit tie with 12L1

Engineering Start Date – Project Completion Date: 2022 – 2025

Estimated Cost of Traditional Solution (Investment Grade): $8,000,000

Criteria Violation: There are no criteria violations. However, there are several contingency loss scenarios (e.g., 115kv supply line, Michael Ave Sub Transformer and other factors (e.g., long distance from source, mobile lead time and voltage violations) that could result in long-term outages.

Benefits of Planned Wires Upgrade: Resolves load at risk resulting from loss of the Michael Ave 115 kV supply or Transformer and improves reliability for the Bellows Falls area. However, the Michael Ave Sub property presents an opportunity for PV and battery storage and/or Microgrid solution for this contingency issue and presents other benefits in cost savings.

Coincident Area Load in Need Year: 20,000 kVA

Annual Growth Rate: 0.2%

Non-Wires Solution #1

Project Description:

- Install Microgrid consisting of 1 MW solar with 4 MWh storage in front of the meter at Customer A's location in Charlestown
- Will provide islanding of Customer A, while still providing power to the residential customers in the area from the Vilas Bridge 12L1 during loss of supply or transformer
- Microgrid may also serve other purposes such as peak load reduction

Engineering Start Date – Project Completion Date: 2022 – 2025

Estimated Cost of Non-Wires Wires Solution #1 (Investment Grade): $2,900,000

Non-Wires Solution #2

Project Description:

- Install Microgrid consisting of 1 MW solar and 4 MWh of storage at Michael Ave to serve the loss of a transformer or supply line at the substation
- Will provide flexibility to move load between the Vilas Bridge and Michael Ave substations and the Microgrid during loss of supply or transformer; for example, move the load from the industrial customer to the 12L1 feeder and serve other customers from Michael Ave with the Microgrid
- Microgrid may also serve other purposes such as peak load reduction

Engineering Start Date – Project Completion Date: 2022 – 2025

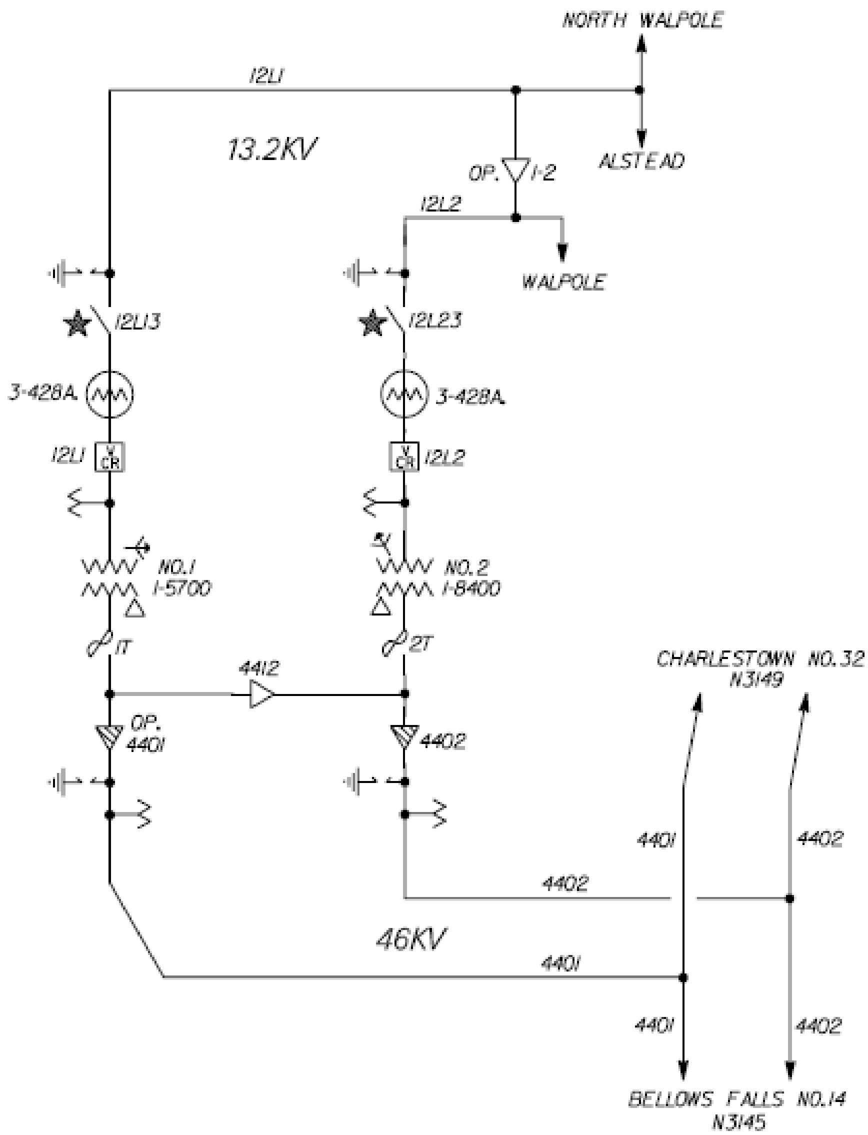
Estimated Cost of Non-Wires Wires Solution #2 (Investment Grade): $2,900,000

The difference between the two solutions is the first solution provides that the customer will allow the Company to install the Microgrid at or near the premises of their business providing the opportunity to island the customer if the supply line is lost, and the other customers will be switched to another feeder. The second solution provides for the Microgrid to be sited at the Michael Ave substation instead, where the load in the area, minus Customer A, may be served with the Microgrid, and Customer A will be switched to another feeder. In both instances, the Company is looking to work with Customer A to reduce their load through energy efficiency and potentially demand response.

7.0 Appendices

7.1 Appendix A.1 – System One Lines

Figure 3 [redacted]



VILAS BRIDGE NO. 34

Figure 4 [redacted]

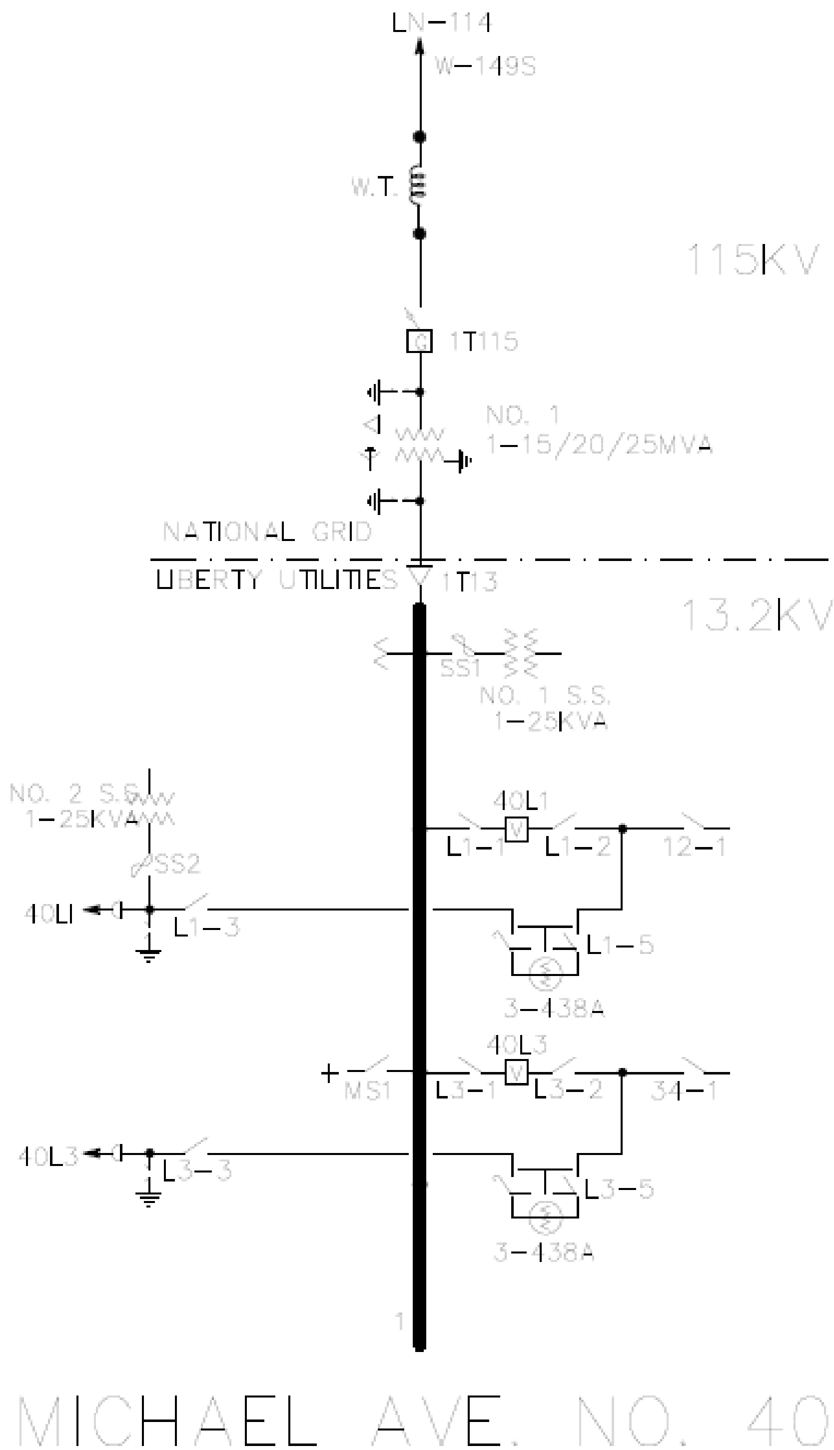


Figure 5 [redacted]

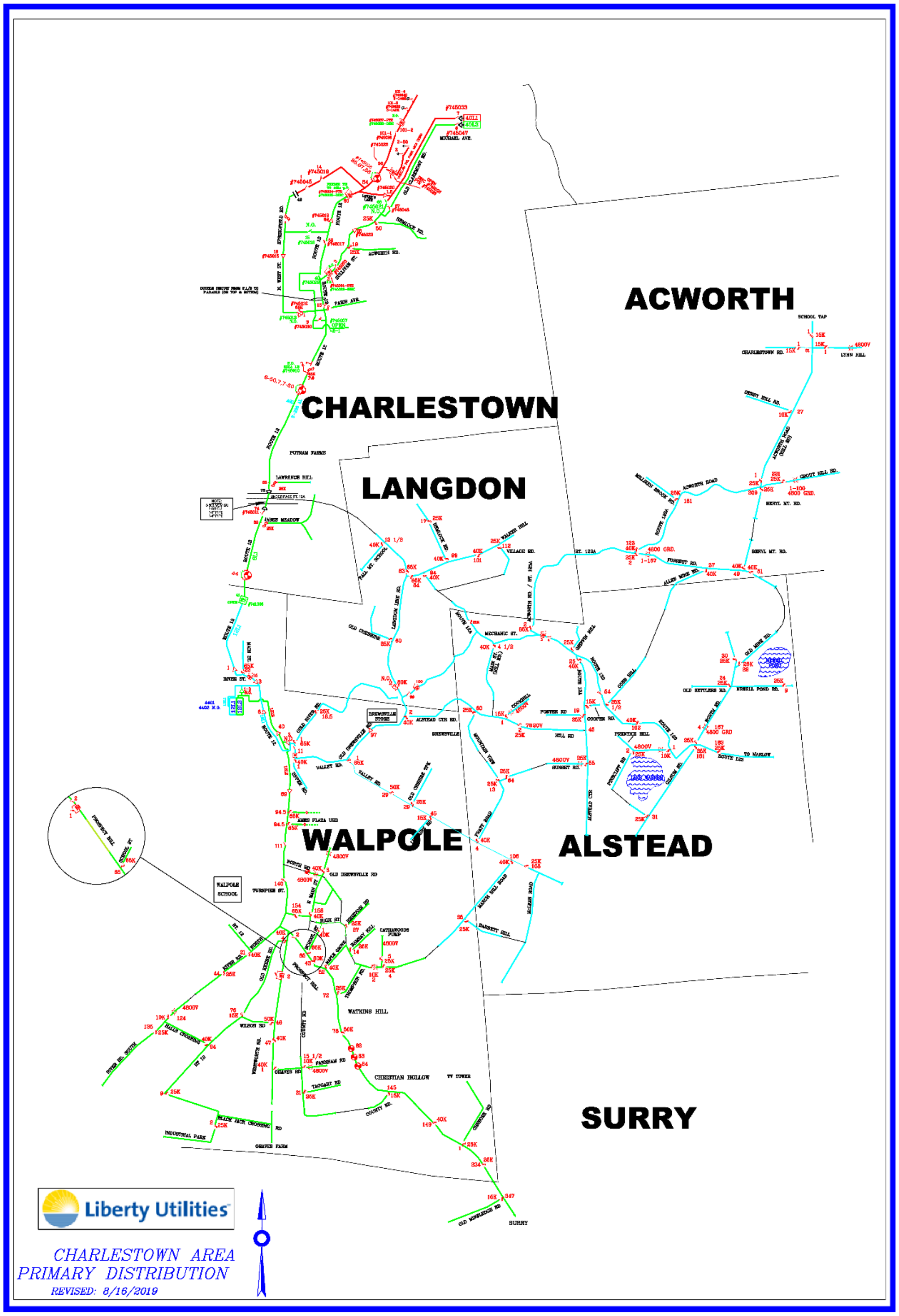
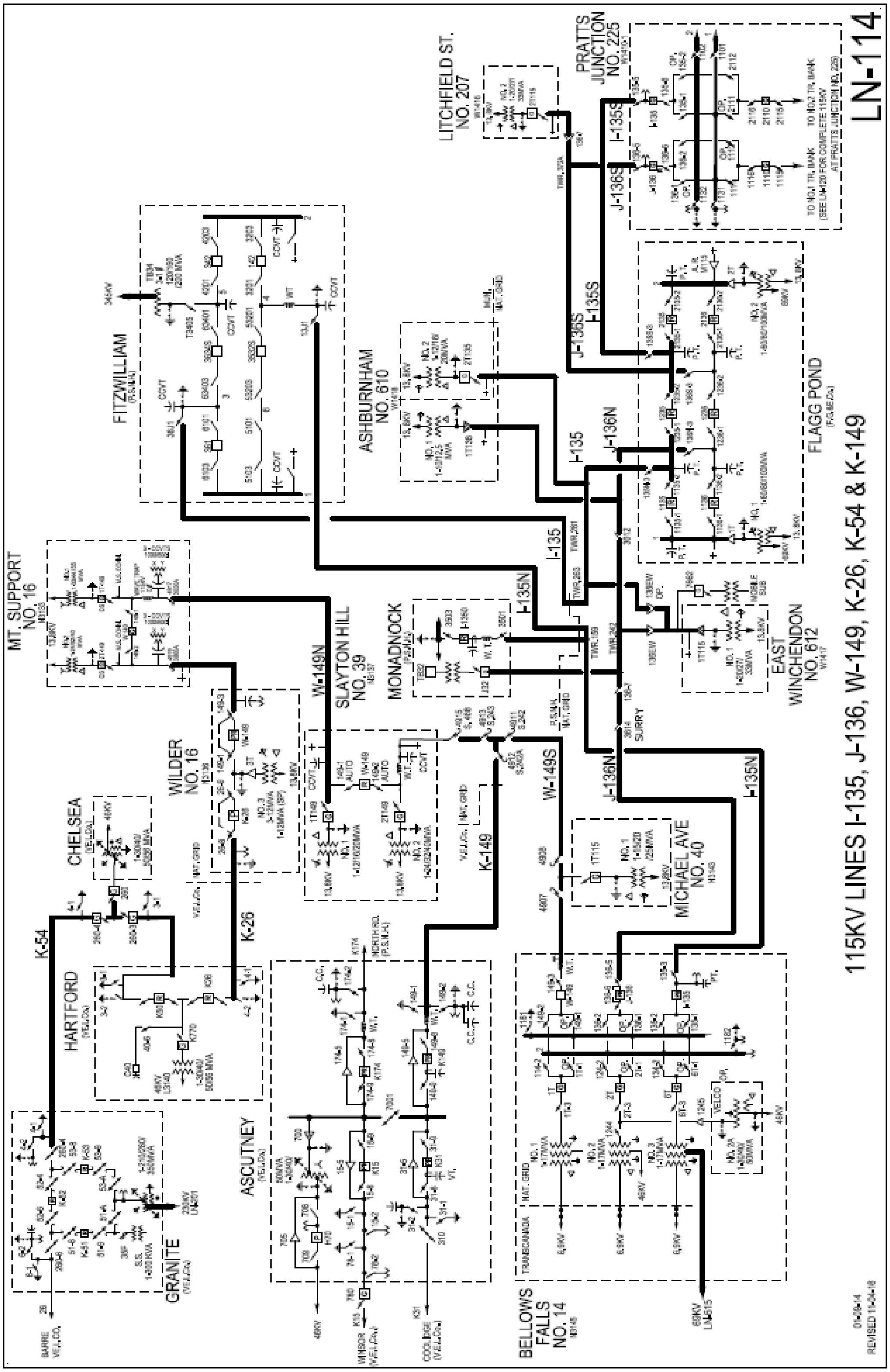


Figure 6 [redacted]



1 **7.2 Appendix B.1 – Switch Plan 2020**

2 Table 18 2020 Distribution Circuit Switch Plan

Operation		Dropped				Picked Up				
Action	Switch	From	Max Amps	Miles	Cust	To	Max Amps	Miles	Cust	Problems
12L2 Feeder										
0 - Open	PTR12L2	12L2	230	65 4	1176	---	---	---	---	12L2 load transfers to 12L1 will require a transfer of 59A from 12L1 to 40L3
1 - Open	PTR741003	12L1	59	4 9	385	---	---	---	---	
2 - Open	65 A K Link	Unfed	20	7 8	74	---	---	---	---	
3 - Close	745010	---	---	---	---		0	0	0	
4 - Close	PTR741006	---	---	---	---	40L3	59	4 9	385	
5 - Close	741010	---	---	---	---	12L1	230	65 4	1176	Transfer to 12L1 could result in voltages as low as 0 94 pu
12L1 Feeder										
0 - Open	PTR12L1	12L1	244	133 3	2232	---	---	---	---	
1 - Open	PTR741003	Unfed	59	4 9	385	---	---	---	---	
2 - Open	65 A K Link	Unfed	20	7 8	74	---	---	---	---	
3 - Close	745010	---	---	---	---		0	0	0	
4 - Close	PTR741006	---	---	---	---	40L3	59	4 9	385	
5 - Close	741010	---	---	---	---	12L2	185	128 4	1847	Transfer to 12L2 could result in voltages as low as 0 92 pu
40L1 Feeder										No Issues
0 - Open	40L1	40L1	284	14 9	470	---	---	---	---	
1 - Close	745021	---	---	---	---	40L3	287	14 9	470	
40L3 Feeder										No Isssues
0 - Open	40L3	40L3	220	31 5	1117	---	---	---	---	
1 - Close	745021	---	---	---	---	40L1	220	31 5	1117	
Michael Ave Station										
0 - Open	40L1	40L1	282	14 9	470	---	---	---	---	
1 - Open	40L3	40L3	220	31 5	1117	---	---	---	---	
2 - Open	741009	12L1	177	127 6	1825	---	---	---	---	
3 - Close	741010	---	---	---	---	12L2	177	127 6	1825	
4 - Open	65 A K Link	Unfed	20	7 8	74	---	---	---	---	
5 - Close	745010	---	---	---	---		0	0	0	
6 - Close	PTR741006	---	---	---	---	12L1	246	31 5	1117	
7 - Open	745034	Unfed	252	2 6	34	---	---	---	---	
8 - Close	PTR745004	---	---	---	---	12L1	273	2 6	34	With the loss of Michael Ave: - The Vilas Bridge 12L1 feeder could be loaded to 159% of SE rating and result in voltages as low as 0 86 pu - 3 Recloser, 2 Regulator banks exceed settings/ratings - Over 36,000 ft of conductors loaded to above emergency ratings
9 - Close	745021	---	---	---	---	12L1	33	12 3	436	
Michael Ave Station with load shed										
0 - Open	40L1	40L1	282	14 9	470	---	---	---	---	
1 - Open	40L3	40L3	220	31 5	1117	---	---	---	---	
2 - Open	741009	12L1	177	127 6	1825	---	---	---	---	
3 - Close	741010	---	---	---	---	12L2	177	127 6	1825	
4 - Open	65 A K Link	Unfed	20	7 8	74	---	---	---	---	
5 - Close	745010	---	---	---	---		0	0	0	
6 - Close	PTR741006	---	---	---	---	12L1	246	31 5	1117	
7 - Open	PTR745025	Unfed	143	0 8	5	---	---	---	---	Load Shed 143A - Customer A
8 - Open	140 A K Lin	Unfed	66	0	1	---	---	---	---	Load Shed 66A - Customer A
9 - Open	745034	Unfed	252	2 6	34	---	---	---	---	
10 - Close	PTR745004	---	---	---	---	12L1	42	1 8	28	The contingency loss of the Michael Ave station would require a load shed of 4 8 MVA (115 MWhr) This could still result in voltages as low as 0 91 pu on the Vilas Bridge 12L1 feeder even after load shed
11 - Close	745021	---	---	---	---	12L1	32	12 3	436	

7.3 Appendix C.1 – Switch Plan 2025

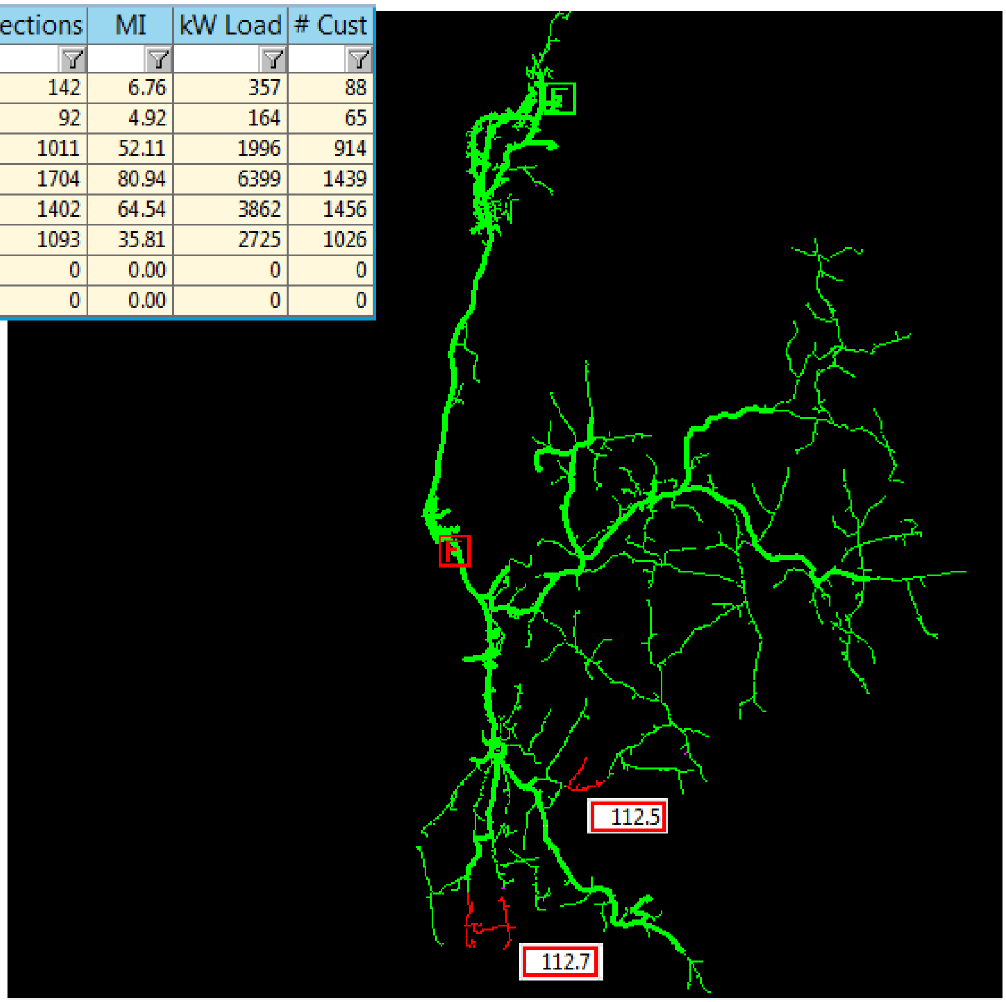
Table 19 2025 Distribution Circuit Switch Plan

Operation		Dropped				Picked Up				
Action	Switch	From	Max Amps	Miles	Cust	To	Max Amps	Miles	Cust	Problems
Plan : 12L2										
0 - Open	PTR12L2	12L2	255	64	1155	---	---	---	---	12L2 load transfers to the 12L1 feeder will first require a transfer of 67A from the 12L1 to the 40L3 feeder
1 - Open	PTR741003	12L1	67	4 9	385	---	---	---	---	
2 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
3 - Close	745010	---	---	---	---		0	0	0	
4 - Close	PTR741006	---	---	---	---	40L3	67	4 9	385	
5 - Close	741010	---	---	---	---	12L1	255	64	1155	
6 - Open	PTR744003	12L1	70	40	529	---	---	---	---	The contingency loss of the Vilas Bridge 12L2 feeder could result in the 12L1 feeder to be loaded to 110% of its summer emergency rating and will require the load shed of 1 MVA of load Transfer to 12L1 could also result in voltages as low as 0 93 pu
Plan : 12L1										
0 - Open	PTR12L1	12L1	244	133 3	2232	---	---	---	---	
1 - Open	PTR741003	Unfed	59	4 9	385	---	---	---	---	
2 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
3 - Close	745010	---	---	---	---		0	0	0	
4 - Close	PTR741006	---	---	---	---	40L3	59	4 9	385	
5 - Close	741010	---	---	---	---	12L2	185	128 4	1847	Transfers to the 12L2 feeder could result in voltages as low as 0 9
Plan : 40L1										No Issues - Need additional switching to avoid overloading OH wires
0 - Open	40L1	40L1	318	14 9	470	---	---	---	---	
1 - Open	745014	40L3	221	23	772	---	---	---	---	
2 - Open	745030	Unfed	145	7 6	299	---	---	---	---	
3 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
4 - Close	745010	---	---	---	---		0	0	0	
5 - Close	PTR741006	---	---	---	---	12L1	86	15 4	473	
6 - Close	745021	---	---	---	---	40L3	320	14 9	470	
7 - Close	PTR745004	---	---	---	---	40L3	145	7 6	299	
Plan : 40L3										No Issues - Need additional switching to avoid overloading OH wires
0 - Open	40L3	40L3	249	31 5	1117	---	---	---	---	
1 - Open	745014	Unfed	221	23	772	---	---	---	---	
2 - Open	745030	Unfed	145	7 6	299	---	---	---	---	
3 - Close	745021	---	---	---	---	40L1	51	8 5	345	
4 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
5 - Close	745010	---	---	---	---		0	0	0	
6 - Close	PTR741006	---	---	---	---	12L1	86	15 4	473	
7 - Close	PTR745004	---	---	---	---	40L1	145	7 6	299	
Michael Ave Station										
0 - Open	40L1	40L1	318	14 9	470	---	---	---	---	
1 - Open	40L3	40L3	249	31 5	1117	---	---	---	---	
2 - Open	741009	12L1	200	127 6	1825	---	---	---	---	
3 - Close	741010	---	---	---	---	12L2	200	127 6	1825	
4 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
5 - Close	745010	---	---	---	---		0	0	0	
6 - Close	PTR741006	---	---	---	---	12L1	284	31 5	1117	
7 - Open	745034	Unfed	284	2 6	34	---	---	---	---	
8 - Close	PTR745004	---	---	---	---	12L1	309	2 6	34	The contingency loss of the Michael Ave station could result in: - The Vilas Bridge 12L1 feeder loaded to 190% of SE rating voltages as low as 0 87 pu - 2 Reclosers, 2 Regulator banks exceed settings/ratings - Over 36 000 ft of conductors loaded above emergency ratings
9 - Close	745021	---	---	---	---	12L1	104	12 3	436	
Michael Ave Station with load shed										
0 - Open	40L3	40L3	249	31 5	1117	---	---	---	---	
1 - Open	40L1	40L1	318	14 9	470	---	---	---	---	
2 - Open	741009	12L1	211	129	1846	---	---	---	---	
3 - Close	741010	---	---	---	---	12L2	211	129	1846	
4 - Open	65 A K Link 851	Unfed	20	7 8	74	---	---	---	---	
5 - Close	745010	---	---	---	---		0	0	0	
6 - Close	PTR741006	---	---	---	---	12L1	284	31 5	1117	
7 - Open	PTR745037	Unfed	101	0 1	2	---	---	---	---	Load Shed 101A - Customer A
8 - Open	PTR745025	Unfed	161	0 8	5	---	---	---	---	Load Shed 161 A - Customer A
9 - Open	745034	Unfed	284	2 6	34	---	---	---	---	
10 - Close	PTR745004	---	---	---	---	12L1	21	1 7	27	A loss of Michael Ave station would require a load shed of 6 2 MVA (149 MWhr) This could still result in voltages as low as 0 91 pu on the Vilas Bridge 12L1 feeder
11 - Close	745021	---	---	---	---	12L1	36	12 3	436	

7.4 Appendix D.1 – Voltage Performance Normal Condition

Figure 7 2020 Voltage Performance 12L2 – Normal Configuration

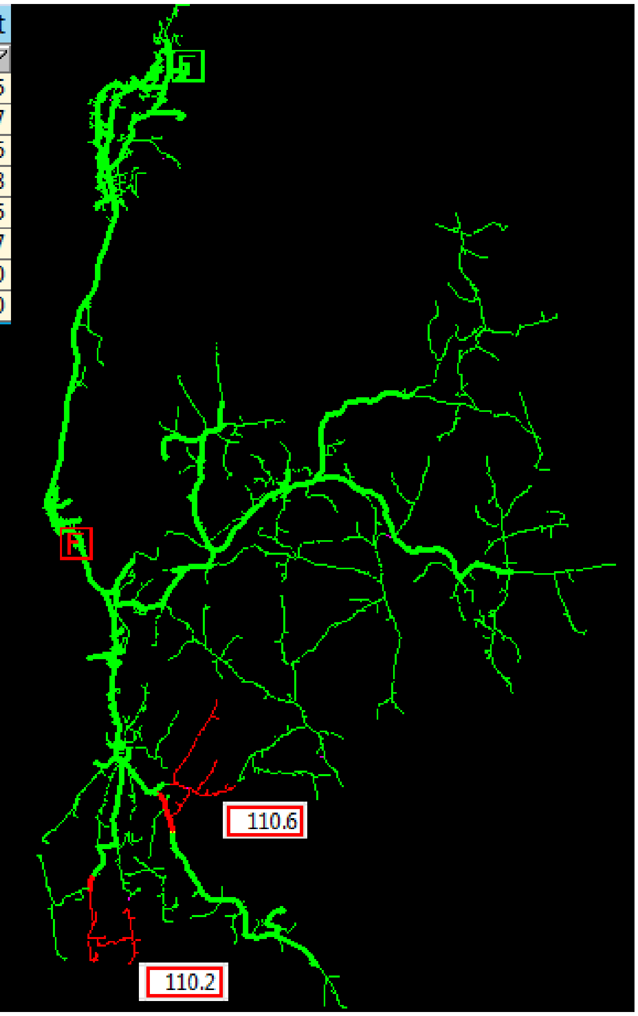
Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	142	6.76	357	88
114.00 - 116.00 V	92	4.92	164	65
116.00 - 118.00 V	1011	52.11	1996	914
118.00 - 120.00 V	1704	80.94	6399	1439
120.00 - 122.00 V	1402	64.54	3862	1456
122.00 - 124.00 V	1093	35.81	2725	1026
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0



The figure below shows the areas where voltage is expected to exceed limits under normal configuration in 2025.

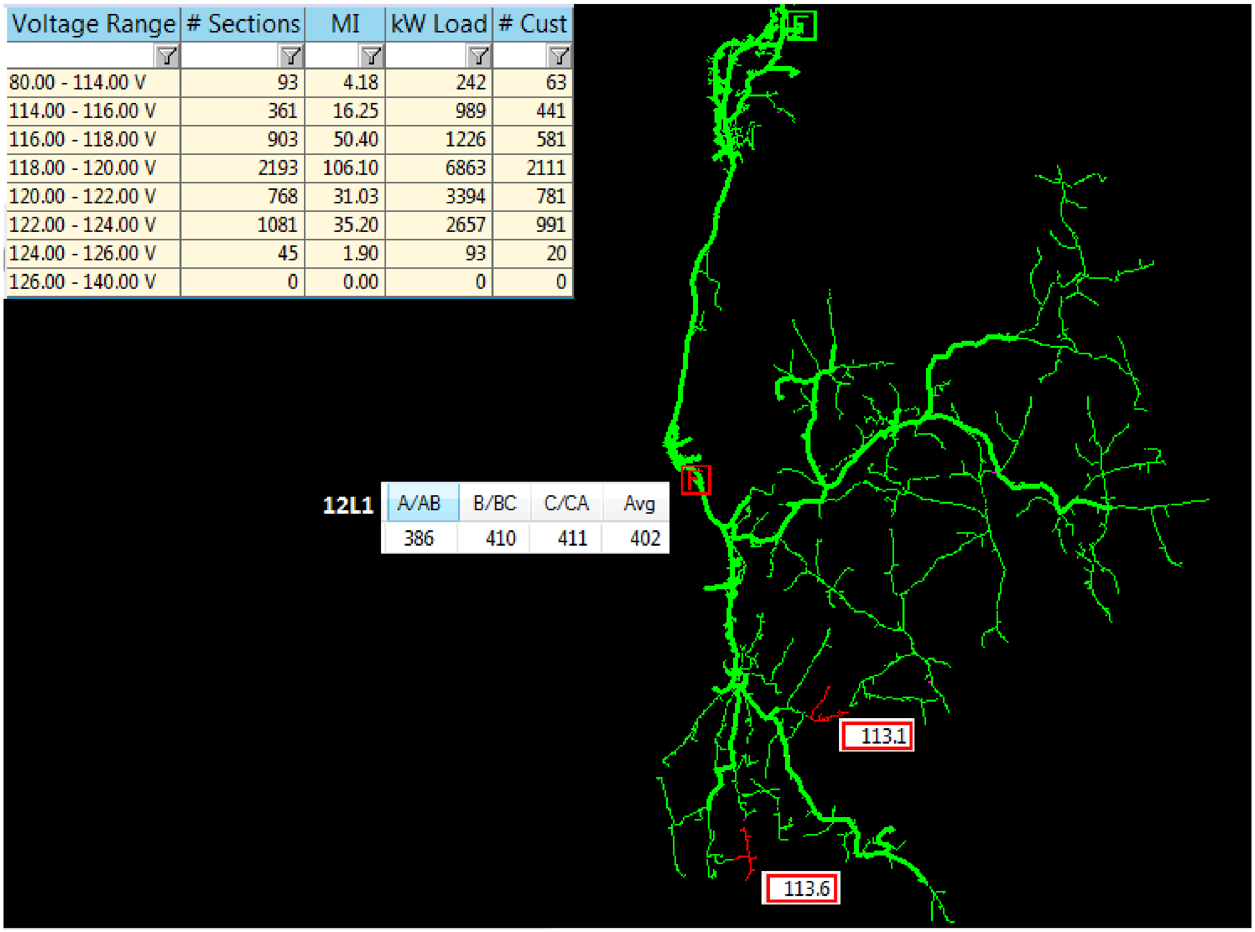
Figure 8 2025 Predicted Voltage Performance 12L2 – Normal Configuration

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	220	10.84	560	145
114.00 - 116.00 V	535	30.35	968	387
116.00 - 118.00 V	875	41.13	2419	876
118.00 - 120.00 V	1778	81.62	7458	1588
120.00 - 122.00 V	1093	49.48	3363	1055
122.00 - 124.00 V	943	31.66	2670	937
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0



7.5 Appendix E.1 – Voltage Performance Contingency Condition

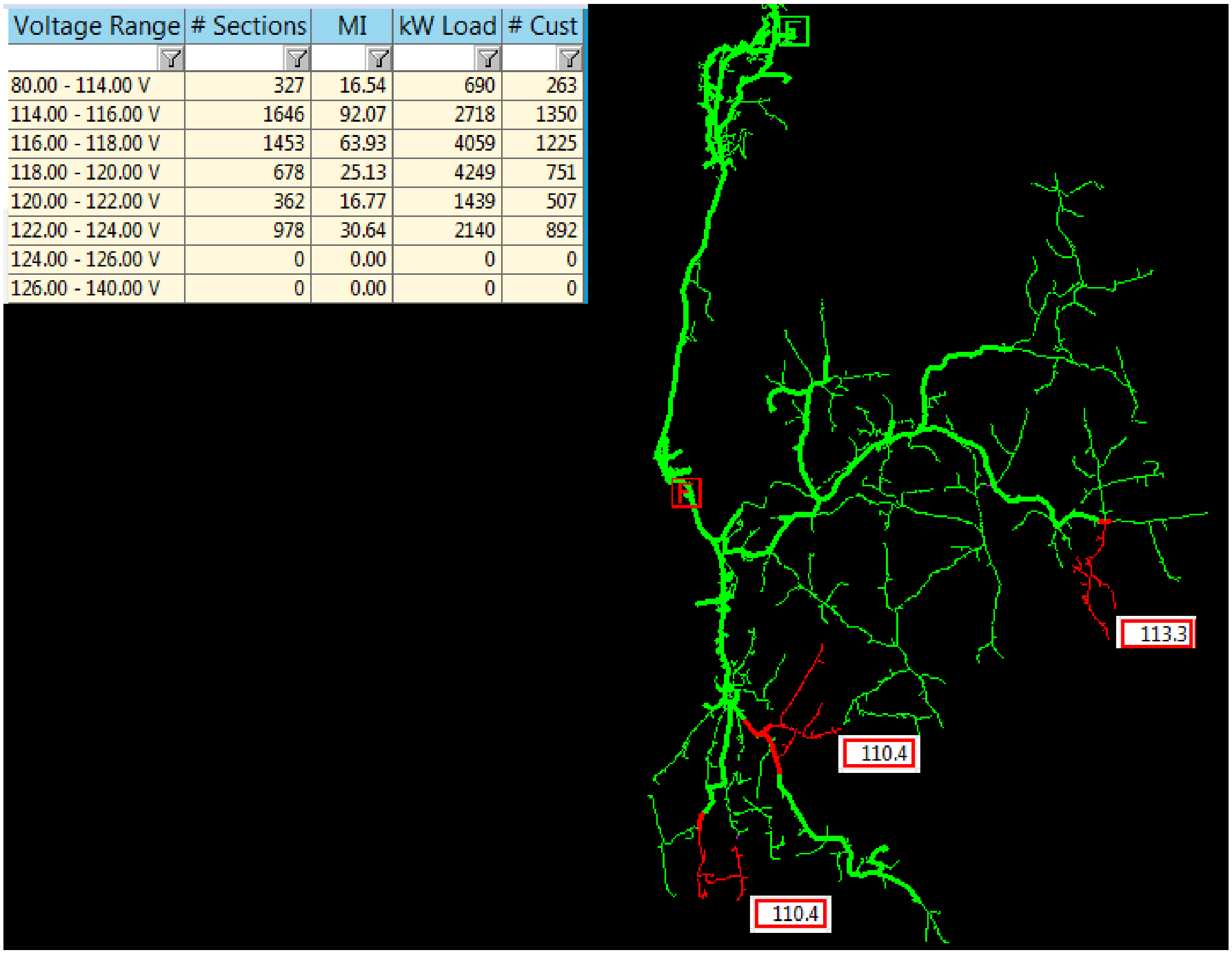
Figure 9 2020 Voltage Performance 12L2 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	93	4.18	242	63
114.00 - 116.00 V	361	16.25	989	441
116.00 - 118.00 V	903	50.40	1226	581
118.00 - 120.00 V	2193	106.10	6863	2111
120.00 - 122.00 V	768	31.03	3394	781
122.00 - 124.00 V	1081	35.20	2657	991
124.00 - 126.00 V	45	1.90	93	20
126.00 - 140.00 V	0	0.00	0	0

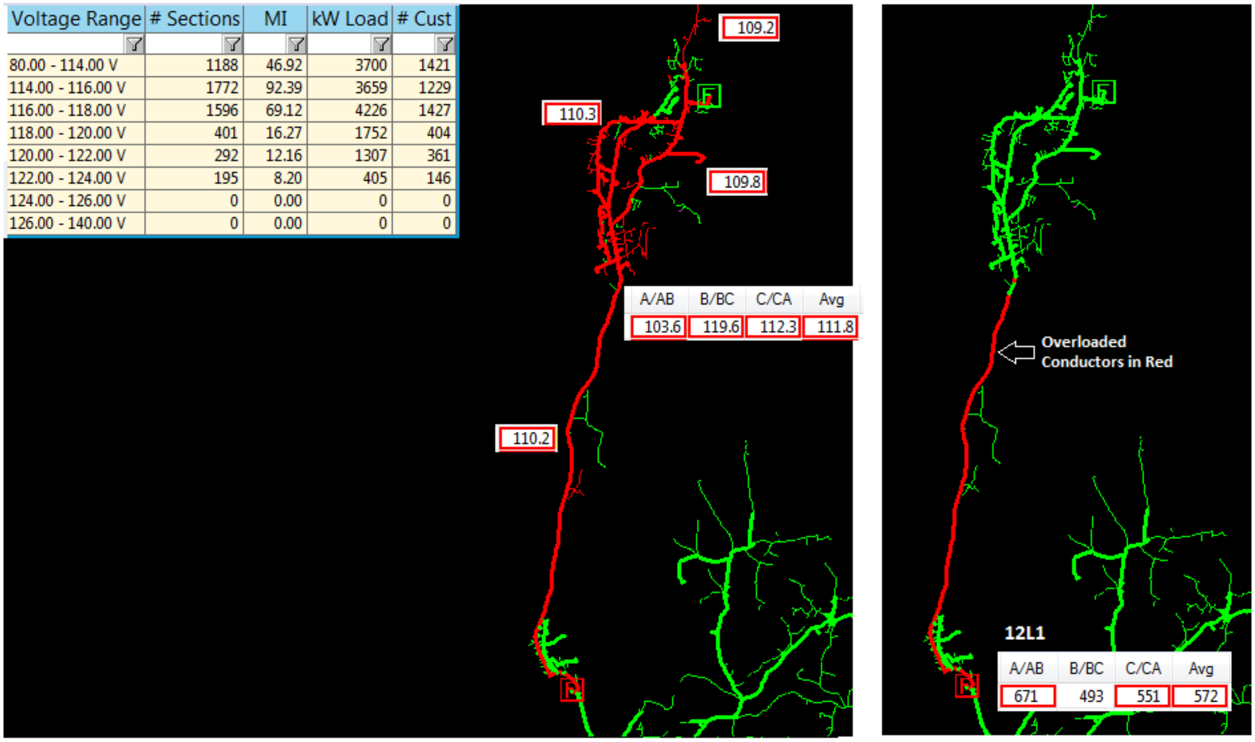
12L1	A/AB	B/BC	C/CA	Avg
	386	410	411	402

Figure 10 2020 Voltage Performance 12L1 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	327	16.54	690	263
114.00 - 116.00 V	1646	92.07	2718	1350
116.00 - 118.00 V	1453	63.93	4059	1225
118.00 - 120.00 V	678	25.13	4249	751
120.00 - 122.00 V	362	16.77	1439	507
122.00 - 124.00 V	978	30.64	2140	892
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 11 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	1188	46.92	3700	1421
114.00 - 116.00 V	1772	92.39	3659	1229
116.00 - 118.00 V	1596	69.12	4226	1427
118.00 - 120.00 V	401	16.27	1752	404
120.00 - 122.00 V	292	12.16	1307	361
122.00 - 124.00 V	195	8.20	405	146
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 11 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration

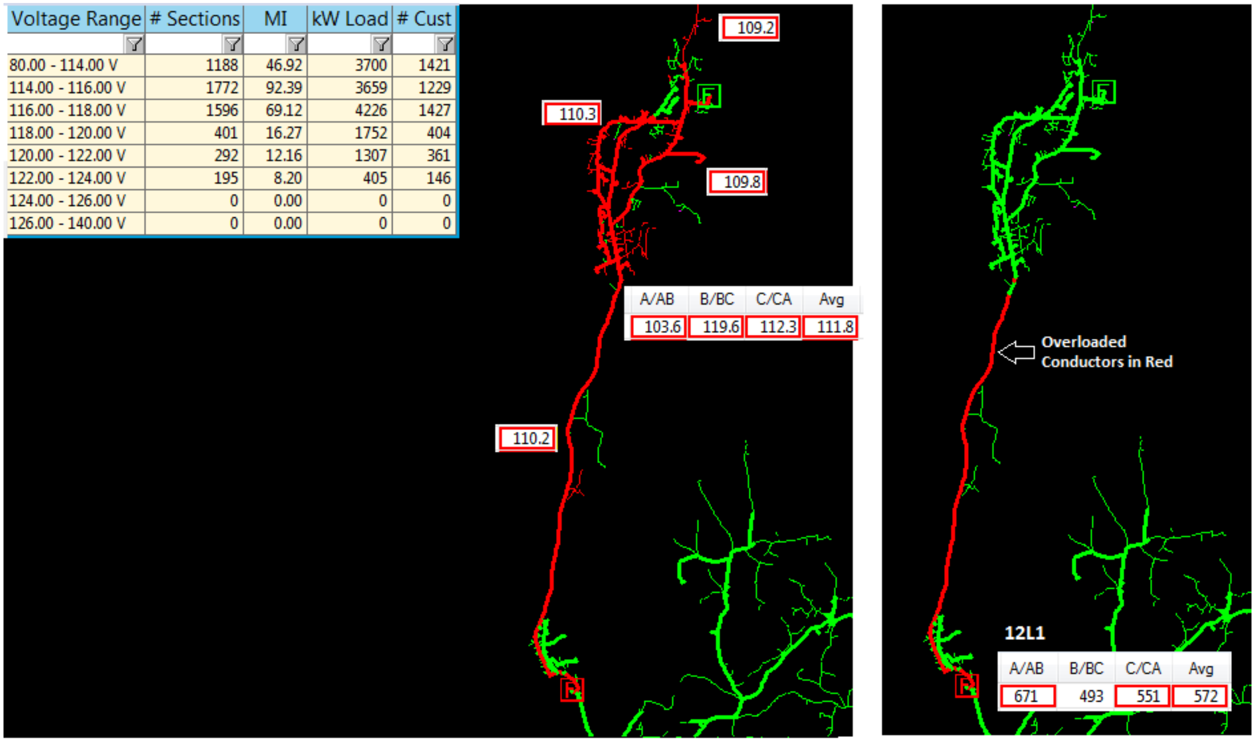
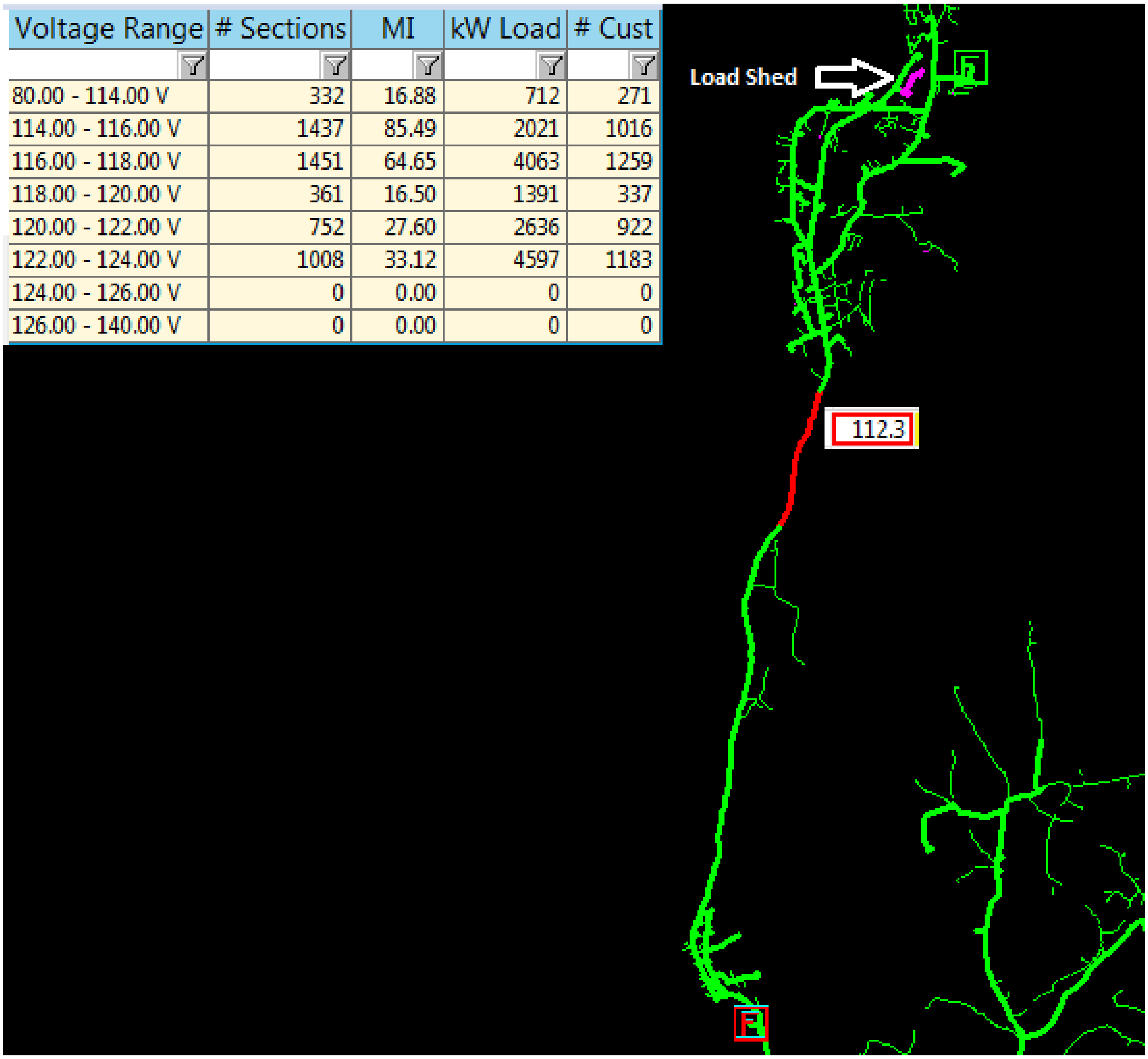


Figure 8 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration with load shed



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	332	16.88	712	271
114.00 - 116.00 V	1437	85.49	2021	1016
116.00 - 118.00 V	1451	64.65	4063	1259
118.00 - 120.00 V	361	16.50	1391	337
120.00 - 122.00 V	752	27.60	2636	922
122.00 - 124.00 V	1008	33.12	4597	1183
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

Figure 9 2025 Voltage Performance 12L2 – Contingency Configuration

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	95	4.60	305	62
114.00 - 116.00 V	352	16.36	1005	377
116.00 - 118.00 V	1207	61.35	4029	995
118.00 - 120.00 V	1583	72.51	5683	1460
120.00 - 122.00 V	1414	66.07	4141	1329
122.00 - 124.00 V	794	24.29	2285	765
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

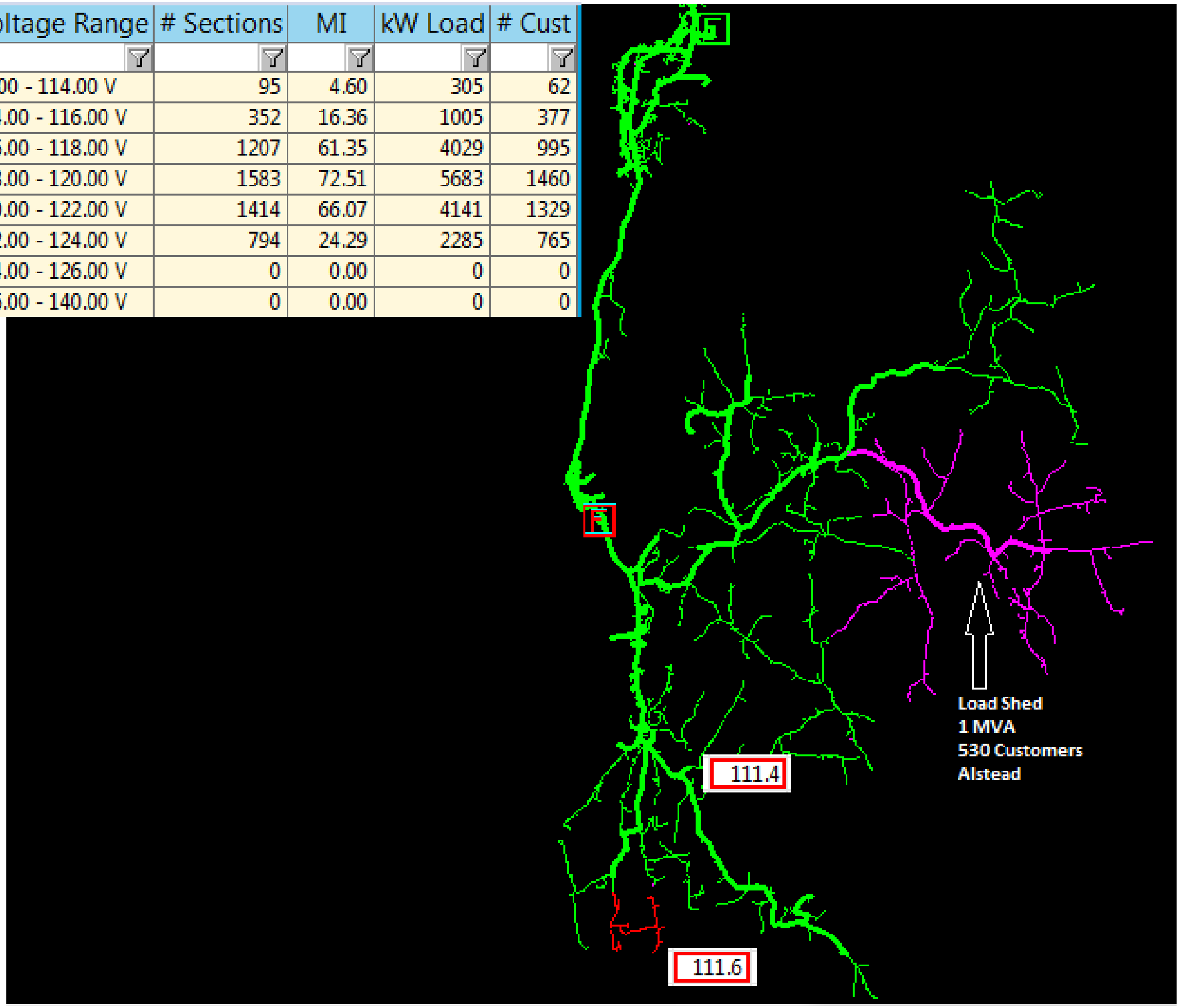
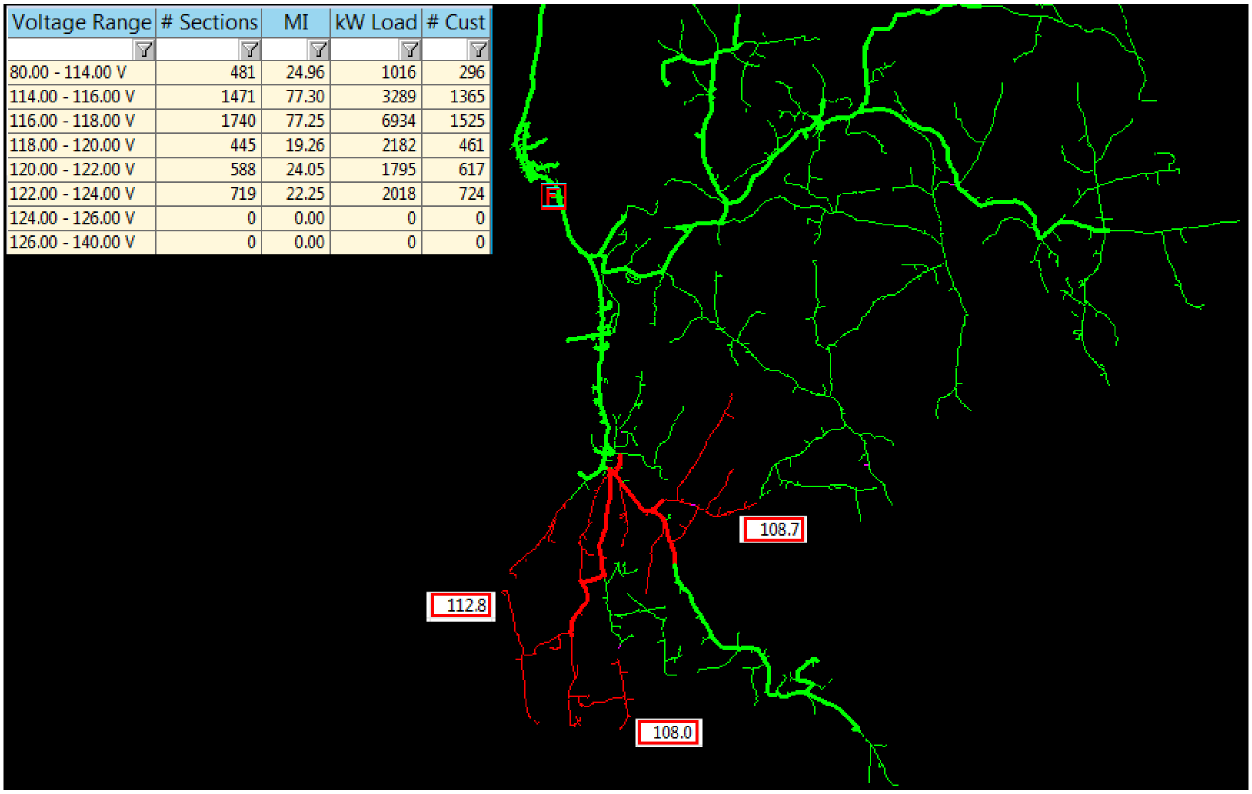
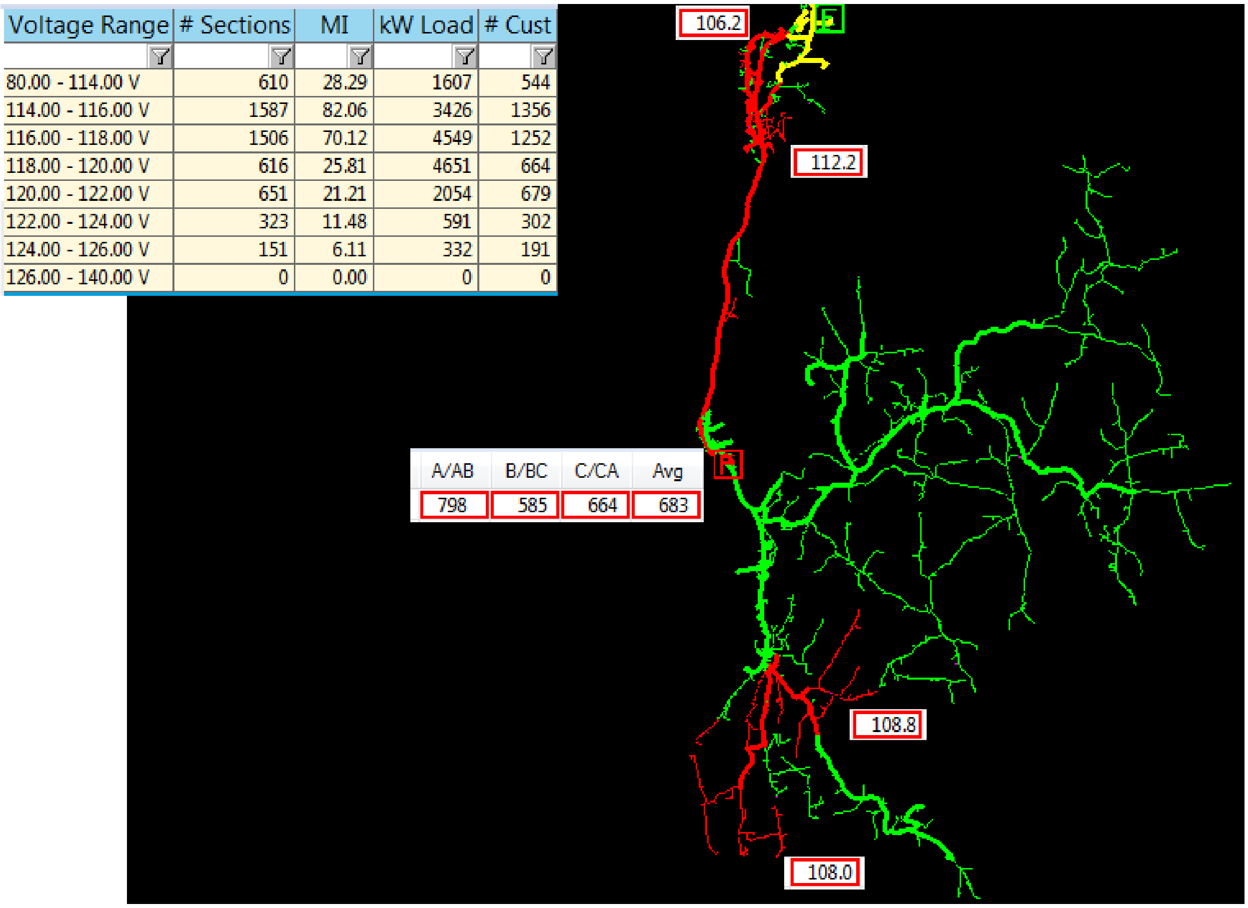


Figure 10 2025 Voltage Performance 12L1 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	481	24.96	1016	296
114.00 - 116.00 V	1471	77.30	3289	1365
116.00 - 118.00 V	1740	77.25	6934	1525
118.00 - 120.00 V	445	19.26	2182	461
120.00 - 122.00 V	588	24.05	1795	617
122.00 - 124.00 V	719	22.25	2018	724
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0

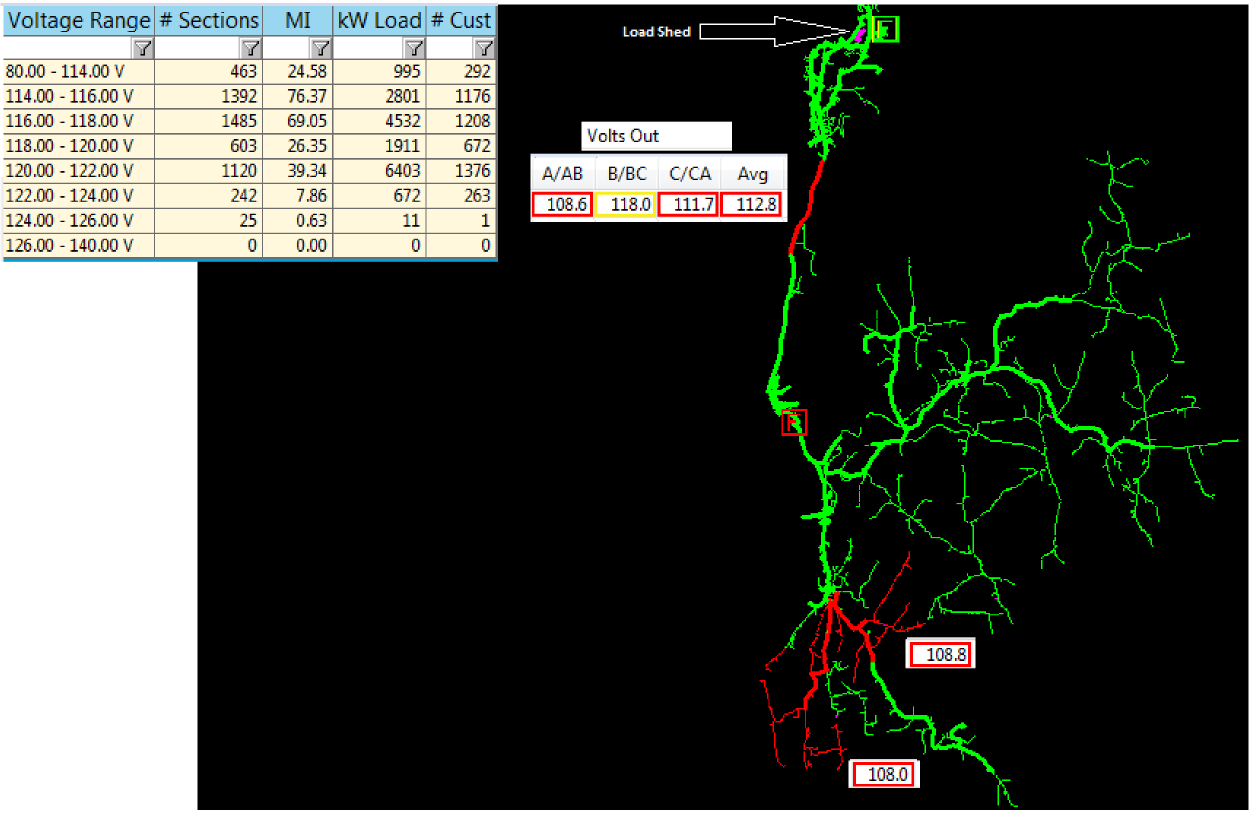
Figure 11 2025 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	610	28.29	1607	544
114.00 - 116.00 V	1587	82.06	3426	1356
116.00 - 118.00 V	1506	70.12	4549	1252
118.00 - 120.00 V	616	25.81	4651	664
120.00 - 122.00 V	651	21.21	2054	679
122.00 - 124.00 V	323	11.48	591	302
124.00 - 126.00 V	151	6.11	332	191
126.00 - 140.00 V	0	0.00	0	0

A/AB	B/BC	C/CA	Avg
798	585	664	683

Figure 16 2025 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration with load shed



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	463	24.58	995	292
114.00 - 116.00 V	1392	76.37	2801	1176
116.00 - 118.00 V	1485	69.05	4532	1208
118.00 - 120.00 V	603	26.35	1911	672
120.00 - 122.00 V	1120	39.34	6403	1376
122.00 - 124.00 V	242	7.86	672	263
124.00 - 126.00 V	25	0.63	11	1
126.00 - 140.00 V	0	0.00	0	0

1 ## 7.6 Appendix F.1 – NWS Project Analysis

NWA EVALUATION SUMMARY

11/2/2020

Identified Problem: Contingency Loss Michael Ave Sta

Project Need Year: 2025

Brief Project Description/need:

With the loss of a transformer or supply line at Michael Ave station, the Vilas Bridge Substation does not have the capacity or operational flexibility to supply Michael Ave station during peak hours and could result in extended outages for customers.

Project Scope	Option
Michael Station expansion	1
Vilas Bridge Station rebuild	2
PV + Storage	3
DER - Large Customer	4

Scoring Values

Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Comments
Total Cost	30%	1	2	3	4	
Reliability Risk	20%	4	3	1.8	1.5	
Feasibility Risk	20%	2.4	2.7	2.6	2.65	
Performance Risk	20%	3.6	2.8	2.2	1.95	
Enviromental Risk	10%	1.75	1.5	2.75	4	
Total Assessment	**100%**	**2.48**	**2.45**	**2.50**	**2.82**	
	Ranking	3	4	2	1	

Identified Problem: Contingency Loss Michael Ave Sta
11/2/2020

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Customer Outage Experience	50%	4	3	2	1
Automated Restoration	30%	4	3	2	2
Power Quality	20%	4	3	1	2
Totals	**100%**	**4**	**3**	**1.8**	**1.5**
	Ranking	**1**	**2**	**3**	**4**

Identified Problem: **Contingency Loss Michael Ave Sta**
11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Likelihood of Timely Completion	35%	2	2	3	3
Predictable Long Term Solution	25%	4	4	1	2
Historical Field Experience	10%	4	4	1	2
Uncertainty	30%	1	2	4	3
Totals	**100%**	**2.4**	**2.7**	**2.6**	**2.65**
	Ranking	**4**	**1**	**3**	**2**

Identified Problem: **Contingency Loss Michael Ave Sta**
11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Likelihood of Timely Completion	35%	2	2	3	3
Predictable Long Term Solution	25%	4	4	1	2
Historical Field Experience	10%	4	4	1	2
Uncertainty	30%	1	2	4	3
Totals	**100%**	**2.4**	**2.7**	**2.6**	**2.65**
	Ranking	**4**	**1**	**3**	**2**

Identified Problem: Contingency Loss Michael Ave Sta
11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Availability	25%	4	3	2	2
Operability	20%	4	3	2	1
Required Maintenance	10%	3	4	1	2
Aligns with Company Goals	15%	2	1	4	3
Capacity Provided - Demand	20%	4	3	2	2
Capacity Provided - Hosting	10%	4	3	2	2
Totals	**100%**	**3.6**	**2.8**	**2.2**	**1.95**
	Ranking	**1**	**2**	**3**	**4**

Identified Problem: Contingency Loss Michael Ave Sta
11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Wetland Impact	25%	2	1	3	4
Tree Clearing	25%	2	2	1	4
Community Impacts	25%	2	2	4	4
Municipal Impacts	25%	1	1	3	4
Totals	**100%**	**1.75**	**1.5**	**2.75**	**4**
	Ranking	**3**	**4**	**2**	**1**

Lebanon Area

System Planning Summary 2020

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1.0 Executive Summary

Liberty Utilities completed the Lebanon Area system planning review for 2020. The revised Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System upgrades required to meet existing and future capacity requirements. The review focused on the distribution requirements needed to resolve deficiencies in system capacity, reliability, power quality or asset condition.

In 2017 the Mount Support substation was expanded to add a second 115kV Transmission line, a second 115/13 kV Transformer and two new 13 kV feeders. This project addressed concerns with the lack of capacity on the sub transmission system and with load at risk that resulted from the contingency loss of the Mount Support Supply Line or Transformer.

2.0 Introduction

2.1 Purpose

The purpose of this review was to resolve all identified area concerns in the Lebanon Area through the 15-year 2020-2036 study horizon. An in-depth review of the area was performed that included the analysis of thermal loading, voltage, reliability, asset condition, power quality, environmental, safety and voltage performance. Alternative plans were developed and a preferred plan was recommended as being most prudent after detailed plan comparisons.

2.2 Problem

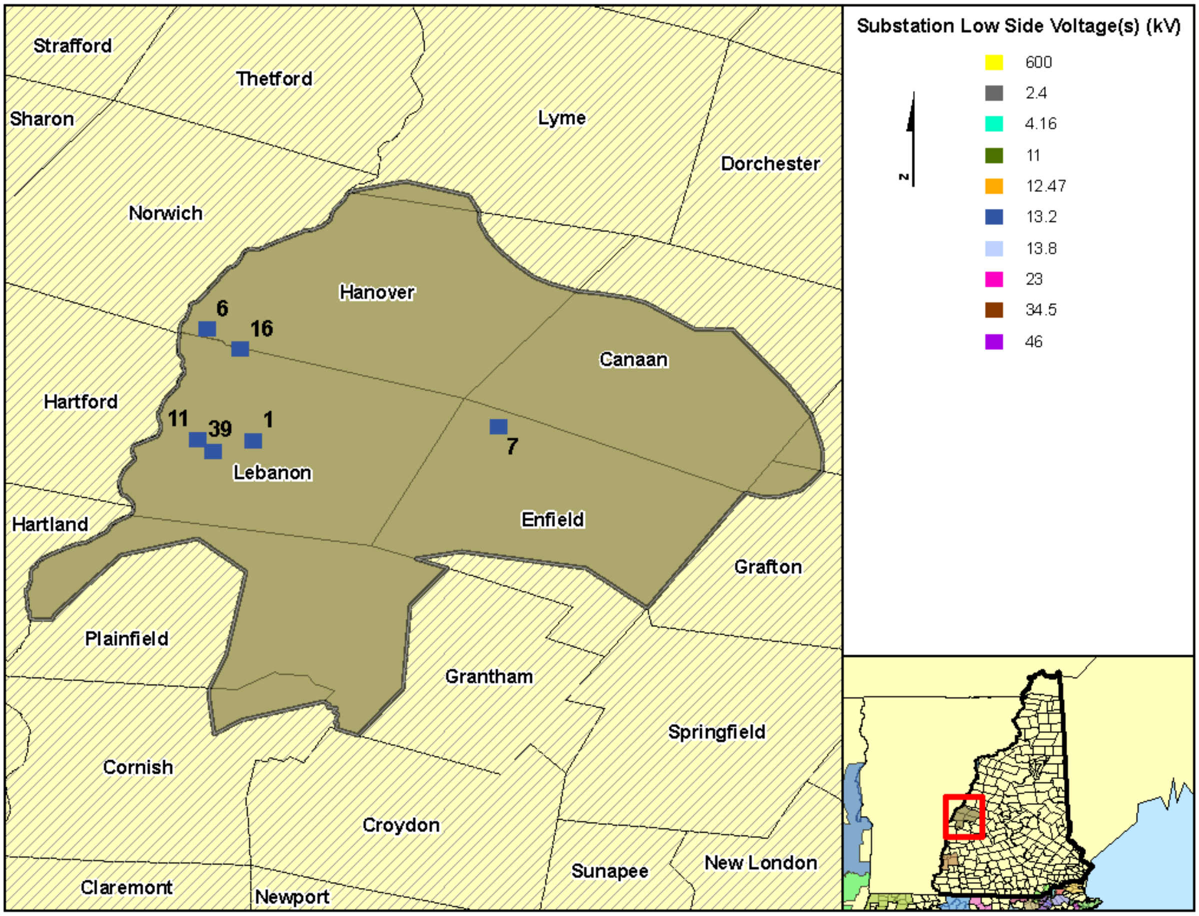
A study's initial system assessment is typically based on the needs identified through the problem identification process guided by the Company's Planning Criteria and Asset Strategies.

3.0 Background

3.1 Geographic Scope

The Lebanon study area is rural residential with commercial/industrial in scattered parks. This area was historically supplied from the Wilder hydro generating plant developed on the Connecticut River by New England Power Company. There are six substations: Craft Hill, Enfield, Hanover, Lebanon Mt. Support, and Slayton Hill. Mt. Support and Slayton Hill are jointly owned by the New England Power Company and Liberty Utilities. This area is confined to the towns of Lebanon, Hanover, Enfield and Canaan with small excursions into Orange, Lyme, Cornish and Grafton. See Figure 1 below:

Figure 1 Lebanon Geographical Map



3.2 Electrical Scope

The Lebanon Study Area includes 115 kV transmission supply, five 13.8 kV supply lines, and eighteen 13.2 kV feeders interconnected through six area substations. Supply is from a network of paralleled, radial 13.8 kV sub transmission lines originating at Wilder and Slayton Hill substations. The Table 1 below summarizes these interconnections:

Table 1: Lebanon Area Electric System

Supply	Alternate Supply	Station	Feeder	Customers
1313	1304	Lebanon 1	1L1	341
1313	1304		1L2	3746
1304	1313		1L3	1357
1304	1313		1L4	0
1L4	1L1	Enfield 7	7L1	2082
1L1	1L4		7L2	1311
1363	1304	Hanover 6	6L2	689
1363	1304		6L3	1,596
1304	1363		6L4	141
1333	1304	Craft Hill 11	11L1	1,926
1333	1304		11L2	356
W-149N	W-149S	Slayton Hill 39[1]	39L1	86
			39L2	551
			1313	5398
			1333	2,282
W-149	W-149N	Mount Support 16[2]	16L1	866
			16L2	405
			16L3	678
			16L4	1
			16L5	1070
			1363	830
W-149	K-26	Wilder [3]	1303	0
			1304	5,035

The 115 kV transmission supply is owned and operated by National Grid. These lines originate from Bellows Falls and Wilder Substations and feeds one transformer at Wilder and two

1 Customers supplied by the 1313 and 1333 supply lines are a summation of customers supplied from the related substation transformers. These supply lines do not directly serve customers at 13.8 kV service voltage.

2 Customers supplied by the 1363 supply line are a summation of customers supplied from the related substation transformers. This supply line do not directly serve customers at 13.8 kV service voltage.

3 Customers supplied by the 1303 and 1304 supply lines are a summation of customers supplied from the related substation transformers. These supply lines do not directly serve customers at 13.8 kV service voltage. Wilder Substation is located in Vermont and is owned and operated by National Grid.

transformers at Mount Support and at Slayton Hill Substations. Appendix A.1, Figure 5 - Lebanon 115 kV Transmission System, shows the 115kV supply to the area.

The five 13.8kV sub transmission supply lines originate from Wilder, Slayton Hill and Mount Support Substations and supplies Hanover, Lebanon and Craft Hill regulating stations. Table 2 below summarizes these interconnections and Figure 2 in Appendix A – System One Lines shows the 13.8 kV Supply System.

Table 2: Lebanon Area 13.8kV Supply System

Circuit	To	From
1303	Wilder #16	Wilder Switch
1303	Wilder Switch	Mt. Support #16
1304	Wilder #16	Wilder Switch
1304	Wilder Switch	Hanover #6
1304	Wilder Switch	Craft Hill #11
1304	Craft Hill #11	Lebanon #1
1313	Slayton Hill #39	Slayton Hill Tap
1313	Slayton Hill Tap	Lebanon #1
1333	Slayton Hill Tap	Craft Hill #11
1333	Craft Hill #11	Wilder Switch
1363	Mt. Support	Hanover #6

Liberty Utilities serves 17,202 Customers in the Lebanon Area supplied by eighteen 13.2kV distribution feeders. In 2020, the Planning Study Area generated a peak demand of 93.3 MW. This area consists of approximately 15 miles of 13.8 kV three-phase supply line, 420 miles of 13.2 kV three-phase distribution and 750 miles of 7.62 kV single-phase distribution. Figure 6, in Appendix A.1 – System One Lines shows the 13.2 kV Distribution System.

3.3 Load and Load Forecast

The Lebanon Study Area is a summer peaking area and is limited by summer equipment ratings. The study was conducted using load data beginning with the recorded 2020 peak load; refer to Table 3, below:

Table 3 Lebanon Area 2019 Peak Loads

Station	Circuit	2020 Peak Load	Limiting Element	SN	% of SN
		Amps		Amps	
CRAFT HILL 11	11L1	296	Relay/Fuse	476	62%
CRAFT HILL 11	11L2	172	OH Line	425	40%
ENFIELD 7	7L1	197	Relay/Fuse	238	83%
ENFIELD 7	7L2	109	Relay/Fuse	238	46%
HANOVER 6	6L2	106	Regulator	516	21%
HANOVER 6	6L3	321	Relay/Fuse	476	67%
HANOVER 6	6L4	193	Regulator	516	37%
LEBANON 1	1L1	145	OH Line	345	42%
LEBANON 1	1L2	321	Relay/Fuse	510	63%
LEBANON 1	1L3	181	OH Line	485	37%
LEBANON 1	1L4	198	Regulator	387	51%
MOUNT SUPPORT 16	16L1	314	UG Cable	500	63%
MOUNT SUPPORT 16	16L2	221	UG Cable	494	45%
MOUNT SUPPORT 16	16L4	369	Regulator	515	72%
MOUNT SUPPORT 16	16L3	270	OH Line	515	52%
MOUNT SUPPORT 16	16L5	320	OH Line	515	62%
MOUNT SUPPORT 16	1363	299	OH Line	1,094	27%
SLAYTON HILL 39	39L1	170	UG Cable	500	34%
SLAYTON HILL 39	39L2	214	UG Cable/OH Line	530	40%
SLAYTON HILL 39	1313	466	OH Line	1094	43%
SLAYTON HILL 39	1333	468	OH Line	1094	43%
WILDER	1303	0	OH Line	1119	0%
WILDER	1304	700	OH Line	1119	63%

The Company developed an econometric model to forecast peak demands through 2036. The forecast model incorporates the impact of weather as well as demographic and local economic conditions on peak demands. The load was escalated through 2036 using the seasonal peak forecast under a 90/10 extreme weather scenario; refer to Table 4, below:

Table 4 LUNH 2020-2036 90/10 Western PSA Growth Rate

Year	% Increase
2020	
2021	11.98%
2022	0.3%
2023	0.3%
2024	0.3%
2025	0.2%
2026	0.2%
2027	0.2%
2028	0.2%
2029	0.2%
2030	0.2%
2031	0.2%
2032	0.2%
2033	0.19%
2034	0.18%
2035	0.17%
2036	0.16%

The forecast model was then adjusted for spot loads to reflect new customer demands larger than 300 kilowatts ("kW"), refer to Table 5 below. The Distribution System was modeled and analyzed using the Synergi application to perform the load flow analysis.

1 Table 5 Lebanon Area Spot Loads

Year	Feeder	Location	Load (MW)
2020	16L2	[redacted]	1.5
2020	16L5	[redacted]	0.7
2020	16L5	[redacted]	0.8
2020	16L5	[redacted]	0.7
2021	16L5	[redacted]	0.4
2022	16L5	[redacted]	1
2021	16L7	[redacted]	2.7
2021-2024	11L1	[redacted]	2.25
2022	6L4	[redacted]	1.2
2022	16L4	[redacted]	1.3
2022	16L3	[redacted]	1.1
2022	16L5	[redacted]	0.4
2023	16L1	[redacted]	2

2 3.4 Modeling and Criteria

3 Synergi electric models were created for the Lebanon area 13.2 kV distribution system.
4 Transformers, supply lines, and distribution circuits were evaluated and modeled for each year
5 thru 2036. The peak load and the available tie capacity for each component of the system was
6 determined. Contingencies for the loss of a major component of the electrical system (N-1) were
7 developed, and the system consequences reviewed.

8 Distribution System Ratings were used to identify any station, supply line, and distribution circuit
9 system capacity and reliability deficiencies, as applicable to Liberty Utilities Planning Criteria
10 which is summarized below.

Table 6 Liberty Utilities Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.	Loading to remain within 100% of normal rating. Voltage at customer meter to remain within acceptable range. Circuit phasing is to remain balanced.
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 are expected to be made within 24 hours. Evaluate alternatives if more than **120 MWhr** of load at risk results following post-contingency switching.	Load must be transferred to nearby transformer to within their LTE rating. Repairs or installation of Mobile Transformer expected to take place within 24 hours. For transformers larger than 10 MVA nameplate, evaluate alternatives if more than **180 MWhr** of load at risk results following post-contingency switching.	Load must be transferred to nearby feeder to within their LTE rating. Repairs expected to be made within 24 hours. Evaluate alternatives if more than **16 MWhr** of load at risk results following post. (Guideline)
N-1 Contingency, which results in facilities operating above their Short-Term Emergency (STE) rating.	As Needed - Typically 15 min 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 15 min for OH conductors and 1-24 hours for UG cables.

4.0 Problem Identification

The goal of system planning is to provide adequate capacity for safe, reliable, and economic service to customers with minimal impact on the environment. System Planning also includes careful management of system assets; addressing asset conditions and protection issues where present to avoid failures, protect the equipment and provide a safe working environment for utility workers.

4.1 Thermal Loading

Analysis results in this section represent the 2020 peak base case. Planning criteria for normal and contingency load serving requirements are applied in concert with the thermal ratings of the facilities to identify capacity violations. Refer to the Company's Distribution Planning Criteria for methodology on rating the equipment. The distribution system load is planned, measured, and forecasted with the goal to serve all customer electric load under system intact (normal conditions or "N-0") and N-1 first contingency conditions.

a. Normal Configuration

i. Sub-Transmission System

Table 7 13.8kV Sub Transmission Loading – Normal Configuration

Lebanon Supply Line Analysis														
			Line Section		Limiting Element	Element Specifics	Rating (MVA)		Projected Load					
									2020		2025		2036	
Study Area	Circuit	Voltage	From	To			SN	SE	MVA	%SN	MVA	%SN	MVA	%SN
Lebanon	1303	13.8	Wilder #16	Wilder Switch	OH Line	795 ACSR	26.7	31.3	0.0	0%	0.0	0%	0.0	0%
Lebanon	1303	13.8	Wilder Switch	Mt. Support #16	OH Line	795 ACSR	26.7	31.3	0.0	0%	0.0	0%	0.0	0%
Lebanon	1304	13.8	Wilder #16	Wilder Switch	OH Line	795 ACSR	26.7	31.3	14.5	54%	16.4	61%	16.8	63%
Lebanon	1304	13.8	Wilder Switch	Hanover #6	OH Line	1113 ACSR	26.4	30.2	7.5	28%	0.0	0%	0.0	0%
Lebanon	1304	13.8	Wilder Switch	Craft Hill #11	OH Line	1113 ACSR	26.4	30.2	7.1	27%	16.4	62%	16.8	64%
Lebanon	1304	13.8	Craft Hill #11	Lebanon #1	OH Line	1113 ACSR	26.4	30.2	7.1	27%	16.4	62%	16.8	64%
Lebanon	1313	13.8	Slayton Hill #39	Slayton Hill Tap	OH Line	1113 ACSR	26.4	30.2	10.2	38%	11.5	43%	11.7	44%
Lebanon	1313	13.8	Slayton Hill Tap	Lebanon #1	OH Line	1113 ACSR	26.4	30.2	10.2	38%	11.5	43%	11.7	44%
Lebanon	1333	13.8	Slayton Hill Tap	Craft Hill #11	OH Line	1113 ACSR	26.4	30.2	13.0	49%	17.0	64%	17.4	66%
Lebanon	1333	13.8	Craft Hill #11	Wilder Switch	OH Line	1113 ACSR	26.4	30.2	0.0	0%	0.0	0%	0.0	0%
Lebanon	1363	13.8	Mt. Support	Hanover #6	OH Line	795 ACSR	26.7	31.3	6.7	25%	8.9	33%	9.1	34%

ii. Transformers

Analysis under normal conditions resulted in no violations for Transformers within the Planning Horizon.

Table 8 Transformer Loading – Normal Configuration

Lebanon Transformer Analysis																
			System Voltage (kV)		Maximum	Rating (MVA)		Projected Load								
								2020			2025			2036		
Study Area	Substation	Tranf. ID.	From	To	Nameplate Rating	SN	SE	MVA	N-1	% SN	MVA	N-1	% SN	MVA	N-1	% SN
Lebanon	MOUNT SUPPORT 16	T1	115	13.8	55	78.7	91.6	20.9	70.7	27%	30.7	60.9	39%	31.3	60.3	40%
Lebanon	MOUNT SUPPORT 16	T2	115	13.8	40	50.3	56	20.2	35.8	40%	29.7	26.3	59%	30.3	25.7	60%
Lebanon	SLAYTON HILL 39	T1	115	13.8	55	78.7	91.6	17.1	74.6	22%	21.5	70.1	27%	22.0	69.7	28%
Lebanon	SLAYTON HILL 39	T2	115	13.8	40	54	58	15.8	42.2	29%	17.9	40.1	33%	18.3	39.7	34%
Lebanon	WILDER 16	T3	115	13.8	36	48	56	14.5	41.5	30%	16.4	39.6	34%	16.8	39.2	35%

iii. Feeders

Analysis on feeder normal loading conditions, identified three violations within the planning horizon. By 2026 loading on the following feeders is projected to exceed 100% of summer normal rating:

- Craft Hill 11L1 – 105% SN
- Mount Support 16L4 – 119% SN
- Mount Support 16L5 – 102% SN

Table 9 Feeder Loading – Normal Configuration

Lebanon Feeder Analysis																
								Projected Load								
								2020			2025			2036		
Study Area	Substation	Voltage (kV)	Feeder	Normal Limiting Element	SN Rating (Amps)	Emergency Limiting Element	SE Rating (Amps)	Amps	N-1	%SN	Amps	N-1	%SN	Amps	N-1	%SN
Lebanon	CRAFT HILL 11	13.2	11L1	Relay/Fuse	476	Relay/Fuse	476	357	119	75%	502	-26	105%	513	-37	108%
Lebanon	CRAFT HILL 11	13.2	11L2	OH Line	425	Relay/Fuse	476	213	263	50%	241	235	57%	246	230	58%
Lebanon	ENFIELD 7	13.2	7L1	Relay/Fuse	238	Relay/Fuse	238	187	51	79%	212	26	89%	216	22	91%
Lebanon	ENFIELD 7	13.2	7L2	Relay/Fuse	238	Relay/Fuse	289	122	167	51%	138	151	58%	141	148	59%
Lebanon	HANOVER 6	13.2	6L2	UG Cable	500	Regulator	612	108	504	22%	122	490	24%	125	487	25%
Lebanon	HANOVER 6	13.2	6L3	Relay/Fuse	476	Relay/Fuse	476	326	150	68%	369	107	77%	377	99	79%
Lebanon	HANOVER 6	13.2	6L4	Regulator	516	OH Line	595	187	408	36%	266	329	51%	271	324	53%
Lebanon	LEBANON 1	13.2	1L1	OH Line	345	OH Line	420	145	275	42%	164	256	48%	168	252	49%
Lebanon	LEBANON 1	13.2	1L2	Relay/Fuse	510	Relay/Fuse	510	299	211	59%	338	172	66%	346	164	68%
Lebanon	LEBANON 1	13.2	1L3	OH Line	485	Relay/Fuse	510	122	388	25%	138	372	28%	141	369	29%
Lebanon	LEBANON 1	13.2	1L4	Regulator	387	Regulator	462	187	275	48%	212	250	55%	216	246	56%
Lebanon	MOUNT SUPPORT 16	13.2	16L1	UG Cable	499.5	UG Cable	592.9	317	276	63%	446	146	89%	456	137	91%
Lebanon	MOUNT SUPPORT 16	13.2	16L2	UG Cable	493.9	UG Cable	586.3	220	366	45%	315	271	64%	322	264	65%
Lebanon	MOUNT SUPPORT 16	13.2	16L4	Regulator	515	Relay/Fuse	612	369	243	72%	597	15	116%	610	2	119%
Lebanon	MOUNT SUPPORT 16	13.2	16L3	OH Line	515	Relay/Fuse	612	272	340	51%	358	254	68%	366	246	69%
Lebanon	MOUNT SUPPORT 16	13.2	16L5	OH Line	515	Relay/Fuse	612	326	286	62%	538	74	102%	550	62	104%
Lebanon	MOUNT SUPPORT 16	13.2	16L6	UG Cable	515	Relay/Fuse	612	0	612	0%	0	612	0%	0	612	0%
Lebanon	SLAYTON HILL 39	13.2	39L1	UG Cable	500	Relay/Fuse	612	176	436	35%	199	413	40%	203	409	41%
Lebanon	SLAYTON HILL 39	13.2	39L2	UG Cable/OH Line	530	Relay/Fuse	612	249	363	47%	282	330	53%	288	324	54%
Lebanon	SLAYTON HILL 39	13.2	39L4	UG Cable/OH Line	530	Relay/Fuse	612	0	612	0%	0	612	0%	0	612	0%

iv. Phase Imbalance

The feeders in the Lebanon Planning Study Area were reviewed for phase balance. The peak average phase loading between July 2020 and August 2020 was selected for each feeder for phase imbalance review.

Liberty utilizes the following criteria for corrective action to phase imbalance:

- The calculated neutral current should not exceed 30% of the feeder ground relay pickup setting;

- The loading between the low and high phase should not exceed 100A.
- Liberty will strive to maintain phase balancing below 10% (guideline).

Any circuit violating these criteria will be monitored to get actual loading data, and will be corrected if the imbalance is verified.

The table below identifies where the imbalance is greater than 10%, and provides recommended mitigation. The cost to address these is minimal.

Table 10 Feeder Phase Balance above 10%

	Amps						Loading		Criteria			Mitigation
Source	A	B	C	Avg	Max	N	% Rat	% Imb	Grnd Relay	% Relay	Dif Max/ Min	
Craft Hill 11L2	167	213	198	193	213	41	50.1	13.3	200	20.5	46	Monitor load.
Lebanon 1L2	299	287	278	288	299	18	58.6	3.8	200	9	21	For voltage support, Transfer 17A from A to C at Fuse 973
Lebanon 1L3	100	122	120	114	122	21	25.2	12.3	240	8.8	22	Monitor load.
Lebanon 1L4	184	157	186	176	186	28	78.2	10.6	240	11.7	29	See Enfield 7L1
Slayton Hill 39L2	249	200	212	220	249	44	47.0	13.0	200	22	49	Monitor load.
Hanover 6L3	277	326	285	296	326	46	68.5	10.1	200	23	49	Transfer 7A from B to A at Fuse 2642 to improve % Imb to 7.8%
Enfield 7L1	184	157	186	176	186	28	78.2	10.6	140	20	29	Transfer 5A from C to B at Fuse 895 and 6A from C to B to improve % Imb to 4.4%
Enfield 7L2	108	122	73	101	122	44	51.3	27.7	140	31.4	49	Transfer 31A from B to C at Fuse 140 to improve % Imb to 9.9%

b. Contingency and Load-at-Risk

i. Sub-Transmission System

Contingency analysis resulted in no existing violations for the 2020 base case model for Supply Lines. In 2025, for the loss of the Slayton Hill 1333 line, the Wilder 1304 supply line is projected to be loaded to 107% of its emergency rating. This contingency does not exceed the load at risk limit for supply lines, however automatic transfers at Craft Hill Station will need to be disabled when loading is above the emergency rating of the 1304 supply. If this contingency event were to occur, loading on the 1304 line can be reduced by transferring a portion of the 11L1 to the Slayton Hill 39L1 feeder.

Table 11 13.8kV Sub Transmission Loading – Contingency Configuration

Circuit	Voltage (kV)	Line Section		Limiting Element	Rating (MVA)		Projected Contingency								
							2020			2025			2036		
		From	To		SN	SE	MVA	Load > SE	% SE	MVA	Load > SE	% SE	MVA	Load > SE	% SE
1303	13.8	Wilder #16	Wilder Switch	OH Line	26.7	31.3	**13.0**	0 0	42%	**17.0**	0 0	54%	**17.4**	0.0	56%
1303	13.8	Wilder Switch	Mt. Support #16	OH Line	26.7	31.3	**0.0**	0 0	0%	**0.0**	0 0	0%	**0.0**	0.0	0%
1304	13.8	Wilder #16	Wilder Switch	OH Line	26.7	31.3	**27.5**	0 0	88%	**33.4**	2.1	107%	**34.1**	2.9	109%
1304	13.8	Wilder Switch	Hanover #6	OH Line	26.4	30.2	**14.2**	0 0	47%	**17.3**	0 0	57%	**17.7**	0.0	59%
1304	13.8	Wilder Switch	Craft Hill #11	OH Line	26.4	30.2	**17.2**	0 0	57%	**19.5**	0 0	64%	**19.9**	0.0	66%
1304	13.8	Craft Hill #11	Lebanon #1	OH Line	26.4	30.2	**17.2**	0 0	57%	**19.5**	0 0	64%	**19.9**	0.0	66%
1313	13.8	Slayton Hill #39	Slayton Hill Tap	OH Line	26.4	30.2	**17.2**	0 0	57%	**19.5**	0 0	64%	**19.9**	0.0	66%
1313	13.8	Slayton Hill Tap	Lebanon #1	OH Line	26.4	30.2	**17.2**	0 0	57%	**19.5**	0 0	64%	**19.9**	0.0	66%
1333	13.8	Slayton Hill Tap	Craft Hill #11	OH Line	26.4	30.2	**13.0**	0 0	43%	**17.0**	0 0	56%	**17.4**	0.0	57%
1333	13.8	Craft Hill #11	Wilder Switch	OH Line	26.4	30.2	**0.0**	0 0	0%	**0.0**	0 0	0%	**0.0**	0.0	0%
1363	13.8	Mt. Support	Hanover #6	OH Line	26.7	31.3	**14.2**	0 0	45%	**17.3**	0 0	55%	**17.7**	0.0	57%

ii. Transformers

Contingency analysis resulted in no existing violations for the 2020 base case model for Transformers. In 2025, for the loss of the 115kV W-149 Line or the Mount Support T1 Transformer, the Mount Support T2 transformer is projected to be loaded to 108% of its emergency rating. This contingency does not exceed the load at risk limit for bulk transformers but automatic transfers at the Mount Support Station will need to be disabled when loading is above the emergency rating of the T2 Transformer. If this contingency event were to occur, loading for the Mount Support Transformer can be reduced by transferring a portion of the 16L5 feeder to the Lebanon 1L3 feeder.

Table 12 13.8kV Transformer Loading – Contingency Configuration

Substation	Tranf. ID.	System Voltage (kV)		Maximum	Rating (MVA)		Projected Contingency					
							2020		2025		2036	
		From	To	Nameplate Rating	SN	SE	MVA	% SE	MVA	% SE	MVA	% SE
MOUNT SUPPORT 16	T1	115	13.8	55	78.7	91.6	41.1	45%	60.4	66%	61.8	67%
MOUNT SUPPORT 16	T2	115	13.8	40	50.3	56.0	41.1	73%	60.4	108%	61.8	110%
SLAYTON HILL 39	T1	115	13.8	55	78.7	91.6	32.9	36%	39.5	43%	40.3	44%
SLAYTON HILL 39	T2	115	13.8	40	54.0	58.0	32.9	57%	39.5	68%	40.3	70%
WILDER 16	T3	115	13.8	36	48.0	56.0	21.3	38%	25.3	45%	25.8	46%

iii. Feeders

A switch plan has been developed for each feeder breaker for both 2020 and 2025 base case. Detailed results of this analysis can be found in Appendix B.1 – 2020 Switch Plan and Appendix C.1 – 2025 Switch Plan.

The following table summarizes facilities which are expected to be loaded above 100% of emergency limits during the planning horizon. The conductor size will be confirmed for accuracy. Additional information for each identified problem is provided in Appendix D.1 and E.1.

Table 13 13.8kV Feeder Loading – Contingency Configuration

Dropped Circuit	Year	% Overload	Device	Affected Circuit	Location	Reference
7L1 or 7L2	2020	149	UG Cable	1L2	I-89 Crossing	Figure 10
16L5	2020	143	OH Line	16L1	Gibson Rd	Figure 9
7L1	2025	107	Relay	7L2	Enfield Substation	Figure 11
7L1 or 7L2	2025	170	UG Cable	1L2	I-89 Crossing	Figure 11
7L1 or 7L2	2025	112	OH Line	1L2	Dulac St	Figure 11
16L1	2025	113	UG Cable	16L2	Medical Center Dr	Figure 12
16L3	2025	106	OH Line	6L2	School St	
16L4	2025	126	UG Cable	16L1	Medical Center Dr	
16L5	2025	201	OH Line	16L1	Gibson Rd	Figure 13
16L5	2025	126	UG Cable	16L5	Medical Center Dr	Figure 13

4.2 Circuit Analysis

a. Voltage Performance during Normal Operation

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 mounted line regulators. The ultimate goal is to keep all customers' service voltages within accepted limits.

The table below shows the areas where voltage is expected to exceed limits under normal configuration within the planning horizon. Refer to Appendix D.1 for additional details.

Table 14 Voltage Performance – Normal Configuration

Year	Voltage (p.u.)	Affected Circuit	Reference
2020	0.95	16L1	Figure6
2020	0.89	1L2	
2025	0.938	16L1	Figure 7
2025	0.93	16L5	
2025	0.875	1L2	

b. Voltage Performance during Contingency Operation

The figure below shows the areas where voltage is expected to exceed limits under contingency configuration within the planning horizon. Refer to Appendix E.1 for additional details.

Table 15 Voltage Performance – Contingency Configuration

Dropped Circuit	Year	Voltage (p.u.)	Affected Circuit	Reference
7L1 or 7L2	2020	0.87	1L2	Figure 9
16L1	2020	0.9	16L5	Figure 8
16L4	2020	0.89	16L5	
16L5	2020	0.928	16L1	Figure 9
1L2	2020	0.88	1L1	Figure 11
7L1 or 7L2	2025	0.86	1L2	Figure 12
16L1	2025	0.85	16L5	Figure 13
16L4	2025	0.85	16L5	
16L5	2025	0.89	16L1	Figure 14
1L2	2025	0.91	1L1	Figure 15
1L2	2025	0.92	1L3	Figure 15

c. Power Factor

Liberty will strive to maintain a 98% power factor at the substations to provide quality power to its customers and limit system losses via the addition of new capacitor banks. In addition, annual reviews for system power factor will allow Liberty to properly manage reactive support by adjusting settings from capacitor bank controls.

The table below identifies feeders where the power factor is lower than 98% and provides recommended mitigation.

Table 16 Feeder Power Factor below 98%

Source	Amps				Power Factor %				Mitigation
	A	B	C	Avg	A	B	C	Avg	
11L2	167	213	198	193	90	90	90	90	Placed 1200 kVAR capacitor bank CB42 in-service to improve PF to 97%
16L1	314	317	310	314	91	91	91	91	Placed 900 kVAR capacitor bank CB13 in-service and 600 kVAR CB8939 to improve PF to 97%
16L2	208	219	214	214	96	96	96	96	Placed 1200 kVAR capacitor bank CB12540 in-service to improve PF to 99%
1L1	145	143	126	138	-90	-90	-90	-90	Placed 1200 kVAR capacitor bank CB2 in-service to improve PF to -99%
39L2	249	200	212	220	96	96	96	96	Placed 1200 kVAR capacitor bank CB14150 in-service to improve PF to 99%
1333	469	470	480	473	96	96	96	96	See 11L2
6L2	92	108	105	102	-70	-70	-70	-70	Adjusted 1200 kVAR capacitor bank control settings CB12543 to improve PF to -96%
6L4	182	187	174	181	93	93	94	93	Install 1200 kVAR capacitor bank to improve PF to 99%
7L2	108	122	73	101	-96	-96	-96	-96	Install 600 kVAR capacitor bank and adjusted 1200 kVAR capacitor bank CB95 settings to improve power factor to 99%

d. Sector Report

Where practical, Liberty's goal is to limit feeders to 2,500 customers and sectionalized such that the number of customers does not exceed 500 or the load between disconnecting devices does not exceed 2,000kVA.

The Lebanon 1L2 feeder supplies 3,744 customers in the towns of Lebanon, Enfield, Plainfield and Cornish and is the only feeder that supplies over 2,500 customers.

Liberty reviewed the load and customers between disconnecting devices to determine areas where these limits are exceeded. The table below summarizes these findings:

Table 17 Sector Report

# Sectors > 2 MVA	# Sectors > 500 Cust.	Sector Average MVA	Sector Average Cust. Served
16	9	3.48	732

4.3 Asset Condition

Refer to Liberty Utilities Distribution Asset Strategy in Appendix D for details on the company's plans.

The major equipment to be addressed in the Lebanon Study Area within the planning horizon is:

- Upgrade Hanover 6L3 circuit breaker and control
- Upgrade Craft Hill 11L2 circuit breaker and control
- Retire Enfield 7L1 circuit breaker and control
- Retire Enfield 7L2 circuit breaker and control
- Upgrade Monroe 15H1 breaker and voltage regulator.

4.4 Reliability

Refer to Appendix F - Liberty Utilities Reliability Report for details on the company's results and plans.

4.5 Protection Analysis

The analysis identified 18 fuse replacements. An upcoming substation upgrade project by National Grid will impact the coordination and protection of the Lebanon Area and will require several protection changes in the area. For details refer to Appendix E.1 - Liberty Utilities Lebanon Area Protection Review.

5.0 Problem Solutions

The following section provides infrastructure improvement projects to address the deficiencies listed in Section 4, including potential non-wires solutions (NWS) to resolve the problem.

The project costs presented in this section are of investment grade. Project scope and estimates will be refined as part of detailed engineering activities. Upon initial analysis, Liberty is evaluating potential NWA solutions for the Craft Hill 11L1 project – see below.

5.1 Thermal Loading

a. N-1 Normal Configuration

i. Craft Hill 11L1 – 2023

The Craft Hill 11L1 feeder is projected to be loaded to 105% of its summer normal rating in 2025 mainly due to proposed new commercial development "River Park" in West Lebanon NH. It is projected that the feeder will exceed its summer normal rating in 2023.

Proposed Solution:

This commercial development is in its design phase and the Company continues to work with the development to meet expected in-service dates for the first phase of the project. The Company will continue monitoring the progress of the development and in the interim can transfer up to 1.6 MVA of load to adjacent feeder Lebanon 1L3 to reduce loading within ratings while a permanent solution is employed.

This transfer would be considered temporary since the 1L3 feeder is part of an automated restoration scheme with the 16L5 and provides backup supply to the 1L2 feeder. Increasing the load on this feeder further constrains the available capacity to support the 16L5 feeder in the town of Lebanon and further worsens the voltage problems identified in this report. An existing bridge project from the Town could make this tie unavailable until construction is complete.

As more information becomes available Liberty will evaluate the installation of new feeder Slayton Hill 39L4 in 2025 to address this projected overload if needed. This project is estimated at $600,000.

Since this project is expected to exceed its summer normal rating in 2023, and there is some uncertainty on the pace of the proposed commercial expansion, this feeder may lend itself to a potential non-wires solution, such as solar PV + storage solution or a hybrid solution. Liberty conducted an initial NWS Analysis for this project and evaluated the costs and risks of all solution options and determined that the traditional alternative is preferred. For details refer to Appendix

G. Liberty previously recommended a NWS as part of its Tesla battery program to reduce the 11L1 feeder peak load but the plan was later discarded.

Liberty is committed to working with Commission Staff and other stakeholders to identify a non-wires solution that best fits the needs of our Customers.

Project Cost: $600,000 – Pending NWS Consideration and Stakeholder Review

Risk Score: 34

ii. Mount Support 16L4 – 2021

The Mount Support 16L4 feeder is projected to be loaded to 103% of its summer normal rating mainly due to a 3 MW hospital expansion slated to be complete in 2021.

Proposed Solution (In Progress):

To resolve forecasted overloads it was proposed to install a new Mount Support 16L7 feeder.

Performing field transfers to adjacent feeders to provide additional capacity is not feasible due to the lack of spare capacity from adjacent feeders. The new 16L7 feeder will provide the customer with a second 13.2kV feeder for added supply redundancy and future growth. Non Wires Solutions was not evaluated because the need for solution is less than 24 months in the future.

Project Cost: $740,000

Risk Score: 37

iii. Mount Support 16L5 – 2022

The Mount Support 16L5 feeder is projected to be loaded to 101% of its summer normal rating in 2022 mainly due to customer growth in the town of Lebanon.

Proposed Solution:

It is recommended to transfer 2.3 MVA of load to adjacent feeder Lebanon 1L1 to reduce loading within ratings.

The 16L5 feeder is part of an automated restoration scheme with the 16L1 and 1L3 feeders and also provides backup to the 16L2 feeder. This transfer will improve voltage conditions during contingency.

Project Cost: Minimal

Risk Score: 37

iv. N-1 Contingency and Load-at-Risk

The following conductors could experience thermal overloads under a contingency condition. These conductor sizes will be investigated in the field for accuracy prior to any design activities take place.

Table 18 Overloaded Conductors – Contingency Configuration

Year	% Overload	Device	Affected Circuit	Location	Distance (ft)	Estimate ($)	Risk Score
2022	149	UG Cable	1L2	I-89 Crossing	400	$85,000	48
2022	143	OH Line	16L1	Gibson Rd	900	$75,000	48
2025	106	OH Line	6L2	School St	1,200	$100,000	41
2025	112	OH Line	7L2	Dulac St	1,400	$120,000	45

5.2 Circuit Analysis

a. Voltage Performance

The following projects aim to address existing and projected problem issues during and normal and contingency conditions.

i. Mount Support 16L1 – 2022

Feeder 16L1 could experience voltage deficiencies during normal and contingency conditions. This feeder is part of an automated restoration scheme with the 16L5 feeder.

To mitigate, it is recommended to install one 900 kVAR capacitor bank at Old Etna Rd in 2022 and one 167 kVA voltage regulator at Great Hollow Rd in 2023.

Project Cost: $90,000

Risk Score: 45

ii. Mount Support 16L5 - 2022

Feeder 16L5 could experience voltage deficiencies during normal and contingency conditions. This feeder is part of an automated restoration scheme with the 16L1 feeder and the 1L3 feeder. To mitigate, it is recommended to transfer 2.3 MVA of load to adjacent feeder Lebanon 1L1 in

2022. The installation of a new regulator and capacitor at Great Hollow Rd mentioned above, will also support emergency restoration of the 16L5.

Project Cost: Minimal

Risk Score: 45

iii. Lebanon 1L2 - 2022

Feeder 1L2 could experience voltage deficiencies during normal and contingency conditions. To mitigate, it is recommended to install one 167 kVA regulator at Connecticut Valley Hwy. Plainfield and one 600 kVAR capacitor bank at Eastman Hill Rd Enfield in 2022.

Project Cost: $65,000

Risk Score: 48

iv. Voltage Conversion – 2020 - 2025

To address low voltage problems in step down areas, the following will be evaluated and prioritized for voltage conversion. These conversions are expected to cost between approximately $50,000 and $150,000 per location pending engineering design review. In general, Liberty assigns a risk score of 41 to voltage conversion projects.

- Old Route 10 Enfield - 2025
- Croydon Turnpike Plainfield - 2020
- Bonner Rd Plainfield - 2022
- Hopkins Rd Plainfield - 2024
- Route 120 Cornish - 2024
- River Rd Plainfield - 2020
- Dogford Rd Hanover - 2023

b. Power Factor Correction

In order to improve power factor for the Hanover 6L2 and Enfield 7L2 feeders, it is recommended to install a 1200 kVAR capacitor bank at Currier Pl Hanover and a 600 kVAR capacitor bank at Shaker Hill Rd Enfield in 2022.

Project Cost: $25,000

Risk Score: 36

c. Sector Problems

In 2024 a new tie is planned to be constructed between the 1L2 and 1L3 feeders near Spencer St Lebanon to transfer 1.4 MVA and 430 Customers to the Lebanon 1L3 feeder. This tie will reduce the number of customers served from the 1L2 feeder and provide a new tie to support the eastern part of Lebanon and the northern part of Enfield where currently the only source is from the Slayton Hill Substation. The 1L3 tie to the area will provide an alternate source from the Wilder Substation which will provide additional flexibility to restore customers during emergencies. In general, Liberty assigns a risk score of 34 to these projects.

Project Cost: $200,000

Liberty has prioritized the locations on the distribution system based on severity where there is over 2 MVA of load or 500 customers between disconnects. These locations will be reviewed for improved sectionalizing opportunities, reliability history and exposure. In order to limit the exposure to customers and improve restoration times, Liberty expects to address two locations per year between 2022 and 2025.

Project Cost: $30,000/yr. ($120,000 total)

6.0 Appendices

6.1 Appendix A.1 – System One Lines

Figure 2 [redacted]

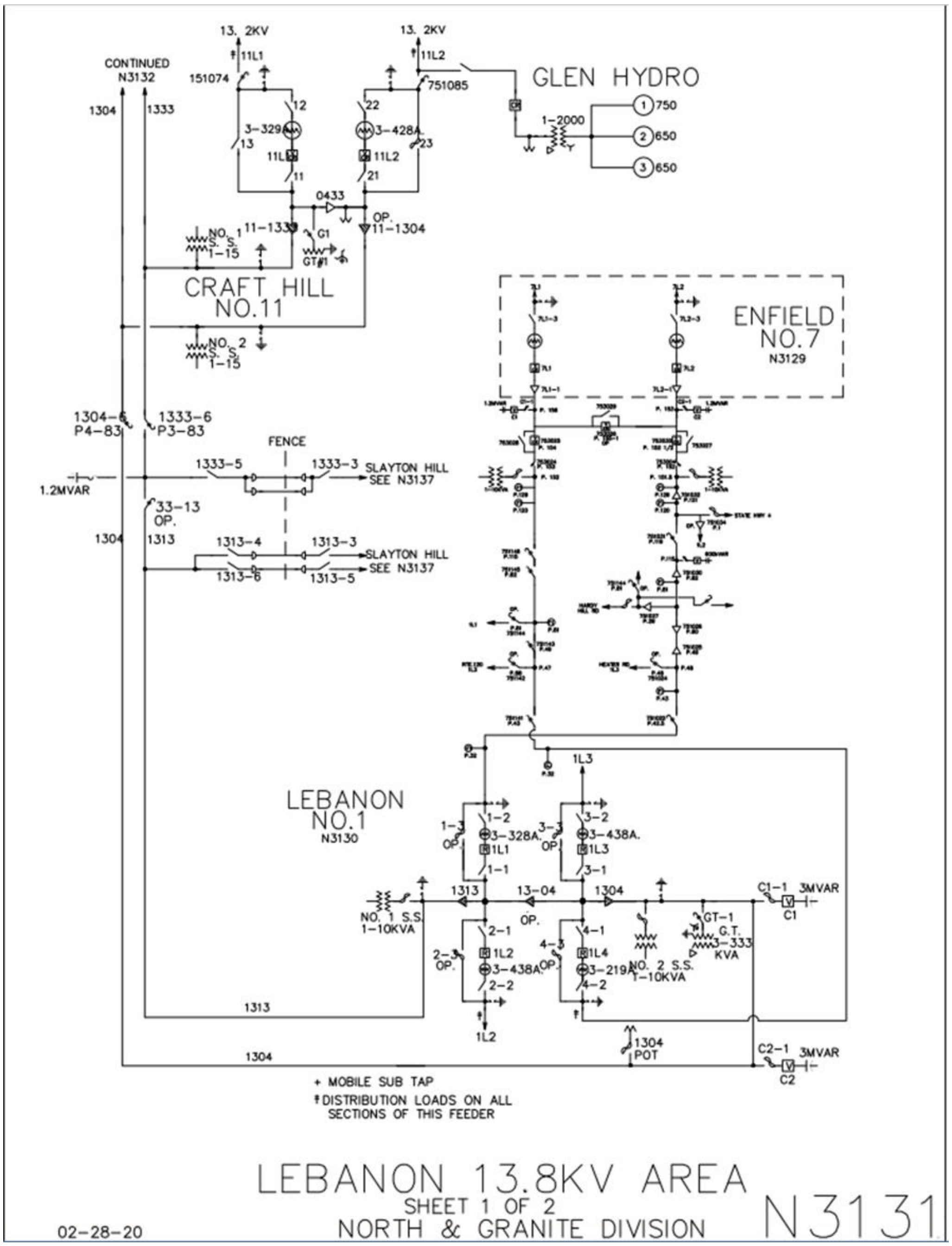


Figure 3 [redacted]

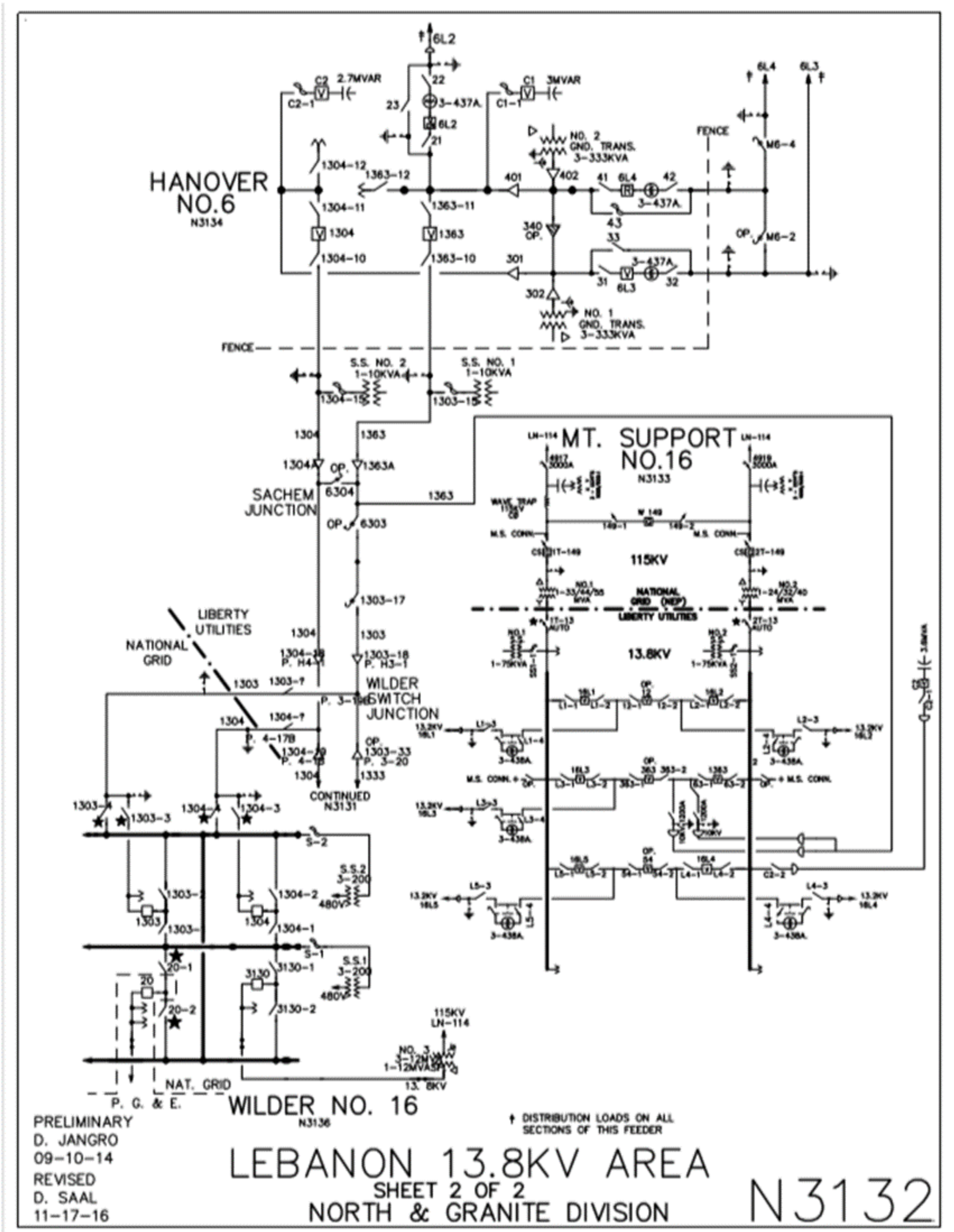


Figure 4 [redacted]

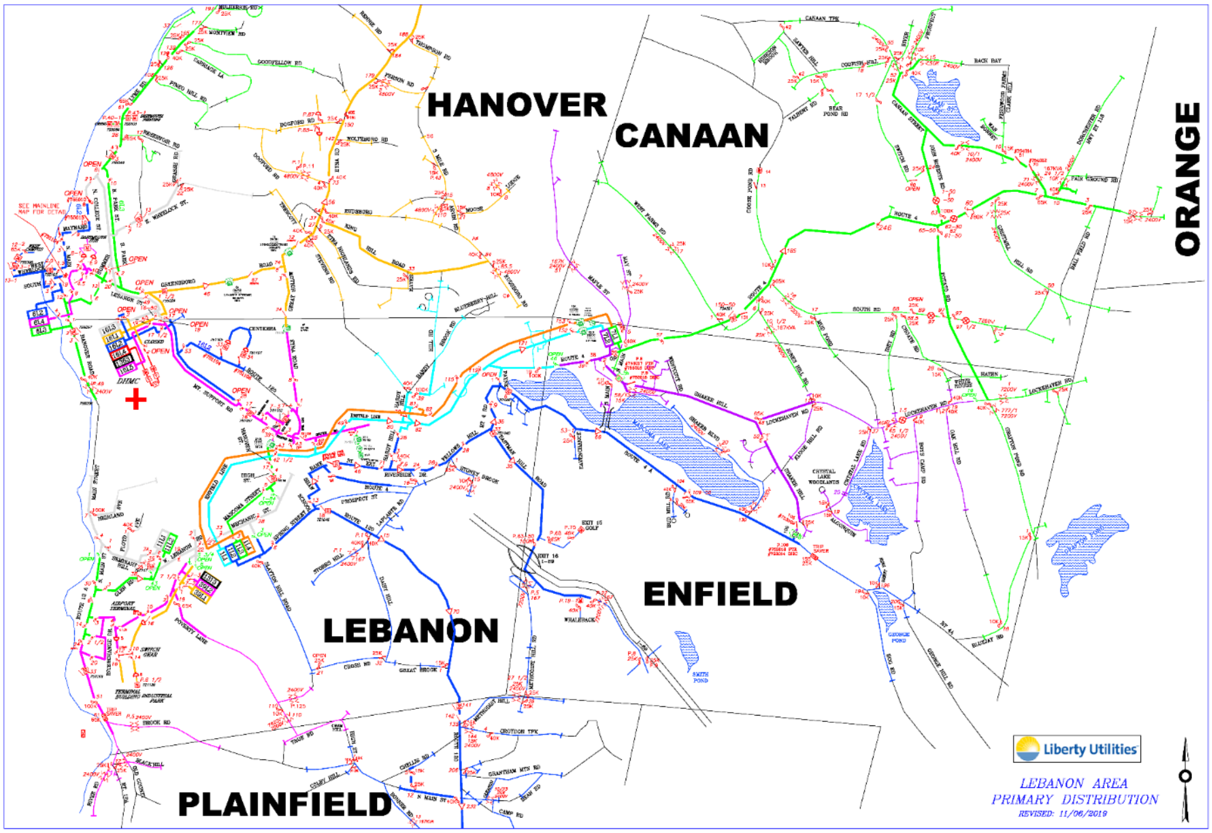
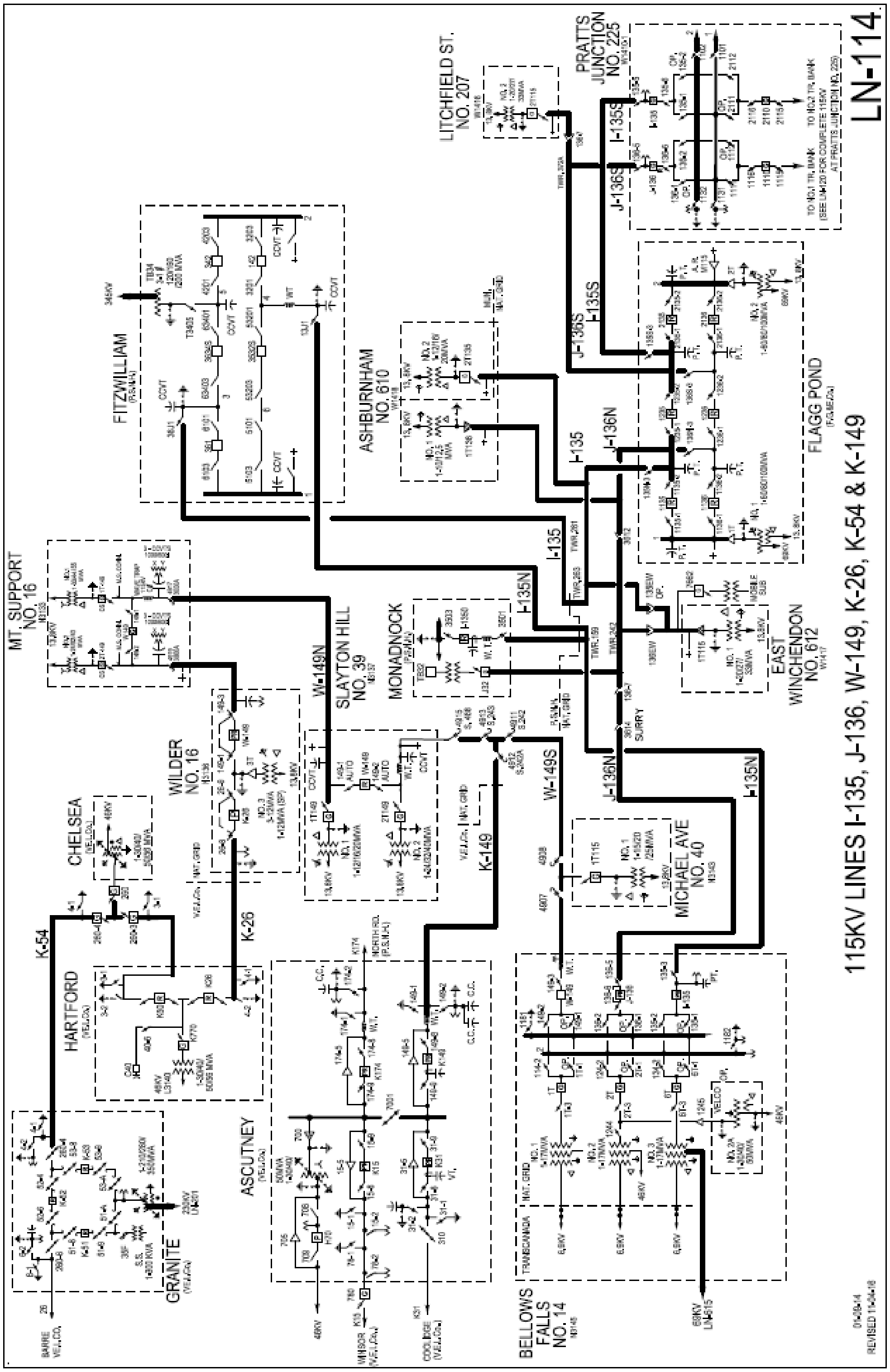


Figure 5 [redacted]



1 **6.2 Appendix B.1 – Switch Plan 2020**

2 Table 19 2020 Switch Plan Part 1

Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
Plan : Feeder 11L1										
0 - Open	PTR11L1	11L1	357	23 4	1717	---	---	---	---	
1 - Close	751065	---	---	---	---	1L3	358	23 4	1717	
Plan : Feeder 11L2										
0 - Open	PTR11L2	11L2	213	7 4	315	---	---	---	---	
1 - Close	751092	---	---	---	---	39L2	214	7 4	315	
Plan : Feeder 16L2										
0 - Open	751096	16L2	174	9	94	---	---	---	---	
1 - Close	SW94764	---	---	---	---	16L5	174	9	94	
2 - Open	16L2	16L2	51	4 6	164	---	---	---	---	
3 - Close	755095	---	---	---	---	16L1	51	4 6	164	
Plan : Feeder 39L1										
0 - Open	39L1	39L1	176	3 5	81	---	---	---	---	
1 - Close	751172	---	---	---	---	39L2	176	3 5	81	
Plan : Feeder 39L2										
0 - Open	39L2	39L2	249	39 2	499	---	---	---	---	
1 - Close	751172	---	---	---	---	39L1	249	39 2	499	
Plan : Feeder 6L2										
0 - Open	755027	6L2	108	7 3	543	---	---	---	---	
1 - Close	755010	---	---	---	---	16L3	108	7 3	543	
Plan : Feeder 6L3										
0 - Open	PTR6L3	6L3	326	41 9	1430	---	---	---	---	
1 - Close	755028	---	---	---	---	6L2	326	41 9	1430	
Plan : Feeder 6L4										
0 - Open	PTR6L4	6L4	187	2 4	127	---	---	---	---	
1 - Close	755007	---	---	---	---	6L2	187	2 4	127	
Plan : Feeder 7L1										
0 - Open	PTR7L1	7L1	186	92 9	1843	---	---	---	---	
1 - Close	753001	---	---	---	---	7L2	187	92 9	1843	
2 - Open	PTR753017	7L2	85	24 5	699	---	---	---	---	
3 - Close	PTR753018	---	---	---	---	1L2	114	24 5	699	Transfer to 1L2 could result in voltages as low as 0 87 pu and 400 ft of overloaded underground cables
Plan : Feeder 16L1										
0 - Open	PTR755072	16L1	144	51 1	540	---	---	---	---	
1 - Close	PTR751135	---	---	---	---	16L5	147	51 1	540	Transfer to 16L5 could result in voltages as low as 0 9 pu
2 - Open	16L1	16L1	182	8 9	260	---	---	---	---	
3 - Close	755095	---	---	---	---	16L2	182	8 9	260	
4 - Open	751163	16L5	120	3 4	99	---	---	---	---	
5 - Close	751142	---	---	---	---	1L1	110	3 4	99	

Table 19 2020 Switch Plan Part 2

Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
Plan : Feeder 16L3										
0 - Open	755021	16L3	221	0 4	7	---	---	---	---	
1 - Close	755010	---	---	---	---	6L2	221	0 4	7	
2 - Open	16L3	16L3	71	14 9	610	---	---	---	---	
3 - Close	755040	---	---	---	---	6L3	71	14 9	610	
Plan : Feeder 16L4										
0 - Open	16L4	16L4	368	0 8	1	---	---	---	---	
1 - Close	PTR52T	---	---	---	---	16L1	369	0 8	1	
2 - Open	PTR755072	16L1	144	51 1	540	---	---	---	---	
3 - Close	PTR751135	---	---	---	---	16L5	147	51 1	540	Transfer to 16L5 could result in voltages as low as 0 89 pu
Plan : Feeder 16L5										
0 - Open	PTR751157	16L5	315	12	635	---	---	---	---	
1 - Open	PTR751102	Unfed	194	4 4	75	---	---	---	---	
2 - Close	PTR751161	---	---	---	---	1L3	130	7 5	561	
3 - Close	PTR751135	---	---	---	---	16L1	196	4 4	75	Transfer to 16L1 could result in voltages as low as 0 928 pu and 900 ft of overloaded overhead wires
4 - Open	16L5	16L5	12	3 8	187	---	---	---	---	
5 - Close	751139	---	---	---	---	16L2	12	3 8	187	
Plan : Feeder 1L1										
0 - Open	1L1	1L1	54	25 8	313	---	---	---	---	
1 - Close	PTR753029	---	---	---	---	1L4	54	25 8	313	
Plan : Feeder 1L2										
0 - Open	PTR751046	1L2	101	46 2	1235	---	---	---	---	
1 - Close	751034	---	---	---	---	1L1	101	46 2	1235	Transfer to 1L1 could result in voltages as low as 0 88 pu
2 - Open	1L2	1L2	205	67 3	2142	---	---	---	---	
3 - Open	751021	11L1	61	2 2	301	---	---	---	---	
4 - Open	1L2	Unfed	205	67 3	2142	---	---	---	---	
5 - Close	751065	---	---	---	---	1L3	61	2 2	301	
6 - Close	751037	---	---	---	---	1L3	206	67 3	2142	Transfer to 1L3 could result in voltages as low as 0 92 pu
Plan : Feeder 1L3										
0 - Open	PTR751164	1L3	62	6 3	691	---	---	---	---	
1 - Close	PTR751161	---	---	---	---	16L5	62	6 3	699	
2 - Open	1L3	1L3	70	10 9	511	---	---	---	---	
3 - Close	751065	---	---	---	---	11L1	70	10 9	488	
Plan : Feeder 7L2										
0 - Open	PTR753017	7L2	85	24 5	699	---	---	---	---	
1 - Close	PTR753018	---	---	---	---	1L2	114	24 5	699	Transfer to 1L2 could result in voltages as low as 0 87 pu and 400 ft of overloaded underground cables
2 - Open	PTR7L2	7L2	44	10 2	488	---	---	---	---	
3 - Close	753001	---	---	---	---	7L1	44	10 2	488	

6.3 Appendix C.1 – Switch Plan 2025

Table 20 2025 Switch Plan Part 1

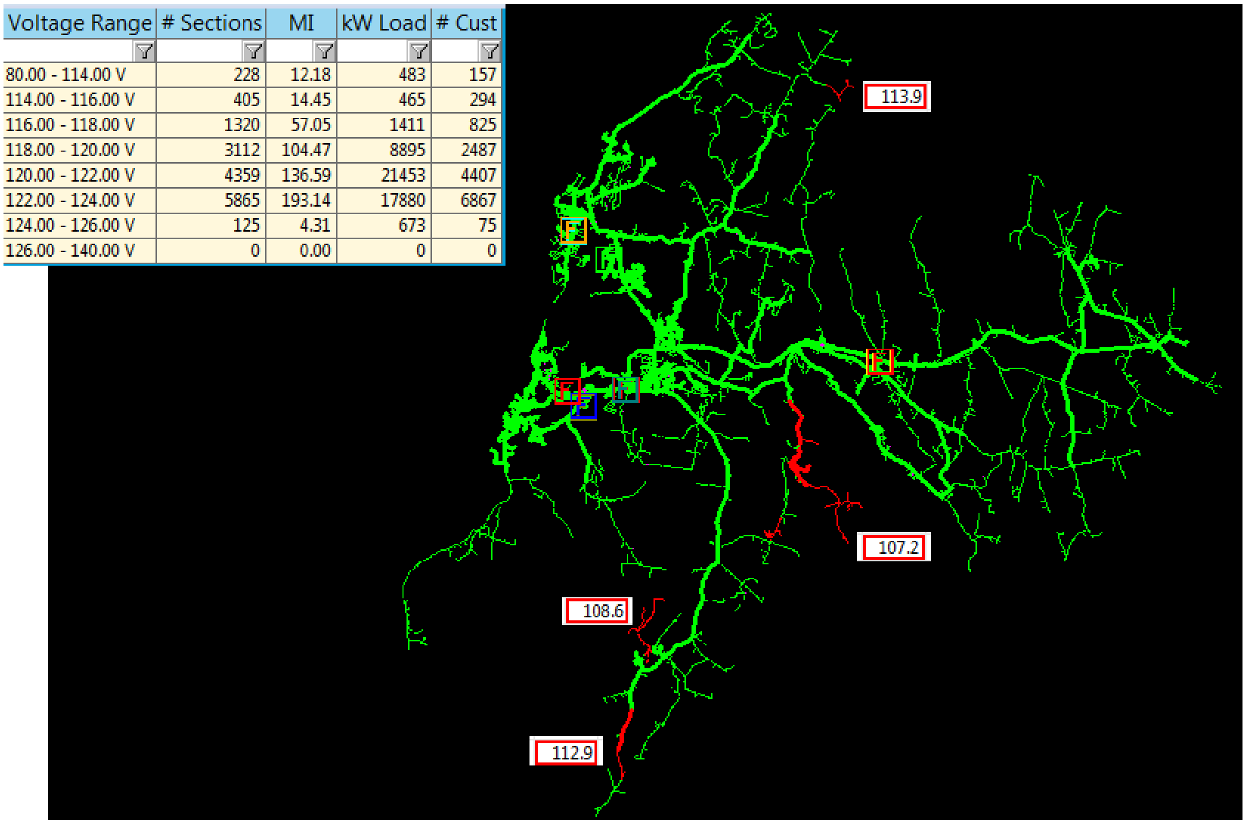
Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
: Feeder 11L1										
0 - Open	PTR11L1	39L2	102	2 6	75	---	---	---	---	
1 - Close	751076	---	---	---	---	11L2	102	2 6	75	
2 - Open	751065	11L2	183	10 3	789	---	---	---	---	
3 - Open	751082	1L3	315	13 1	928	---	---	---	---	
4 - Close	751140	---	---	---	---		0	0	0	
5 - Close	751092	---	---	---	---	11L1	493	23 4	1717	
: Feeder 11L2										
0 - Open	PTR11L2	11L2	239	7 4	315	---	---	---	---	
1 - Close	751092	---	---	---	---	39L2	241	7 4	315	
: Feeder 16L2										
0 - Open	751096	16L2	259	9	94	---	---	---	---	
1 - Close	SW94764	---	---	---	---	16L5	259	9	94	
2 - Open	16L2	16L2	56	4 6	164	---	---	---	---	
3 - Close	755095	---	---	---	---	16L1	56	4 6	164	
: Feeder 39L1										
0 - Open	39L1	39L1	195	3 5	81	---	---	---	---	
1 - Close	751172	---	---	---	---	39L2	195	3 5	81	
: Feeder 39L2										
0 - Open	39L2	39L2	277	39 2	499	---	---	---	---	
1 - Close	751172	---	---	---	---	39L1	277	39 2	499	
n : Feeder 6L2										
0 - Open	755027	6L2	116	7 3	543	---	---	---	---	
1 - Close	755010	---	---	---	---	16L3	115	7 3	543	
n : Feeder 6L3										
0 - Open	PTR6L3	6L3	362	41 9	1430	---	---	---	---	
1 - Close	755028	---	---	---	---	6L2	362	41 9	1430	
n : Feeder 6L4										
0 - Open	PTR6L4	6L4	208	2 4	127	---	---	---	---	
1 - Close	755007	---	---	---	---	6L2	208	2 4	127	
n : Feeder 7L1										
0 - Open	PTR7L1	7L1	206	92 9	1843	---	---	---	---	
1 - Close	753001	---	---	---	---	7L2	206	92 9	1843	Transfer could result in Enfield 7L2 feeder being loaded to 107% of its emergency rating
2 - Open	PTR753017	7L2	94	24 5	699	---	---	---	---	
3 - Close	PTR753018	---	---	---	---	1L2	122	24 5	699	Transfer to 1L2 could result in voltages as low as 0 86 pu, 400 ft of overloaded underground cables and 1,400 ft of overloaded overhead wires
: Feeder 16L1										
0 - Open	16L1	16L1	442	60	800	---	---	---	---	
1 - Open	PTR755072	Unfed	163	51 1	540	---	---	---	---	
2 - Close	PTR751135	---	---	---	---	16L5	169	51 1	540	Transfer to 16L5 could result in voltages as low as
3 - Close	755095	---	---	---	---	16L2	288	8 9	260	Transfer to 16L2 could result in 1,400 ft of overloaded underground cables
4 - Open	751163	16L5	134	3 4	99	---	---	---	---	
5 - Close	751142	---	---	---	---	1L1	122	3 4	99	

Table 20 2025 Switch Plan Part 2

Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
: Feeder 16L3										
0 - Open	755021	16L3	292	0 4	7	---	---	---	---	
1 - Close	755010	---	---	---	---	6L2	292	0 4	7	Transfer to 6L2 could result in 1,200 ft of overhead wires being loaded to 106% of emergency rating
2 - Open	16L3	16L3	79	14 9	610	---	---	---	---	
3 - Close	755040	---	---	---	---	6L3	79	14 9	610	
: Feeder 16L4										
0 - Open	16L4	16L4	584	0 8	1	---	---	---	---	
1 - Open	PTR755072	16L1	163	51 1	540	---	---	---	---	
2 - Close	PTR751135	---	---	---	---	16L5	169	51 1	540	Transfer to 16L5 could result in voltages as low as 0 85 pu
3 - Open	751163	16L5	134	3 4	99	---	---	---	---	
4 - Close	751142	---	---	---	---	1L1	122	3 4	99	
5 - Open	755050	16L1	125	7 4	258	---	---	---	---	
6 - Close	755095	---	---	---	---	16L2	125	7 4	258	
7 - Close	PTR52T	---	---	---	---	16L1	584	0 8	1	Transfer to 16L1 could result in feeder being loaded to 126% of its emergency rating (3 5 MVA Load at
: Feeder 16L5										
0 - Open	16L5	16L5	534	15 8	822	---	---	---	---	
1 - Open	PTR751102	Unfed	314	4 4	75	---	---	---	---	
2 - Close	PTR751135	---	---	---	---	16L1	317	4 4	75	Transfer to 16L1 could result in feeder being loaded to 126% of its emergency rating, voltages as low as 0 89 pu and 900 ft of overloaded overhead wires
3 - Close	PTR751161	---	---	---	---	1L3	237	11 3	748	
n : Feeder 1L1										
0 - Open	1L1	1L1	60	25 8	313	---	---	---	---	
1 - Close	PTR753029	---	---	---	---	1L4	60	25 8	313	
n : Feeder 1L2										
0 - Open	PTR751046	1L2	112	46 2	1235	---	---	---	---	
1 - Close	751034	---	---	---	---	1L1	112	46 2	1235	Transfer to 1L1 could result in voltages as low as 0 91
2 - Open	1L2	1L2	230	67 3	2142	---	---	---	---	
3 - Open	751021	11L1	68	2 2	301	---	---	---	---	
4 - Open	1L2	Unfed	230	67 3	2142	---	---	---	---	
5 - Close	751065	---	---	---	---	1L3	68	2 2	301	
6 - Close	751037	---	---	---	---	1L3	232	67 3	2142	Transfer to 1L3 could result in voltages as low as 0 92
n : Feeder 1L3										
0 - Open	PTR751164	1L3	68	6 3	691	---	---	---	---	
1 - Close	PTR751161	---	---	---	---	16L5	67	6 3	691	
2 - Open	1L3	1L3	78	10 9	511	---	---	---	---	
3 - Close	751065	---	---	---	---	11L1	78	10 9	511	
n : Feeder 7L2										
0 - Open	PTR753017	7L2	94	24 5	699	---	---	---	---	
1 - Close	PTR753018	---	---	---	---	1L2	122	24 5	699	Transfer to 1L2 could result in voltages as low as 0 86 pu, 400 ft of overloaded underground cables and 1,400 ft of overloaded overhead wires
2 - Open	PTR7L2	7L2	49	10 2	488	---	---	---	---	
3 - Close	753001	---	---	---	---	7L1	49	10 2	488	

6.4 Appendix D.1 – Voltage Performance Normal Condition

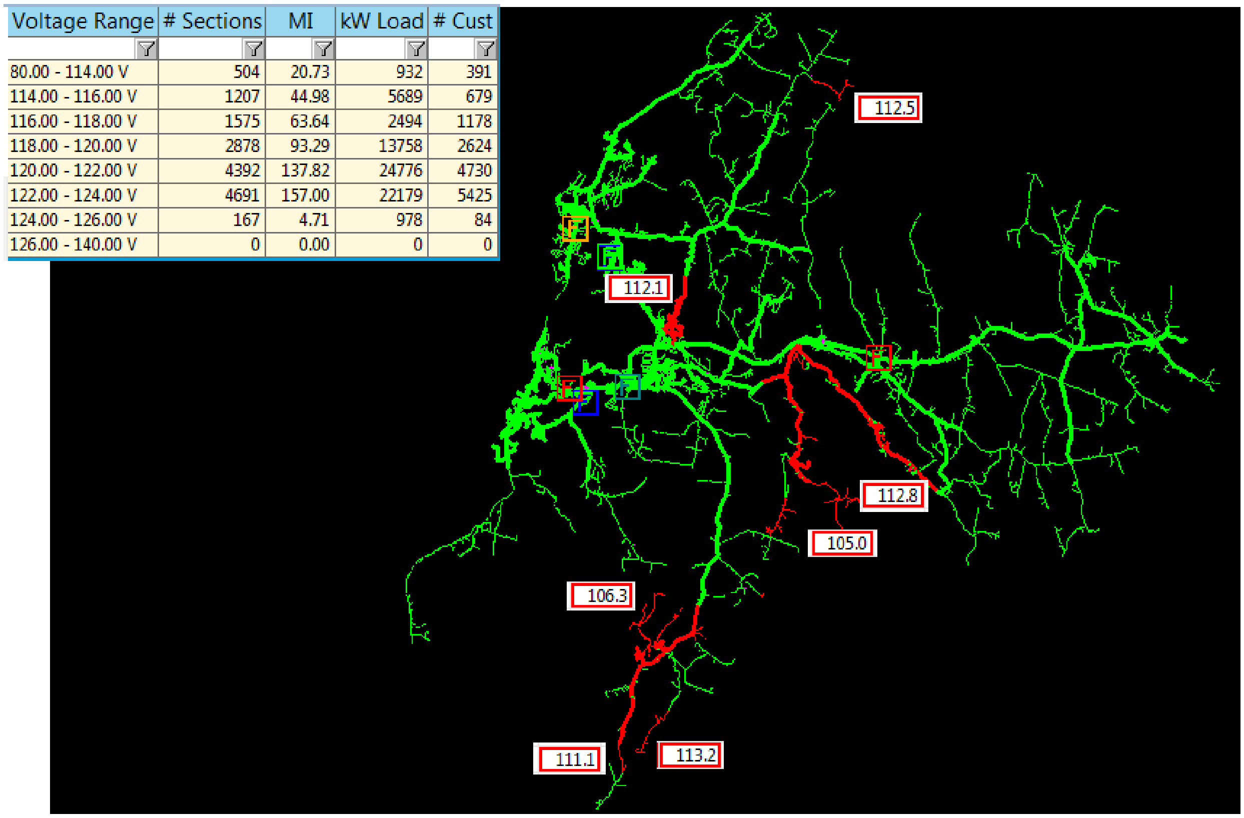
Figure 6 2020 Voltage Performance 1L2 – Normal Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	228	12.18	483	157
114.00 - 116.00 V	405	14.45	465	294
116.00 - 118.00 V	1320	57.05	1411	825
118.00 - 120.00 V	3112	104.47	8895	2487
120.00 - 122.00 V	4359	136.59	21453	4407
122.00 - 124.00 V	5865	193.14	17880	6867
124.00 - 126.00 V	125	4.31	673	75
126.00 - 140.00 V	0	0.00	0	0

The figure below shows the areas where voltage is expected to exceed limits under normal configuration in 2025.

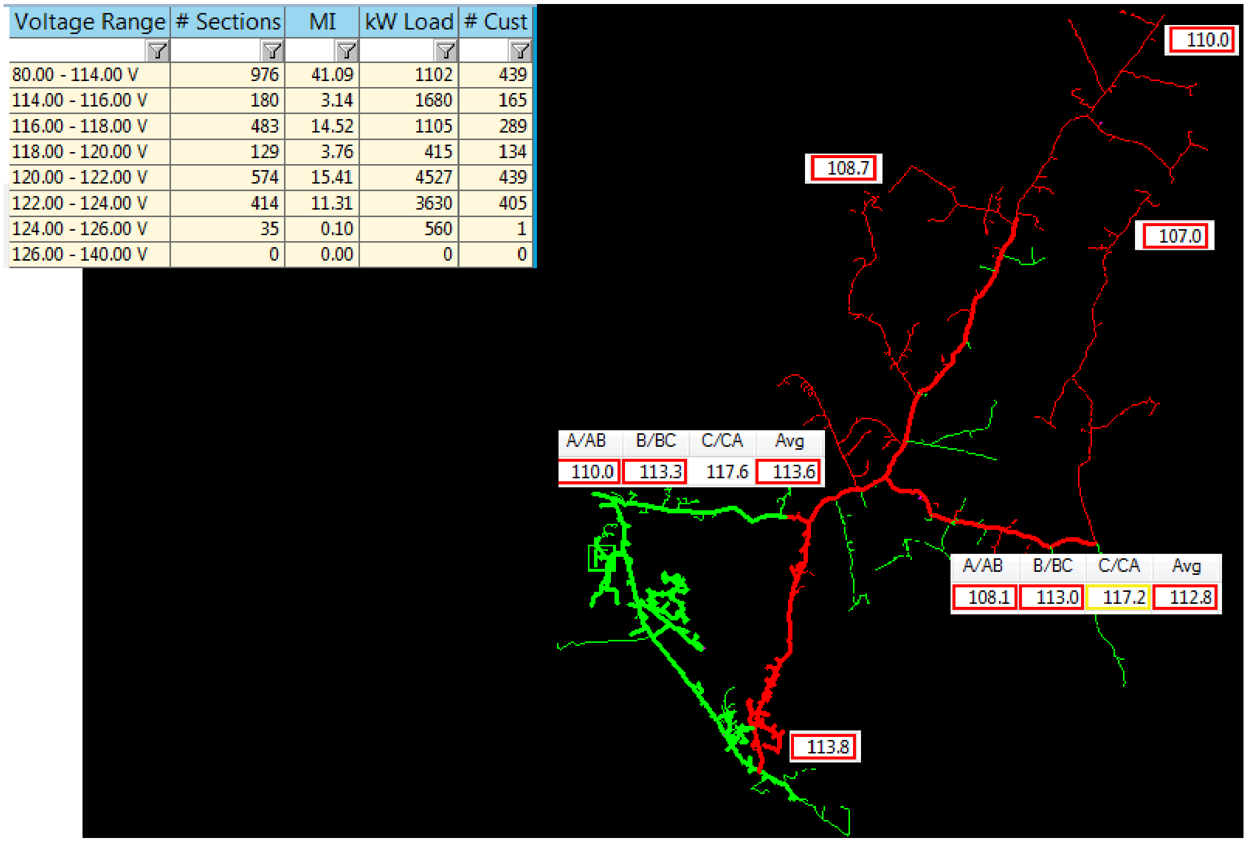
Figure 7 2025 Predicted Voltage Performance 1L2, 16L5, 16L1 – Normal Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	504	20.73	932	391
114.00 - 116.00 V	1207	44.98	5689	679
116.00 - 118.00 V	1575	63.64	2494	1178
118.00 - 120.00 V	2878	93.29	13758	2624
120.00 - 122.00 V	4392	137.82	24776	4730
122.00 - 124.00 V	4691	157.00	22179	5425
124.00 - 126.00 V	167	4.71	978	84
126.00 - 140.00 V	0	0.00	0	0

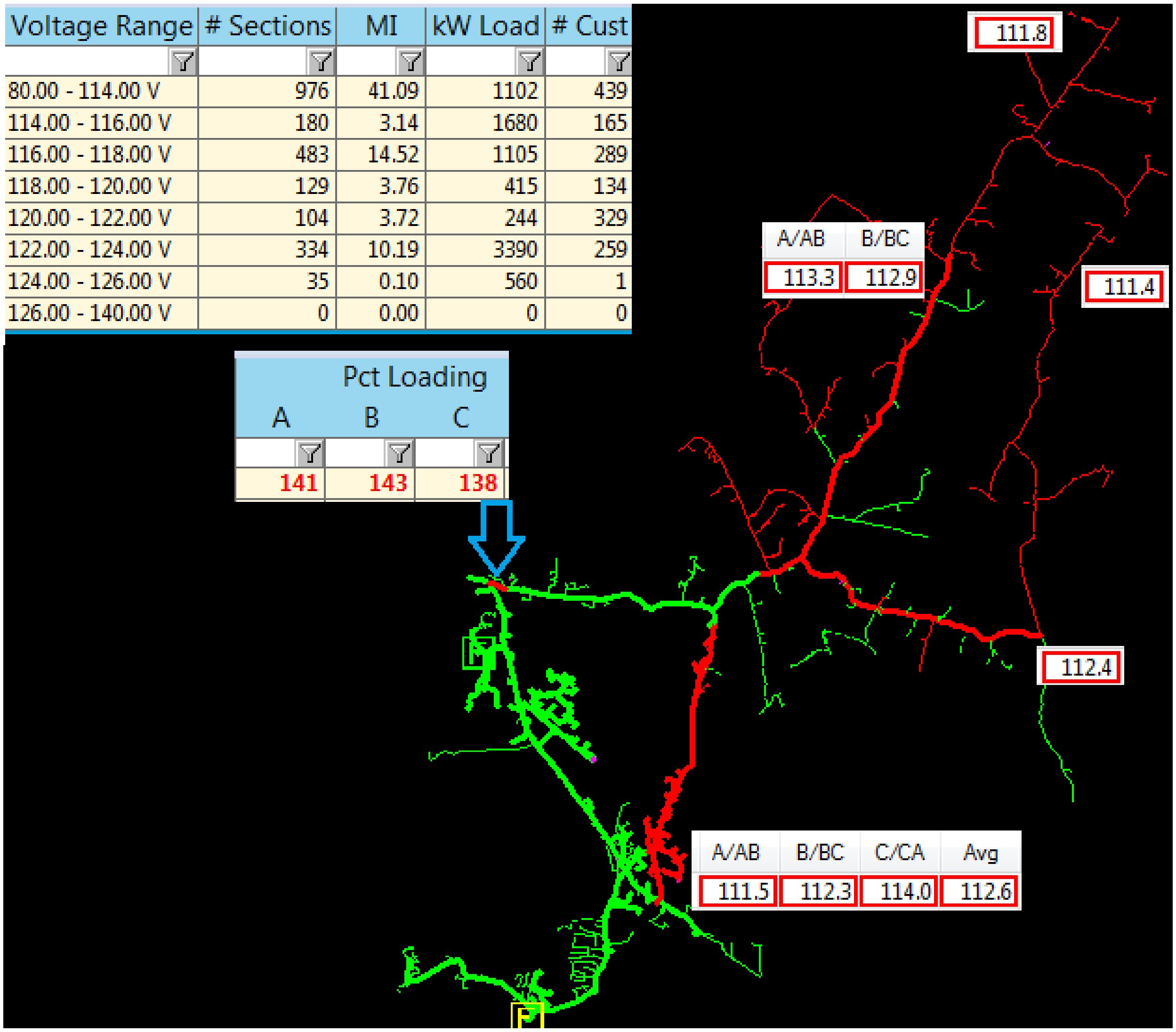
6.5 Appendix E.1 – Voltage Performance Contingency Condition

Figure 8 2020 Voltage Performance 16L1 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	976	41.09	1102	439
114.00 - 116.00 V	180	3.14	1680	165
116.00 - 118.00 V	483	14.52	1105	289
118.00 - 120.00 V	129	3.76	415	134
120.00 - 122.00 V	574	15.41	4527	439
122.00 - 124.00 V	414	11.31	3630	405
124.00 - 126.00 V	35	0.10	560	1
126.00 - 140.00 V	0	0.00	0	0

Figure 9 2020 Voltage Performance 16L5 – Contingency Configuration



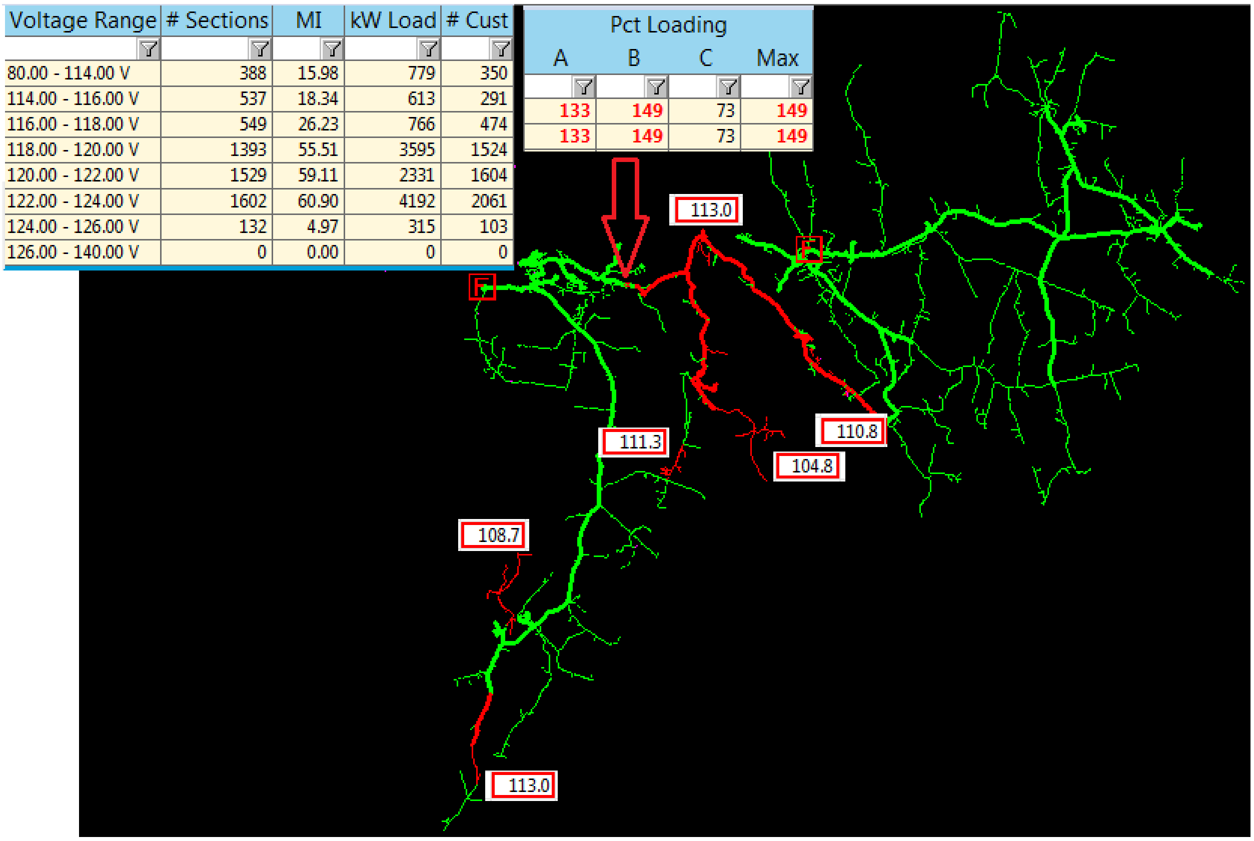
Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	976	41.09	1102	439
114.00 - 116.00 V	180	3.14	1680	165
116.00 - 118.00 V	483	14.52	1105	289
118.00 - 120.00 V	129	3.76	415	134
120.00 - 122.00 V	104	3.72	244	329
122.00 - 124.00 V	334	10.19	3390	259
124.00 - 126.00 V	35	0.10	560	1
126.00 - 140.00 V	0	0.00	0	0

Pct Loading A	Pct Loading B	Pct Loading C
141	143	138

A/AB	B/BC
113.3	112.9

A/AB	B/BC	C/CA	Avg
111.5	112.3	114.0	112.6

Figure 10 2020 Voltage Performance 7L1 or 7L2 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	388	15.98	779	350
114.00 - 116.00 V	537	18.34	613	291
116.00 - 118.00 V	549	26.23	766	474
118.00 - 120.00 V	1393	55.51	3595	1524
120.00 - 122.00 V	1529	59.11	2331	1604
122.00 - 124.00 V	1602	60.90	4192	2061
124.00 - 126.00 V	132	4.97	315	103
126.00 - 140.00 V	0	0.00	0	0

Pct Loading			
A	B	C	Max
133	149	73	149
133	149	73	149

Figure 12 2025 Voltage Performance 7L1 or 7L2 – Contingency Configuration

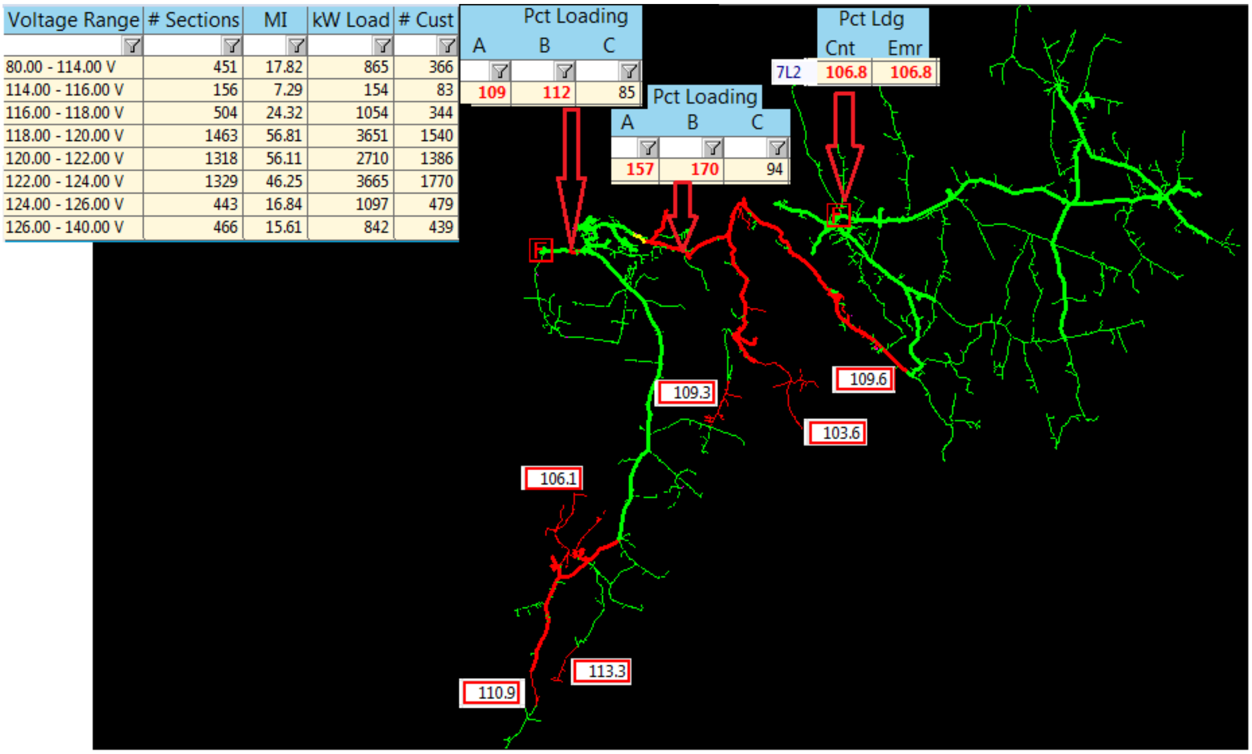


Figure 13 2025 Voltage Performance 16L1 – Contingency Configuration

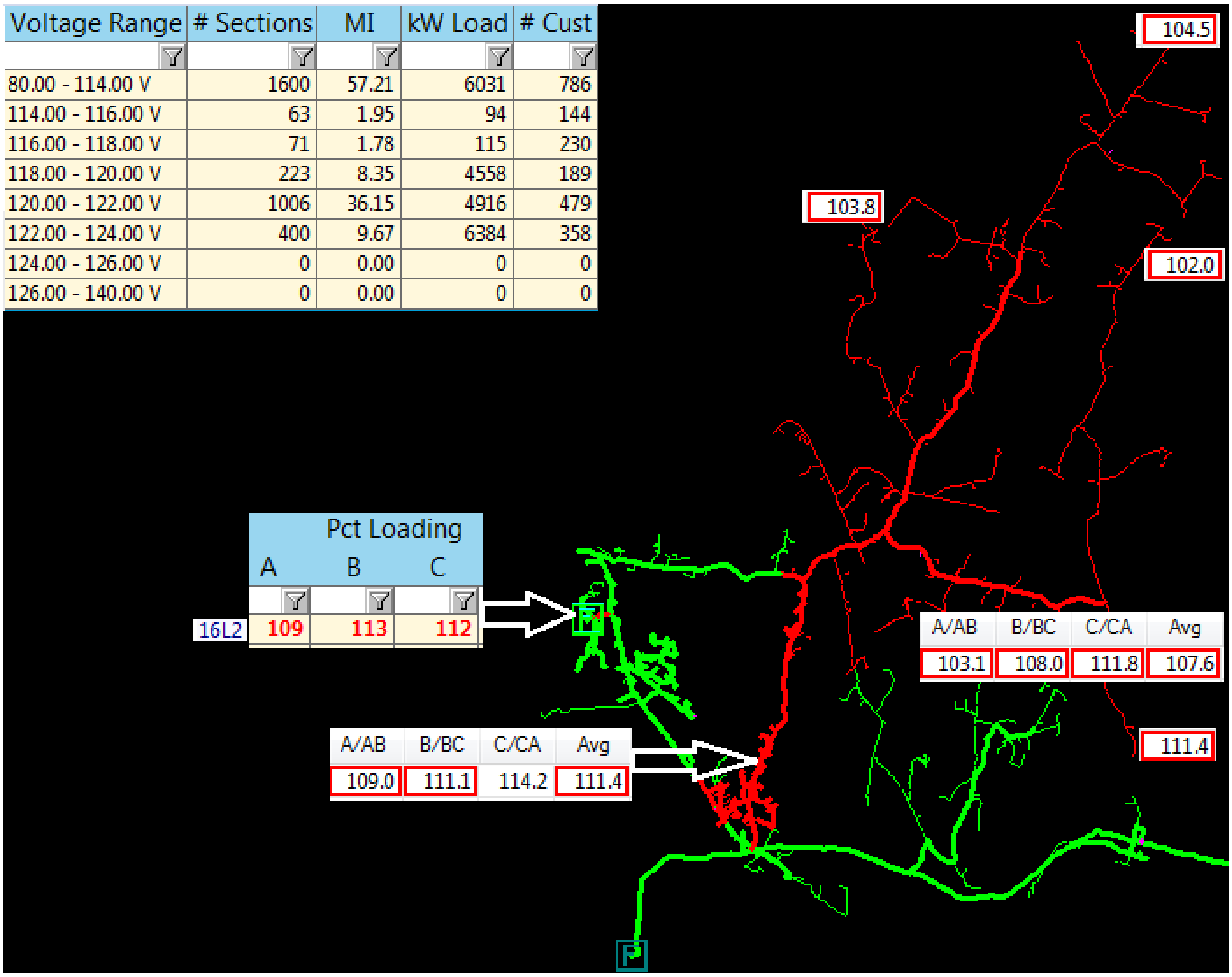
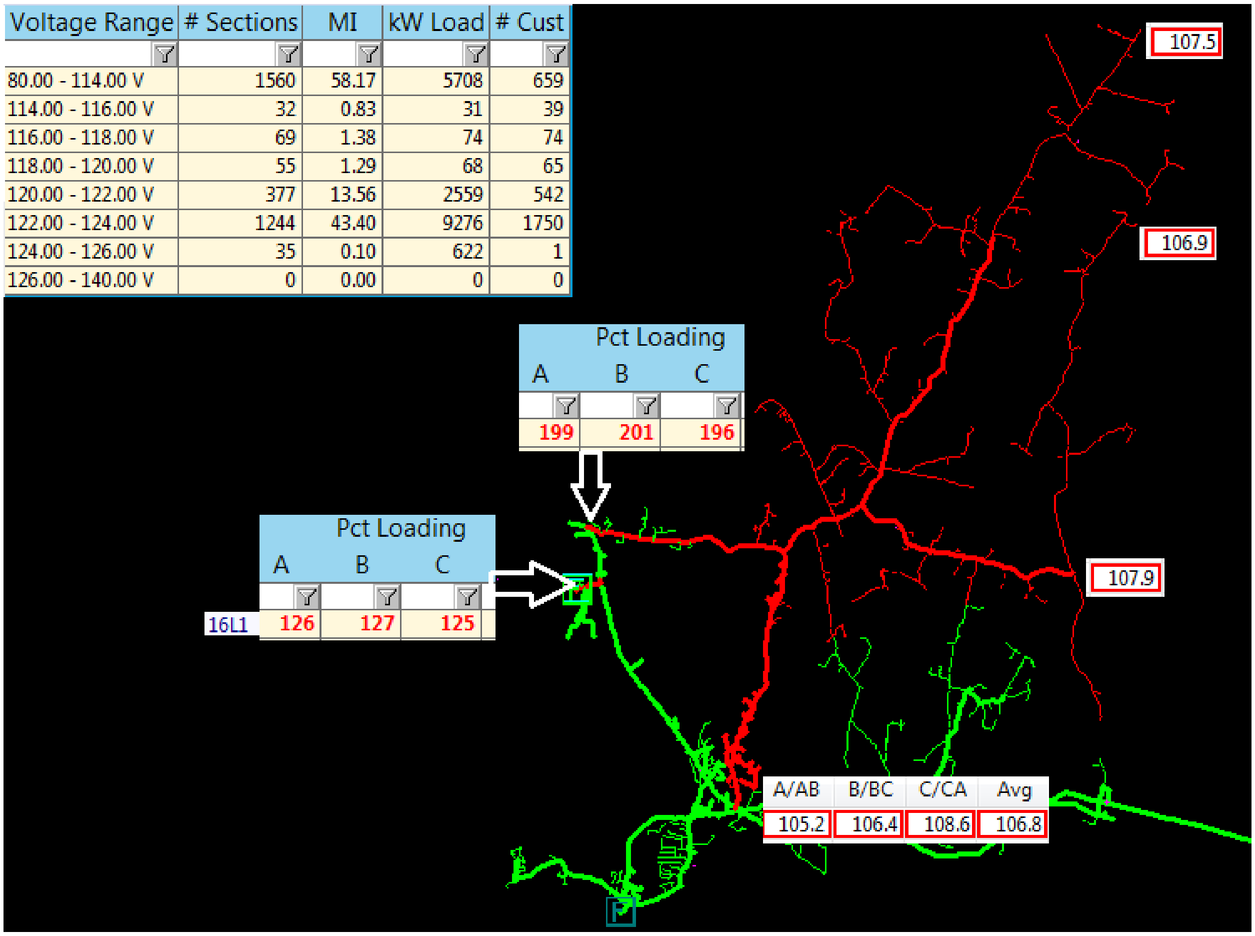


Figure 14 2025 Voltage Performance 16L5 – Contingency Configuration



Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	1560	58.17	5708	659
114.00 - 116.00 V	32	0.83	31	39
116.00 - 118.00 V	69	1.38	74	74
118.00 - 120.00 V	55	1.29	68	65
120.00 - 122.00 V	377	13.56	2559	542
122.00 - 124.00 V	1244	43.40	9276	1750
124.00 - 126.00 V	35	0.10	622	1
126.00 - 140.00 V	0	0.00	0	0

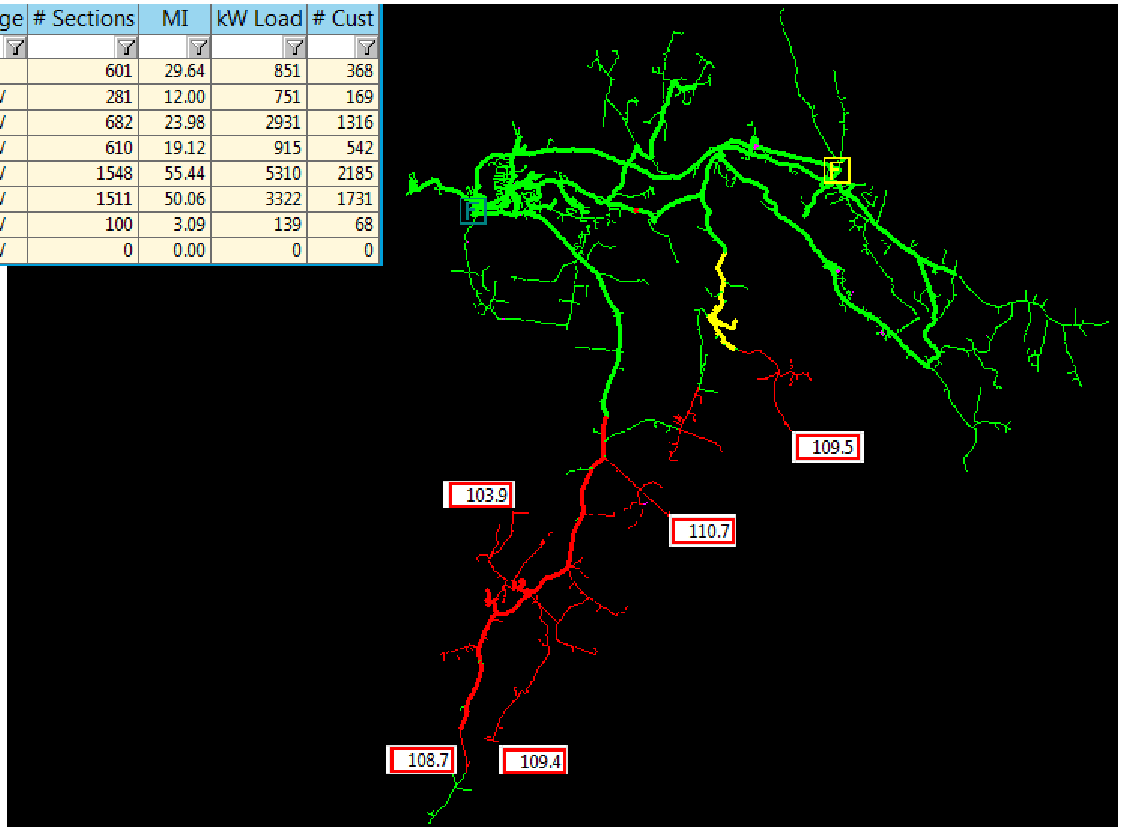
	Pct Loading	
A	B	C
199	201	196

		Pct Loading	
	A	B	C
16L1	126	127	125

A/AB	B/BC	C/CA	Avg
105.2	106.4	108.6	106.8

Figure 15 2025 Voltage Performance 1L2 – Contingency Configuration

Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	601	29.64	851	368
114.00 - 116.00 V	281	12.00	751	169
116.00 - 118.00 V	682	23.98	2931	1316
118.00 - 120.00 V	610	19.12	915	542
120.00 - 122.00 V	1548	55.44	5310	2185
122.00 - 124.00 V	1511	50.06	3322	1731
124.00 - 126.00 V	100	3.09	139	68
126.00 - 140.00 V	0	0.00	0	0



6.6 Appendix F.1 – Lebanon Area Reliability Report

a. Executive Summary

National Grid will be modifying their Wilder #16 substation and introducing a new 13.8 kV supply transformer that will supply Liberty's 1303 and 1304 lines. The new transformer will have a different winding configuration and impedance than the existing and, consequently, fault current contributions will be different.

The existing transformer (3T) will become a backup for the new transformer. This will impact the operation of protective devices on the 1303 and 1304 lines and the protective devices on substations and circuits supplied by those lines.

The 1304 line provides the primary supply to Liberty's Hanover 6L3, Lebanon 1L3 and 1L4 feeders. The Lebanon 1L4 line, in turn, supplies Liberty Electric's Enfield 7L1 circuit. The 1303 line provides the backup supply to Liberty's 1333 and 1363 lines.

The purpose of this Study is to review the Protection Coordination of the impacted protective devices and make recommendations for any required setting changes to mitigate potential issues with safety and mis-operation of protective equipment.

Cost Estimate

The total estimated cost for all required System Modifications is $363,000.

b. System Overview

National Grid's Wilder #16 substation's existing 3T transformer bank, consists of three (3) single phase 12 MVA units, connected to form a three (3) phase bank. Each unit has a 66.4 kV primary and 13.8 kV secondary, with an impedance of Z = 8% on a 12 MVA Base.

The 3T bank has been configured 115 kV Wye Grounded to 13.8 kV delta. The 3T is the current 13.8 kV source for Liberty's 1303 and 1304 lines. The 1304 line normally supplies Liberty's Hanover 6L3, Lebanon 1L3 and Lebanon 1L4 line. The Lebanon 1L4, in turn, supplies Liberty's Enfield 7L1 circuit. The 1303 Line normally does not carry load and is used as a backup for the 1333 and 1363 line.

National Grid's proposed modifications to Wilder #16 will include a new 13.8 kV supply transformer for the 1303 and 1304 lines consisting of a new three phase, 40 MVA, 115 kV Delta to 13.8 kV Wye Grounded supply transformer with an impedance of Z = 13% on a 24 MVA base. The new transformer has a different winding configuration and impedance than the existing supply transformer bank and, consequently, its fault current contributions will be different and will impact the operation of protective devices downstream of it .

i. Short Circuit & Protection Coordination Analysis

The ASPEN OneLiner version 14.3 modeling program was used to model the substations, circuits and protective devices impacted by the new 1303/1304 supply transformer.

Substation and circuit protective devices associated with Liberty's 1303, 1304, 1363, Hanover #6, Lebanon #1, Enfield #7, Mount Support, and Slayton Hill substations were reviewed.

The initial review determined that with the New 13.8 kV supply operational, and with the current settings in place, a good deal of mis-coordination between devices will exist, most protective devices will have much longer clearing times, and some protective devices will not operate for bolted faults that may occur within their zone of protection, which raises safety concerns.

To mitigate these issues, protection equipment and settings were analyzed for normal ("N-0") and contingency ("N-1") conditions at Hanover #6, Lebanon #1, and Enfield #7 substations and circuits, for both the existing and proposed new 13.8 kV supply at Wilder #16.

The ideal goal was to make all relayed protectives able to clear an end of zone bolted faults within one (1) second while maintaining adequate coordination with other series protective devices. Some leeway was given to the preferred 1.0 second or less end of zone clearing time due to the low fault current levels predicted on some of the impacted circuits. However, coordination between devices is maintained without the need for alternate settings for N-1 conditions.

The analysis determined that the existing grounding banks at the Hanover #6 and Lebanon #1 substations should remain in service, even with the new 13.8 kV Wilder #16 Supply's ability to source zero sequence fault current. These grounding banks are needed to facilitate sensing end of zone line to ground faults on the associated circuits, otherwise these faults may not be detected and cleared in in an acceptable manner.

The analysis also determined that a single set of protective device settings can be used for normal, N-1, and for both the existing and new 13.8 kV supply conditions. This will allow Liberty to perform necessary setting changes in anticipation of the changes at the Wilder Substation which are expected to be completed in the fourth quarter of 2024. Protective device modifications will be implemented at the substation level first then sequentially on downstream protective devices.

➢ Wilder #16

The Wilder #16 substation protective devices and settings associated with the 1303 and 1304 lines are National Grid's responsibility. Liberty provides any recommended settings changes for the Hanover #6, and Lebanon #1 substation breakers to enable National Grid to coordinate with those settings.

- **Hanover #6**

The Hanover 6L3 circuit is normally supplied by the Wilder 1304 line, the backup supply is the Mount Support 1363 line. Setting changes and protective device modifications are recommended due to the impact of the new 13.8 kV supply transformer and from the addition transformation proposed at CRREL (Primary Metered Customer expanding to 9.5 MVA total). These modifications include the following:

- Hanover #6 Substation 1363/Bus 1 and 1304/Bus 2 setting changes.
- Hanover 6L2:
  - Hanover #6 Substation 6L2 Recloser setting changes (to coordinate with 1363/B1 setting changes)
  - 6L2 PTR Pole #2-50 W. Wheelock Rd, Hanover (to coordinate with 1363/B1 setting changes)
- Hanover 6L3:
  - Hanover #6 Substation 6L3 Recloser setting changes (can coordinate with 100K).
  - 6L3 PTR Pole #2 West Lebanon Rd, Hanover setting changes.
  - 6L3 PTR Pole #3 Lyme Rd, Hanover setting changes (can coordinate with 100K).
  - 6L3 Cooper Form 3A PTR Pole #40-1 Lyme Rd replacement with Viper/SEL 651R control and new settings (CRREL PCC recloser). This replacement is required to allow coordination with the 6L3 PTR Pole #3 Lyme Rd.

- **Lebanon #1**

The Lebanon 1L3 and 1L4 circuits are normally supplied by the 1304 line, with the backup supply is the Slayton Hill 1313 Line. The #1 Lebanon 1L1 and 1L2 are normally supplied by the Slayton Hill 1313 Line, with backup provided by the Wilder 1304 line, refer to Figures 2 & 5 Appendix A. The following protection modifications are recommended:

- Lebanon #1 Substation 1L1 setting changes (can coordinate with 100K and Slayton Hill).
- 1L1 PTR Pole #152.5 Enfield R.O.W. setting changes, add reclosing, replaces Enfield 7L2 (can coordinate with 100K).[1]

- 1L1/1L4 PTR Pole # 155-1 Enfield R.O.W. setting changes,
- Lebanon #1 Substation 1L2 setting changes (can coordinate with 100K and Slayton Hill).
- 1L2 PTR Pole #18 School St Lebanon setting changes (can coordinate with 80K).
- 1L2 PTR Pole #141 Plainfield Rd Plainfield setting changes (can coordinate with 80K).
- 1L2 PTR Pole #36 Bank St Lebanon setting changes (can coordinate with 100K).
- 1L2 PTR Pole #33 Eastman Hill Lebanon setting changes (can coordinate with 100K).
- 1L2 PTR Pole #6 Route 4A Lebanon setting changes (can coordinate with 65K).
- 1L2 PTR Pole #106 Shaker Hill/Bishop Ln Enfield setting changes (can coordinate with 65K).
- Lebanon #1 Substation 1L3 setting changes (can coordinate with 100K).
- Lebanon #1 Substation 1L4 setting changes (can coordinate with 100K).
- 1L4 PTR Pole #154 Enfield R.O.W. Lebanon setting changes, replaces Enfield 7L1 (can coordinate with 80K).1

➢ **Enfield #7**

The Enfield 7L1 is normally supplied by the Lebanon 1L4 circuit and the Enfield 7L2 is normally supplied from the Lebanon 1L1 circuit. There is a distribution automation scheme between the 1L1 and 1L4 to provide backup to both the 7L1 and 7L2 for loss of either supply involving PTRs on Poles #s 152.5, 154, and 155-1 (N.O.P) in the Enfield R.O.W.

There is also a loop scheme between the 1L2 and 7L2 involving the N.O.P., 1L2 PTR on Pole #106 Shaker Hill/Bishop Ln Enfield and the 7L2 PTR Pole #8 South St, Enfield, where the 1L2 picks up a portion of the 7L2 up to the Pole #8 PTR.

Due to the limitations of the existing Cooper Form 3A recloser controls used on both the 7L1 and 7L2 breakers and their proximity to the Enfield R.O.W PTRs on Pole #152.5 and 154, It is recommended that the existing 7L1 and 7L2 breakers be retired. Protection of the 7L1 can be taken over by the 1L4 PTR on Pole # 154 and 7L2 protection can be handled by the 1L1 pole # 152.5 PTR, both in the Enfield R.O.W. Recommended protection modifications are as follows:

- 7L1 breaker Bypass remove from service, refer to 1L4 PTR Pole #154 setting changes.
- 7L2 breaker Bypass remove from service, refer to 1L1 PTR Pole #152.5 setting changes.
- 7L1 PTR Pole #150-50 Route 4 Canaan setting changes (can coordinate with 80K).
- 7L1 new PTR in vicinity of Pole #63 John Roberts Rd Canaan and new settings, to replace 100 K fuse (can coordinate with 80K). This new recloser is required to allow coordination with the 7L1 PTR Pole 150-50 Route 4 and to improve the coordination further downstream at the Cardigan Mtn School Canaan.
- 7L2 PTR Pole #8 South St Enfield setting changes (can coordinate with 80K).

ii. Alternatives

The existing protection device settings were developed to accommodate the fault current levels associated with the existing Wilder # 16, 13.8 KV supply, the proposed new 13.8 kV Wilder supply will deliver less fault current ,which will impact the operation of all the protective devices on all the circuits it ultimately supplies. If no action is taken, protective devices may not operate as intended, possibly impacting system reliability and the safety of both line personal and the public.

iii. Cost Estimates

The cost planning grade estimate for the Company’s work associated with mitigating coordination and protection issues associated with the changes at the Wilder Substation, as identified in this report, are $360,000 +/-25%, and includes the breakdown of items listed in Table 1 below:

Table 1: Protection Cost Estimates +/-25%

Work Item		Conceptual Cost +/-25% Planning Grade Cost Estimate			Total Customer Costs
	System Modifications Liberty Utilities	Capital	O&M	Removal	Total $
1	Retire existing 7L1 and 7L2 breakers at Enfield Substation	$0	$0	$150,000	$150,000
2	Install new 6L3 Recloser at P40-1 Lyme Rd	$70,000	$0	$5,000	$75,000
3	Install new 7L1 Recloser at P63 John Roberts Rd	$70,000	$0	$5,000	$75,000
4	Remove 3-65K fuses at Pole #38 John Roberts Rd. Remove 3-50K fuses at Pole 2 Back Bay Rd. Remove 3-30K fuses at Pole 9-3 Back Bay Rd Install 3-80K fuses at Pole #38 John Roberts Rd. Install 3-65K fuses at Pole 2 Back Bay Rd. Install 3-50K fuses at Pole 9-3 Back Bay Rd	$0	$5,000	$0	$5,000
5	Reprogram relay setting changes & test Hanover #6 B1. Reprogram relay setting changes & test Hanover #6 B2. Re-program relay setting changes & test 6L2 Circuit Breaker Re-program relay setting changes & test 6L2 P2 -50 West Wheelock Rd Recloser Re-program relay setting changes and test 6L3 Circuit Breaker Re-program relay setting changes and test 6L3 P2 West Lebanon Rd Recloser Reprogram relay setting changes and test 6L3 P3 Lyme Rd Recloser	$0	$10,500	$0	$10,500
6	Re-program relay setting changes and test 1L1 Circuit Breaker Re-program relay setting changes and test 1L1 P152-50 Enfield ROW Recloser Re-program relay setting changes and test 1L1/1L4 P155-1 Enfield ROW Tie Recloser	$0	$4,500	$0	$4,500
7	Re-program relay setting changes and test 1L2 Circuit Breaker Re-program relay setting changes and test 1L2 P18 School St Recloser Re-program relay setting changes and test 1L2 P141 Connecticut Valley Hwy Recloser Re-program relay setting changes and test 1L2 P36 Bank St Recloser Re-program relay setting changes and test 1L2 P33 Route 4 Recloser Re-program relay setting changes and test 1L2 P6 Route 4A Recloser	$0	$9,000	$0	$9,000
8	Re-program relay setting changes and test 7L2 P8 South St Recloser Re-program relay setting changes and test 7L2/1L2 P106 Shaker Hill Rd Tie Recloser Re-program relay setting changes and test 7L1 PTR 15050 Route 4 Recloser	$0	$4,500	$0	$4,500
9	Re-program relay setting changes and test 1L3 Circuit Breaker Re-program relay setting changes and test 1L4 Circuit Breaker Re-program relay setting changes and test 1L4 P154 Enfield ROW	$0	$4,500	$0	$4,500
10	Engineering and Supervision Cost	$15,000	$5,000	$5,000	$25,000
	Totals	$155,000	$43,000	$165,000	$363,000

iv. Conclusion

Analysis concludes that certain protective device modifications are recommended to ensure proper protective device operation and coordination, as a result of National Grid's proposed addition of a new 13.8 kV supply transformer that supplies Liberty's 1303 and 1304 lines.

Additionally, the Hanover 6L3 circuit also is impacted by CRREL'S proposed facility expansion to include up to 9.5 MVA of Connected transformation. The recommended settings and protective device modifications, discussed in detail in the preceding Protection Review section, are acceptable for use with either the existing Wilder #16 13.8 KV supply or the proposed new 13.8 kV supply in service for both normal and N-1 contingencies. This affords Liberty some flexibility in its ability to schedule the implementation of protection modifications prior to National Grid's proposed Wilder #16 13.8 kV supply changes. The estimated planning grade cost for the Company's work associated with the Project is $363,000, +/- 25%.

1 ## 6.7 Appendix G.1 – NWS Project Analysis

NWA EVALUATION SUMMARY

11/2/2020

PROJECT NAME: Craft Hill 11L1

Project Need Year: 2023

Brief Project Description/need:

The Craft Hill 11L1 feeder is projected to be loaded to 109% of its summer normal rating in 2025 mainly due to a proposed new commercial development in West Lebanon NH.

Project Scope	Option
Load transfer to Lebanon 1L3 circuit	1
Install new Slayton Hill 39L4 feeder	2
PV with storage	3
DER - Large Customer	4

Scoring Values

Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Comments
Total Cost	30%	4	3	1	2	
Reliability Risk	20%	1	3.6	2.7	2.7	
Feasibility Risk	20%	3.25	3.65	2.3	2.65	
Performance Risk	20%	2	3.6	2.85	2.95	
Enviromental Risk	10%	4	3	2.25	3.5	
Total Assessment	**100%**	**2.85**	**3.37**	**2.10**	**2.61**	
	Ranking	2	1	4	3	

PROJECT NAME: Craft Hill 11L1
11/2/2020

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Customer Outage Experience	50%	1	4	2	2
Automated Restoration	30%	1	4	3	3
Power Quality	20%	1	2	4	4
Totals	**100%**	**1**	**3.6**	**2.7**	**2.7**
	Ranking	**4**	**1**	**2**	**2**

PROJECT NAME: Craft Hill 11L1
11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Likelihood of Timely Completion	35%	4	3	2	2
Predictable Long Term Solution	25%	1	4	2	3
Historical Field Experience	10%	4	4	2	3
Uncertainty	30%	4	4	3	3
Totals	**100%**	**3.25**	**3.65**	**2.3**	**2.65**
	Ranking	**2**	**1**	**4**	**3**

PROJECT NAME: Craft Hill 11L1
11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Availability	25%	3	4	3	3
Operability	20%	1	4	3	3
Required Maintenance	10%	4	3	1	2
Aligns with Company Goals	15%	1	2	4	4
Capacity Provided - Demand	20%	1	4	3	3
Capacity Provided - Hosting	10%	3	4	2	2
Totals	**100%**	**2**	**3.6**	**2.85**	**2.95**
	Ranking	**4**	**1**	**3**	**2**

PROJECT NAME: Craft Hill 11L1

11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	**Weighing Factor**	**Option 1**	**Option 2**	**Option 3**	**Option 4**
Wetland Impact	25%	4	4	4	4
Tree Clearing	25%	4	2	1	4
Community Impacts	25%	4	3	3	4
Municipal Impacts	25%	4	3	1	2
Totals	**100%**	**4**	**3**	**2.25**	**3.5**
	Ranking	**1**	**3**	**4**	**2**

Reliability Review 2020

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1.0 Executive Summary

The purpose of this document is to report on the overall reliability performance of the Liberty Distribution System for calendar year 2019. This report identifies root cause and locations within the distribution system that are experiencing repeated interruptions. The information is summarized for each Area, feeder and poor performing sub sections of the feeders, including smaller pockets supplied by fuses.

In 2019, tree related interruptions contributed to approximately 50% of the reliability performance of the Company. In addition interruptions in radial areas contributed to approximately 40% of the SAIDI performance of the Company. The project recommendations made in this report support the Company's reliability and resiliency initiatives to reach top quartile performance and improve the resiliency of the distribution system.

Reliability metrics for CY2019 are presented in the table below based on both the PUC Standard[1] for excluding major weather events and the IEEE Standard 1366[2] method for excluding major event days. The metrics presented also exclude transmission supply outages, planned or notified outages, and all other applicable exclusions[3]. The metrics include customers interrupted ("CI"), customer minutes interrupted ("CMI"), system average interruption frequency index ("SAIFI"), system average interruption duration index ("SAIDI"), customer average interruption duration index (CAIDI), and customers interrupted per interruption index (CIII).

[1] PUC Major Storm: [(CI >= 15 % of Customers Served and 30 concurrent events) or (45 concurrent events)], Using PUC criteria, six days were excluded in Calendar Year 2019: January 9, October 16-18 and October 31 – November 1.

[2] IEEE Major Event Days: Using IEEE criteria, no days were excluded in Calendar Year 2019.

[3] Events that are excluded are those involving loss of supply from another utility, customer-owned facilities, fire or police emergencies, load shedding, planned maintenance, events whose duration was 5 minutes or less and/or events which involve only one customer.

No Exclusions								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	650	41,337	5,178,620	44,784	0.9236	115.689	125.28	63.60

Excludes Only IEEE Major Events								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	650	41,337	5,178,620	44,784	0.9236	115.689	125.28	63.60

Excludes Only PUC Major Events								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	485	31,467	3,522,934	44,784	0.7031	78.757	111.96	64.88

Excludes Only Loss of Supply by Other Utility or Transmission Outage								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	650	41,337	5,178,620	44,784	0.9236	115.689	125.28	63.60

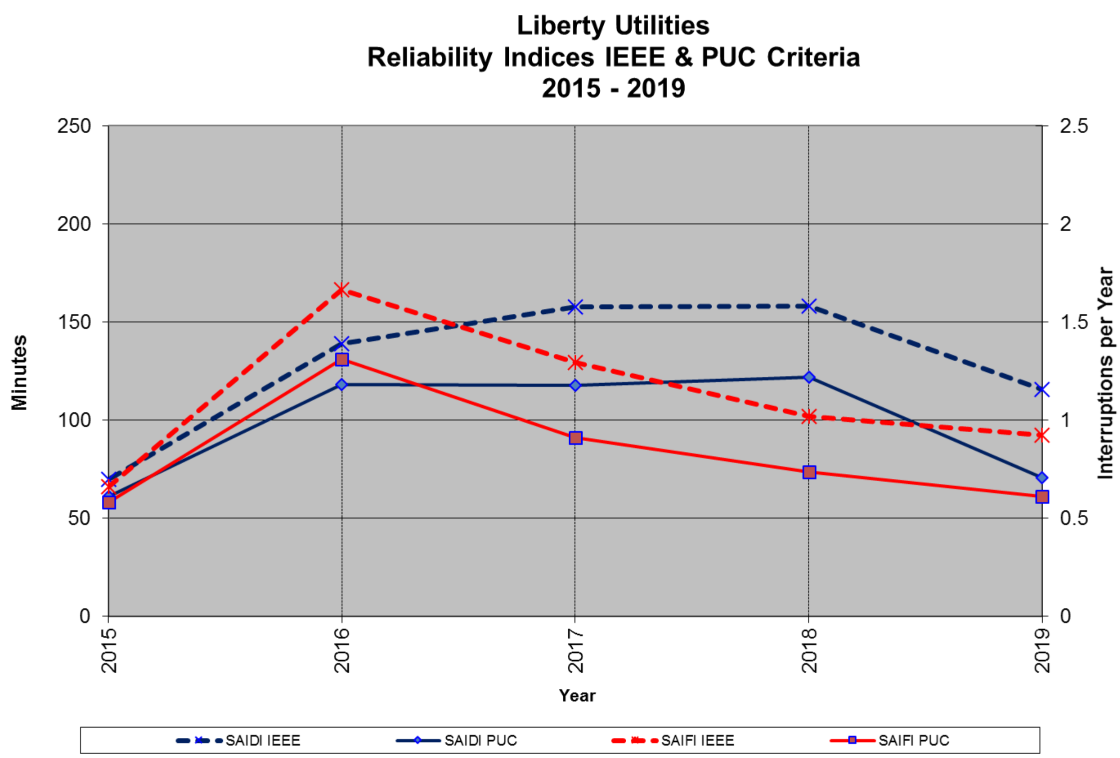
Excludes Only Planned Maintenance								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	589	40,520	5,141,462	44,784	0.9053	114.861	126.89	68.79

All Exclusions: IEEE Major Events, loss of supply, transmission, planned maintenance, Load Shedding, Single Customer Outages, Fire/Police Request								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	515	37,139	4,817,005	44,784	0.8298	107.6070	129.70	72.11

All Exclusions: PUC MEDs, loss of supply, transmission, planned maintenance, Load Shedding, Single Customer Outages, Fire/Police Request								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	350	27,269	3,161,319	44,784	0.6094	70.675	115.93	77.91

The historical reliability performance for the Company for the time period from 2015–2019 is outlined in Figure 1 below. This chart displays annual SAIDI and SAIFI performance using IEEE-1366 and PUC criteria.

Figure 1 Liberty Utilities 5 Year Reliability Performance

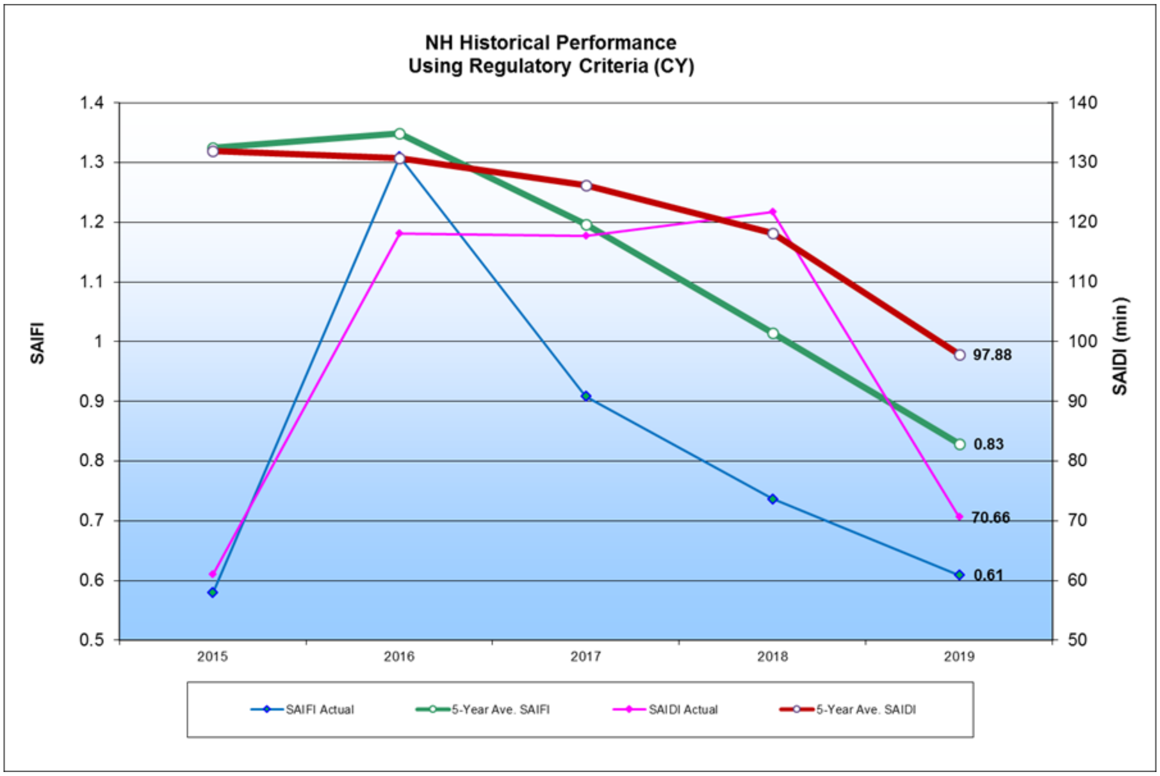


In terms of both SAIDI and SAIFI, the reliability performance for the Company in 2019 (based on IEEE-1366) was the second best performance in the last five years. The SAIDI performance of 115.64 minutes in 2019 is lower than the five-year average of 128 minutes. The SAIFI performance of 0.923 is lower than the five-year average of 1.11 minutes.

Liberty's annual reliability targets are determined by calculating the average of the previous five year SAIDI and SAIFI performance.

As shown on Figure 2 below, based on PUC criteria, the SAIFI performance of 0.61 and the SAIDI performance of 70.66 for CY2019 continue on an improving, downward trend, with the 2019 SAIFI and SAIDI results being the second best in twenty years. Only calendar year 2015 resulted in a lower SAIFI and SAIDI performance.

Figure 2 Liberty Utilities 5 Year Rolling Average Reliability Performance



In summary, Liberty met its SAIFI and SAIDI targets of 1.01 and 118.17 minutes, respectively, which are based on a five-year rolling average and has done so for five consecutive years (2014-2019). Liberty expects this overall positive performance in SAIFI and SAIDI to continue as further positive impacts from our reliability and vegetation management initiatives are experienced.

2.0 Reliability Performance

2.1 Performance vs. Goals

Figure 3 Liberty Quarterly SAIFI Performance

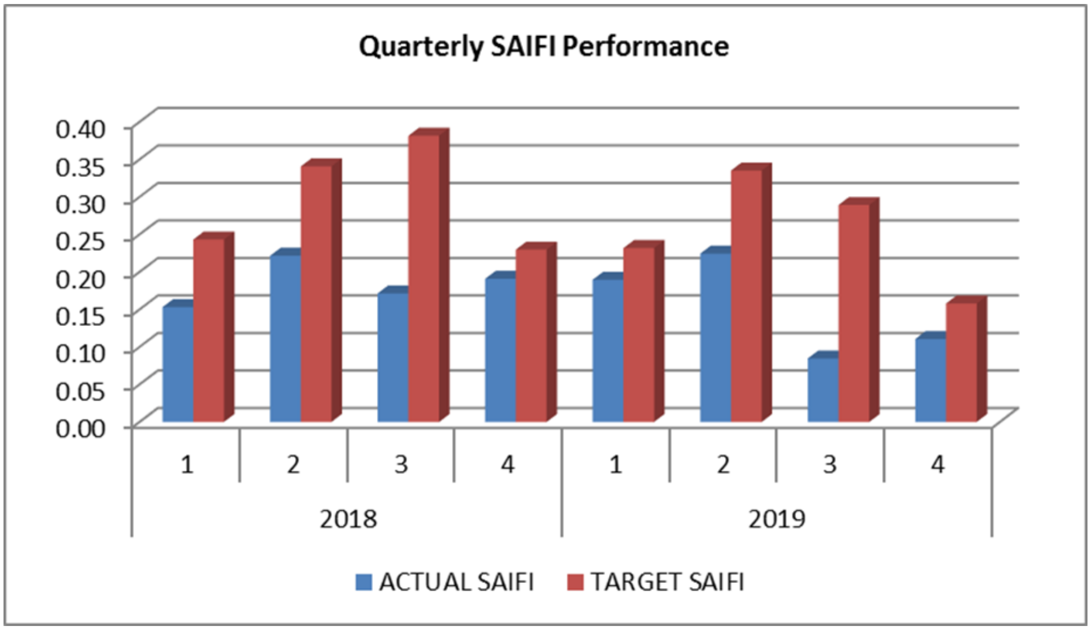
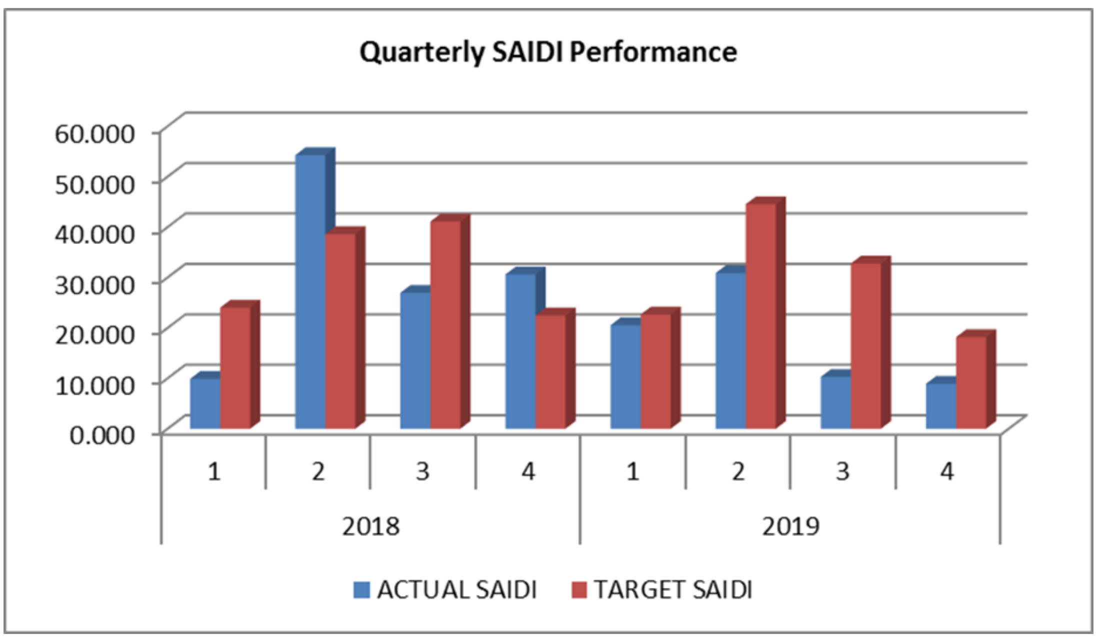


Figure 4 Liberty Quarterly SAIDI Performance



2.3 Reliability Results by Area

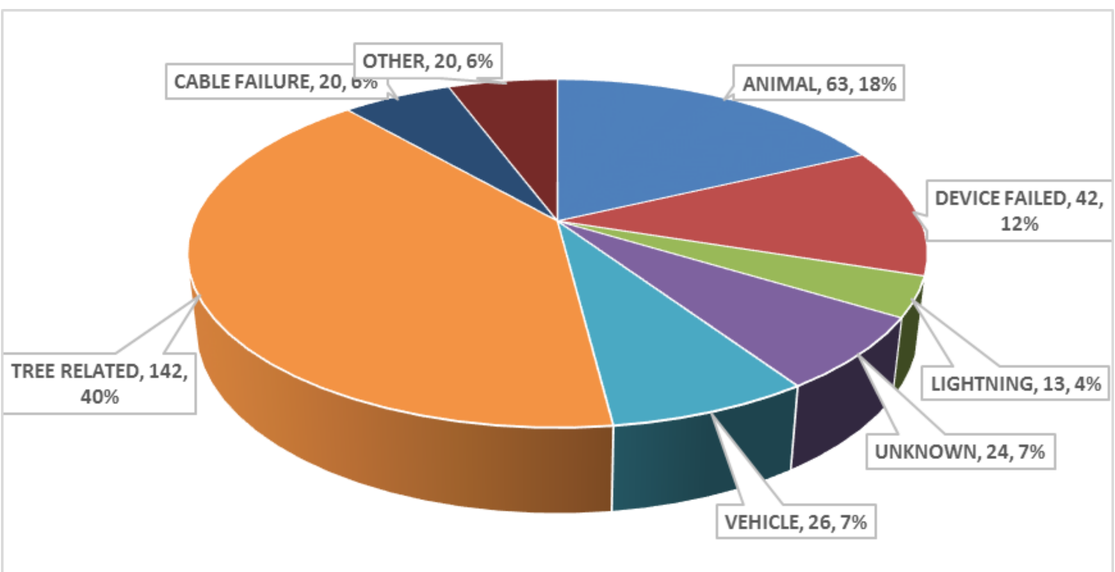
Table 2: Liberty Utilities Reliability Performance by Area

2019 CALENDAR YEAR TARGETS						
NH Regulatory Criteria (Calendar Year)	SAIFI		SAIDI (mins)		CAIDI (mins)	
	Target	Results	Target	Results	Target	Results
SALEM AREA	0.479	0.271	45.998	27.08	96.06	99.83
LEBANON AREA	0.376	0.232	45.170	22.74	120.09	98.14
BELLOWS FALLS AREA	0.159	0.104	26.998	19.56	169.47	188.19
TOTAL	1.014	0.609	118.17	70.66	116.50	115.97

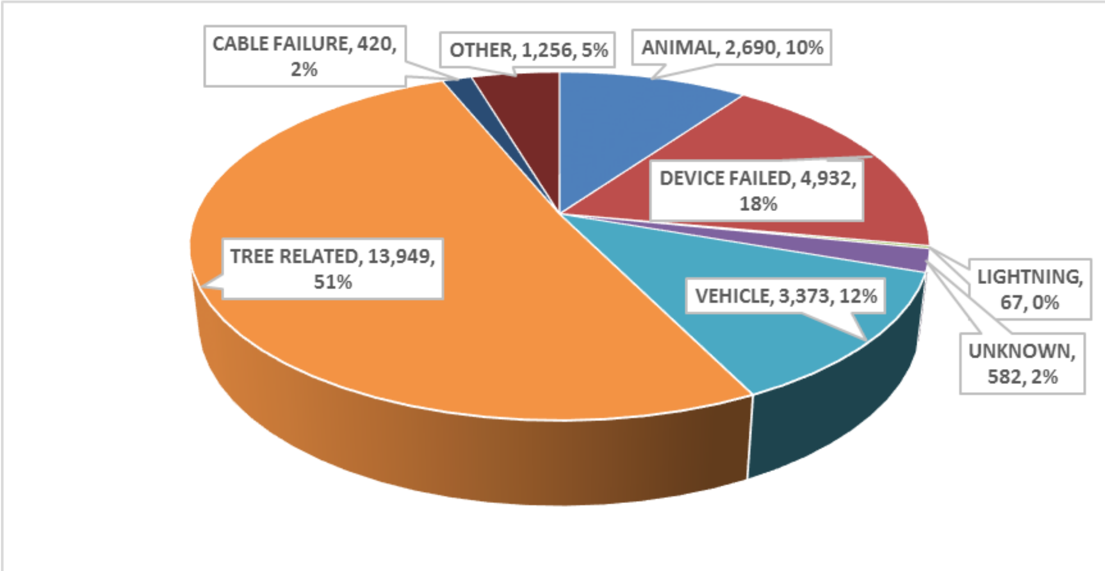
3.0 Interruptions by Cause

This section provides a breakdown of all outages by cause code experienced during 2019. Figures 5, 6 and 7 show the number of interruptions, customers interrupted and customer minutes interrupted by cause, respectively. Tree related incidents contribute to over 50% of the reliability performance for the Company.

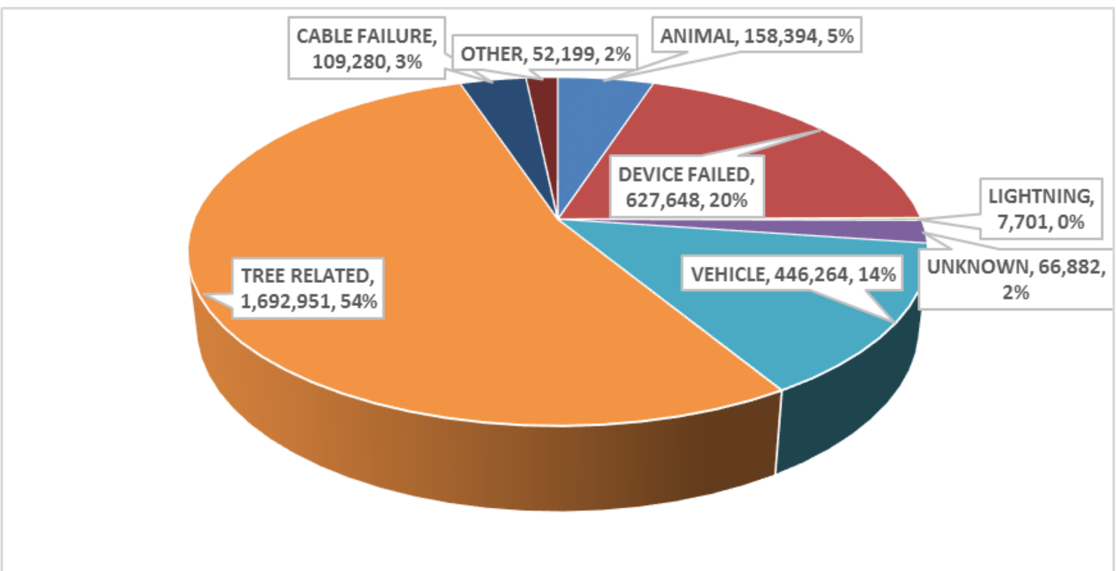
Figure 5 Number of Interruptions by Cause



1 Figure 6 Customers Interrupted by Cause



2 Figure 7 Customer Minutes Interrupted by Cause



4.0 Interruptions by Tree Related Events

4.1 2019 Tree Related Reliability Performance

The tree related reliability performance during the time period from January 1, 2019 through December 31, 2019 is summarized by area in Table 3 below.

Table 3: 2019 Tree Related Reliability Performance

2019	BELLOWS FALLS		LEBANON		SALEM			
	TREE - BROKEN LIMB	TREE FELL	TREE - BROKEN LIMB	TREE FELL	TREE - BROKEN LIMB	TREE FELL	TREE GROWTH	VINES
# of Events	12	20	30	33	18	26	1	2
CI	463	1,117	3,985	3,581	2,847	1,919	29	8
CMI	25,608	206,122	442,193	327,547	311,478	378,271	928	804
SAIFI	0.01	0.02	0.09	0.08	0.06	0.04	0.00	0.00
SAIDI	0.57	4.60	9.90	7.33	6.97	8.46	0.02	0.02

The wind and weather statistics of the tree related interruptions is shown in the tables below. Table 4 summarizes the tree related incident results by wind strength and Table 5 by weather events. Strong winds over 32 mph contributed to 46% of the customer minutes interrupted. In addition weather events contributed to 46% of the customers interrupted.

Table 4: 2019 Tree Related Reliability Performance by Wind Strength

Wind Strength	# of Incidents	Customers Interrupted	Customers Minutes Interrupted
2-Wind-Strong (32-54 mph)	37	4,788	773,849
0-Calm to Light Wind (0-12 mph)	74	6,154	726,885
1-Moderate Wind (13-31 mph)	28	2,970	190,485

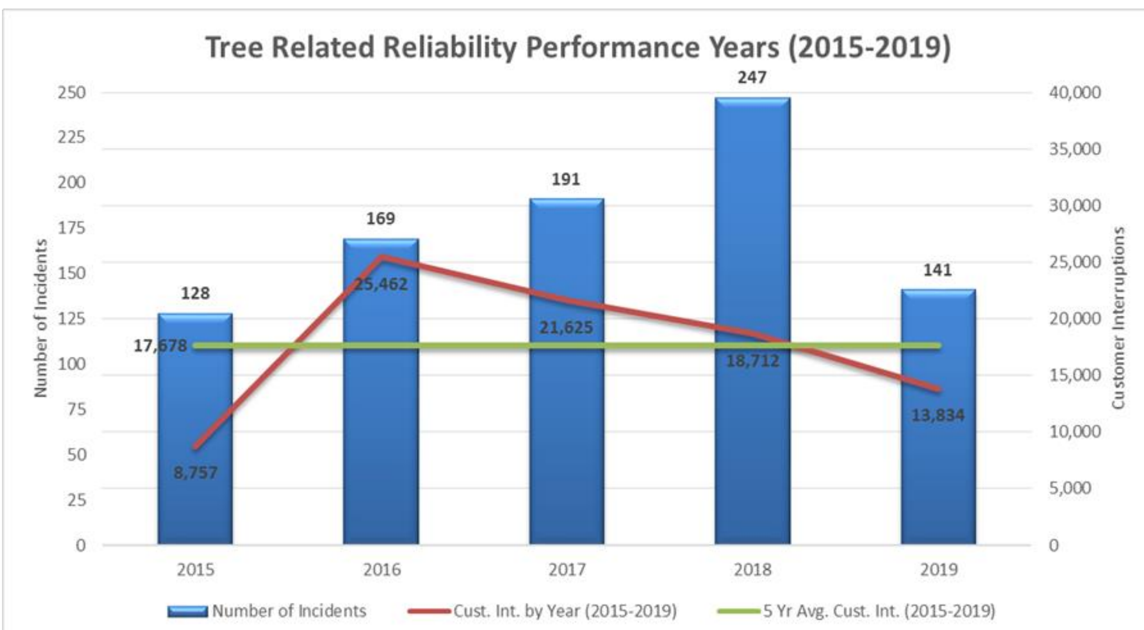
Table 5: 2019 Tree Related Reliability Performance by Weather Event Type

Weather Events	# of Incidents	Customers Interrupted	Customer Minutes Interrupted
1-Clear/Cloudy	88	7,565	989,707
2-Rain-light/Moderate	40	4,938	557,748
3-Rain-Heavy	5	969	114,724
7-Snow-wet	4	378	24,280
6-Snow-dry	2	62	4,760

4.2 2015-2019 Tree Related Reliability Performance

The tree related reliability performance for the Company was reviewed using regulatory criteria. Figure 8 below displays the number of tree related incidents per year and the number of customers interrupted from tree related incidents from 2015 to 2019. For comparison the five-year average of number of customers interrupted from tree related incidents is also shown.

Figure 8 Customer Minutes Interrupted by Cause



a. Tree Related Performance – Lebanon Area

The tree related reliability performance of the Lebanon Area feeders during the time period from January 1, 2015 through December 31, 2019 is summarized in Table 6 below[4]. These are ranked by circuit SAIFI.

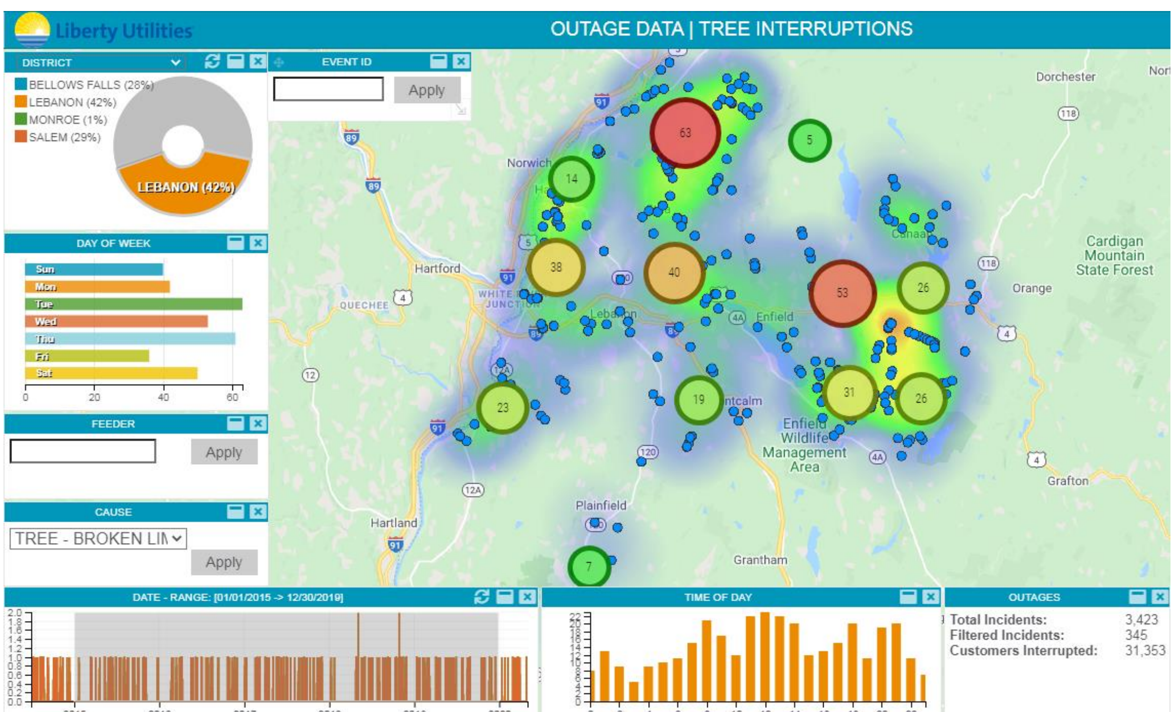
[4] The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

Table 6: 5-Yr. Average Tree Related Reliability Performance – Lebanon Area

Feeder	# Incidents	cKAIFI	cKAIDI
41-7L2	7	0.75	94.67
41-16L1	12	0.71	153.21
41-1L1	4	0.57	70.62
41-7L1	19	0.52	85.36
41-6L3	8	0.47	76.06
41-39L2	5	0.46	83.57
41-1L2	10	0.45	42.82

The location of tree related incidents that resulted in an interruption during the time period from January 2015 through December 31, 2019, using regulatory criteria, is shown in the map below.

Figure 9 Lebanon Area Tree Related Incidents



b. Tree Related Performance – Salem Area

The tree related reliability performance of the Salem Area feeders during the time period from January 1, 2015 through December 31, 2019 is summarized in Table 7 below[5]. These are ranked by circuit SAIFI.

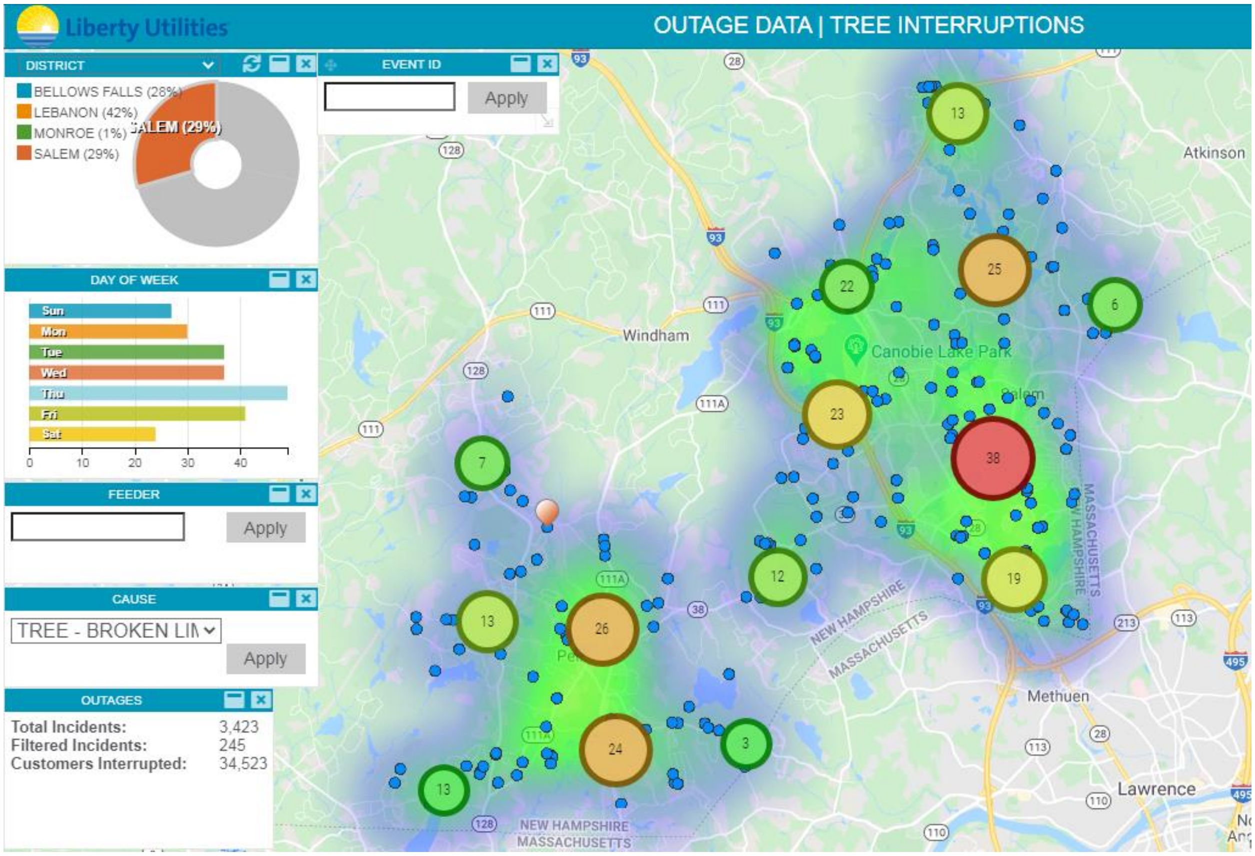
Table 7: 5-Yr. Average Tree Related Reliability Performance – Salem Area

Feeder	# Incidents	cKAIFI	cKAIDI
42-18L4	2	0.65	30.92
42-14L2	8	0.63	71.35
42-9L3	5	0.58	88.17
42-14L3	6	0.50	39.29
42-18L3	1	0.41	14.75
42-13L3	6	0.40	39.43
42-10L2	2	0.37	34.99
42-14L1	7	0.35	47.87
42-10L1	2	0.22	36.56
42-13L2	5	0.21	12.96
42-13L1	5	0.19	21.68
42-10L4	3	0.15	21.11

The location of tree related incidents that resulted in an interruption during the time period from January 2015 through December 31, 2019, using regulatory criteria, is shown in the map below.

[5] The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

Figure 10 Salem Area Tree Related Incidents



c. Tree Related Performance – Bellows Falls Area

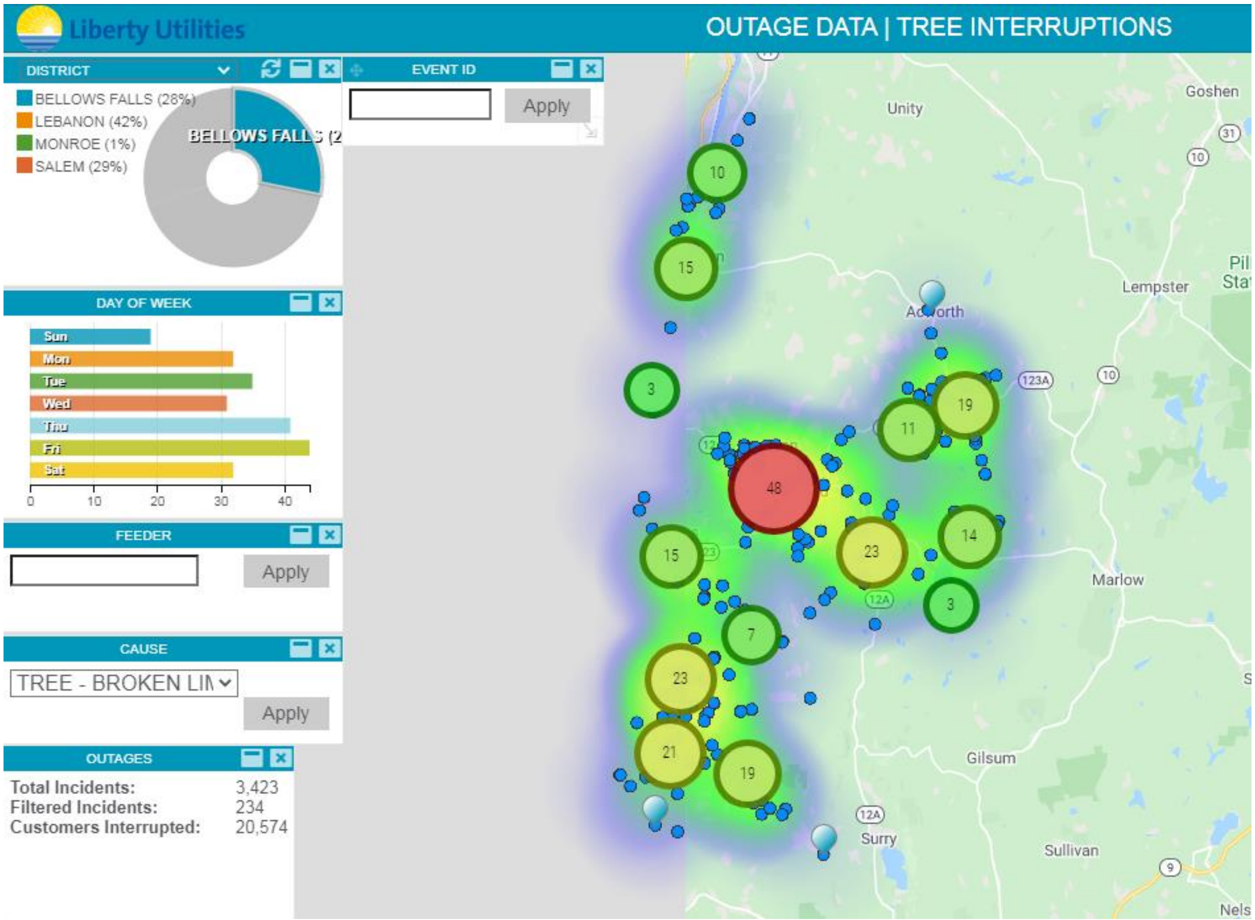
The tree related reliability performance of the Bellows Falls Area feeders during the time period from January 1, 2015 through December 31, 2019 is summarized in Table 8 below[6]. These are ranked by circuit SAIFI.

Table 8: 5-Yr. Average Tree Related Reliability Performance – Bellows Falls Area

Feeder	# Incidents	cKAIFI	cKAIDI
43-12L2	14	1.05	180.47
43-12L1	28	0.83	177.47
43-40L3	4	0.65	60.08

[6] The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

Figure 11 Bellows Falls Area Tree Related Incidents



5.0 Poor Performing Feeders

A distribution feeder that possesses a cKAIDI or ckAIFI value for a reporting year that is among the highest five of all of feeders is considered a Poor Performing Feeder. For additional details refer to Document DAS-010 Poor Performing Feeder Strategy.

5.1 2019 Poor Performing Feeders

Table 9 below shows the ten worst circuits ranked by the total number of Customer Minutes Interrupted during the time period between January 1, 2019 and December 31, 2019.

Table 9: 2019 Ten Worst Performing Feeders

Feeder	Area	# Incidents	Customers Interrupted	Customer Minutes Interrupted	cKAIFI	cKAIDI	CAIDI
43-12L1	Bellows Falls	32	2,943	565,317	1.18	227.49	192.09
41-7L1	Lebanon	25	3,293	533,820	1.59	257.12	162.11
43-12L2	Bellows Falls	22	1,149	266,607	0.89	205.87	232.30
42-14L2	Salem	20	1,752	265,140	0.86	130.57	151.41
42-9L3	Salem	16	1,254	190,163	0.97	146.81	151.93
41-1L2	Lebanon	23	3,914	184,955	1.05	49.48	47.26
42-13L1	Salem	21	1,631	173,439	0.73	77.80	106.32
42-14L3	Salem	21	1,759	154,426	1.56	136.90	87.91
41-16L1	Lebanon	18	725	115,847	0.82	131.39	159.77
42-13L3	Salem	23	1,287	93,892	0.49	36.13	72.99

Table 10 below provides detail on the major causes of the outages on each of these circuits. Number of Incidents, Customers Interrupted and Customer Minutes of interruption are given for the five most prevalent causes during 2019.

Table 10: 2019 Ten Worst Performing Feeders Analysis by Cause

Feeder		Animal	Device Failed	Tree - Broken Limb	Tree Fell	Vehicle
43-12L1	# Incidents	3	9	5	11	4
	CI	14	2,158	117	216	439
	CMI	1,462	422,333	7,216	26,069	107,373
41-7L1	# Incidents	1	5	4	10	3
	CI	155	77	2,192	715	133
	CMI	27,280	16,181	333,447	133,289	21,939
43-12L2	# Incidents	2	2	3	6	1
	CI	5	3	40	819	144
	CMI	270	447	5,707	172,460	64,944
42-14L2	# Incidents	6	2	3	5	
	CI	43	7	1,555	92	
	CMI	2,987	1,162	239,512	16,902	
42-9L3	# Incidents	3	1	2	6	1
	CI	17	2	28	944	6
	CMI	767	354	1,114	169,479	1,152
41-1L2	# Incidents	3	2	4	5	3
	CI	26	1,456	296	1,949	77
	CMI	2,058	83,736	10,736	64,434	10,016
42-13L1	# Incidents	2	2	4	6	3
	CI	16	26	434	421	578
	CMI	2,184	7,126	25,058	49,410	59,140
42-14L3	# Incidents	4	4	1	2	1
	CI	50	654	6	187	153
	CMI	3,951	49,103	672	48,930	27,611
41-16L1	# Incidents			7	7	
	CI			96	585	
	CMI			15,571	98,017	
42-13L3	# Incidents	11	2	2	3	2
	CI	314	19	770	66	21
	CMI	16,659	4,333	40,216	10,860	10,053

Table 11 below provides the 3 worst incidents for the 5 worst performing feeders in 2019 ranked by Customers Minutes Interrupted.

1 Table 11: 2019 Five Worst Performing Feeders – Top 3 Incidents

ID	Feeder	Date	CI	CMI	Average Duration (Min)	Town	Comments	Cause
53466	12L1	4/28/2019	1,984	398,784	201	WALPOLE	PTR# 741002 P13 RT 123, LOCKED OUT AFTER DEVICE FAILED.	DEVICE FAILED
52818	12L1	2/24/2019	272	81,840	301	WALPOLE	100K TRIPSAVER P1 VALLEY RD LOCKED OUT- MVA P9 VALLEY RD	VEHICLE
55308	12L1	10/28/2019	130	15,990	123	ALSTEAD	BLOWN 40K LINE FUSE P181 FOREST RD. - MVA P30 GILSUM MINE RD	VEHICLE
52464	7L1	1/23/2019	2,079	323,080	155	ENFIELD	7L1 CIRCUIT BREAKER LOCKED OUT DUE TO FALLEN TREE LIMB AT POLE 150-50 ROUTE 4.	TREE - BROKEN LIMB
53155	7L1	4/3/2019	351	95,823	273	CANAAN	BLOWN A & C 80K FUSES P63 US ROUTE 4 - TREE DOWN P25-P26 ROBERTS RD	TREE FELL
56041	7L1	12/22/2019	155	27,280	176	CANAAN	BLOWN PHASE C 65K FUSE P39 ROBERTS RD DUE TO ANIMAL CONTACT - P8 CAANAN ST	ANIMAL
54640	12L2	8/22/2019	266	67,564	254	WALPOLE	PTR 741021 PH A & C PHASE LOCKOUT @ P2 WENTWORTH RD / WIRES DOWN DUE TO FALLEN TREE BETWEEN P45 AND P46 WENTWORTH RD	TREE FELL
55809	12L2	11/24/2019	144	64,944	451	WALPOLE	3-40K FUSES BLOWN AT P149 COUNTY RD - MVA AT P155	VEHICLE
54417	12L2	7/30/2019	344	54,415	158	WALPOLE	BLOWN 80K LINE FUSE (1 OF 3) P43 PROSPECT HILL RD / TREE ON PRIMARY P89 WATKINS HILL RD	TREE FELL
53206	14L2	4/3/2019	926	160,198	173	PELHAM	PTR 704008 P5 NASHUA RD, LOCKED OUT - CAUSE BROKEN TREE LIMB.	TREE - BROKEN LIMB
51849	14L2	1/6/2019	624	78,624	126	PELHAM	PTR# 704008 P5 NASHUA RD LOCKED OUT DUE TO BRANCH ON LINES P12 NASHUA RD	TREE - BROKEN LIMB
53712	14L2	5/28/2019	38	11,715	308	PELHAM	BLOWN 40K LINE FUSE P28 SHERBURNE RD/TREE DOWN CAUSED BROKEN POLE 10 AND DOWNED TRANSFORMER AT MCGRATH RD	TREE FELL
52660	9L3	2/8/2019	546	97,188	178	WINDHAM	PTR #703013 P7 RANGE RD, LOCKED OUT AFTER TREE FELL AT P27 RANGE RD	TREE FELL
53111	9L3	4/3/2019	184	56,856	309	SALEM	PTR #701076 @ P1.5 BROOKDALE RD LOCKED OUT. CAUSE: TREE FELL P5-P6 BROOKDALE RD	TREE FELL
52610	9L3	2/5/2019	1,313	43,854	33	SALEM	SALEM DEPOT 9L3 CIRCUIT BREAKER LOCKED OUT DUE TO ANIMAL CONTACTING L3-4 DISCONNECT.	ANIMAL

5.2 2015 – 2019 Poor Performing Feeders

The annual performance of the five worst feeders in terms of circuit SAIDI and SAIFI for each of the past five years is shown in the tables below using the regulatory criteria. Table 12 lists the five worst performing feeders ranked by circuit SAIDI and Table 13 lists the five worst performing feeders ranked by circuit SAIFI.

Table 12: 2015 – 2019 Poor Performing Feeders – cKAIDI

RANK	2015		2016		2017		2018		2019	
	Feeder	cKAIDI	Feeder	cKAIDI	Feeder	cKAIDI	Feeder	cKAIDI	Feeder	cKAIDI
1	42-14L2	274.75	41-7L2	436.23	41-15H1	742.19	43-12L2	639.22	41-7L1	257.12
2	42-9L2	140.60	43-12L2	303.82	41-6L4	352.59	43-12L1	548.60	43-12L1	227.49
3	42-18L1	139.01	42-13L2	296.52	41-39L2	307.12	41-16L1	451.75	43-12L2	205.87
4	41-16L1	137.00	41-1L1	262.57	41-6L3	298.09	42-9L3	240.55	42-9L3	146.81
5	41-6L3	136.96	41-6L4	228.66	41-6L2	269.47	41-39L2	235.80	42-14L3	136.90

Table 13: 2015 – 2019 Poor Performing Feeders – cKAIFI

RANK	2015		2016		2017		2018		2019	
	Feeder	cKAIFI	Feeder	cKAIFI	Feeder	cKAIFI	Feeder	cKAIFI	Feeder	cKAIFI
1	42-18L1	1.98	41-7L2	3.44	42-14L3	3.23	43-12L2	1.60	41-7L1	1.59
2	42-14L2	1.87	41-1L1	3.38	41-39L2	2.75	41-7L2	1.58	42-14L3	1.56
3	42-9L2	1.75	42-13L2	3.36	41-6L4	2.26	42-14L4	1.52	41-1L1	1.37
4	41-16L1	1.60	43-12L2	2.97	41-6L2	2.17	41-6L3	1.39	41-39L2	1.28
5	41-6L3	1.34	42-18L4	2.53	43-12L2	2.11	42-14L2	1.36	43-12L1	1.18

If a distribution feeder is among the highest five for two and three consecutive years, it is considered a Problem Feeder and Chronic Feeder respectively.

From a circuit SAIDI standpoint, there are no chronic feeders but feeders 12L1, 12L2 and 9L3 are currently Problem Feeders. From a circuit SAIFI standpoint, there are no chronic or problem feeders, however feeder 12L2 was a chronic feeder for being amongst worst 5 feeders between 2016 and 2018.

6.0 Radial Distribution Areas

It is estimated that in 2019, only 4% of interruptions occurred in portions of the Liberty distribution system where there are no adjacent feeder ties to partially restore unaffected portions. However, given the longer restoration times in these areas, these incidents contributed to 40% of all customer minute interruptions for the year. Table 14 below shows for each Planning Area, the number of events, customers interrupted and customer minutes interrupted for interruptions occurring in radial areas. Table 15 shows the percent contribution that these incidents had on the area's number of customers interrupted and customer minutes interrupted.

Table 14: 2019 Interruptions in Radial Areas

Area	Events	Customers Interrupted	Customer Minutes Interrupted
BELLOWS FALLS	6	3,063	691,344
LEBANON	2	2,436	378,415
SALEM	5	1,377	195,275

Table 15: 2019 Interruptions in Radial Areas % Contribution

Area	Events	Customers Interrupted	Customer Minutes Interrupted
BELLOWS FALLS	9%	66%	79%
LEBANON	2%	23%	37%
SALEM	3%	11%	15%

6.1 Problem Radial Areas

Table 16 below shows for each Radial Location, the average number of customers interrupted, the average customer minutes interrupted and the percent that these contribute to their distribution feeder. The table also shows for each location, the load at risk, distance of overhead line exposure and amount of customers served. These factors coupled with the reliability performance are used to determine a relative ranking of impact for each location.

7.0 Pockets of Poor Performance

Table 17 below shows pockets of Liberty's distribution system that have experienced more than 5 interruptions since 2015. This table excludes Radial locations listed in Section 6.1. For additional details refer to Document DAS-009 Pockets of Poor Performance Strategy.

Table 17: Pockets of Poor Performance

Device Location	# of Interruptions	Customers Interrupted	Customer Minutes Interrupted	Planning Area
Ibey Rd	17	421	58,845	Lebanon
South Rd	14	437	61,226	Lebanon
Potato Rd	11	486	77,588	Lebanon
McGrath Rd	9	336	37,979	Salem
Old County Rd	9	151	21,829	Bellows Falls
Dogford Rd	9	283	49,907	Lebanon
Ball Rd	9	141	40,847	Bellows Falls
Cold River Rd	7	68	12,978	Bellows Falls
Ermer Rd	6	440	49,572	Salem
Benning St	5	151	5,673	Salem

8.0 Recommendations

This following section describes recommendations to improve overall system reliability in the underperforming areas presented in this document. The recommendations listed below will be compared to other proposed projects on a system-wide basis. A risk analysis will determine the priority of projects for inclusion in the capital budget. All project costs are of investment grade. Project scope and costs will be refined during the detailed engineering process. Liberty's NWS Project Evaluation Process was used to determine if a NWS or a hybrid NWS-Traditional option could defer or replace the Traditional option. Three traditional solutions were evaluated using Liberty's NWS initial screen to determine the risk associated with each proposed solution. For details, refer to Appendix A – NWS Project Analysis. Liberty expects that the remaining projects over $500,000 with a need date of at least 24 months in the future, will have similar results.

8.1 Bare Conductor Replacement Program

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

The bare conductor replacement program prioritizes sections of feeder mainline for replacement that are between the circuit breaker and the first protective device (Zone 1). It also looks to address specific areas of the distribution system that have experienced repeated interruptions.

Table 18 below lists recommended locations for bare wire replacement and provides an estimate of the reliability benefits.

Table 18: Bare Wire Replacement Program – Recommended Projects

Location	Year	Town	Distance	Estimate	$/dCI	$/dCMI	Risk Score
14L2 Burns Rd	2021	Pelham	1.5	$675,000	979	7	37
7L1 Route 4	2021	Enfield	1.7	$750,000	423	4	42
14L1 Bridge St *	2023	Pelham	1.3	$600,000	381	3	42
18L3 S Policy St *	2025	Salem	1	$450,000	1,591	53	37
18L2 S Policy St *	2022	Salem	1.1	$485,000	635	8	37
14L2 Marsh Rd *	2022	Pelham	0.9	$430,000	193	1	42
1L3 Mascoma St *	2023	Lebanon	0.7	$300,000	1,243	8	37
6L3 S Main St	2024	Hanover	1.2	$530,000	2,338	6	37
14L1 Marsh Rd	2025	Pelham	1.3	$571,023	4,102	48	24

8.2 Enhanced Bare Conductor Replacement Program

The Enhanced Bare Conductor Replacement Program targets specific areas of the distribution system that are beyond the first protective device and have experienced repeated interruptions.

Table 19 below lists recommended locations for bare wire replacement and provides an estimate of the reliability benefits.

Table 19: Enhanced Bare Wire Replacement Program – Recommended Projects

Location	Year	Town	Distance	Estimate	$/dCI	$/dCMI	Risk Score
12L2 Watkins Hill Rd Phase 1	2021	Walpole	2.25	$860,000	1,360	5	42
12L2 Watkins Hill Rd Phase 2	2022	Walpole	1.5	$590,000	4,775	36	24
9L3 Range Rd - W Shore Rd	2023	Windham	1.4	$590,000	1,614	8	31
13L1 Ermer Rd	2022	Derry	0.4	$160,000	890	7	24
12L1 Rt. 123A	2024	Alstead	2	$790,000	2,749	7	37
39L2 Plainfield Rd Phase 1	2025	Lebanon	0.8	$375,000	2,277	18	24

8.3 Distribution Automation

For details on the Company's distribution automation strategy refer to Document DAS-002 Distribution Automation Strategy. In general, the Company gives DA projects a Risk Score of 34.

8.4 Underperforming Feeder Program

For details refer to Document DAS-010 Poor Performing Feeder Strategy. Table 20 below lists recommended projects to improve the reliability of Poor Performing Feeders.

Table 20: Poor Performing Feeder Program – Recommended Projects

Location	Year	Town	Distance	Estimate	$/dCI	$/dCMI	Risk Score
12L2 Watkins Hill Rd Phase 3	2023	Walpole	1.5	$550,000	2,999	24	24
12L1 - 12L2 Tie March Hill Rd	2022	Walpole	1	$225,852	-	10	24

8.5 Pocket of Poor Performance Program

For details refer to Document DAS-009 Pockets of Poor Performance Strategy. Table 21 below lists recommended projects to improve the reliability of these pockets of poor performance.

Table 21: Pocket of Poor Performance Program – Recommended Projects

Location	Year	Town	Distance	Estimate	$/dCI	$/dCMI	Risk Score
10L1 Hampshire Rd	2022	Salem	0.11	$40,000	-	3	24
14L3 Ledge Rd Fuse Savers	2022	Pelham	2	$10,000	141	4	24
1L2 Ibey Rd	2023	Canaan	1	$225,000	3,207	23	37
1L2 South Rd	2024	Canaan	1.1	$250,000	2,301	16	37
1L2 Potato Rd	2025	Enfield	0.8	$180,000	1,666	10	37
14L2 McGrath Rd Trip Saver	2022	Pelham	1	$5,000	74	1	31
1L2 South Rd Trip Saver	2022	Canaan	1	$5,000	46	0	37
12L1 Cold River Rd Trip Saver	2025	Walpole	3	$15,000	1,103	6	24
16L1 Dogford Rd Trip Saver	2022	Hanover	1	$5,000	106	1	37
39L2 Old County Rd Trip Saver	2022	Plainfield	1	$5,000	132	1	37
10L4 Benning St Trip Saver	2022	Salem	1	$5,000	166	4	24

8.6 Vegetation Management

In 2017, Liberty implemented the first year of the four-year trim cycle as approved by the Commission in Docket No. DE 16-383, to minimize the amount of spot or interim trimming between cycles and to reduce the time between cycles. This provide for earlier detection of dead/dying and weakly attached limbs forming since the last cycle. Broken tree limbs, both alive and dead, are a major cause of tree interruptions on the Liberty system. A four-year cycle will allow for quicker identification and treatment of trees that have been damaged in storm events and trees with limbs that have heavier foliage especially at the ends of limbs during a good growth year or several good growth years. Thus, it is anticipated that the number of broken tree limbs will decline annually during the cycle resulting in expected reliability benefits.

9.0 Conclusion

A reliable supply of electricity to each customer is very important to regulators and utilities – and it is measurable.

However, customers demand three key things from their electric utility (not necessarily in this order):

- Lights come on when I flip the switch (reliability/resilience)
- Afford to pay my bill (efficiency)
- Don’t hurt me or my property (safety and environment)

Customers expect electric utilities to deliver on all three of these expectations, holding their utility accountable for balancing all three. For example, a utility could spend a lot more money to improve reliability, but it would increase bills (e.g. oversized transformers and conductors) and create higher community/environmental impacts (e.g. more aggressive vegetation management programs).

So, while Liberty is keenly aware of the importance of reliability metrics, they must be balanced with the customer desires to keep bills reasonable and minimize physical threats to them and their property.

Tree related causes of customer interruptions in Liberty’s service territory are clearly the single biggest cause of both the frequency and duration of customer outages. Vegetation management is particularly challenging due to the natural tension between minimizing costs and environmental impacts of tree trimming and a desire to reduce customer outages.

Liberty will continue to evaluate the use of new monitoring devices to locate specific problem areas prior to a tree related outage and are monitoring the costs and benefits of these technologies.

The recommendations made in this report target specific trouble areas of the distribution system that contribute in large part to the poor reliability performance of the Company. These recommendations support the Company’s reliability and resiliency initiatives to reach top quartile performance. If enacted, these will provide considerable reliability and resiliency benefits for our Customers.

10.0 Appendix A.1 – NWS Project Evaluation

NWA EVALUATION SUMMARY

11/2/2020

Identified Problem: 12L2 Watkins Hill Rd P149 Tree Related Interruptions

Project Need Year: 2023

Brief Project Description/need:

Improve reliability for Watkins Hill Rd customers experiencing multiple interruptions from tree related causes.

Project Scope	Option
Replace 1.5 miles of bare wires with spacer cable	1
Small Storage	2
	3
	4

Scoring Values

Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Comments
Total Cost	30%	1	1			
Reliability Risk	20%	1.7	1.5			
Feasibility Risk	20%	2	1			
Performance Risk	20%	1.65	1.35			
Enviromental Risk	10%	1.25	1.75			
Total Assessment	100%	1.50	1.25	0.00	0.00	
	Ranking	1	2	3	3	

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Customer Outage Experience	50%	2	1		
Automated Restoration	30%	1	2		
Power Quality	20%	2	2		
Totals	100%	1.7	1.5	0	0
	Ranking	1	2	3	3

Identified Problem: 12L2 Watkins Hill Rd P149 Tree Related Interruptions
11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Likelihood of Timely Completion	35%	2	1		
Predictable Long Term Solution	25%	2	1		
Historical Field Experience	10%	2	1		
Uncertainty	30%	2	1		
Totals	**100%**	**2**	**1**	**0**	**0**
	Ranking	**1**	**2**	**3**	**3**

Identified Problem: 12L2 Watkins Hill Rd P149 Tree Related Interruptions
11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Availability	25%	2	1		
Operability	20%	2	1		
Required Maintenance	10%	2	1		
Aligns with Company Goals	15%	1	2		
Capacity Provided - Demand	20%	1	2		
Capacity Provided - Hosting	10%	2	1		
Totals	**100%**	**1.65**	**1.35**	**0**	**0**
	Ranking	**1**	**2**	**3**	**3**

PROJECT NAME: 12L2 Watkins Hill Rd P149 Tree Related Interruptions
11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4
Wetland Impact	25%	1	2		
Tree Clearing	25%	1	2		
Community Impacts	25%	1	2		
Municipal Impacts	25%	2	1		
Totals	**100%**	**1.25**	**1.75**	**0**	**0**
	Ranking	**2**	**1**	**3**	**3**

NWA EVALUATION SUMMARY

11/2/2020

Identified Problem: **Meriden Rd Plainfield**

Project Need Year: **2024**

Brief Project Description/need:

Reliability improvement - Meriden Rd Area

Project Scope	Option
Install new tie and implement DA	1
Replace 3.2 miles of bare conductors	2
Large Storage + PV	3
Small Storage	4
Reconductor 3.2 miles of bare conductors and Small Storage	5

Scoring Values

Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Option 5	Comments
Total Cost	30%	3	3	1	3	2	
Reliability Risk	20%	5	2.6	2.1	1.5	3.8	
Feasibility Risk	20%	4.65	4.45	2.3	2.35	2.35	
Performance Risk	20%	4.1	2.85	2.5	2.05	3.45	
Enviromental Risk	10%	2.75	2.75	2.5	4.75	4	
Total Assessment	**100%**	**3.93**	**3.16**	**1.93**	**2.56**	**2.92**	
	Ranking	1	2	5	4	3	

Identified Problem: Meriden Rd Plainfield

11/2/2020

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Customer Outage Experience	50%	5	3	2	1	4
Automated Restoration	30%	5	1	3	2	4
Power Quality	20%	5	4	1	2	3
Totals	100%	5	2.6	2.1	1.5	3.8
	Ranking	1	3	4	4	2

Identified Problem: Meriden Rd Plainfield

11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Likelihood of Timely Completion	35%	4	5	2	2	2
Predictable Long Term Solution	25%	5	4	2	3	3
Historical Field Experience	10%	5	5	2	3	3
Operational Uncertainty	30%	5	4	3	2	2
Totals	**100%**	**4.65**	**4.45**	**2.3**	**2.35**	**2.35**
	Ranking	**1**	**2**	**5**	**3**	**3**

Identified Problem: Meriden Rd Plainfield

11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Availability	25%	4	4	2	2	3
Operability	20%	5	3	2	1	4
Required Maintenance	10%	3	3	1	5	2
Most Aligns with Company Goals	15%	2	1	4	3	4
Capacity Provided - Demand	20%	5	2	4	1	4
Capacity Provided - Hosting	10%	5	4	1	2	3
Totals	**100%**	**4.1**	**2.85**	**2.5**	**2.05**	**3.45**
	Ranking	**1**	**3**	**4**	**5**	**2**

PROJECT NAME: Meriden Rd Plainfield

11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Wetland Impact	25%	4	4	4	5	4
Tree Clearing	25%	2	3	1	5	4
Community Impacts	25%	2	2	4	4	3
Municipal Impacts	25%	3	2	1	5	5
Totals	**100%**	**2.75**	**2.75**	**2.5**	**4.75**	**4**
	Ranking	**3**	**3**	**5**	**1**	**2**

NWA EVALUATION SUMMARY

11/2/2020

Identified Problem: Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield

Project Need Year: 2024

Brief Project Description/need:

Improve reliability of customers supplied from 7L1 and 7L2 feeders in Enfield NH

Project Scope	Option
Install new tie and implement DA	1
Replace 3.5 miles of bare conductors	2
Large Storage + PV	3
Small Storage	4
Replace 3.5 miles of bare conductors and Small Storage	5

Scoring Values

Marginal with mitigation	1
Marginal without mitigation	2
Acceptable	3
Best Solution	4

Evaluation Summary

Evaluation Criteria	% Weight Factor*	Option 1	Option 2	Option 3	Option 4	Option 5	Comments
Total Cost	30%	3	3	1	3	2	
Reliability Risk	20%	4.2	2	2.2	2.3	3.8	
Feasibility Risk	20%	4.4	4.45	1.95	2.35	2.35	
Performance Risk	20%	4.2	2.95	2.5	1.85	3.45	
Enviromental Risk	10%	2.75	2.75	2.5	4.5	3.75	
Total Assessment	**100%**	**3.74**	**3.06**	**1.88**	**2.65**	**2.90**	
	Ranking	1	2	5	4	3	

Identified Problem: Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield

11/2/2020

RELIABILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Customer Outage Experience	50%	5	3	2	1	4
Automated Restoration	30%	5	1	2	4	4
Power Quality	20%	1	1	3	3	3
Totals	**100%**	**4.2**	**2**	**2.2**	**2.3**	**3.8**
	Ranking	1	5	4	2	2

Identified Problem: Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield

11/2/2020

FEASIBILITY Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Likelihood of Timely Completion	35%	4	5	2	2	2
Predictable Long Term Solution	25%	4	4	1	3	3
Historical Field Experience	10%	5	5	1	3	3
Uncertainty	30%	5	4	3	2	2
Totals	**100%**	**4.4**	**4.45**	**1.95**	**2.35**	**2.35**
	Ranking	**2**	**1**	**5**	**3**	**3**

Identified Problem: Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield

11/2/2020

PERFORMANCE Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Availability	25%	4	4	2	2	3
Operability	20%	5	3	2	1	4
Required Maintenance	10%	4	4	1	3	2
Most Aligns with Company Goals	15%	2	1	4	3	4
Capacity Provided - Demand	20%	5	2	4	1	4
Capacity Provided - Hosting	10%	5	4	1	2	3
Totals	**100%**	**4.2**	**2.95**	**2.5**	**1.85**	**3.45**
	Ranking	**1**	**3**	**4**	**5**	**2**

PROJECT NAME: Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield

11/2/2020

ENVIRONMENTAL Risk Evaluation Criteria	Weighing Factor	Option 1	Option 2	Option 3	Option 4	Option 5
Wetland Impact	25%	4	4	4	5	4
Tree Clearing	25%	2	2	1	5	4
Community Impacts	25%	2	2	4	4	3
Municipal Impacts	25%	3	3	1	4	4
Totals	**100%**	**2.75**	**2.75**	**2.5**	**4.5**	**3.75**
	Ranking	**3**	**3**	**5**	**1**	**2**