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## Least Cost Integrated Resource Plan

Liberty Utilities (Granite State Electric) Corp.  
d/b/a Liberty

Docket No. DE 21-XXX

January 14, 2021



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1 **1. EXECUTIVE SUMMARY**

2 Pursuant to the laws governing least cost integrated resource plans (“LCIRP”), RSA 378:37  
3 through 378:40, Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty (“Liberty” or the  
4 “Company”) submits this LCIRP for the period 2022 through 2026. The Company’s most  
5 recent LCIRP was approved by the New Hampshire Public Utilities Commission  
6 (“Commission”) in Order No. 26,039 (July 10, 2017). The current LCIRP was prepared in  
7 compliance with the Commission’s directives in Order Nos. 26,039 and 26,408 (Sept. 23,  
8 2020).<sup>1</sup>

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

15 The LCIRP follows the general approach, format, and objectives of the Company’s most  
16 recent LCIRP filing in 2016 and modified LCIRP filing in 2019, which is to comply with  
17 RSA 378:37, the New Hampshire Energy Policy:

18 [I]t shall be the energy policy of this state to meet the energy  
19 needs of the citizens and businesses of the state at the lowest

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1 “In this Order, the Commission finds that Liberty’s July 15, 2019, filing meets the requirements  
of Order No. 26,039 and Order No. 26,261, which granted partial waiver of Liberty’s statutory  
requirement to file a 2019 Least Cost Integrated Resource Plan and instead required a more limited  
document. Consistent with the filing requirements under RSA 378:38, Liberty shall submit its 2021  
LCIRP filing on or before January 14, 2021.” Order No. 26,408 at 1.

1 reasonable cost while providing for the reliability and  
2 diversity of energy sources; to maximize the use of cost  
3 effective energy efficiency and other demand side resources;  
4 and to protect the safety and health of the citizens, the  
5 physical environment of the state, and the future supplies of  
6 resources, with consideration of the financial stability of the  
7 state's utilities.

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

- 10 • A forecast of future demand for the utility's service area;
- 11 • An assessment of demand-side energy management programs, including  
12 conservation, efficiency, and load management programs;
- 13 • An assessment of supply options including owned capacity, market procurements,  
14 renewable energy, and distributed energy resources;
- 15 • An assessment of distribution and transmission requirements, including an assessment  
16 of the benefits and costs of "smart grid" technologies, and the institution or extension  
17 of electric utility programs designed to ensure a more reliable and resilient grid to  
18 prevent or minimize power outages, including but not limited to, infrastructure  
19 automation and technologies;
- 20 • An assessment of plan integration and impact on state compliance with the Clean Air  
21 Act of 1990, as amended, and other environmental laws that may impact a utility's  
22 assets or customers;
- 23 • An assessment of the plan's long- and short-term environmental, economic, and  
24 energy price and supply impact on the state; and
- 25 • An assessment of plan integration and consistency with the state energy strategy  
26 under RSA 4-E:1.

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

1 This LCIRP also addresses Commission’s directives in Order No. 26,408, which required the  
2 Company to:

- 3 • Work with Staff to provide access to the distribution electric operating procedures  
4 through the Liberty Utilities – Manuals site.
- 5 • Develop a list of planned capital projects that may be candidates for avoidance and/or  
6 deferral through deployment of Non-Wires Solutions (“NWS”).
- 7 • Meet with the Settling Parties to identify an NWS candidate that should be the focus  
8 of a more detailed analysis provided within the LCIRP filing. This analysis of NWS  
9 should consider utility system benefits including, but not limited to, avoided  
10 distribution capacity costs, avoided energy costs, and avoided transmission costs.  
11 The analysis shall include an evaluation of the demand reduction potential associated  
12 with energy efficiency and load curtailment, as well as other NWSs.
- 13 • Include a document similar to Sections 4.4 (“Distribution Planning Process”) and 5  
14 (“Non-Wires Alternatives T&D Integration Process”), and Appendix E  
15 (“Hypothetical Case Study: Evaluation of Non-Wires Solution”) of the 2016 LCIRP  
16 which provide descriptions of the planning process employed to assess NWS as part  
17 of the Company’s broader planning processes, and, the steps taken to incorporate  
18 NWS into its planning decisions to reduce or defer traditional infrastructure  
19 investments.
- 20 • Work with the settling parties to determine how the following issues will be  
21 addressed within the 2021 LCIRP: 1) how the risk profile evaluation for NWS is  
22 conducted, including contributing factors and issues; 2) options to mitigate identified  
23 risks; 3) how risk is incorporated into the planning process, including how risks and  
24 costs are weighted to identify when a reduction in cost justifies additional risk; 4) the  
25 potential for hybrid projects; 5) ways in which the Company might attain a more  
26 detailed analysis of the benefits and costs; and 6) how potential NWS are identified  
27 for detailed analysis.

28 The Company met with the Settling Parties on December 18, 2020, to discuss the non-wires  
29 solution presented in this plan. The Bellows Falls Study, which describes the reliability and  
30 resilience issues in this area, is included in this Plan in Appendix F. Liberty has agreed to

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1 evaluate non-wires solutions in the Bellows Falls area and provide a detailed NWA  
2 evaluation within 6 months of this filing as an amendment to this Plan. The Settling Parties  
3 appreciated the discussion and noted they looked forward to seeing the information in the  
4 filing.

5 The LCIRP describes the Company's four planning phases. The first phase is to develop a  
6 long-term forecast of demand requirements. The second phase is to develop a detailed  
7 energy supply plan to meet those requirements. The third phase is to prepare a distribution  
8 plan that includes evaluation of wires and non-wires alternatives to address system  
9 deficiencies. The fourth and final phase is to evaluate and integrate the energy efficiency and  
10 demand side management programs into the LCIRP.

11 In the first phase, the Company developed an econometric model to forecast peak demands  
12 through 2037. The forecast model incorporates the impact of weather as well as  
13 demographic and local economic conditions on peak demands. Refer to Section 2 for  
14 additional details.

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

20 The Company performed a detailed evaluation of its distribution system based on the forecast  
21 results discussed above and the condition of its distribution facilities. The evaluation utilized

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1 the forecast of peak demands for each feeder and substation based on extreme weather  
2 conditions, as well as data depicting the operating performance and condition of the  
3 distribution facilities. This evaluation is used to determine whether the operating capacity of  
4 the distribution facilities is adequate under normal and contingency conditions.

5 Liberty established planning criteria, which were filed in Docket No. DE 19-064 and  
6 approved by Order No. 26,376 (June 30, 2020), for normal and contingency operating  
7 conditions that are applied in concert with the thermal ratings of the distribution facilities to  
8 identify violations or deficiencies in the capacity of the distribution facilities. The  
9 deficiencies are then prioritized by risk of occurrence and impact on customers. The  
10 Company develops solutions to the deficiencies in the form of individual project proposals,  
11 which are then included in the Company's five-year capital budget based on their priority  
12 level and cost considerations. Non-wires alternatives are evaluated and considered as  
13 potential solutions to distribution system deficiencies, subject to certain screening criteria and  
14 risk analyses.

15 Liberty has evaluated its distribution system in light of substantial changes in customer  
16 expectations and regulatory directives in recent years and is proposing to incorporate selected  
17 "Smart Grid" technologies that will modernize the Liberty distribution system. The Grid  
18 Modernization element of this plan provides substantial positive value to customers,  
19 including increasing resilience (i.e. faster recovery from system damage), lower overall  
20 customer costs, and improved safety and reliability of its system. The new Advanced  
21 Distribution Management Systems ("ADMS") and Automated Metering Infrastructure

1 (“AMI”) will serve as the backbone of this grid modernization program that Liberty plans to  
2 implement over the next five years, investing in an enhanced customer service experience of  
3 the future. As demonstrated in Section 5 of this LCIRP, the costs of these new digital  
4 technology management systems will provide positive economic value for customers that  
5 substantially exceed the costs of these programs over the next 10 years.

6 The Company performed a detailed assessment of its NHSaves energy efficiency measures  
7 and programs to ensure they meet the requirements of the LCIRP. The assessment shows  
8 that the Company’s energy efficiency programs have resulted in savings of more than  
9 910,000 lifetime megawatt hours at a benefit value of almost \$89 million, reductions in peak  
10 load, and significant environmental and health benefits.

11 Key results and findings of the LCIRP include:

- 12 • Under the extreme weather scenario, Liberty’s summer peak demand is projected to  
13 grow an average of 0.87% per year over the 2021 to 2037 planning period. Winter  
14 peak demand is projected to grow 0.74% per year on average over the same time  
15 period. These growth rates incorporate forecasted PV and electric vehicle charging  
16 projections for New Hampshire.

17 The Company’s five-year capital budget is \$124 million, with spending on mandated  
18 and growth programs representing 41% of the budget, and spending on discretionary  
19 items representing 59% of the budget;

- 20 • The five-year capital budget includes \$21 million for the recommended Distribution  
21 Grid Modernization Program, which will bring many benefits to customers,  
22 including, (1) enhanced outage management system allowing for faster recovery from  
23 system damage, (2) lower costs through use of “conservation voltage management,”  
24 (3) better forecasting for each feeder on the system, (4) improved asset management,  
25 and (5) more efficient integration of distributed energy resources. Liberty is  
26 proposing to implement this Program with specific pilot projects as described in

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1 detailed in the Liberty Grid Modernization Study in Section 5 and Appendix E in this  
2 Plan.

- 3 • The Company’s distribution planning process integrates non-wires alternatives,  
4 although the Company’s pursuit of non-wires alternative solutions requires a more  
5 detailed analysis of the benefits and costs, including technical studies that would  
6 require additional resources;
- 7 • The LCIRP is filed in conjunction with the filing of the three-year Energy Efficiency  
8 Resource Standard Settlement Agreement in Docket No. DE 20-092. As of the date  
9 of this filing, the Settlement Agreement has not been approved.
- 10 • The key impacts of the Company’s LCIRP on environmental, economic, and energy  
11 price and supply impacts on the State of New Hampshire include the following:
  - 12 ○ The Company’s competitively sourced energy supply procurement process,  
13 consistent with the Settlement Agreement approved by the Commission in  
14 Docket No. DE 05-126 in Order No. 24,577 (Jan. 13, 2006),<sup>2</sup> ensures energy  
15 supply is delivered to customers at the lowest reasonable cost, while  
16 considering certain financial and qualitative criteria.
  - 17 ○ The Company’s Renewable Energy Certificates (“REC”) procurement, energy  
18 efficiency programs, and net metering tariffs to provide economic and  
19 environmental benefits to the state by supporting jobs in the renewable energy  
20 industry and reducing reliance on sources of electric generation produced  
21 outside the state that emit greater amounts of pollutants.<sup>3</sup>
  - 22 ○ The integration of grid modernization technologies and use of non-wires  
23 solutions into the Company’s distribution planning process will provide  
24 economic and other benefits to the state through lower costs to the customer,  
25 improved reliability, planning, increase in customer DERs, de-carbonization,  
26 and the reduction of peak loads.

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2 As amended by Order Nos. 24,922 (Dec. 19, 2008) in Docket No. DE 08-011, amended by Order No. 25,601 (Nov. 27, 2013) in Docket No. DE 13-018, and further amended by Order No. 25,806 (Sept. 2, 2015) in Docket No. DE 15-010 (as amended through these subsequent orders, the “Settlement Agreement”).

3 Specifically, carbon dioxide (CO<sub>2</sub>), sulfur oxides (SO<sub>x</sub>), nitrogen oxides (NO<sub>x</sub>), particulates, and other pollutants.

1 These results and findings demonstrate compliance with RSA 378:38 as detailed in the  
2 following sections.

3 The remainder of this LCIRP filing is organized as follows:

4 Section 2 discusses the Company's demand forecast methodology, including the econometric  
5 model used to develop the demand forecast.

6 Section 3 describes energy supply options, which are met by the wholesale markets and  
7 administered by the Independent System Operator New England ("ISO-NE"). This section  
8 describes how energy markets within ISO-NE are structured such that the Company can  
9 procure an adequate supply and provide demand resources to meet reliability objectives at  
10 the lowest reasonable cost. The LCIRP also details the transmission planning process and  
11 the Company's ongoing collaboration with National Grid, Liberty's transmission provider.

12 Section 4 describes the process to enhance the reliable operations of the electric distribution  
13 system that provides electric service to Liberty's customers, including the role of non-wires  
14 alternatives in Liberty's distribution planning and procurement process.

15 Section 5 describes the proposed Distribution Grid Modernization Program that will integrate  
16 selected digital technologies, providing economic and other benefits to customers and the  
17 other citizens in the State of New Hampshire.

18 Section 6 describes the role of energy efficiency and demand side management programs in  
19 resource planning and procurement process.



1 **2. DEMAND FORECAST**

2 **2.1 Purpose**

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

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

18 **2.2 Methodology**

19 The Company utilizes a multi-step, top-down / bottom-up process. First, the Company uses  
20 an econometric model to forecast Liberty’s system summer and winter peak loads (i.e.,  
21 “bottom-up”) for each area. The explanatory variables include historical and forecasted  
22 economic conditions at the county level, historical peak demand data for each Area, and a  
23 forecast of weather conditions based on historical data from a Concord, New Hampshire,  
24 weather station. The model also applies certain demographic variables such as number of

1 households. The system seasonal peak forecasts are then split into Eastern and Western  
2 jurisdictions using Liberty's township sales information, as well as July and December 2019  
3 peak coincident Eastern and Western area percent contributions. Appendix B includes the  
4 Company's detailed demand forecast report.

5 The econometric model is used to simulate the historical and forecasted peak demand for  
6 each PSA under normal and extreme weather conditions. The normal weather simulation  
7 assumes average weather conditions for each year of the forecast. Normal weather  
8 conditions are determined by averaging the weather for the highest peak day of a 20-year  
9 historical period. As an average of historical weather, the normal weather forecast becomes a  
10 "50/50" case, with a 50% probability that actual weather is greater than or less than the  
11 forecasted conditions. The extreme weather scenario takes the weather conditions associated  
12 with the highest peak day over a 20-year history and applies these extreme conditions to all  
13 future years of the forecast. Based on the historical experience, there is only a ten percent  
14 probability that actual peak-producing weather will be equal to or more extreme than the  
15 extreme weather scenario. That is, the extreme weather forecast is a "1 in 10" case.

16 The peak demand forecast for each area incorporates historic energy efficiency savings  
17 achieved, since such savings are reflected in the historical usage data employed by the model.  
18 The energy efficiency measures are those specifically installed through the NHSaves  
19 efficiency programs relating to both residential and non-residential customers. Similarly, the  
20 impact of distributed generation installed to date is also included in the historical peak  
21 demand. In developing the peak demand forecasts, the forecast assumes that load reductions

1 achieved historically through the Company's energy efficiency programs continue through  
2 the time period of the forecast.

3 Liberty has developed a demand forecast that incorporates growth in electric vehicle  
4 charging and in distributed generation activity. For electric vehicle charging, the ISO-NE  
5 Final 2020 Transportation Electrification Forecast<sup>4</sup> was applied based on Liberty's  
6 proportion of the 2020 winter and summer non-coincident peaks. The distributed generation  
7 growth uses both historic Liberty distributed generation capacity and the ISO-NE Final 2020  
8 PV Forecast<sup>5</sup> for New Hampshire. Liberty's behind the meter PV forecast growth is based  
9 on the ISO-NE's forecast of PV growth for New Hampshire. Liberty took the proportion of  
10 existing PV installed for the Company against the installed capacity in the entire state and  
11 applied that proportion to the ISO-NE forecast to determine the gross PV forecast for  
12 Liberty. To avoid double counting PV growth, the company developed an auxiliary  
13 regression model that includes installed capacity and time. The company took the resulting  
14 PV projections from the auxiliary regression model and subtracted the gross PV forecast to  
15 come out with the net and final behind the meter PV forecast to be applied to the summer  
16 peak.

17 Once the forecast is developed, Liberty makes certain "out of model adjustments" to account  
18 for known future loads or generation (i.e., "top-down"). Specifically, adjustments are made  
19 for new load greater than 300 kW interconnecting to Liberty's distribution system in the near  
20 future, or distributed generation greater than 1,000 kW that is expected to interconnect. To

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4 [https://www.iso-ne.com/static-assets/documents/2020/04/final\\_2020\\_transp\\_elec\\_forecast.pdf](https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_transp_elec_forecast.pdf)  
5 [https://www.iso-ne.com/static-assets/documents/2020/04/final\\_2020\\_pv\\_forecast.pdf](https://www.iso-ne.com/static-assets/documents/2020/04/final_2020_pv_forecast.pdf)

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1 the extent that any distributed generation below 1,000 kW occurred in the historical period, it  
2 is captured in the historical peak data used to develop regression models and therefore is  
3 considered “embedded” in the data.

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

10 System seasonal peak forecasts are divided into the Company’s Eastern and Western  
11 jurisdictions, using town-level sales information as well as July and December 2021 peak  
12 coincident Eastern and Western PSA percent contributions. Separate annual forecasts are  
13 estimated for 19 towns in the Company’s New Hampshire service territory.<sup>6</sup> The regression  
14 equations relate annual town-level kilowatt-hour (“kWh”) deliveries to a time trend variable  
15 and Cooling Degree Days (“CDD”) to predict town kWh load for each forecast year. In  
16 order to flatten the change in township usage over the historic period, the time trend variable  
17 is expressed as a log function. The system peak day values are allocated to the individual  
18 townships by utilizing the annual township sales regression models.

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

1           **2.3    Results**

2           The forecast model projects an increase in Liberty’s summer peak demand from a weather  
3           adjusted 188.5 megawatts (“MW”) in 2021 to 202.6 MW in 2037.<sup>7</sup> This results in an  
4           average annual increase of 0.4% prior to any “out of model adjustments” for new load greater  
5           than 300 kW.

6           The Company developed an “extreme weather” forecast of summer peak demands based on a  
7           1-in-10 weather scenario. The extreme weather forecast model projects an increase from  
8           188.5 MW in 2020 to 217.34 MW in 2037. This results in an average annual increase of  
9           0.87%.

10          The Company also developed a forecast of peak demands for Liberty’s Eastern and Western  
11          distribution areas.<sup>8</sup> Under the extreme weather scenario, the forecast model projects an  
12          increase in summer peak demand in Eastern area from 105.4 MW in 2021 to 110.6 MW in  
13          2037. In the Western area, the model projects an increase in summer peak demand from  
14          101.6 MW in 2021 to 106.7 MW in 2037.

15          The forecast model was then adjusted for spot loads to reflect new customer demands larger  
16          than 300 kilowatts (“kW”) that will be added to the system in 2021 or beyond.

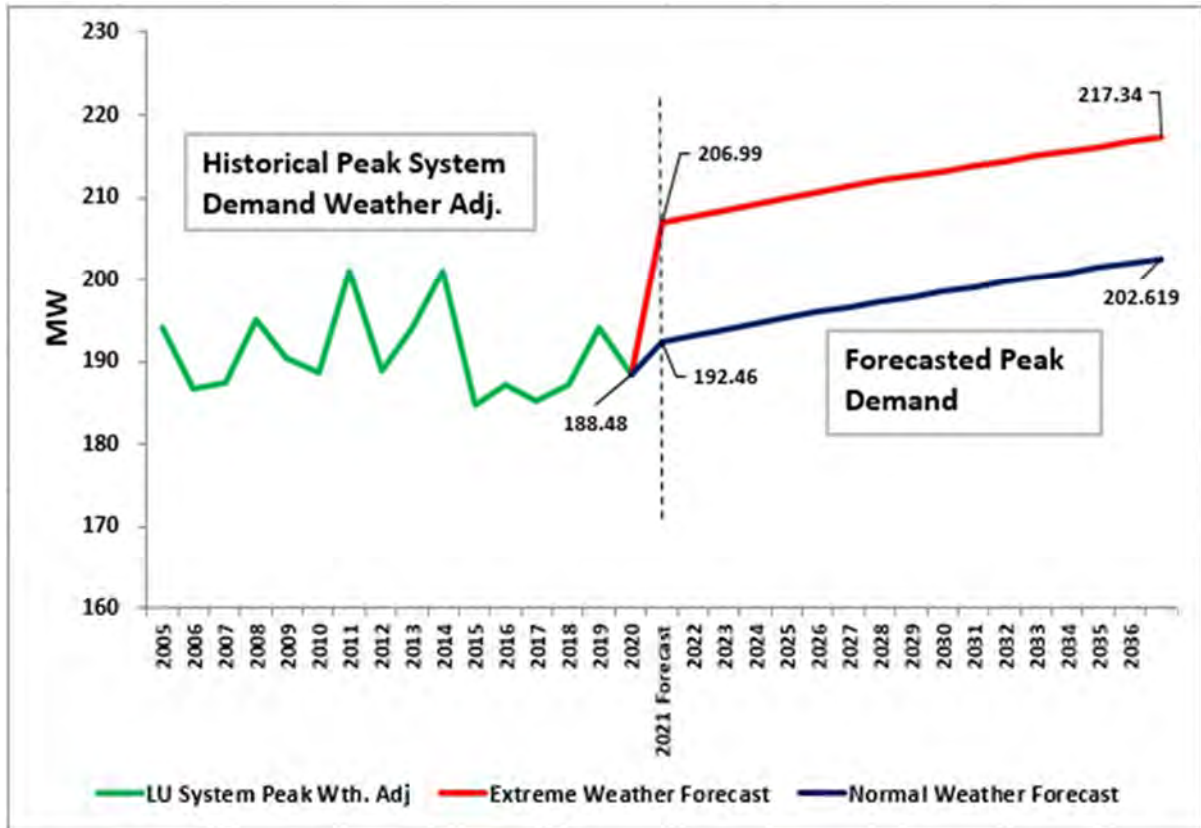
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7           Liberty’s distribution system in New Hampshire is, in general, summer peaking and summer limited.

8           The Eastern PSA includes the towns of Derry, Pelham, Salem, and Windham. The Western PSA includes the towns of Acworth, Alstead, Bath, Canaan, Charlestown, Cornish, Enfield, Grafton, Hanover, Langdon, Lebanon, Lyme, Marlow, Monroe, Orange, Plainfield, Surry, and Walpole.

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

3 **Figure 2.1. Summary of Peak Demand Forecast**



4 **3. ENERGY SUPPLY & TRANSMISSION PLANNING**

5 **3.1 Electricity Market Overview**

6 The ISO-NE is the independent, not-for-profit company authorized by the Federal Energy  
7 Regulatory Commission (“FERC”) to perform three critical, complex, and interconnected

1 roles for the New England region: (1) wholesale electric grid operation, (2) market  
2 administration, and (3) power system planning.<sup>9</sup>

3 The ISO-NE, with input from the New England Power Pool (“NEPOOL”) stakeholder  
4 process, is responsible for administering the wholesale electricity markets and for ensuring  
5 reliability throughout the New England region.

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

14 *Summary of the ISO-NE Wholesale Market*

15 To maintain the reliable and efficient operation of the New England power system, the ISO-  
16 NE undertakes a comprehensive regional system planning process each year.

17 Notwithstanding the region’s system improvements, the ISO-NE notes that the region is  
18 facing three key issues:

- 19 • Energy security—Although many projects for resource development have been  
20 proposed in the region, energy-security and reliability issues may arise from energy-

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9 <http://www.iso-ne.com/about/what-we-do/three-roles>

1 production limitations associated with “just-in-time” fuel sources (i.e., natural gas);  
2 variable energy resources (VERs), like intermittent wind and photovoltaics (PV); and  
3 compliance with environmental regulations. In response, New England state policies  
4 and incentives for developing renewable resources, as well as energy efficiency (EE)  
5 and imports from neighboring regions, are helping offset regional natural gas  
6 demand. Additionally, the ISO, with stakeholder input, is working on near-term and  
7 long-term market improvements to expand the existing suite of energy and ancillary  
8 services that will cost effectively address uncertainties and supply limitations and  
9 enhance energy security.

- 10 • Transmission development—Transmission improvements are needed to maintain and  
11 enhance the reliability of the regional power system and support state policies to  
12 access remotely located sources of clean energy. Transmission plans are in place  
13 throughout the region to meet system needs.
- 14 • Grid transformation—The widespread addition of inverter-based technologies (which  
15 use power electronics to convert between alternating current [AC] frequencies or  
16 between AC and direct current [DC] frequencies) and distributed energy resources  
17 (most which the ISO cannot observe or control like traditional resources) would  
18 require transmission upgrades and control system improvements for reliably  
19 interconnecting these resources to the grid. Structural changes to the transmission  
20 and distribution systems are being analyzed and implemented, and new procedures  
21 put in place, to help transform the grid and improve the reliable, economical, and  
22 environmental performance of the system overall.

23 The ISO-NE and its stakeholders are modifying the market design, system operations, and  
24 planning activities to address these regional strategic planning issues, prepare for changes  
25 likely to confront the New England power system, and assess potential system enhancements  
26 and modifications. These planning activities, which are designed to ensure a reliable and  
27 economical power system, take place through an open stakeholder process that includes input  
28 from the Planning Advisory Committee (“PAC”). The ISO-NE also receives advisory input



1 through the NEPOOL committee structure on potential changes to the market design,  
2 provisions of the Open Access Transmission Tariff (“OATT”), and supporting procedures.<sup>10</sup>

3 Auctions in the Forward Capacity Market (“FCM”) ensure the system has sufficient  
4 resources to meet the future demand by paying resources to exist and be available to meet the  
5 projected demand for electricity three years out. For the first seven auctions, excess capacity  
6 in the region helped keep capacity prices relatively low. The eighth Forward Capacity  
7 Auction (“FCA #8”) concluded in a small deficit in necessary power system resources,  
8 resulting in higher prices to meet consumer demand in New England in 2017–2018. FCA #9  
9 concluded with sufficient resources for 2018–2019 but at clearing prices that were higher  
10 than in previous auctions, reflecting the need for new resources to ensure a reliable supply of  
11 power in New England. Since then changes in the auction rules and competition have  
12 lowered the clearing prices substantially. The most recent auction, FCA 14, cleared at an all-  
13 time low price of \$2/kW-month. The surplus capacity in FCA 14 was almost 1,500 MW, or  
14 5%, above the installed capacity requirement, despite a significant amount of capacity (over  
15 2,500 MW) exiting the capacity market, mostly for a one-year period, in response to low  
16 prices.

17 According to the ISO-NE, New England is currently energy constrained with its existing fuel  
18 infrastructure dependent on natural gas. This is especially challenging in the winter. While  
19 ISO-NE projects sufficient resources through 2028 it will be challenged to integrate the  
20 significant quantity of intermittent resources planned for New England. As of April 2019

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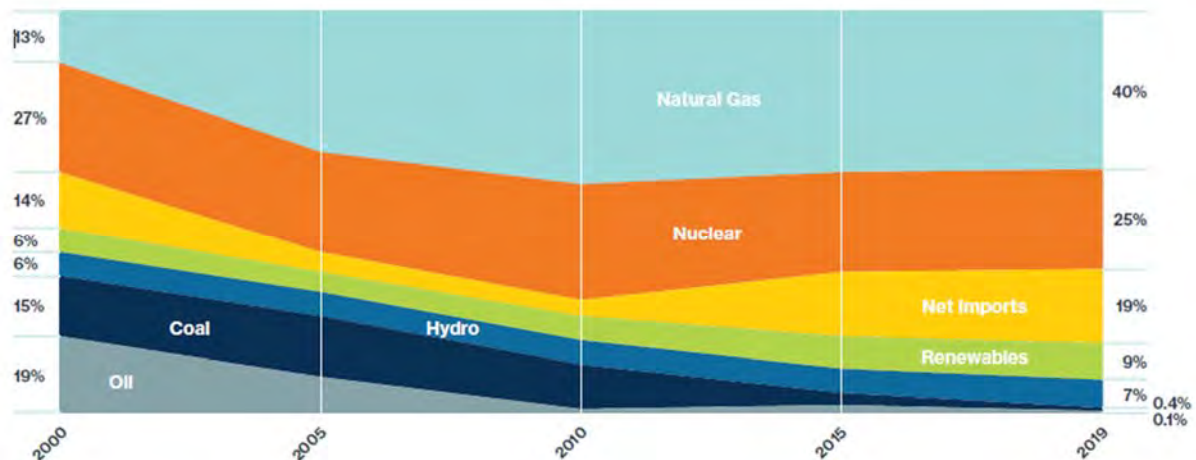
10 *Ibid.*

1 there are planned 11,316 MW of wind resources, 3,070 MW of large-scale PV, and 1,381  
 2 MW of battery storage to be interconnected to the New England power system.

3 *Energy Market Prices*

4 In 2019, natural gas accounted for 40% of total electric energy production in the New  
 5 England region, while coal, oil, nuclear, and hydro/renewables<sup>11</sup> accounted for 0.4%, 0.1%,  
 6 25%, and 16%, respectively and net imports of 18.5%. This compares to a resource mix of  
 7 15% natural gas, 18% coal, 22% oil, 31% nuclear, and 15% hydro/renewables in 2000 (See  
 8 Figure 3.1 below).<sup>12</sup>

9 **Figure 3.1 Percent of Total Electric Energy Production by Fuel Type<sup>13</sup>**

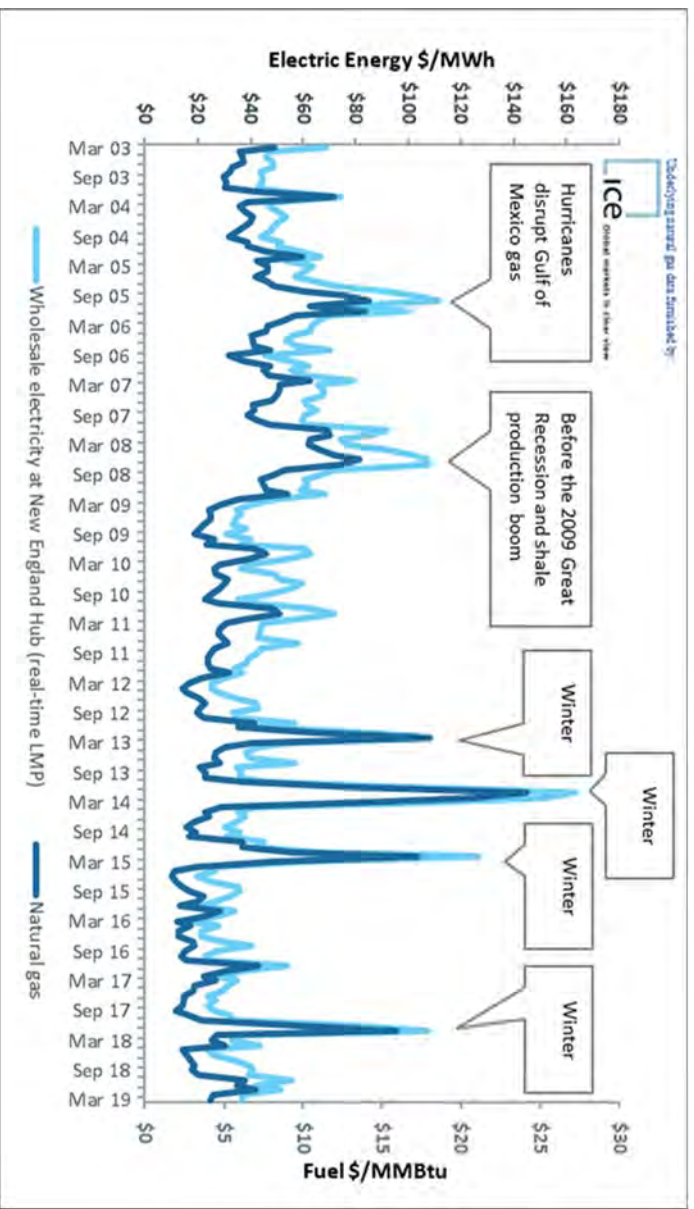


10 Because a majority of New England’s electricity generation is fueled by natural gas, energy  
 11 market prices in New England closely track movement in natural gas market costs (see

11 <https://www.iso-ne.com/about/key-stats/resource-mix>.  
 12 <http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix>  
 13 <http://www.iso-ne.com/about/what-we-do/key-stats/resource-mix>

1 Figure 3.2 below). The marginal unit setting the energy market clearing price is most often a  
2 natural gas fired generator, and such generating units were the marginal units setting the real-  
3 time energy market clearing price during approximately 75% of the hours during 2019.<sup>14</sup>

4 **Figure 3.2. Link between Natural Gas and New England Wholesale Electricity Prices**<sup>15</sup>



5 From 2003 through 2019, the price of natural gas declined significantly in New England with  
6 increasing production from the Marcellus Shale and moderate winter weather that resulted in  
7 minimal natural gas pipeline constraints. As such, wholesale electricity prices declined  
8 simultaneously.<sup>16</sup>

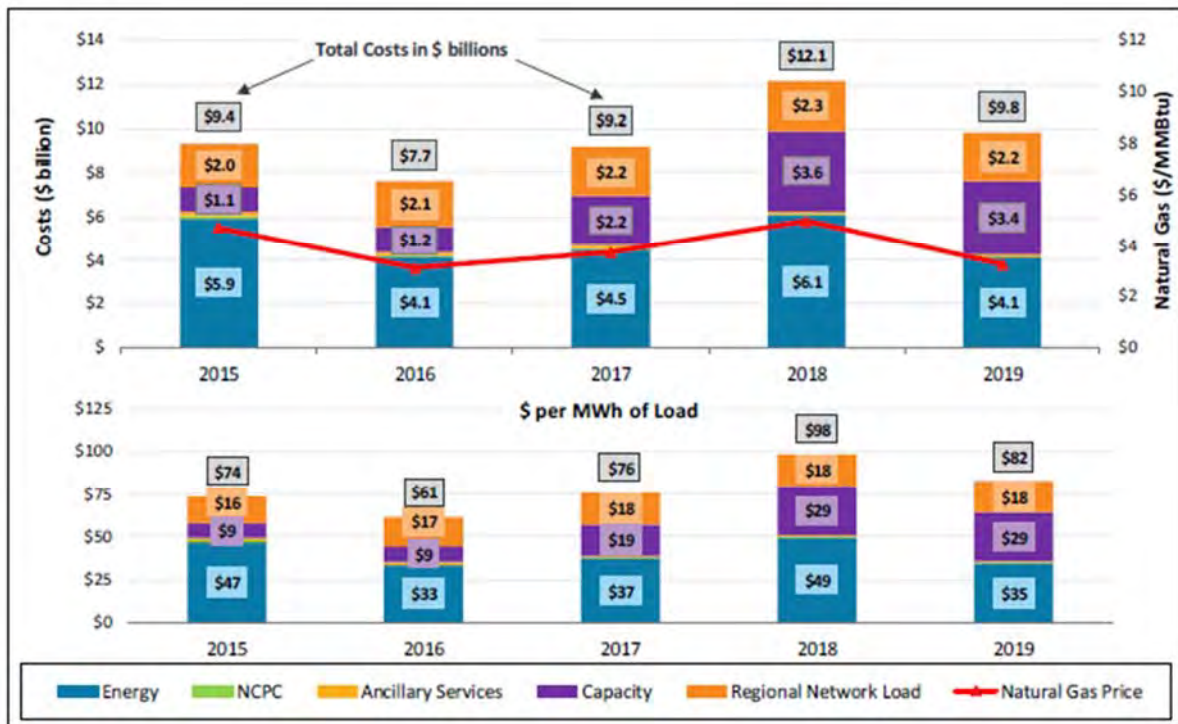
14 ISO New England's Internal Market Monitor, 2019 Annual Markets Report, May 26, 2020, at 100.

15 Source: <http://www.iso-ne.com/about/what-we-do/key-stats/markets>

16 <http://isonewswire.com/updates/2015/10/30/summer-2015-the-lowest-natural-gas-and-power-prices-since-20.html>. In fact, summer 2015 saw the lowest average wholesale power prices since the competitive wholesale electric markets were implemented in 2003.

1 Figure 3.3 below provides a comparison of the wholesale costs of electricity to natural gas  
2 pricing. The trend in wholesale costs to meet the Company’s default service requirements  
3 over this same period is similar to that depicted below:

4 **Figure 3.3. ISO-NE Wholesale Market Cost Summary<sup>17</sup>**



5 **3.2 Supply Planning**

6 New Hampshire partially restructured its retail electricity market in 1998, severing  
7 generation from distribution (with the exception of Public Service Company of New  
8 Hampshire (“PSNH”)), and PSNH, now Eversource, completed divestiture of its generating  
9 assets in 2018. As such, New Hampshire’s electric distribution companies, including

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

1 Liberty, do not own generation. Instead, Liberty procures electricity supply for its customers  
2 on energy service every six months through a solicitation process that is reviewed and  
3 approved by the Commission.

4 The solicitation, bid evaluation, and procurement process that is used to procure energy  
5 service for Liberty's customers complies with a Settlement Agreement approved by the  
6 Commission in Order No. 24,577 (Jan. 13, 2006). The Settlement Agreement has been  
7 amended multiple times to respond to changes in the wholesale market. The most recent  
8 amendment was the result of the Commission's approval to shift the two six-month  
9 solicitation periods from November 1/May 1 to February 1/August 1 to reduce the retail price  
10 volatility of the winter period by splitting the two highest cost winter months (January and  
11 February) into two separate periods. The Commission approved this change in Order No.  
12 25,806 (Sept. 2, 2015). The Commission later found that Liberty's most recent solicitation  
13 for Energy Service complied with the procedures approved in the Settlement Agreement, that  
14 the selection of the winning suppliers was reasonable and appropriate, and that the resulting  
15 retail rates were market-based and thus approved the filing. Order No. 26,431 (Dec. 14,  
16 2020). Liberty expects to issue its next solicitation in May 2021 for a six-month energy  
17 service supply starting on August 1, 2021.

### 18 **3.3 Renewables Planning**

19 Liberty, like all retail suppliers of electricity in New Hampshire, is required to meet annual  
20 Renewable Portfolio Standards ("RPS") based on its sales of energy service. Liberty's  
21 process to comply with the RPS is specified in a Settlement Agreement approved by the

1 Commission in Order No. 24,953 (Mar. 23, 2009). Liberty issues a solicitation for RPS  
2 Renewable Energy Certificates (“REC”) twice a year around the same time as its energy  
3 service solicitations are issued. Liberty contracts for RECs on a short term basis to reflect  
4 both the actual or expected energy service sales. This is done to minimize any oversupply of  
5 RECs due to migration of energy service customers to a retail choice supplier and to take  
6 advantage of market prices.

### 7 **3.4 Transmission Planning**

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

1           **3.5    Impact Assessment**

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

6           **4.   DISTRIBUTION PLANNING**

7           *Introduction*

8           The purpose of this section is to describe Liberty’s distribution planning process, including  
9           the evaluation of wire and non-wire solutions to address system deficiencies. This section  
10          will also discuss compliance with the Commission’s requirements in Docket No. DE 16-097,  
11          the proceeding in which the Company’s most recent LCIRP was reviewed and approved,  
12          along with the approved Settlement Agreement in Docket No. DE 19-120, 2019 Least Cost  
13          Integrated Resource Plan. See Order No.26,039 and Order No. 26,408, respectively.

14          The goal of distribution planning is to provide adequate capacity for safe, reliable, resilient,  
15          and economic service to customers with minimal impact on the environment. To achieve  
16          that goal, the distribution system is planned, measured, and operated with the objective of  
17          providing electric service to customers under system intact conditions (i.e., “normal” or “N-  
18          0”) and first contingency conditions (“N-1”) incorporating existing planning criteria.

19          Planning engineers apply tools and criteria to evaluate the capacity and performance of the  
20          system, while harnessing the capability of existing facilities that are under-utilized before  
21          constructing new facilities. When new facilities are required to address system needs, the

1 Company has initiated a process to evaluate non-wire solutions in addition to more  
2 traditional wire alternatives, as circumstances permit.

3 Liberty updated the Distribution Planning Criteria as part of the settlement agreement  
4 resolving Liberty's most recent rate case, Docket No. DE 19-064. Liberty's distribution  
5 planning criteria is included as Appendix D to this LCIRP.

#### 6 **4.1 Background**

7 For purposes of distribution planning it is important to define the terms "supply system,"  
8 "supply line," "distribution system," and "distribution line."

- 9 • A supply system is a collection of electrical facilities, including transformers and  
10 lines, which transports power between substations. The objective of a supply system  
11 is to move power from one substation to another for use at its final destination. From  
12 a distribution perspective, Liberty's supply system in New Hampshire operates at  
13 voltages between 23 kV and 13.8 kV.
- 14 • Supply lines may be overhead or underground and operate within the voltage levels  
15 described above. At least two supply lines usually serve any one substation,  
16 providing redundant electric service if one line fails.
- 17 • A distribution system is a collection of overhead and underground lines that route the  
18 power from the substation to customers for direct use. Transformers change voltage  
19 at substations from transmission or supply lines to primary distribution levels, which  
20 range from 13.2 kV to 2.4 kV. Distribution voltages are regulated for utilization  
21 within specified ranges in accordance with Puc 304.02. Additional transformation  
22 occurs along each distribution line to convert voltage to a useable value for  
23 customers, such as 120 or 240 volts.
- 24 • A distribution line is a single radial feeder that can serve up to 12 MVA of load. The  
25 main line of each feeder branches into several main routes that end at open  
26 interconnection points. Here, the feeder may be interconnected to an adjacent circuit  
27 to facilitate manual reconfiguration in order to isolate faulted sections of the line and



1 to “switch before fixing” to quickly restore customers. Each feeder is usually divided  
 2 into several switchable elements. During emergencies, segments can be reconfigured  
 3 to isolate damaged sections and re-route power to customers who would otherwise  
 4 have to remain out of service until repairs were made. All individual distribution  
 5 lines in an area constitute a distribution system.

6 Liberty’s distribution system is comprised of supply (or sub-transmission) and distribution  
 7 lines shown on Figure 4.1.

8 **Figure 4.1. Supply and Distribution Lines**

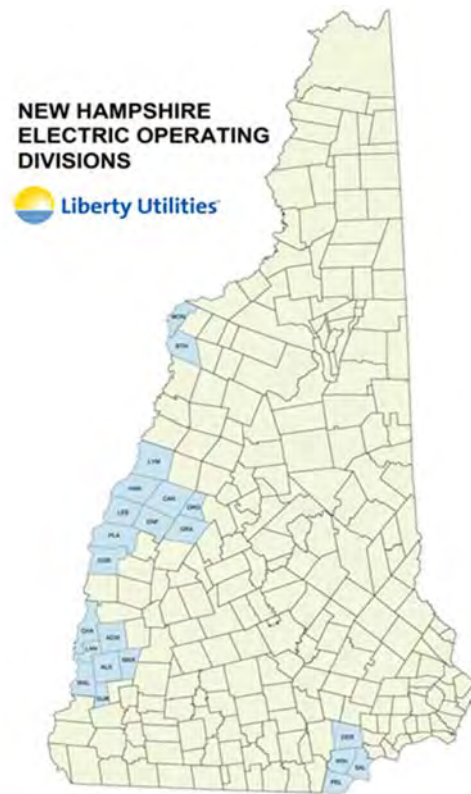
<b>Voltage</b>	<b>Line Miles</b>
<b>13.2 kV Distribution</b>	1,154
<b>2.4 kV Distribution</b>	13
<b>13.8 kV Sub-Transmission (Supply)</b>	18.5
<b>23 kV Sub-Transmission (Supply)</b>	13

9 **4.2 Overview of Distribution System**

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

1

**Figure 4.2 Service Area**



2

*Distribution Substations*

3

The distribution substations within Liberty’s territory are a mixture of stations with one or more transformers. In the Eastern area, Baron Ave, Salem Depot, Olde Trolley and Spicket

4

River substations involve 23/13.8 kV, 5-10 MVA rated transformers with individual voltage regulators applied to the feeders and are wholly owned by Liberty. In the Western area,

5

Hanover, Craft Hill, Lebanon, and Enfield substations involve 13.8 kV Supply and 13.2 kV

6

regulation. Distribution substations supplied by the 115 kV circuits are jointly owned

7

8

1 between Liberty and National Grid. Currently, Liberty and National Grid maintain five  
2 distribution substations<sup>18</sup> containing nine power transformers in the Liberty service territory.

3 *Sub-Transmission System*

4 Liberty's sub-transmission system is designed to provide adequate capacity between load  
5 centers at reasonable cost and with minimal impact on the environment. It provides supply to  
6 distribution substations and consists of those parts of the system that are neither bulk  
7 transmission nor distribution. The voltages for the sub-transmission system include 23 kV  
8 and 13.8 kV. The sub-transmission system is designed in an open loop system and generally  
9 provides a redundant supply for distribution substations. Currently, Liberty maintains ten  
10 sub-transmission lines.<sup>19</sup>

11 *Distribution Feeders*

12 The distribution feeders from each substation are in a "radial" configuration with provisions  
13 for transfer of load between feeders, including feeders from adjacent substations.

14 Distribution feeders originate at circuit breakers connected within the distribution  
15 substations. Protections for faults on the feeders consist of relays at the circuit breaker,  
16 automatic circuit reclosers at points on the mainline, and fuses on the branch circuits. The  
17 feeder may be interconnected to an adjacent circuit to facilitate manual reconfiguration in  
18 order to isolate faulted sections on the line and to "switch before fixing" to quickly restore  
19 customers. Each feeder is usually divided into several switchable elements or sectors.

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18 Golden Rock, Pelham, Slayton Hill, Mt. Support, and Michael Avenue.  
19 Of the ten sub-transmission lines, five are jointly maintained by National Grid and Liberty.

1 During emergencies, segments can be reconfigured to isolate damaged sections and re-route  
2 power to customers who would otherwise have to remain without service until repairs were  
3 made. Liberty will increase the use of distribution automation to expedite these  
4 reconfigurations and increase the ability to remotely operate the system. Currently, the  
5 Liberty distribution system is comprised of approximately 40 feeders ranging from 2.4 kV to  
6 13.2 kV.

#### 7 **4.3 Distribution Planning Process**

8 Liberty's distribution system in New Hampshire is, in general, summer peaking and summer  
9 limited. Liberty conducts an annual capacity planning process with inputs from various  
10 stakeholders that is intended to meet future customer demands, identify thermal capacity  
11 constraints, ensure adequate delivery voltage, and assess the capability of the system to  
12 respond to contingencies that might occur. The distribution planning process is illustrated in  
13 Appendix C and incorporates the Improvement Project Evaluation Process and NWS  
14 Analysis Workbook presented in the strategy document DAS-016 Guidelines for Analysis of  
15 Non-Wires Solutions found in Appendix D. The distribution planning process includes the  
16 following tasks:

- 17 • Forecast peak demand using an econometric model, which includes: (a) weather  
18 adjustment to reflect recent actual peak loads; (b) projected customer and demand  
19 growth; (c) incorporation of historical energy efficiency savings; (d) incorporation of  
20 distributed generation; and (e) incorporation of nontraditional demands, such as  
21 electric vehicles;
- 22 • Review and evaluate system performance, which includes: (a) capacity loadings on  
23 each sub-transmission line, substation transformer, and distribution feeder for

- 1 forecasted peak loads vs. ratings; (b) reliability; (c) asset condition; and (d) power  
2 quality and voltage performance;
- 3 • Implement strategies for Planning Criteria, Area Strategy, and Asset Management;
  - 4 • Identify system deficiencies that need addressing to ensure safe, reliable, resilient,  
5 and economic service to customers, which includes consideration of system flexibility  
6 in response to various contingency scenarios;
  - 7 • Identify wires and non-wires solutions, reflecting the guidelines for non-wires  
8 solutions;
  - 9 • Perform evaluation of wires and non-wires solutions;
  - 10 • Decide on solutions that best meet distribution planning goals, informed by  
11 economic, reliability, feasibility, performance and environmental risks and impacts;  
12 and
  - 13 • Develop proposals for system improvement projects.

14 *Prepare Demand Forecast*

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

1        *Evaluate and Identify System Deficiencies*

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

- 9            • Capacity – Planning criteria for normal and contingency load serving requirements  
10           are applied in concert with the thermal ratings of the facilities to identify capacity  
11           violations. Specifically, the distribution system load is planned, measured, and  
12           forecasted with the goal to serve all customer electric load under system intact  
13           (normal conditions or “N-0”) and N-1 first contingency conditions incorporating  
14           existing planning criteria.
- 15           • Asset condition – Asset condition assessments involve monitoring electric equipment  
16           periodically, and using the data collected from those inspections to determine the  
17           condition of each asset and if any mitigation is required to repair or replace the  
18           equipment.
- 19           • Voltage performance – The normal and emergency voltage to all customers shall be  
20           in line with limits specified by the State of New Hampshire and within the limits of  
21           ANSI C84.1-2016. The ultimate goal is to plan and operate the system such that  
22           delivery voltages are within the limits.
- 23           • Reliability – To measure system performance, Liberty utilizes several performance  
24           measures of reliability. These reliability indices include measures of outage duration,  
25           frequency of outages, system availability, and resilience (response time). Liberty’s  
26           target is for its annual SAIDI and SAIFI<sup>20</sup> metrics to be below the five- year rolling  
27           average, excluding severe weather events. Liberty’s goal is to modernize and

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

1 improve the resiliency and reliability of its distribution system. This includes  
2 targeting pockets in the system that have experienced repeated interruptions and areas  
3 that are radially fed without any provisions for load transfers and have experienced  
4 long interruptions.

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

13 The planning criteria were updated in 2020. Refinements reflect Liberty's collaboration with  
14 Commission Staff to address concern that these were too conservative, such as raising the  
15 equipment rating "take action" limit from 75% to 100% on transformers and feeders, and  
16 raising the load at risk limit from 36 to 120 MWhr for supply lines and raising the load at risk  
17 limit from 60 to 180 MWhr for bulk transformers. Application of these criteria could result  
18 in more load at risk than previous criteria, which generally limited load at risk to below 2.5  
19 MW pending the installation of a mobile substation.

1 **Figure 4.3. Summary of Liberty Utilities Distribution 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, 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 <b>120 MWhr</b> 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 <b>180 MWhr</b> 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 <b>16 MWhr</b> 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 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.

2 Environmental considerations are incorporated into the planning and design of distribution  
3 facilities to ensure that all distribution activities are in compliance with environmental laws  
4 and regulations. Engineers receive Environmental Training and Guidance provided by the  
5 Environmental Engineer on a periodic basis. The training includes process steps for  
6 identifying environmental considerations related to project and work order preparation.  
7 During the planning, design, and estimating stages, it is the responsibility of the Engineering  
8 Department to identify and address any environmental considerations related to project or



1 work order activities. The environmental evaluation assesses certain environmental  
2 conditions through discussions with the property owner or others, review of site plans, and/or  
3 field observations.

4 The planning criteria are applied to new installations and/or significant rebuilds and  
5 coordinated with other Company strategies such as substation replacement requirements or  
6 reliability initiatives. As existing assets reach the end of their useful reliable and economic  
7 life or the reliability of the system worsens, these strategies and criteria can be leveraged to  
8 bring system benefits to the customers.

9 *Prioritize System Deficiencies*

10 System deficiencies are evaluated and prioritized based on two criteria: (1) the impact of the  
11 system deficiency (including the number of customers and demand impacted by the  
12 deficiency), the loading (or percent of rated capacity) on the distribution facilities, and the  
13 safety and environmental impact; and (2) the likelihood that such impacts will occur, ranging  
14 from 1 in 100 years to each year. Liberty's prioritization of the system deficiencies is  
15 illustrated on page 3 of Appendix C. This prioritization process is used as a decision making  
16 guide to prioritize projects for inclusion in the capital budget based on risk, need, and  
17 alignment with Company goals and strategies.

18 *Identify Traditional Solutions*

19 Traditional solutions are Company initiatives that address system deficiencies through  
20 construction of new distribution facilities. Traditional solutions are evaluated in the form of  
21 individual project proposals that are prioritized and submitted for inclusion in future capital

1 work plans. Projects in the load relief program typically consist of new or upgraded  
2 substations and new distribution feeder mainline circuits. Other projects in this program are  
3 designed to improve the resiliency and reliability of the network and improve the voltage,  
4 power quality, and power factor performance of the system. Traditional solutions are  
5 evaluated based on the project's scope, schedule, and overall cost effectiveness. Traditional  
6 solutions may also address asset replacement needs and reliability opportunities in  
7 conjunction with their impact on capacity.

8 *Identify Non-Wires Solutions ("NWS")*

9 Non-wires solutions ("NWS") are initiatives that may reduce, avoid, or defer the need for  
10 investment in distribution facilities through actions that reduce peak demand via targeted  
11 energy efficiency and load control programs, including electric energy storage technologies  
12 (e.g. batteries), or increase peak generation via distributed generation. These are also  
13 referred to non-wires alternatives ("NWA"). As described more fully later in this Section,  
14 NWSs include energy efficiency programs, demand response and load control programs,  
15 including electric energy storage, and DG programs that complement and improve operation  
16 of existing transmission and distribution systems, and that individually or in combination  
17 defer the need for upgrades to the transmission and/or distribution system.

18 The Company has integrated non-wires solutions in the distribution planning process. The  
19 goal is to seek the combination of traditional and non-wires solutions that best address  
20 capacity deficiencies in a cost effective manner considering the total cost and potential risks,  
21 including reliability, feasibility, performance, and environmental risks and impacts. As part

1 of this process, a cost and risk analysis is conducted at a level of detail commensurate with  
2 the scale of the problems and the cost of potential solutions. Non-wires alternatives are  
3 screened for initial feasibility, according to the following criteria:

- 4 • Distribution deficiency needs to be addressed in no less than two years, allowing for  
5 development of potential non wires solutions;
- 6 • Distribution deficiency is not based on asset condition; and
- 7 • Traditional solutions, based on engineering judgement, will likely cost more than \$0.5  
8 million, providing sufficient cost savings to evaluate and implement a potential NWS.

9 These screening criteria result in a threshold of acceptance for non-wires projects stemming  
10 from the planning process that seeks to maximize the in-service life and utilization of  
11 existing assets. A non-wires solution is often determined to be infeasible or noncompetitive  
12 when one traditional solution can address a combination of issues that includes asset  
13 condition. For example, traditional solutions typically address a combination of load  
14 capacity, reliability, and asset condition issues. As with traditional solutions, specific non-  
15 wires solutions are evaluated based on the project's scope, schedule, and overall cost  
16 effectiveness. Refer to Strategy document DAS-016 Guidelines for Analysis of Non-Wires  
17 Solutions which describes Liberty's Project Evaluation Process and NWS Analysis  
18 Workbook found in Appendix D.

#### 19 **4.4 Tools to Evaluate the Distribution System**

20 A variety of tools enable engineers to evaluate fault duty, coordination of protective devices,  
21 loading on all facilities, and voltage on all electrical system elements. The actual electrical

1 configuration can be modeled in these tools, which allow the simulation of various system  
2 conditions and subsequent analysis. The primary modeling and analysis application tools  
3 are:

- 4 • The Synergi Electric 6.0 load flow program models supply system and distribution  
5 feeders. It also assists in determining fault coordination between protective  
6 equipment and the short circuit duty at all sub-transmission and distribution facilities.
- 7 • The Geographical Information System (“GIS”) geographically maps customer  
8 locations, supply and distribution lines, and is used to determine demands at a service  
9 point level and/or a supply transformer level. Liberty has developed a process to  
10 extract the distribution attributes from the GIS system and the customer demand  
11 history from the Customer Information System (Cogsdale) to update the load flow  
12 model periodically. The Company is in the process of upgrading its GIS and expects  
13 to complete the data migration between 2021 and 2022.
- 14 • The Supervisory Control and Data Acquisition (“SCADA”) system provides for  
15 monitored facilities, real time loading and voltage data and provides historical status,  
16 load and voltage data used to support various system planning activities.
- 17 • The Responder System serves as an outage management system (“OMS”) and  
18 provides real time outage information and a consolidation and statistical analysis of  
19 reliability data. The Company is in the process of upgrading its OMS system to an  
20 Advanced Distribution Automation System (“ADMS”). Refer to Section 5.3 Liberty  
21 Utilities Distribution Grid Modernization Initiatives for details.
- 22 • The Quadra system serves as a work management tool, as well as an estimation tool.  
23 The Company is in the process of upgrading its enterprise resource planning tools  
24 which will result in improved business processes and project documentation. In  
25 addition, the Company will integrate the Distribution Design Studio (DDS) with the  
26 GIS and AMI application to improve the design and estimating processes.

27 Figure 4.4 below compares the proposed evaluation tools being implemented by Liberty with  
28 those currently in use.

1

**Figure 4.4. Evaluation Tools: Liberty Utilities**

<b>Application</b>	<b>Proposed</b>	<b>Existing</b>
<b>Load Flow</b>	Synergi Electric / CYME (to be determined)	Synergi Electric
<b>Circuit Analytics</b>	ArcGIS Dashboard / Smart M.Apps	None
<b>Circuit Protection</b>	ASPEN /Synergi Electric	Synergi Electric / Light-Table
<b>Mapping/GIS</b>	ArcGIS Desktop	ArcGIS 10.1
<b>Energy Management</b>	Telvent Oasis / ADMS Schneider	Telvent Oasis / Responder Explorer
<b>Plant Information</b>	SAP	Great Plains
<b>Circuit Loading</b>	ADMS / Pi	Telvent Oasis
<b>Interruption Analysis</b>	ADMS / ArcGIS Dashboard / Smart M.Apps	Responder Archive
<b>Distribution Design</b>	Distribution Design Studio (DDS)	ArcGIS Designer
<b>Asset and Relay Management</b>	Powerbase	Databases
<b>DERMS</b>	ADMS / Tesla	Tesla
<b>Distribution Automation and Energy Conservation</b>	ADMS / SEL DNA	Local DA Schemes / No Energy Conservation
<b>Remote Applications</b>	ArcGIS Survey 123 / TerraSpectrum	ArcGIS Survey 123

2 These existing or proposed tools could be revised, replaced, and/or updated once the Grid  
3 Modernization Program described in Section 5 is implemented by Liberty in New Hampshire.

4 **4.5 Reliability Metrics**

5 Since the total system is involved in supplying the customer, ensuring an acceptable  
6 reliability of service to all customers requires designing the supply and the distribution  
7 systems in an integrated manner, taking into account both capacity limitations and reliability

1 of service initiatives to limit the interruption of energy delivery. The metrics that measure  
2 service reliability are SAIFI and CAIDI. The product of these two indices is the SAIDI per  
3 customer served. The Company measures its reliability performance using SAIDI and  
4 SAIFI, as required by the Commission. These indices are mathematically calculated as  
5 follows:

6  $SAIFI = \text{Number of Customer Interruptions ("CI")} / \text{Number of Customers}$   
7  $\text{Served ("CS")}$

8  $SAIDI = \text{Customer Interruption Durations ("CMI")} / \text{Number of Customers}$   
9  $\text{Served ("CS")}$

10 *Where:*

11 CI = Customers Interrupted

12 CMI = Customer Minutes Interrupted

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

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

18 The primary causes of distribution system-related outages in New Hampshire are tree  
19 contacts, equipment failure, storms, vehicle accidents, and animal contacts. To limit the  
20 number of customers affected by these outages the Company has implemented several

1 infrastructure improvement programs including (1) fast feeder patrols,<sup>21</sup> (2) an inspection and  
2 maintenance (“I&M”) program, (3) vegetation management, (4) a recloser program, (5) bare  
3 conductor replacement, (6) underperforming area mitigation, and (7) distribution automation  
4 (“DA”)/grid modernization. As described in Section 5, the Grid Modernization Program will  
5 greatly enhance the ability of Liberty to improve planning, reliability, resilience, asset  
6 management, and operational efficiency to reduce the frequency and duration of customer  
7 outages when implemented.

#### 8 *Infrastructure Improvement Program*

9 Liberty’s Infrastructure Improvement Program includes the following initiatives and  
10 strategies to improve the resiliency of the distribution system:

- 11 • Inspection and Maintenance Program (“I&M”) – The inspection and maintenance  
12 program identifies overhead equipment, including capacitors, reclosers, cutouts,  
13 crossarms, insulators, poles, guys and anchors, and switches that may be at the end of  
14 their useful lives and in need of replacement. Lightning protection upgrades include  
15 the installation of arresters, grounding, and equipment bonding. The I&M program is  
16 augmented with infrared inspections of line and substation equipment, substation  
17 equipment visual and operational inspections, and patrols of distribution supply  
18 facilities.
- 19 • Animal Intrusion Program – Additional actions include application of wildlife  
20 protective devices and substation animal fencing to limit animal intrusion on  
21 distribution equipment and at substations.
- 22 • Overloaded Transformer Program – This program targets replacement of overloaded  
23 transformers. Refer to DAS-006 Distribution Line Transformer Strategy for details.

---

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

- 1       • SCADA / Distribution Automation Program – These initiatives include improving  
2       resiliency in distribution system areas that have historically underperformed by  
3       implementing new SCADA devices with communication abilities to improve  
4       response time to outages. The DA program allows for the installation of automatic  
5       switching devices at selected locations to isolate faulted feeder sections, which can  
6       limit the number of customers affected by a fault on the electric distribution system.  
7       For details refer to DAS-002 Distribution Automation Strategy.
  
- 8       • Low voltage mitigation program – Voltage mitigation is planned for those areas that  
9       have experienced issues with low voltage. Mitigation includes the installation of  
10      capacitor banks and voltage regulators, voltage conversions, load balancing, and  
11      reconductoring.
  
- 12     • Underground Residential Development (“URD”) refurbishment program – This  
13     program recommends URD cable for replacement and/or cable injection based on  
14     condition and/or poor operating history. For details refer to DAS-014 URD/UCD  
15     Cable Strategy document.
  
- 16     • Underground cable replacement program – This program recommends replacement of  
17     Company-owned underground cable based on condition and/or poor operating  
18     history. Typically all cable over 60 years of age is replaced and cables that have  
19     experienced three faults in a five year period are targeted for replacement. For details  
20     refer to DAS-013 Underground Getaway Cable document.
  
- 21     • Worst performing feeder program – This program tracks the worst performing feeders  
22     for the Company and recommends mitigation to address the main causes of  
23     interruption. For details refer to DAS-010 Poor Performing Feeder Strategy.
  
- 24     • Pocket of poor performance program – This program tracks the worst performing sub  
25     sections of distribution feeders and recommends mitigation to address the main  
26     causes of interruption. While these areas do not contribute greatly to the overall  
27     reliability performance of the Company, they are very significant to the customers in  
28     the pocket as they experience more frequent outages. For details refer to DAS-009  
29     Pockets of Poor Performance Strategy.
  
- 30     • Bare conductor replacement – Spacer cable is installed in areas prone to tree outages  
31     that are too costly to rely on vegetation management practices alone to mitigate  
32     feeder lockouts. The application of spacer cable (a covered conductor resistant to tree  
33     related outages) significantly improves mainline circuit performance during windy



1 and stormy conditions and affords protection against incidental tree-conductor contact  
2 at the end of the trim cycle, as well as contact resulting from branches falling from  
3 above the trim zone. Replacement of mainline bare conductor with spacer cable has  
4 proved highly beneficial. Spacer cable is an overhead primary distribution system  
5 that consists of covered conductors held in a close triangular configuration by spacers  
6 that are supported by a messenger and attached to a bracket on a pole. Spacer cable  
7 installations are recommended in heavily treed areas to mitigate the potential for  
8 outages caused by incidental contact of tree limbs to the primary conductors. In some  
9 instances, it may be possible to use tree wire on crossarms as a lower cost alternative  
10 to spacer cable.

11 • Single-phase recloser and trip saver program – Single-phase reclosers and “Trip  
12 Saver” cutouts target circuit segments that would realize reliability benefits from  
13 single-phase tripping and reclosing, as well as isolating faults down to the smallest  
14 single-phase segment possible. These devices are designed to interrupt circuit  
15 segments following a transient or temporary fault condition and then automatically  
16 restore the segment after a short period to allow the fault to clear. These devices not  
17 only improve reliability of service, but also avoid the cost of dispatching a  
18 troubleshooter or line crew to the scene to replace the fuse. Liberty uses single-phase  
19 reclosing devices at select locations of the distribution system to provide mitigation  
20 against transient faults as well as limit the number of customers impacted for  
21 permanent faults.

22 • Pollinator Program – The Company maintains off road distribution/supply lines in the  
23 communities of Lebanon, Hanover, Enfield, and Salem. Transmission corridors  
24 (often leased rights-of-way) convert terrestrial forest habitat to low-growing  
25 shrub/scrub/grassland habitat that is conducive to the safe and reliable transmission of  
26 energy. Periodic Utility Vegetation Management (“UVM”) is required to maintain  
27 vegetation in a state that promotes the safe and reliable transmission and distribution  
28 for our customers. UVM seeks to establish and conserve early successional grassland  
29 habitat which has benefits beyond regulatory compliance. The Company is looking  
30 to return to Integrated Vegetation Management (“IVM”) which simultaneously  
31 maintains infrastructure security and benefits wildlife conservation initiatives,  
32 including pollinator habitat. Currently the Company performs vegetation  
33 management using only mechanical means which promotes invasive woody material,  
34 thereby hampering visibility and movement along the corridor. Implementing IVM  
35 can discourage the aggressive, invasive woody material as well as invasive brush. By  
36 encouraging native local shrubby habitat and pollinator habit, it will require less

1 resources in the future to keep the corridor safe and reliable while promoting natural  
2 and healthy wildlife and pollinator habitat.

3 *Corporate Resiliency Improvement Initiatives*

4 The Corporate agenda for Liberty and its utility affiliates is to move them into the 21<sup>st</sup>  
5 century by exploring opportunities to utilize newer technologies to provide the resiliency  
6 desired by customers. New technologies are being developed continuously and at a rapid  
7 pace. Customer demands are also changing based upon their experiences and interactions  
8 with many other companies that are utilizing new systems to serve their customers.

9 Liberty is committed to adapting to these changing consumer demands as described in the  
10 Company's witness testimony in Docket No. DE 19-197, Development of a Statewide,  
11 Multi-Use Online Energy Data Platform, and Docket No. DE 17-189, Petition to Approve  
12 Battery Storage Program. Liberty serves a wide variety of customers with geographic and  
13 cultural differences, and these issues and solutions can be assessed to determine the extent of  
14 the solution benefits across all regions. This variety allows for knowledge gained from pilot  
15 projects to benefit all customers. In addition, the Corporate agenda is not focused on a single  
16 commodity; therefore, knowledge gained from one commodity will be used to assess the  
17 potential benefits across all commodities and customers. As Corporate explores new  
18 technologies, Liberty will develop systems that are more resilient, sustainable, and customer  
19 oriented in an effort to create thriving communities.

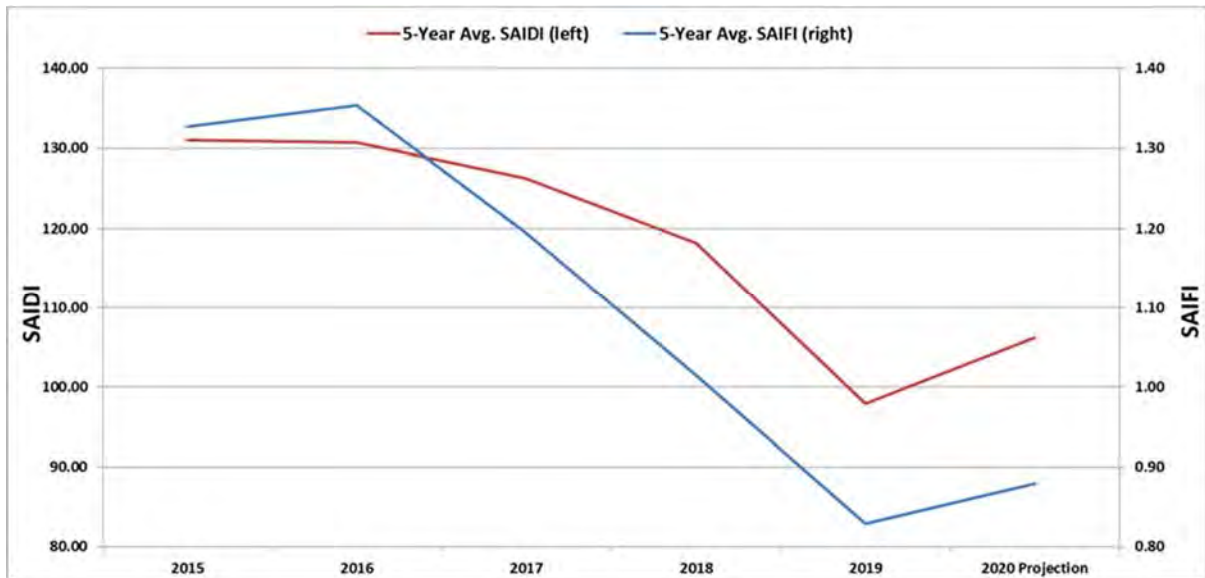
20 The Corporate agenda targets the following initiatives for its New Hampshire Customers:

- 1           • Aging Equipment – This resiliency initiative aims to replace equipment that is over  
2           50 years of age and/or has shown signs of deterioration. Liberty prefers a proactive  
3           approach to replace aging and/or deteriorated equipment prior to a failure because  
4           operating equipment until the eventual catastrophic end of life failure results in a  
5           major lengthy outage as well as creating a potentially dangerous situation within a  
6           substation or near the public.
  
- 7           • Distribution Automation – This initiative aims to improve reliability performance and  
8           power quality, increase power system efficiency by automating processes for data  
9           preparation, optimal decision making and control of distribution operations.
  
- 10          • Animal Guarding – This initiative includes the addition of wildlife and asset  
11          protection equipment on company Substation and Distribution Line assets to improve  
12          reliability performance by reducing outages caused by animal contact.
  
- 13          • Substation Security - This initiative aims to improve the security at substations from  
14          outside threats such as theft, vandalism and cyber-attacks.

15          As shown in Figure 4.5 below, Liberty’s reliability performance improved over the last five  
16          years, as demonstrated by the declining trend in SAIDI and SAIFI metrics since 2015.

1

**Figure 4.5. Calendar Year Electric Reliability Trends, 2015–2020**



2

**4.6 Demand-Side Resources**

3

Demand-side resources can be broadly defined as systems and controls in customer facilities

4

that allow customers or the utility to reduce or control their use of energy. These generally

5

consist of energy efficiency measures, demand response efforts, distributed generation,

6

energy storage, and load controls. Energy efficiency measures generally produce savings

7

whenever a particular load is running, while renewable distributed generation, such as wind

8

and solar photovoltaic (“PV”), provides energy on an intermittent and uncontrollable basis.

9

These types of resources are therefore considered passive resources. Other demand resources

10

are dynamic and can be called on and utilized when economically justified; these are

11

considered active demand resources.

12

Active demand resources, coupled with incentives such as demand response payments or

13

dynamic time-of-use rate design, can create opportunities for customers to benefit from time-

1 specific reductions in energy consumption and/or a shift in the hours that energy is  
2 consumed. Through the use of active demand resource technologies and appropriate  
3 incentive mechanisms, retail costs can more closely reflect the time varying cost to produce  
4 and deliver electricity, and result in behavior changes that create higher system efficiencies.  
5 Generally, this approach works in conjunction with smart metering systems that measure  
6 consumption data at regular intervals and provide such data directly to the customer.

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

#### 10 **4.7 The Link between Demand Response and Planning**

11 As of June 1, 2010, demand response resources participate on a comparable basis with  
12 generation in the regional FCM administered by ISO-NE. Such resources are able to  
13 compete with generation and imports, allowing New England to meet its resource adequacy  
14 requirements. On June 1, 2012, ISO-NE implemented changes to the demand response  
15 program to comply with FERC Order 745. FERC Order 745 requires active demand  
16 resources to be fully integrated into the competitive energy markets administered by ISO-NE.

17 Since Order 745 was approved, FERC has continued to conduct rulemakings to remove  
18 barriers to the integration of DERs with two additional Orders.

19 On February 15, 2018, FERC issued a Final Order 841, establishing guidance related to  
20 Electric Storage Participation in Markets Operated by Regional Transmission Organizations

1 and Independent System Operators. The stated objective of Order 841 was to remove  
2 barriers to the participation of electric storage resources in the capacity, energy, and ancillary  
3 service markets operated by RTOs and ISOs in organized markets in North America. After a  
4 year of deliberation, FERC issued FERC Order 841a, denying a requested rehearing with  
5 respect to the lack of a State “opt-out” for local energy storage resources. Order 841a was  
6 appealed to the U.S. Court of Appeals for the District of Columbia in Docket No. 19-1142 in  
7 which oral arguments were heard on May 5, 2020, and the Three Panel Court delivering it  
8 unanimous opinion on July 10, 2020, supporting the Commission’s order.

9 On September 17, 2020, FERC issued Final Order 2222 requiring RTOs/ISOs to coordinate  
10 with DER Aggregators, electric utilities, and local and state regulators to develop and submit  
11 compliance filings on July 19, 2021. This final rule enables these resources to participate in  
12 the regional organized wholesale capacity, energy, and ancillary services markets alongside  
13 traditional resources.

14 The development and ownership of active demand response resources will then be based on  
15 market incentives as perceived by the developers of such resources. The impact of these  
16 resources on Liberty’s distribution system will depend on the response by these resources to  
17 ISO market signals and Commission guidance.

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

1           **4.8    Incorporation of DG Facilities into Distribution Planning**

2           Liberty has experienced a significant increase in the amount of DG being interconnected to  
3           its distribution system, mostly through the installation of customer-sited solar generation.<sup>22</sup>

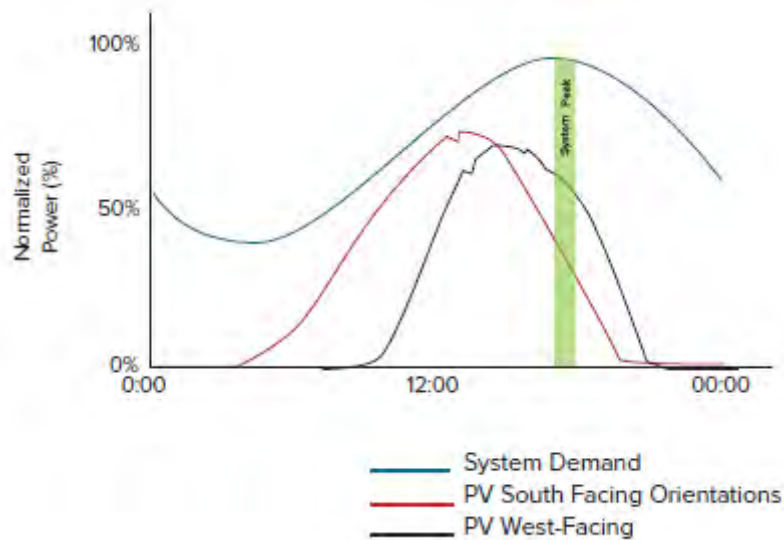
4           The decision to install and run DG systems is made by customers based on economic,  
5           environmental, and operational drivers. Because the Company does not control and cannot  
6           be assured of the development or operation of specific DG systems, their impact on system  
7           planning is typically experienced after they are in place. Once in place, the Company  
8           assumes DG output will continue at its future load projections, while at the same time  
9           recognizing its obligation in some cases to provide standby service to customers with DG  
10          systems. The Grid Modernization Program will substantially improve the ability of Liberty  
11          to incorporate these distributed resources safely and reliably by providing real-world,  
12          detailed system data for utility engineers and planners, along with real-time visibility of grid  
13          performance by utility operators.

14          The majority of the newer DG systems are renewable photovoltaic (“PV”) and wind  
15          generation systems. The output of these systems is intermittent and, in general,  
16          uncontrollable. PV systems typically offer peak reductions during summer peaks in the  
17          range significantly below their ratings, because summer peaks typically occur in the mid-  
18          afternoon on the hottest days when the sun is not at the optimal angle and PV panels are less  
19          efficient due to ambient temperatures. Figure 4.6 below, as published in a 2013 study from  
20          the Rocky Mountain Institute, illustrates this effect:

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

1 **Figure 4.6. Illustrative Example of the Effect of PV positioning on System Peak**<sup>23</sup>



2 PV typically does not impact winter peak loads, because winter peaks occur in the evenings.  
 3 Wind resources are also highly variable and may not impact peak loads the Company expects  
 4 to experience at any given location due to this variability. It is likely that additional  
 5 combined heat and power generation may be installed as fuel prices increase and  
 6 technologies become more mature. However, in many cases such systems run coincident  
 7 with thermal requirements that are heavily weighted towards the winter months and therefore  
 8 may not be able to significantly impact summer peak loads. To the extent that DG does  
 9 impact peak loads, the Company incorporates their historic output into system planning  
 10 going forward through the distribution planning process discussed in Section 4.

11 The interconnection process for customers to install and run DG in parallel with Liberty’s  
 12 distribution system is dependent on the DG system’s size and technology. DG systems with

<sup>23</sup> Source: Rocky Mountain Institute, “A Review of Solar PV Benefit and Cost Studies,” 2<sup>nd</sup> Edition, September 2013, at 30.



1 power ratings of 100 kW or less may utilize a simplified application process to facilitate  
2 interconnection with the Company’s electric power system. Larger DG systems proposing to  
3 interconnect with the Company must undergo a more robust application process and must  
4 supply sufficient technical information to allow the Company to determine the scope and cost  
5 of any potential modifications to the Company’s distribution system required to  
6 accommodate the DG system. This typically requires an engineering study performed by the  
7 Company at the DG developer’s cost. Safety, system operation and protection, and service  
8 quality are the Company’s primary considerations in such studies. For larger DG systems,  
9 the Company takes into consideration such parameters as voltage and frequency fluctuations,  
10 protective device coordination, available fault duty impact, potential for islanding, and ability  
11 to automatically and manually isolate the DG from the system.

#### 12 **4.9 Smart Grid**

13 RSA 378:38, IV, requires a utility’s LCIRP to include an assessment of “Smart Grid”  
14 technologies. For the purposes of this LCIRP filing, Liberty defines smart grid technologies  
15 as digital technology that allows for two-way communication between the utility and its  
16 customers, and the application of computer-based remote control and automation  
17 technologies to electric transmission and distribution systems.<sup>24</sup> Smart Grid consists of

---

24 As defined by the U.S. Department of Energy’s definition of “smart grid.” See, U.S. Department of Energy, <http://energy.gov/oe/services/technology-development/smart-grid>, and [https://www.smartgrid.gov/the\\_smart\\_grid/smart\\_grid.html](https://www.smartgrid.gov/the_smart_grid/smart_grid.html).

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1 controls, computers, automation, and new technologies and equipment working together,  
2 which respond digitally to quickly changing electric demand conditions.<sup>25</sup>

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

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

17 In 2019, Liberty engaged a "Smart Grid" consulting company, CMG Consulting LLC, to  
18 work with our planners and engineers to evaluate the many potential "smart grid"  
19 technologies, including a detailed cost/benefit analysis of the technologies that would provide

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25 [https://www.smartgrid.gov/the\\_smart\\_grid/smart\\_grid.html](https://www.smartgrid.gov/the_smart_grid/smart_grid.html).

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

1 the maximum benefits for Liberty's customers in New Hampshire. This Grid Modernization  
2 report was completed in June 2019 and was updated in November 2020 and serves as the  
3 basis for the Grid Modernization Program described in Section 5 of this LCIRP. The CMG  
4 Grid Modernization report is provided in Appendix E to this LCIRP, and provides the  
5 economic basis for concluding that certain smart grid technologies selected by Liberty will  
6 provide substantially more benefits than costs to its customers.

7 Smart grid investment may require regulatory changes. For example, some smart grid  
8 technologies rely on innovative rate structures (i.e., time of use rates), which would require  
9 approval through additional regulatory proceedings. On February 12, 2019, the Commission  
10 Staff submitted its recommendation on grid modernization in Docket No. IR 15-296 and  
11 proposed that the LCIRP be replaced by a new submission, an Integrated Distribution Plan.  
12 After providing a round of public comment, the Commission issued Order No. 26,254 which  
13 provides acceptance of Staff's recommendations. While this Grid Modernization Order is on  
14 hold pending a motion for rehearing, Liberty has attempted to incorporate the spirit of this  
15 order into this LCIRP. Liberty will continue to be an active participant as the Grid  
16 Modernization investigation progresses.

#### 17 **4.10 Capital Investment Plans**

18 System capacity, performance, asset, and reliability and resiliency improvement capital  
19 projects are identified as a result of reviews and the annual capacity planning process. The  
20 adopted solutions are cash flowed by year and entered into the five-year capital investment  
21 plan along with other capital initiatives such as new business, public requirements, response

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1 to damage and failure, and other mandatory category projects. The five-year plan is then  
2 optimized according to project need, risk management, and availability of resources. Once  
3 initiated, multi-year projects are typically progressed to completion with their system  
4 solutions incorporated into current and future studies. The annual budget of capital projects  
5 greater than \$100,000 is filed with the Commission as part of the Form E-22 filing required  
6 pursuant to Puc 308.07.

7 Figure 4.7 summarizes the Company's five-year capital investment plan totaling \$120  
8 million, and provides the definition for each of Liberty's budget categories.

1 **Figure 4.7. Summary of 5-Year Capital Investment Plan and Budget Category Definitions**

Category	2022-2026 Capital Budget (\$)	2022-2026 Capital Budget (%)	Project Prioritization Category	Definition
<b>Mandated</b>	\$22.6	18%	Mandated / Impending regulatory obligations / Damage/Failure Facilities relocations	Programs that are required by Statutes, Codes, etc. that have limited, if any, discretionary component relative to meeting a prescribed program. These programs would be related to specific obligations that have been imposed on the utility to carry out the project
<b>Growth</b>	\$28.3	23%	Growth	Capital needed to support servicing growth in the customer base
<b>Regulatory Programs</b>	\$0	0%	Regulatory programs with mechanisms	Programs such as the Tesla Battery Program.
<b>Discretionary</b>	\$73.3	59%	Discretionary projects	All other programs with a business case justification
<b>5-Year Total</b>	\$124.2	100%		

2 **4.11 Non Wires Solutions Integration Process**

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

1 In some cases where the expansion of the T&D system is required on a localized basis to  
2 meet increased demand, there may be alternatives that reduce demand at a potentially lower  
3 cost than T&D infrastructure investments. When non-wires alternatives can be provided at a  
4 lower cost and risk than traditional infrastructure, these programs can enhance the  
5 Company's ability to provide service at the lowest reasonable cost and risks to customers

#### 6 **4.12 Liberty NWS Planning Process**

7 Liberty has incorporated the evaluation of Non-Wires Solutions into its ongoing system  
8 planning process as described in this section. Refer to strategy document DAS-016  
9 Guidelines for Analysis of Non-Wires Solutions. This initial screening was modeled after  
10 Unitil's Cost/Benefit Analysis Spreadsheet presented in their 2020 Least Cost Integrated  
11 Resource Plan.

12 To ensure proper coordination and communication at all levels of the organization, the cross-  
13 functional team includes representatives from electric supply planning, electric system  
14 planning, energy efficiency administration, system standards, policies and codes, and  
15 regulatory. With the planning team in place, the Company is prepared to evaluate non-wires  
16 solutions on an equal basis as traditional infrastructure.

17 As described in this document, the Company applies a set of screening criteria for evaluating  
18 non-wires solutions specific to its service territory and size of its operation. The process  
19 begins with demand forecasts that are prepared in sufficient geographic detail to make non-  
20 wires solutions viable. Demand forecasts are prepared for each substation, sub-transmission  
21 line, and feeder under extreme weather scenarios to determine if capacity is adequate to meet

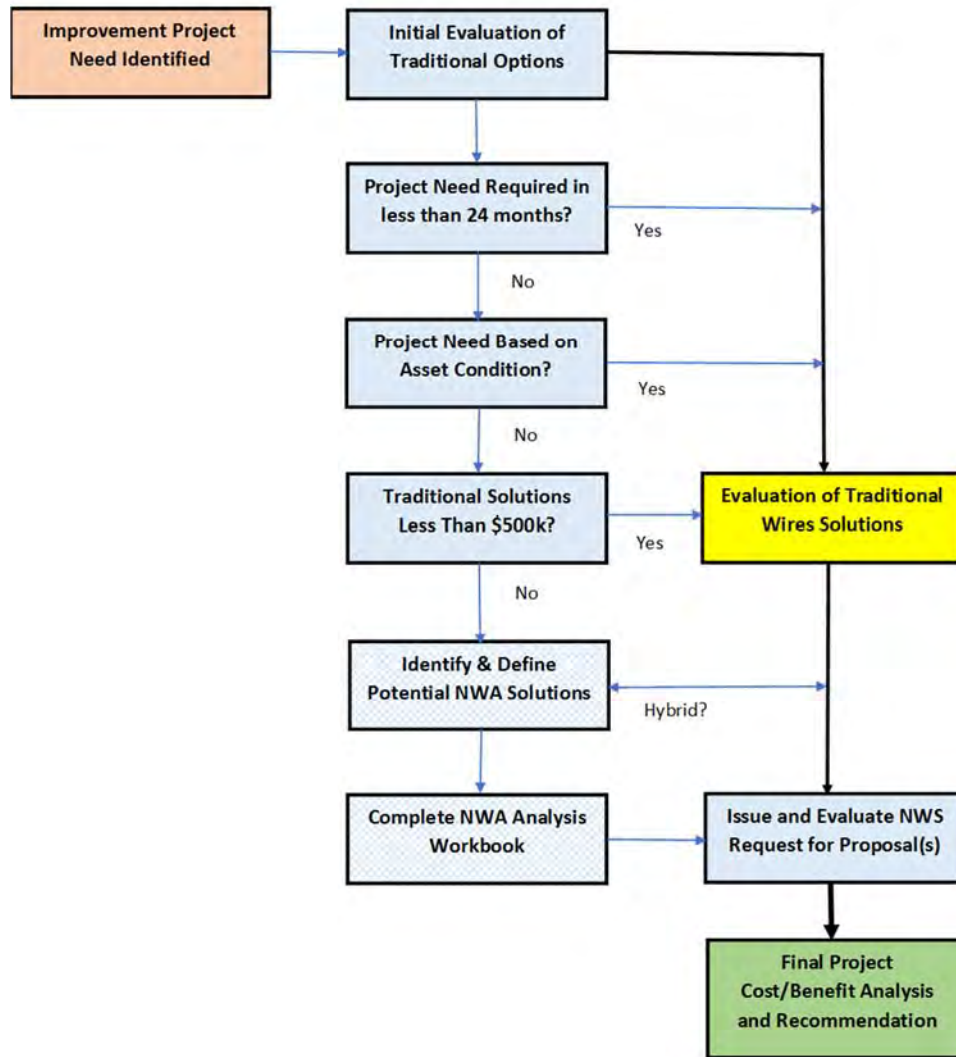
1 demand under normal and contingency configurations. Planning criteria of normal and  
2 contingency configurations are then applied in concert with the thermal ratings of the  
3 facilities to identify if and when any of the planning criteria are violated. The geographic  
4 detail of the starting point enhances the feasibility of non-wires solutions, and the operating  
5 characteristics ensure that the deficiency is not based on asset condition.

6 Next, the planning group develops wires and non-wires alternative proposals that address  
7 those instances when and where the planning criteria are violated. The group then performs a  
8 financial analysis of each proposal and prioritizes them.

9 Finally, the group submits the proposals as part of the Company's capital plan. Figure 4.8  
10 below summarizes Liberty's NWS process flow.

1

**Figure 4.8. Liberty NWS Evaluation Process**



2  
3  
4  
5  
6

Two important aspects of the comparative evaluations involve the load profile of the solutions relative to the demand on the system and the financial and risk analysis to put the alternatives on an equal footing. The T&D system can experience peak demand at different times of the day, in different geographic locations, and during different seasons. The ability of a non-wires alternative to reduce, defer, or eliminate a traditional infrastructure



1 investment, therefore, depends on the alignment of hour and season of the peak demand, with  
2 the hourly and seasonal profile of the non-wires alternatives savings. The non-wires  
3 alternative solutions are designed to include those measures that provide a saving profile that  
4 best matches the demand profile it is intended to reduce. The Company also compares a  
5 solution’s risk profile (for both wires and non-wires) based on a number of risk factors,  
6 including reliability, feasibility, performance, and environmental risks. For each potential  
7 traditional and non-wires solution, each of these risk factors is rated on a scale of one to four,  
8 then summed to calculate a total project score for each Traditional and NWS options. Figure  
9 4.9 below provides a summary of each of the risk factors.

10 **Figure 4.9. Project Risk Factor Summary**

	<b>Step</b>	<b>Description</b>
<b>1.</b>	Reliability	The risk that a potential solution can or cannot meet customer reliability requirements.
<b>2.</b>	Feasibility	The risk that a potential solution is commercially available and can be accomplished in time to meet the needs of customers
<b>3.</b>	Performance	The risk that a potential solution will perform as predicted including the amount of “real-world” operational data for the proposed technology
<b>4</b>	Environmental	The risk of environmental impact of each proposed solution

11 Liberty’s financial evaluation of the non-wires alternatives and wires solutions relies on the  
12 Total Resource Cost test.

1 The final result of the total cost for each non-wires and wires alternative solution is,  
2 therefore, the calculation of the net present value of both capital expenditures and ongoing  
3 operations and maintenance costs. These results, along with the ranked risk assessment  
4 allow the group to compare and prioritize the solutions based on their relative net benefits.

5 Strategy document DAS-016 Guidelines for Analysis of Non-Wires Solutions provides an  
6 illustration of the process Liberty would undertake to evaluate and implement a traditional  
7 and non-wires alternative solutions using a new NWA Analysis Workbook completed for  
8 improvements that meet the screening criteria for consideration of non-wires solutions.

#### 9 **4.13 Company-owned Distribution Generation**

10 In addition to customer owned distributed generation, the Company also recognizes the  
11 potential value of Company-owned installations, as allowed for in RSA Chapter 374-G. That  
12 statute makes Liberty eligible to have up to 6% of its total distribution peak load  
13 (approximately 12 MW) in utility-owned DG. The pursuit and application of such generation  
14 would be driven by consideration of the factors described in RSA 374-G:5, including:

- 15 • The targeted reduction in feeder or area peak demand (in kW) as well as the timing  
16 for the reduction;
- 17 • The availability of potential sites on the feeder for utility owned generation; most  
18 likely open space, agricultural land, or unused industrial/commercial land or rooftops;
- 19 • The size, orientation, and type of DG, as well as the estimated capacity factor of the  
20 installation;
- 21 • Feeder engineering, operating, and performance considerations specific to the site, the  
22 feeder, and the size/type of installation;

- 1       • The installation cost on a dollars-per-kilowatt and total cost basis;
- 2       • The ability to permit the site according to local codes and requirements;
- 3       • The degree of acceptance and support exhibited by the local community for such an  
4       installation;
- 5       • Affirmation of the recovery of installation costs, including fair return on investment,  
6       through the appropriate tariff;
- 7       • The benefits to any specific customer as well as to all other customers; and
- 8       • The amount of investment to be made by Liberty and, for customer-sited distributed  
9       generation, the amount to be invested by the customer.

10       The RSA 374-G process enables the Company to evaluate Company-owned or contracted  
11       DG options on an equal footing with other wires and non-wires alternatives when selecting  
12       the least cost alternative to reducing demand on a particular feeder or group of feeders  
13       serving an area.

14       Should Liberty determine that the benefits of a particular company-owned distributed  
15       generation project outweigh the project's cost, the Company could submit a filing to the  
16       Commission pursuant to RSA 374-G, as was done in the Docket No. DE 17-189 Petition to  
17       Approve Battery Storage Pilot Program.

#### 18       **4.14   Best Practices for Non-Wires Solutions**

19       In general, NWAs are intended to reduce demand via targeted energy efficiency and load  
20       control programs, including electric energy storage technologies, or increase peak generation  
21       through distributed generation measures in specific constrained geographical areas in such a  
22       way that investments in utility transmission and distribution systems can be reduced,

1 deferred, or eliminated. This is beneficial to the system as a whole only if NWSs are ranked  
2 higher than infrastructure expansion. These benefits are initially determined using the  
3 Project Evaluation Workflow presented in DAS-016 Guidelines for Analysis of Non-Wires  
4 Solutions. Another important element of designing non-wires programs is to match the  
5 hourly and seasonal load profile of the energy efficiency measures to the profile of the  
6 demand on the system. If the efficiency does not occur at the time that it is needed, it might  
7 not solve the need for the additional capacity. The level and mix of the energy savings  
8 measures are important determinants of whether the T&D deferral, reduction, or elimination  
9 is possible and for how long.

10 Liberty reviewed non-wires solutions implemented in other jurisdictions. Based on the  
11 documented experiences of other electric utilities, some features of successful non-wires  
12 alternative implementation processes include:<sup>27</sup>

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

---

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

1           **4.15   Grids Needs Assessment**

2           In the November 19, 2018, settlement in Docket No. DE 17-189, the battery storage pilot  
3           docket, Liberty agreed to provide a “Grid Needs Assessment” as part of its next LCIRP  
4           filing. Specifically, that settlement stated:

5                       To that end, Liberty shall provide a detailed grid needs  
6                       assessment within its next LCIRP. That grid needs  
7                       assessment shall describe all forecasted grid needs related to  
8                       distribution system capital investments of \$250,000 or more  
9                       over a five-year planning horizon at the circuit level. The  
10                      grid needs assessment shall be available in spreadsheet  
11                      format and shall include the following attribute-based  
12                      columns and content: (1) Substation, Circuit, and/or Facility  
13                      ID: identify the location and system granularity of grid need;  
14                      (2) Distribution service required: capacity, reliability, and  
15                      resiliency; (3) Anticipated season or date by which  
16                      distribution upgrade must be installed; (4) Existing  
17                      facility/equipment rating: MW, kVA, or other; and (5)  
18                      Forecasted percentage deficiency above the existing  
19                      facility/equipment rating over five years. Upon filing of the  
20                      LCIRP and associated grid needs assessment, Commission  
21                      Staff, the OCA, and Liberty will review planned capital  
22                      investments to identify candidates that may be appropriate  
23                      for NWA opportunities.

24           Settlement Agreement at 16. Figure 4.10 below provides information on the grid needs  
25           estimated at greater than \$250,000 as identified for Substations and Distribution Lines. This  
26           table excludes projects that are needed due to asset condition, along with other capital  
27           initiatives such as new business, public requirements, response to damage and failure, and  
28           other mandatory projects.

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**Figure 4.10. Needs Grids Assessment Results Part 1**

Facility/ Location (1)	System Granularity of Grid Need (1)	Capacity/ Reliability/ Resiliency (2)	Anticipated season or date by which distribution upgrade must be installed (3)	Equipment Rating (4)	Forecasted percentage deficiency above the existing facility/equipment rating 2025 (5)	Additional information:
14L2 Burns Rd, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2021	N/A	N/A	
7L1 Route 4, Enfield	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2021	N/A	N/A	
14L1 Bridge St, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2023	N/A	N/A	
18L3 S Policy St, Salem	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2025	N/A	N/A	
18L2 S Policy St, Salem	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2022	N/A	N/A	
14L2 Marsh Rd, Pelham	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2022	N/A	N/A	
1L3 Mascoma St, Lebanon	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2023	N/A	N/A	
12L2 Watkins Hill Rd Phase 1, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2021	N/A	N/A	
12L2 Watkins Hill Rd Ph. 2, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2022	N/A	N/A	
12L2 Watkins Hill Rd Ph. 3, Walpole	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A	
9L3 Range Rd - W Shore Rd, Windham	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2023	N/A	N/A	
12L1 Rt. 123A, Alstead	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2024	N/A	N/A	

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**Figure 4.11. Needs Grids Assessment Results Part 2**

Facility/ Location (1)	System Granularity of Grid Need (1)	Capacity/ Reliability/ Resiliency (2)	Anticipated season or date by which distribution upgrade must be installed (3)	Equipment Rating (4)	Forecasted percentage deficiency above the existing facility/equipment rating 2025 (5)	Additional information:
39L2 Plainfield Rd Phase 1, Lebanon	Reconductor bare conductors with 1/0 Al. Spacer Cable	Reliability	2025	N/A	N/A	
6L3 S Main St, Hanover	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2024	N/A	N/A	
1L2 Meriden Rd Phase 2, Plainfield	Reconductor bare conductors with 477 Al. Spacer Cable	Reliability	2024	N/A	N/A	
16L1-6L3 Goodfellow Rd Tie, Hanover	Construct circuit tie 16L1 to 6L3 and implement DA	Reliability / Resiliency	2023	N/A	N/A	
7L1-7L2 Lockehaven Rd Tie, Enfield	Construct circuit tie 7L1 to 7L2 and implement DA	Reliability / Resiliency	2024	N/A	N/A	
21L4 New Feeder, Salem	Construct new 21L4 and implement DA	Reliability / Resiliency	2025	N/A	N/A	
14L5 New Feeder, Salem	Construct new 14L5 and implement DA	Reliability / Resiliency	2025	N/A	N/A	
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
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.
16L4 Feeder, Lebanon	Construct new 16L7 to supply new customer expansion.	Resiliency / Capacity	2021	11.7 MVA	116%	
11L1 Feeder, West Lebanon	Construct new 39L4 to resolve forecasted overload with new commercial development	Resiliency / Capacity	2025	10.9 MVA	105%	

1 **5. DISTRIBUTION GRID MODERNIZATION PROPOSAL**

2 **5.1 Introduction**

3 We are witnessing a revolution in the way electric power is transmitted from generators and  
4 distributed to end-use consumers. It is characterized by the convergence of information, data  
5 management, and modular electricity generation and delivery technologies.

6 In the coming years, energy demand is projected to increase due to further evolution of  
7 electrification of our society, a significant percentage of the industry’s skilled workforce is  
8 scheduled to retire with job experience and knowledge that cannot be replaced with a 1:1  
9 ratio, and global demands for decarbonization challenge the stability of energy costs and  
10 reliability. Many regulators favor increased industry competition, information-armed  
11 consumer groups are making greater demands about pricing and other issues, and  
12 governments at home and abroad are pressing for cleaner, more reliable energy. These  
13 dramatic changes in the business environment are encouraging utilities to take advantage of  
14 key technologies to improve the efficiency, quality, reliability, and cost of supplying  
15 services.

16 The movement toward Grid Modernization involves the deployment of “intelligent” or  
17 “smart” utility infrastructure technologies that weds communications, data, hardware, and  
18 other technologies into a future “self-healing” grid. As technologies advance, the  
19 possibilities for this modernization effort expand as well, not just in having more advanced  
20 electric components, but also the consumer devices that get plugged into the grid.

21 Renewables and distributed generation have the potential for adapting utilities to carbon-



1 constrained environments. New storage technologies could save cheap and/or renewable  
2 generation for use in peak periods. Communicating between devices or sensors improves  
3 operations, optimizes asset use, increases reliability and safety while providing stakeholders  
4 with the information they need to make better decisions. This could mean everything from  
5 customers choosing to use electricity differently to utility personnel modifying operating  
6 activities. At the end of the day, Grid Modernization will redefine the way in which utilities  
7 operate and electricity is consumed in the future.

8 The New Hampshire Public Utilities Commission, in Order No. 26,358 (May 22, 2020),  
9 provided further guidance on how the state’s electric distribution utilities need to plan to  
10 accommodate new technologies into its Least Cost Integrated Resource Plan (LCIRP).  
11 Although this order is on hold while the Commission addresses a motion for rehearing,  
12 Liberty has attempted to incorporate the spirit of the order into this LCIRP.

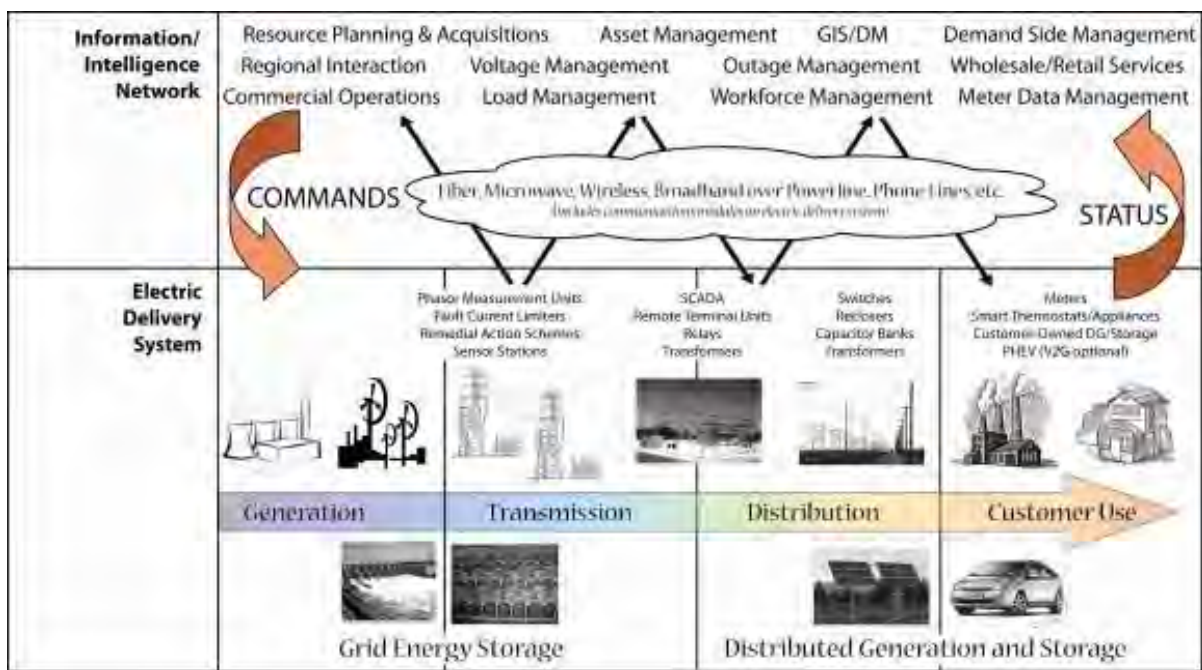
## 13 **5.2 Network Architecture**

14 At a high level, this modernization effort is made up of two parallel networks: the electric  
15 grid itself and the intelligence behind it. The electric grid includes all of the equipment  
16 required to generate and distribute electricity as well as the control devices attached to it.

17 The intelligence network consists of the core communications, data management systems,  
18 and the applications that process data from the devices. What makes the grid “smart” is its  
19 ability to communicate seamlessly between these two parallel networks at every level  
20 including consumption by customers. Enhanced communications and control capabilities  
21 will allow distribution delivery systems to accommodate and support the rapidly evolving

1 needs utilities and their customers have for increased reliability, efficiency, and  
2 environmental quality.

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



8 From a technology point of view, Grid Modernization is all about applying new technologies  
9 to reduce the cost, increase efficiency and improve the quality and reliability, of electric  
10 service. The Department of Energy has identified five key technologies that are the essence

1 of the smart grids, and we have adopted this same perspective to elaborate a definition of  
2 Grid Modernization.

3 The DOE's five sets of technologies are as follows:

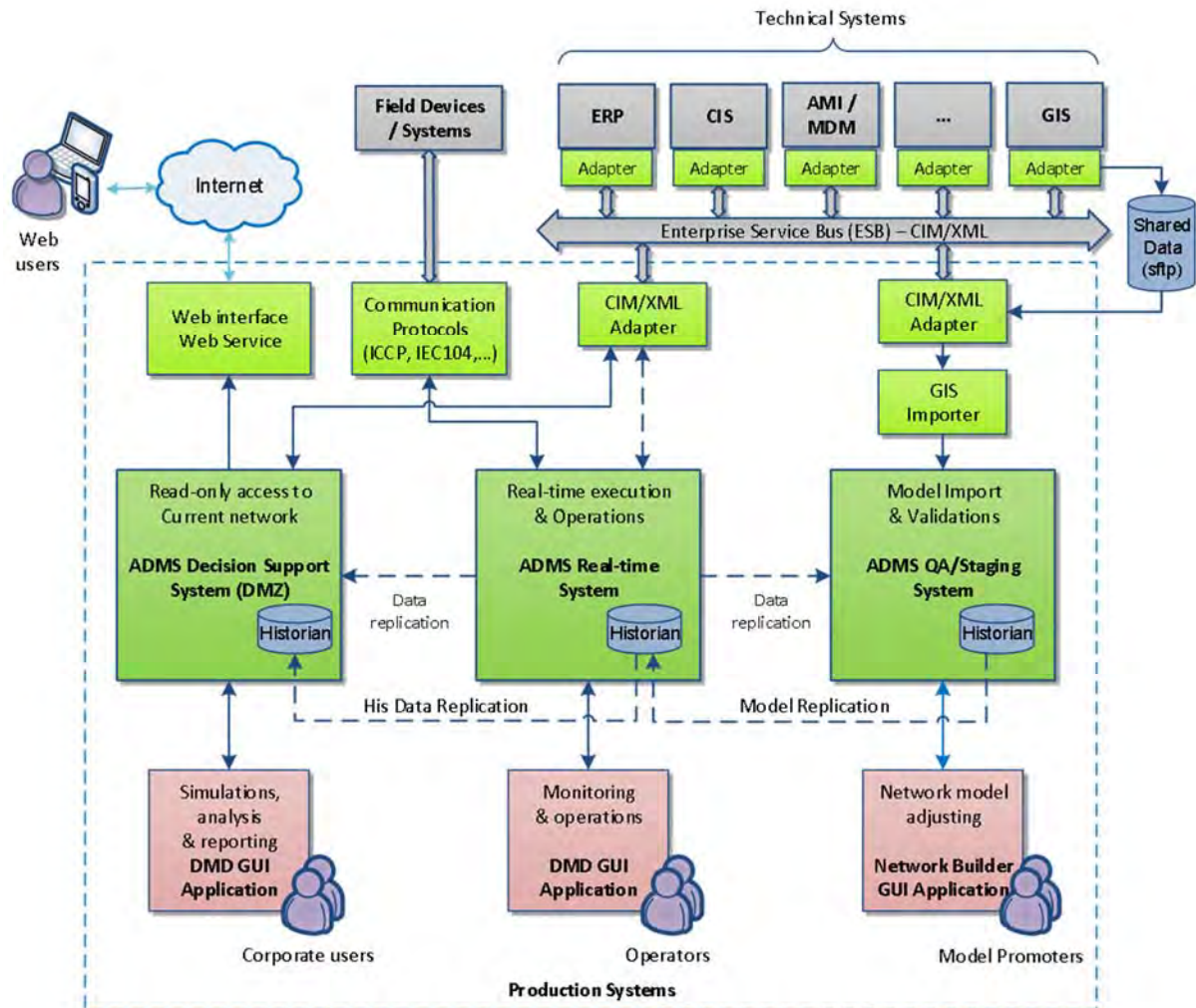
- 4 • Integrated Communications – Connecting all the components of the electric grid  
5 through open architectures, which will provide for real-time information and control  
6 of the grid and thus allow every component to both 'talk' and 'listen.'
- 7 • Sensing and Measurement – Devices that sense and measure various aspects of grid  
8 operation and thus support faster and more accurate response such as remote  
9 monitoring of voltage, current, phase angles, etc.
- 10 • Advanced Components – Applying the latest technologies for superconductivity that  
11 reduce line losses, storage that allows for the use of off-peak generation to meet peak  
12 period requirements, and power electronics and diagnostics that will improve the  
13 operation and efficiency of the grid.
- 14 • Advanced Controls – Monitoring essential components in real-time and thus enabling  
15 early detection and rapid diagnosis in order to provide precise solutions appropriate to  
16 any event before they can cascade into bigger problems.
- 17 • Improved Interfaces and Decision Support – Improving human decision making by  
18 providing grid operators and managers with the information and ability to operate as  
19 visionaries when it comes to seeing into their systems.

### 20 **5.3 Liberty's Distribution Grid Modernization Initiatives**

21 An assessment of the current state of operations at Liberty was conducted by CMG  
22 Consulting with key Liberty subject matter experts, and by evaluating current industry trends.  
23 The Company's Grid Modernization Report was developed in 2019, updated in 2020, and is  
24 included in Appendix E of this LCIRP. The following use cases were evaluated and selected  
25 to be implemented in Liberty's distribution systems:

1     *Advanced Distribution Management System (ADMS)*

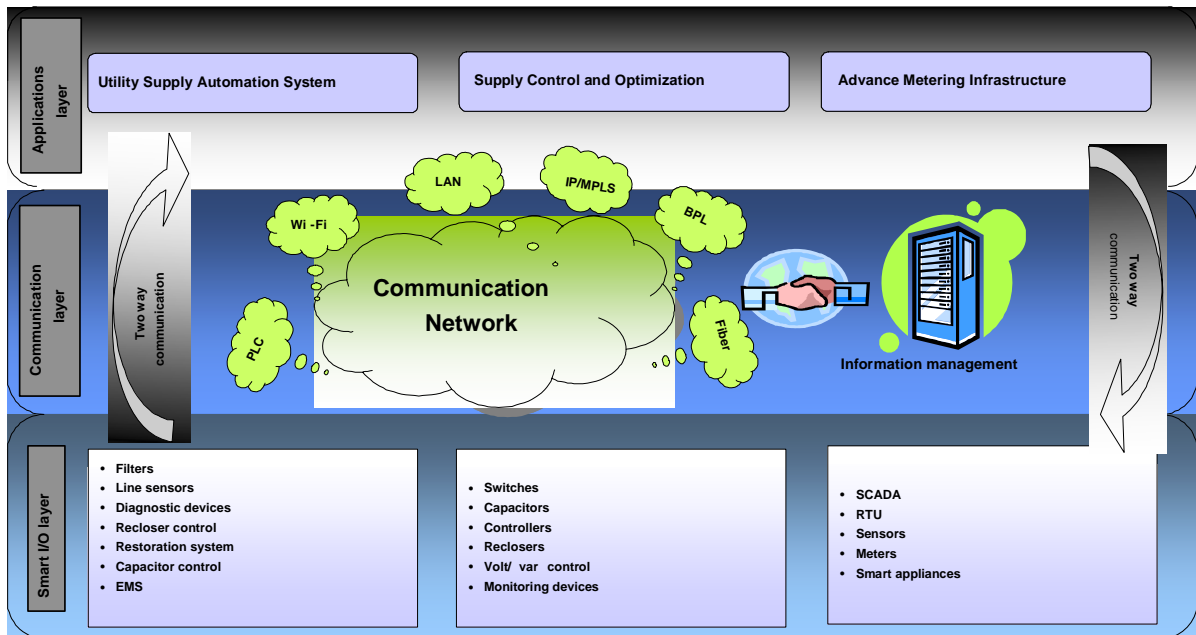
2     An ADMS is the software platform that supports the full suite of distribution asset  
3     management and optimization programs. The ADMS will include functions that integrate  
4     AMI and automate outage restoration, and will optimize the performance of the distribution  
5     grid. ADMS functions that are being developed include fault location, isolation, and  
6     restoration; volt/volt-ampere reactive optimization; conservation through voltage reduction;  
7     peak demand management; and support for microgrids and electric vehicles. The ADMS  
8     real-time solution will replace the legacy OMS and will provide a platform tailored to the  
9     operations required for the distribution grid with a fully integrated solution including full  
10    GIS, OMS, DMS, SCADA, DERMS, with Advanced Application functionality and a single  
11    network model that is maintained with a common set of Data Engineering Tools. Refer to  
12    the figure below for an illustration of how ADMS will integrate with other assets and  
13    systems.



1

2 *Automated Metering Infrastructure*

3 The components of a successful Automated Metering Infrastructure (“AMI”) deployment  
 4 include a robust communications channel, supporting software, and bidirectional meters  
 5 capable of measuring 15 minute intervals. The advanced meters deployed across the  
 6 distribution network also function as grid health monitors by reporting back outages and line  
 7 conditions related to voltage and current. In combination, the AMI and ADMS systems serve  
 8 as the backbone for the entire grid modernization effort.



1

2

### *Connect/Disconnect*

3

Remote connect/disconnect capabilities are enabled by retrofitting existing meters with a

4

collar, or by choosing a remote disconnect capable meter for selected deployments. The

5

ability to remotely disconnect and reconnect energy flow enables labor savings, revenue

6

assurance, and improves service quality. Benefits include revenue improvements and cost

7

reductions.

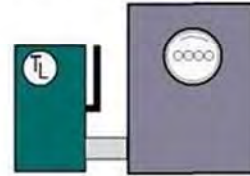


This arrangement probably includes a service disconnect.



Meter socket with main breaker, 120/240V, hot sequence

This arrangement might include a service disconnect.



Meter socket, 480Y/277V, with unfused meter disconnect switch, cold sequence

1

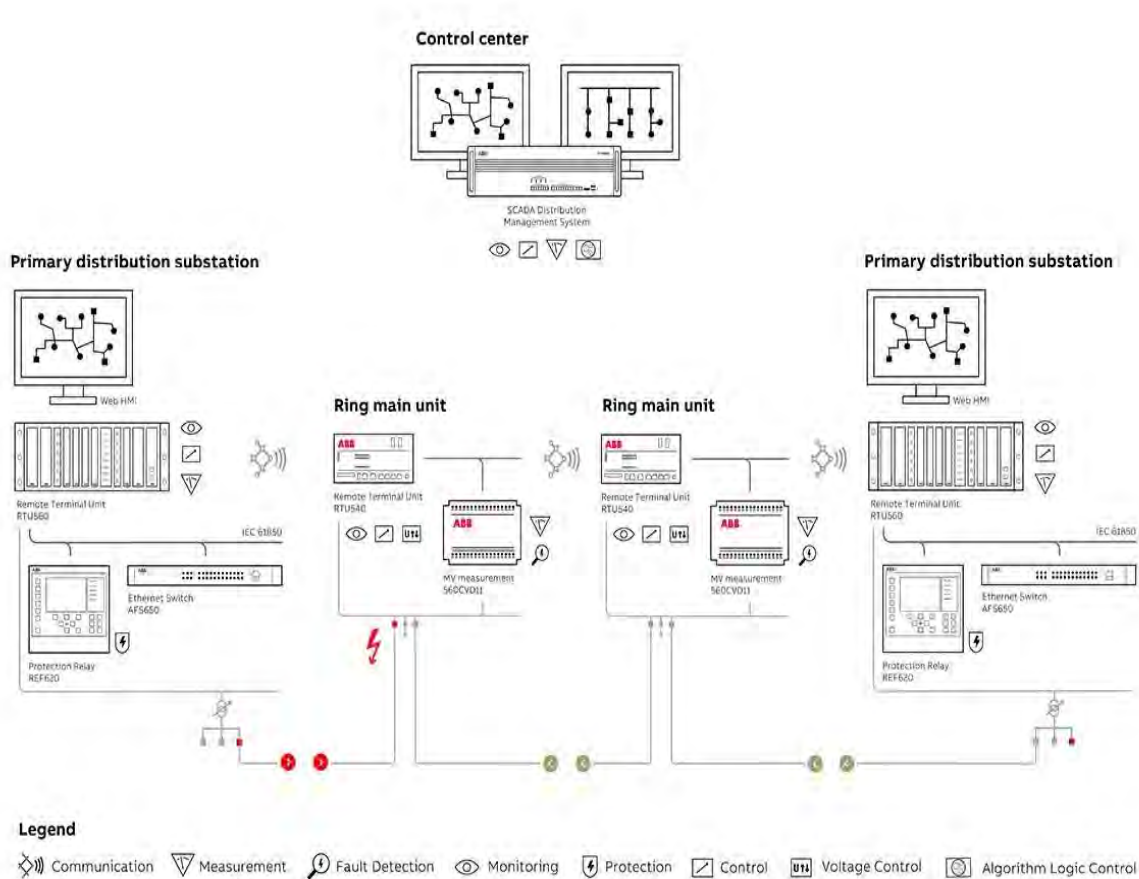
## 2 *Fault Detection*

3 Significant benefits arise from improved capabilities for responding to electrical faults in the  
4 utility's electric delivery system. The automation schemes will provide improved  
5 capabilities to activate protective relays (e.g., tripping substation feeder breakers to protect  
6 fuses) and to instantly switch circuits, as needed, to protect the system. Fault detection  
7 would provide improved controls for automated balancing, shedding, and transferring of  
8 loads; and it would provide advanced decision support systems for human operators.

9 ADMS, AMI, and Outage Management System (OMS) integration allows proactive response  
10 to outages rather than waiting for customers to call in, minimizing customer re-calls and  
11 eliminating the need to phone customers to verify restoration. Real-time communication  
12 links that deliver outage and restoration alarms will send high-priority message when service  
13 is out. Fault detection, isolation, and recovery (FDIR) is a subfield of control engineering



1 which concerns itself with monitoring a system, identifying when a fault has occurred, and  
2 pinpointing the type of fault and its location.



3

4 *Conservation Voltage*

5 Voltage management offers the potential for electric utilities to utilize controls over the

6 voltage levels of the distribution network to enable real operational gains. While utilities

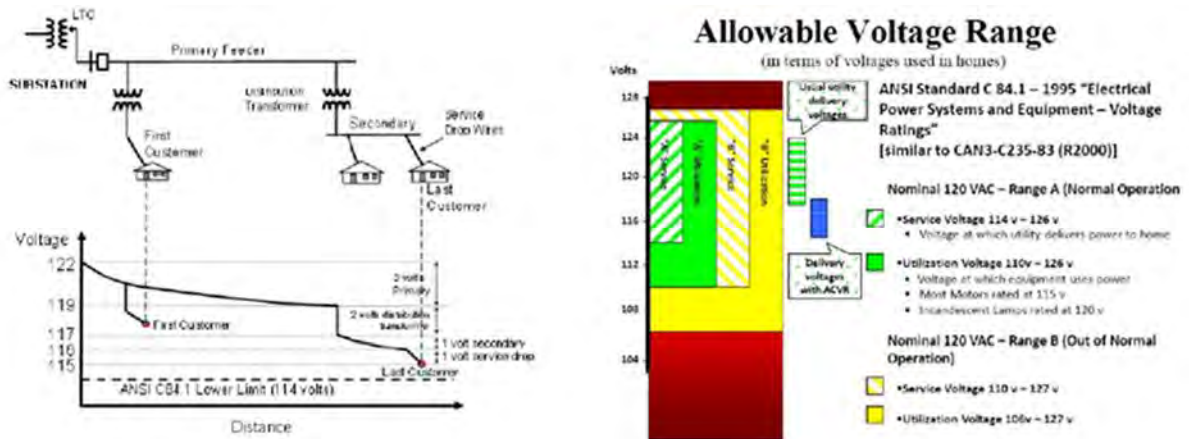
7 typically operate in the upper range of the ANSI voltage band under normal circumstances,

8 voltage can be compressed during key periods in a way that benefits utilities and consumers.

9 Numerous studies have shown that for each 1% drop in voltage levels, energy consumption



1 for residential and commercial loads can be reduced by 0.8%, although this value can vary  
 2 depending on load mix and distribution system configuration.



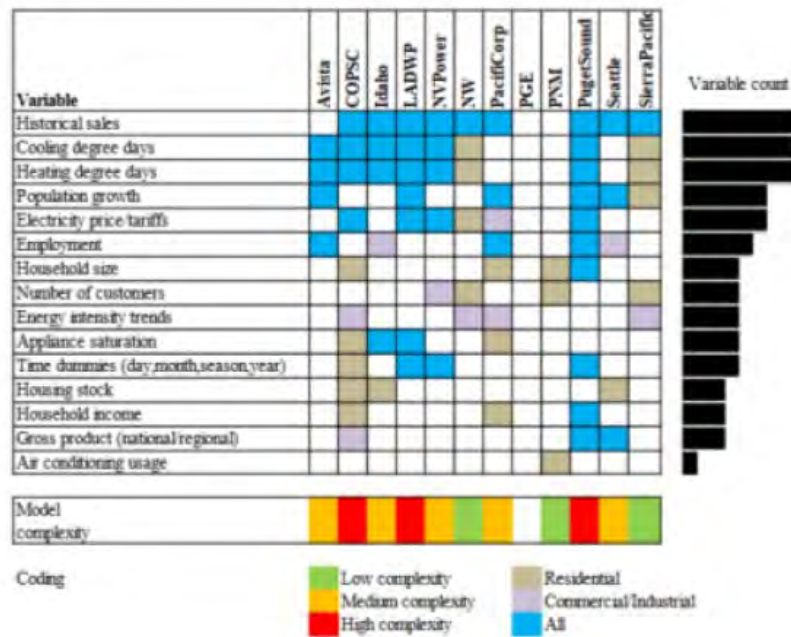
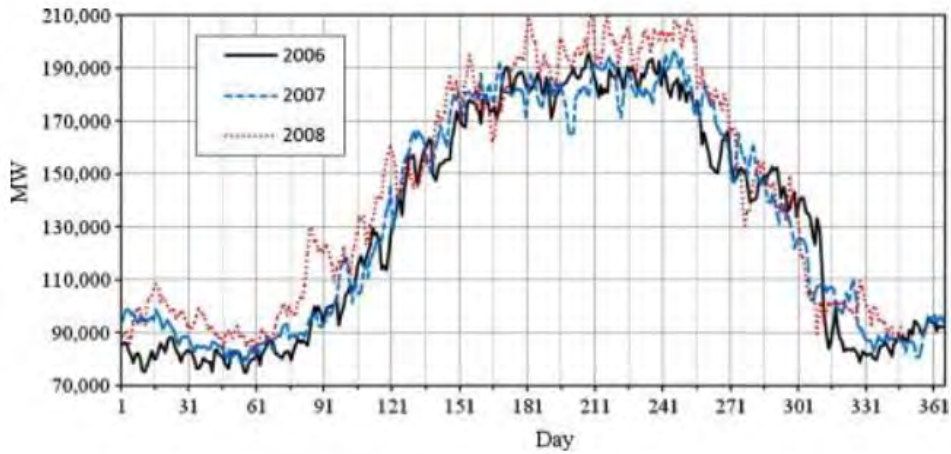
3  
 4 *Load Forecasting*

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

10 Industry analysts have estimated that load predictions have consistently over-forecasted by  
 11 1% each year, which implies that a ten-year utility forecast could result in a 10% over-  
 12 estimation of demand, leading to thousands of dollars in unneeded investment. Automating  
 13 processes with more granular data can support an improved load forecast accuracy.

14 See the following illustrations for enhanced load forecasting.

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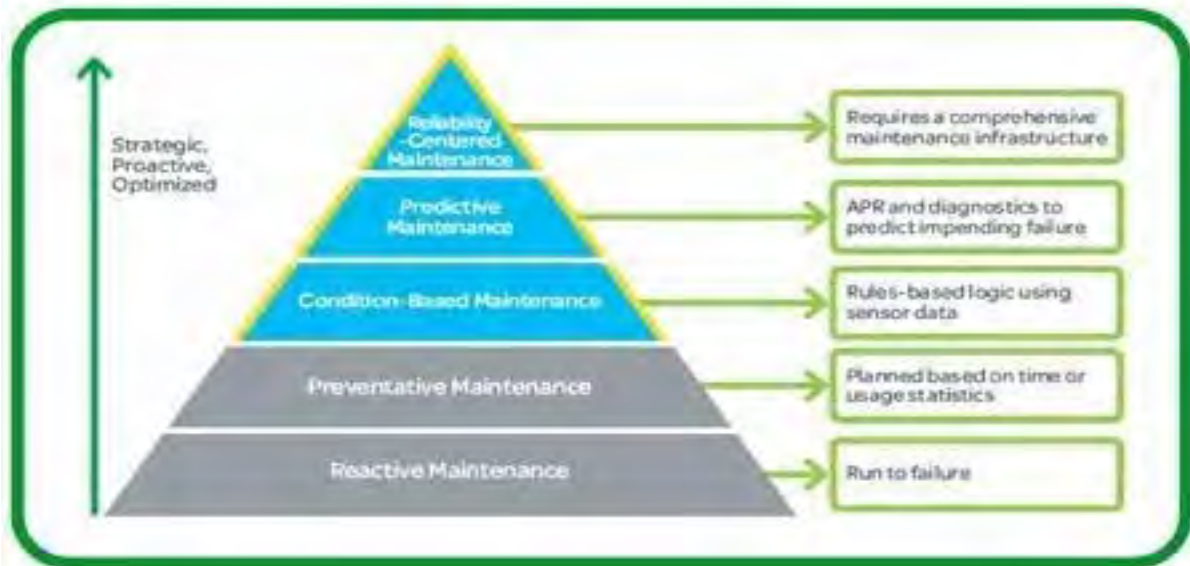


1

2 *Asset Management*

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

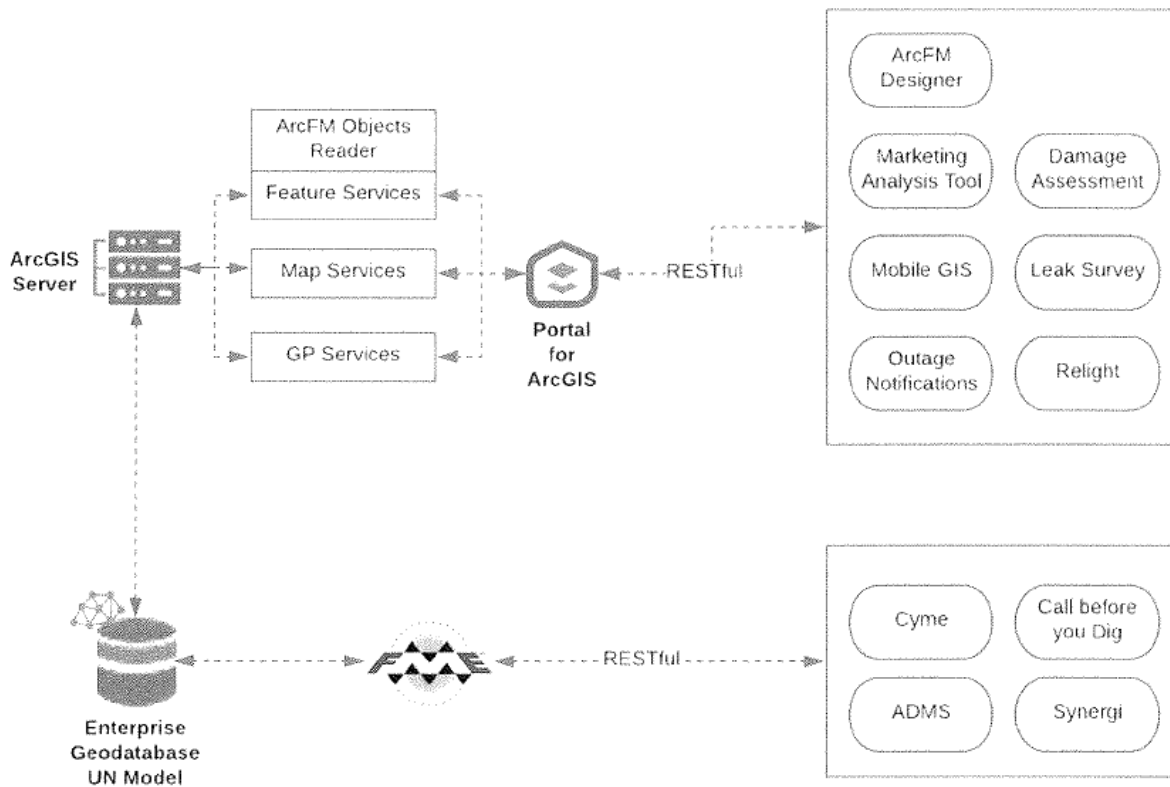
1 Utilities frequently struggle with balancing the need to invest in modern equipment and  
2 infrastructure with demands to minimize costs for customers. One of the most effective ways  
3 to avoid substantial rate increases is to maximize the lifetime value of every existing asset.  
4 Automated asset management tools enable utilities to blend forecasting and business  
5 intelligence with traditional enterprise asset management capabilities. See the illustration  
6 below on the improvements in Asset Management as these technologies are implemented.



7  
8 A key component to the Asset Management program is a common and accurate GIS to know  
9 where electric utility components are located in a digitized “map” across the Liberty network,  
10 and to accurately determine the attributes of such components. The common GIS software is  
11 the master repository for locational data and connectivity information, containing asset  
12 information describing the physical attributes of the components that make up the Liberty

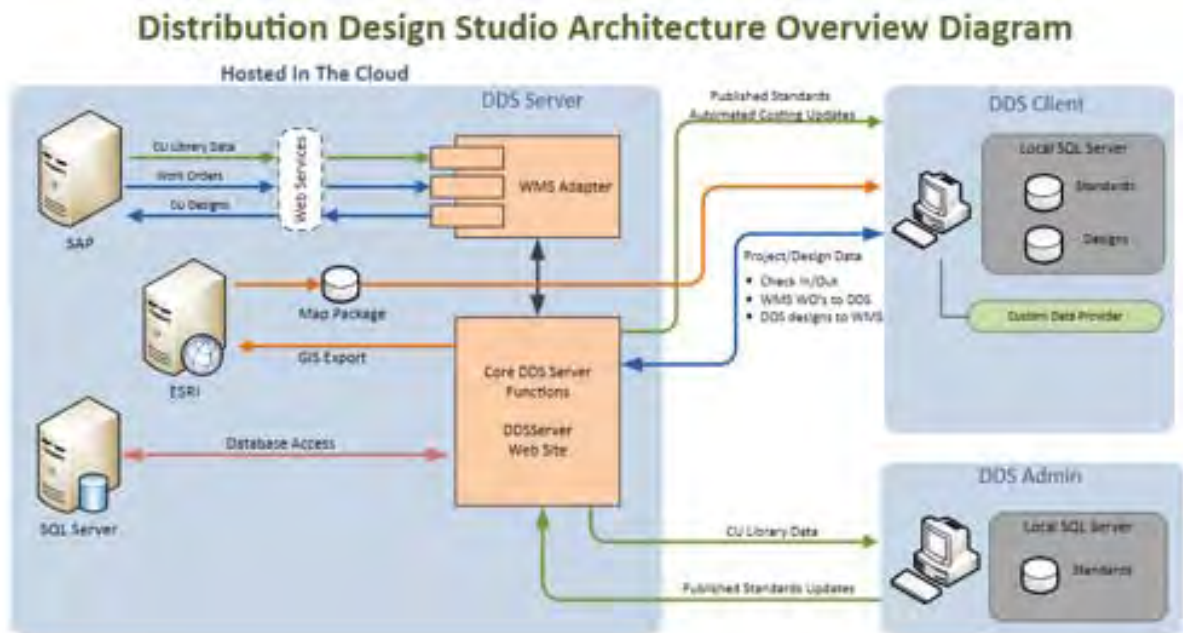
1 distribution network. This system is used by operations staff to locate and identify assets,  
2 increasing worker safety and efficiency. The GIS system is also used as a master repository  
3 to supply other integrated applications such as modeling software.

4 This system is used by the ADMS to greatly increase operational real-time visibility needed  
5 as more distributed energy resources are connected to the distribution system and to perform  
6 fault location, automatic restoration, and voltage conservation. Liberty is currently in the  
7 process of integrating ArcGIS Desktop applications for its distribution network as an early  
8 part of its grid modernization strategy to improve customer service reliability, resilience,  
9 efficiency and costs. See the below illustration on the architectural and integration overview  
10 of the GIS system:



11

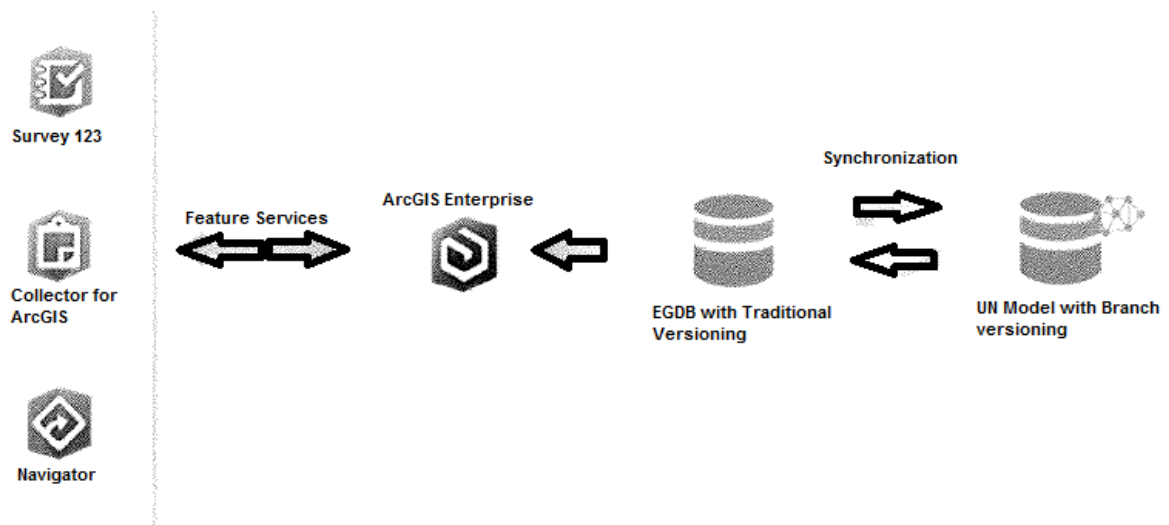
1 The design estimation tool, Distribution Design Studio (“DDS”), in the GIS will allow  
2 engineers and planners to efficiently and effectively design and estimate construction  
3 projects, including customer cost estimates for utility projects. See the below illustration on  
4 the architectural and integration overview of the DDS system.



5  
6 Liberty will also implement a relay management tool to facilitate the management of relay  
7 settings, maintenance of substations, collection of data, reports and analysis of equipment  
8 condition.

9 In addition, Liberty will continue to implement remote applications for its field workers for  
10 the collection of inspection results, including vegetation management and damage assessing.  
11 Currently, the location of vegetation related interruptions are being tracked and the  
12 inspection activities for reclosers and capacitors are being managed using ArcGIS Online  
13 tools and Terra Spectrum application. The Company expects to leverage ArcGIS Desktop

1 and the Terra Spectrum applications to increase the use of remote applications for  
2 maintenance activities, assignment of work, and outage management activities. The use of  
3 remote applications by field workers will allow the Company to better track, document, and  
4 analyze the actual locations and causes of problems. This will better inform other initiatives  
5 for reliability and resiliency improvement. See the below illustration of the mobile  
6 application design for Liberty.



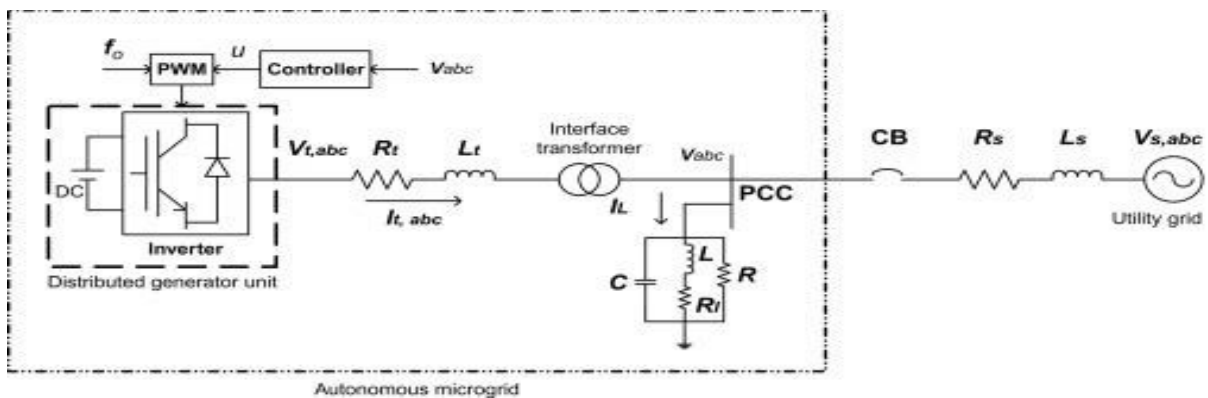
7  
8 Another part of the recommended asset management system would involve automated  
9 systems to ensure power quality analysis on a dynamic basis. Power quality analyzers are the  
10 most commonly used tools to observe real-time readings and to collect data for downloading  
11 to computers for analysis. While historically handheld analyzers have been used to support  
12 isolated troubleshooting functions, a real-time dynamic program would feature systems and  
13 devices permanently installed in the distribution system.

14

1 *Islanding*

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

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



11





1

2 *Distributed Energy Resources*

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

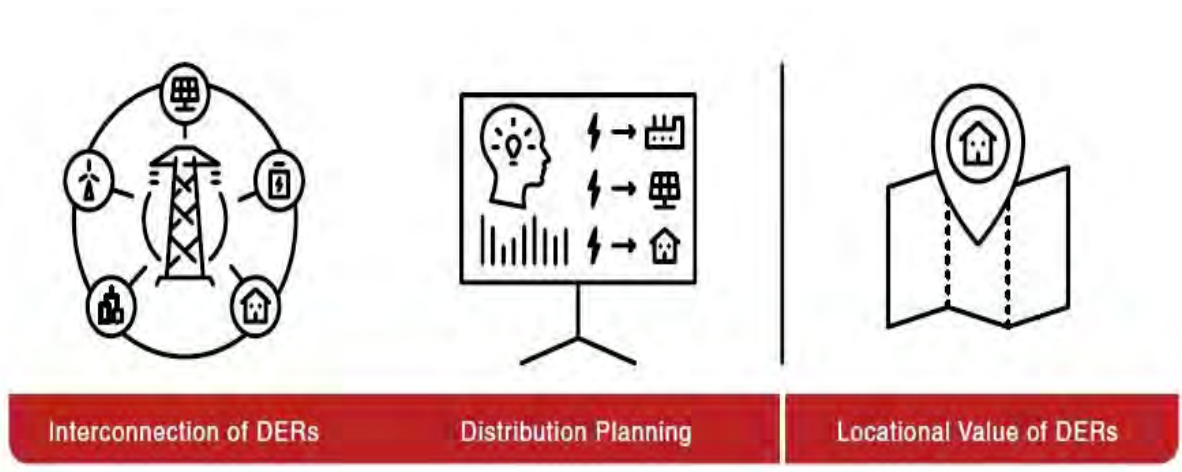


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Application	Description
Generation Deferral	Reduce system peak in order to reduce investments in generation
Wholesale Marketing Resource Call	Reduce system peak in order to provide flexibility in generation requirements during summer peak
Frequency 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

1 One of the considerations for a DER program involves Hosting Capacity Analysis (HCA).  
2 The term “hosting capacity” refers to the amount of DERs that can be accommodated on the  
3 distribution system at a given time and at a given location under existing grid conditions and  
4 operations, without adversely impacting safety, power quality, reliability, or other operational  
5 criteria, and without requiring significant infrastructure upgrades. HCAs allow utilities,  
6 regulators, and electric customers to make more efficient and cost-effective choices about  
7 deploying DER on the grid. If adopted with intention, HCA also functions as a bridge to

1 span information gaps between developers, customers, and utilities, thus enabling more  
2 productive grid interactions and more economical grid solutions.



3

4 The initial purpose of HCA was to make DER interconnections faster and more efficient. If  
5 a utility could know the feeder-level DER penetrations throughout its distribution system, it  
6 could more expeditiously approve an application for a new DER installation. Alternatively,  
7 it could inform the applicant a distribution system infrastructure upgrade is needed to  
8 accommodate new DER or locations on the electrical grid with existing/future grid needs.

9 By accommodating HCA on its system, Liberty will be able to more efficiently plan for  
10 integration of distributed energy resources.

11 The Company is in the process of developing an HCA map, process, and criteria to better  
12 inform the decision making for prospective DG installers in our service territory. The  
13 hosting capacity will depend on the feeder, existing DG deployed, and criteria that will be  
14 rooted in thresholds for voltage, protection, and thermal capability. Using the modeling

1 software tool, solar generation can be added in increments to segments in the feeder until a  
2 criteria threshold is reached.

3 Pending final design of the application, the following information will be provided in the  
4 HCA map:

- 5 • Substation Name, Feeder, Nominal Voltage, Substation Transformer nameplate  
6 MVA;
- 7 • Maximum Hosting Capacity or Maximum amount of DER that can be accommodated  
8 at one point on the feeder;
- 9 • Minimum Hosting Capacity or Minimum amount of DER that can be interconnected  
10 anywhere on the feeder;
- 11 • Circuit Peak Load, Circuit Min Load, and Daytime Min Load for the previous year;
- 12 • Aggregate DG (kW) on feeder, Aggregate DG (kW) Proposed on feeder;
- 13 • Latest Revision date; and
- 14 • Distance to Source.

15 The Company has participated in the Locational Value of DG study that was initiated by the  
16 Commission and conducted by Navigant Consulting. Liberty will continue to support this  
17 effort to better guide the locational benefit of DG on the distribution system.

#### 18 **5.4 Overview of Net Benefits/Costs to Customers**

19 Electric utilities have historically extracted as much value and efficiency as possible with  
20 manual controls. Today, however, we see a major shift in the thinking within the electric  
21 utility industry as it approaches the issue of building the electric infrastructure to ensure

1 reliable and cost effective electric service given a set of challenges all occurring at the same  
2 time:

- 3 • A large percentage of skilled labor within the electric utility industry is expected to  
4 retire within the next five years, placing stresses on electric utilities to effectively  
5 manage systems with a large degree of manual intervention required.
- 6 • The Department of Energy (DOE) and industry experts have estimated that losses to  
7 the economy due to outages, quality disturbances, and other events total in the  
8 billions of dollars annually.
- 9 • Challenging financial times are calling into question how electric utilities can  
10 continue to access the capital needed to keep pace with projected load growth given  
11 the constraints of today's legacy electric grid.
- 12 • Under pressure from environmental groups and governments, federal and state  
13 regulators are assigning increasingly stringent emissions regulations – resulting in  
14 increasing challenges for generators and wires companies to deliver reliable power to  
15 customers.
- 16 • Increasing levels of intermittent renewable energy along all levels of the grid and less  
17 predictable electric vehicle charging at the edge of the grid are placing new  
18 challenges not faced before by electric distribution utilities.

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

1 Liberty has evaluated the economic benefits and costs of available new technologies and has  
2 narrowed its implementation to the following new technologies as part of its overall Grid  
3 Modernization Program, contained in Appendix E.

**Program Comparison - Ranked**

	<u>PV - Benefits</u>	<u>PV - CapEx</u>	<u>PV - OpEx</u>	<u>Terminal Value</u>	<u>NPV</u>	<u>Rank</u>
Conservation Voltage	\$ 8,302,813	\$ 1,792,831	\$ 119,357	\$ 7,453,481	\$ 13,844,106	1
Asset Management	\$ 3,825,127	\$ 500,740	\$ 119,357	\$ 3,388,384	\$ 6,593,413	2
Load Forecasting	\$ 2,672,409	\$ 686,544	\$ 214,843	\$ 2,292,358	\$ 4,063,379	3
Connect/Disconnect	\$ 1,743,802	\$ 873,362	\$ 23,871	\$ 1,568,024	\$ 2,414,593	4
Islanding	\$ 5,793,103	\$ 8,442,949	\$ 167,100	\$ 5,149,434	\$ 2,332,488	5
LED Lighting	\$ 1,514,155	\$ 1,799,658	\$ 286,458	\$ 1,200,848	\$ 628,888	6
Distributed Energy Resources	\$ 2,977,231	\$ 4,463,750	\$ 477,429	\$ 2,409,871	\$ 445,922	7
Fault Detection	\$ 1,760,399	\$ 2,991,099	\$ 124,132	\$ 1,531,260	\$ 176,429	8
Energy Management	\$ 2,776,319	\$ 5,441,529	\$ 119,357	\$ 2,444,279	\$ (340,288)	9
AMI	\$ 3,005,607	\$ 11,197,510	\$ 410,589	\$ 1,849,711	\$ (6,752,781)	10
4 Total	\$ 34,370,966	\$ 38,189,973	\$ 2,062,494	\$ 29,287,650	\$ 23,406,149	

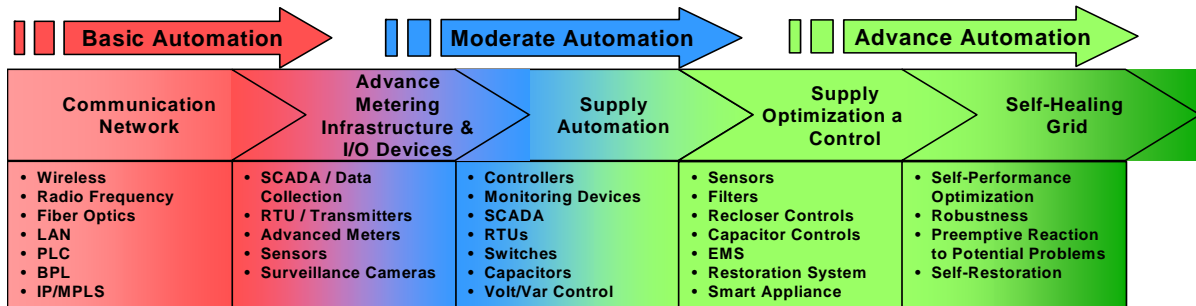
5 As this economic assessment shows, the total net present value (“NPV”) of the Grid  
6 Modernization program greatly exceeds the expected implementation cost, thereby providing  
7 lower costs to customers over this ten year period.

8 At the heart of this initiative is the addition of ADMS/AMI systems across Liberty’s 45,000  
9 meter system over a five-year period, to serve as the platform that will enable the use of  
10 many new technologies and strategies that will improve reliability, resilience, safety, and  
11 efficiency of its distribution systems and provide substantial benefits for its customers.

12 **5.5 Overall Program Planning and Implementation**

13 The recommended approach for developing a suitable implementation plan is based on the  
14 concept of developing core elements that support initial programs while also establishing

1 foundational elements for future aspects of the grid modernization plan. Below is a  
2 conceptual approach:



3  
4 As illustrated above, there are five key stages to the deployment:

- 5 • Stage 1 – The establishment of a communications network to provide a robust  
6 backbone for all grid modernization elements.
- 7 • Stage 2 – Installation of an AMI network, which is seen as a key foundational  
8 element of the overall design. While AMI will provide demonstrable benefits by  
9 itself, it also provides the needed infrastructure for such programs as conservation  
10 voltage, fault detection, and load forecasting.
- 11 • Stage 3 – Supply automation programs (ADMS) provide for the realization of  
12 benefits from those use cases that demonstrate the most viable business cases.
- 13 • Stage 4 – Supply optimization and control programs will enable Liberty to capture  
14 further benefits by enhancing distribution operations on a dynamic basis.
- 15 • Stage 5 – The ultimate goal is to utilize the grid modernization effort to explore ways  
16 to enhance distribution operations with future programs that will be developed over  
17 time.

18 **5.6 Short-Term Plan**

19 With the exception of the Automated Metering Infrastructure implementation, Liberty is  
20 proposing a set of “pilot projects” to evaluate the approach for implementation. These pilot

1 projects will assess the business case coupled with the state of technology development leads  
2 to the development of a recommended migration strategy. Please see the Grid Modernization  
3 Report in Appendix E for the details concerning implementation of the pilot projects.

4 The first five years of the proposed program implementation covers the years 2021–2025.

5 The following steps are planned during this time:

- 6 • ADMS – deployment of the ADMS software, including incorporation of distribution  
7 assets in a common GIS database, will provide the software platform for integrating  
8 distribution assets and new smart devices into its system.
- 9 • AMI – The deployment of the entire AMI system, including all meters, software,  
10 Meter Data Management System (MDMS), communications network, repeaters, and  
11 field collection devices. The forecast calls for a complete system installation within  
12 five years.
- 13 • Connect/Disconnect – All disconnect devices will be installed with the AMI meters  
14 under glass and will be deployed within the same timeframe as the AMI network.
- 15 • Fault Detection – The core elements of the fault detection system will be deployed,  
16 allowing for full capabilities of an outage management system. It is anticipated that  
17 the fault detection system will leverage data from the metering system to identify  
18 locations of outages.
- 19 • Conservation Voltage – The goal is to deploy the conservation voltage system very  
20 quickly. In the short term, bellwether meters will be used to report on voltage levels  
21 across distribution feeders to ensure compliance with ANSI standards. As the AMI  
22 system is deployed across the entire service territory, these bellwether meters will be  
23 displaced by AMI meters.
- 24 • Load Forecasting – The backend systems supporting the load forecasting system will  
25 be deployed initially. AMI meters and distribution assets deployed in the field will be  
26 utilized to report on load conditions on a real time basis as they are deployed.

- 1           • Asset Management – The backend systems supporting the asset management system  
2           will be deployed within the first years of the project. AMI meters and distribution  
3           assets deployed in the field will be integrated into the system as they are deployed.
  
- 4           • Islanding – The goal in the first phase will be to undertake a pilot and deploy enough  
5           islanded resources in order to defer a capital project currently under budget between  
6           fiscal years 2023 and 2025. The Company will also consider pilot opportunities to  
7           test viability of integrating customer-owned DG resources, test capabilities of energy  
8           storage system, and assess electrical and operational efficiency rates.
  
- 9           • Energy Management – Liberty proposes to monitor system development and continue  
10          to evaluate the viability of deployment. Within the first five years, Liberty plans to  
11          implement an initial pilot to further test the viability of a dedicated program.
  
- 12          • Distributed Energy Resources – Liberty is seeking to have a total of 3% of system  
13          peak under management of a dedicated DER program by the end of 2024.

## 14           **5.7     Long-Term Plan**

15          During the first five year of the program, Liberty will monitor results of each program under  
16          management and make adjustments as needed based on actual findings. The current plan for  
17          the subsequent five years, covering the years 2025–2029, would include the following:

- 18          • Advanced Metering – Continue deploying AMI meters in areas of growth within the  
19          service territory. In addition, Liberty will also seek to capture maximum value from  
20          the AMI system by looking to optimize the data mapping to ensure that departments  
21          can access information in the optimal methodology while also redesigning internal  
22          workflows to ensure that work processes are aligned with the new system.
  
- 23          • Connect/Disconnect – Alongside the AMI system, Liberty will seek to learn from the  
24          initial stage of the connect/disconnect program to evaluate how to optimize  
25          operations.
  
- 26          • Fault Detection – Liberty will seek to expand the outage management system by  
27          incorporating elements of isolation recovery to the fault detection system, enabling  
28          automated switching of circuits during major outage events.



- 1           • Conservation Voltage – The goal of the long-term conservation voltage program will  
2           be to optimize operations by testing and implementing automated voltage  
3           management systems.
  
- 4           • Load Forecasting – Liberty will identify and implement advanced systems to utilize  
5           meter and distribution automation data in load forecasting.
  
- 6           • Asset Management – Liberty will identify and implement advanced systems to utilize  
7           meter and distribution automation data in asset management.
  
- 8           • Islanding – The goal in the second phase will be to deploy enough islanded resources  
9           to defer three to four capital projects by one or more years.
  
- 10          • Energy Management – Liberty plans to implement an initial deployment involving  
11          customers with a mix of smart thermostats and energy management systems.
  
- 12          • Distributed Energy Resources – Liberty is seeking to have a total of 6% of system  
13          peak under management of a dedicated DER program by the end of 2029.
  
- 14          • Smart City – The goal is to ensure the installation of LED lights for additional cities  
15          within the service territory.

## 16   **6. ENERGY EFFICIENCY & DEMAND SIDE MANAGEMENT**

### 17       **6.1 Purpose**

18       The purpose of this section is to: (1) provide an overview of Liberty’s energy efficiency and  
19       demand side management programs, (2) present an assessment of these programs’ impact on  
20       energy savings, environmental and health benefits, and (3) discuss at a high-level the  
21       programs proposed as part of the 2021–2023 New Hampshire Statewide Energy Efficiency  
22       Plan and the Energy Efficiency Resource Standard (“EERS”) in Docket No. DE 20-092 and  
23       some notable new initiatives.

1           **6.2    NHSaves Energy Efficiency Programs**

2           *Overview*

3           Energy efficiency is a priority for Liberty and is a key strategy for building a modern and  
4           sustainable energy future. Energy efficiency is emission free and the lowest-cost resource  
5           available to utilities, customers, and states. Every kilowatt-hour (“kWh”) saved through  
6           energy efficiency helps Liberty achieve deeper energy savings, reduce harmful greenhouse  
7           gas (“GHG”) emissions, save customers money, and mitigate the need for additional power  
8           generation.

9           Liberty has a long history of offering energy efficiency programs and services to its  
10          customers, dating as far back as 1987. Since 2002, Liberty has partnered with the New  
11          Hampshire electric and natural gas utilities (“NH Utilities”) to administer a consistent  
12          portfolio of energy efficiency and demand response programs to residential, commercial and  
13          industrial (“C&I”), and municipal customers across the state, currently marketed under the  
14          statewide brand “NHSaves.” Through this utility collaboration, Liberty and the NH Utilities  
15          deliver innovative, award-winning programs that are designed to provide flexible, cost-  
16          effective solutions to all possible customer segments, such as helping residential customers  
17          and homeowners to install more efficient lighting, appliance and HVAC measures; helping  
18          small, mid-size and large businesses install high efficiency motors, processing and control  
19          systems; and helping municipal and school districts install more efficient HVAC, and  
20          indoor/outdoor lighting and control systems.

1 The energy efficiency programs offered by Liberty and the NH Utilities provide significant  
2 value to all customers, both participants and non-participants and help support the state's  
3 economy in multiple ways. Specifically, delivering cost-effective energy efficiency  
4 programs to customers helps lower energy bills, generates local jobs, reduces the energy  
5 dollars that go toward out-of-state energy generation, and increases the quality of the state's  
6 building stock. Businesses can invest energy savings toward making their companies more  
7 profitable, and into operations and personnel. Towns and cities can use taxpayers' dollars to  
8 fund critical infrastructure projects and public services. Homeowners, particularly limited-  
9 income customers, can use their energy savings toward their most critical needs, with their  
10 dollars staying in the local economy. A variety of other non-energy benefits are created as  
11 well, including:

- 12 • Lower asthma rates and other health-related improvements due to better indoor and  
13 outdoor air quality.
- 14 • Improved business performance and productivity due to the installation of high-  
15 efficiency equipment, such as lighting controls and commercial kitchen equipment.
- 16 • Reduced maintenance costs.
- 17 • Improved building value.
- 18 • Increased comfort which can improve occupant performance, whether that be  
19 students in school or office building workers.
- 20 • Improved safety.

21

1        **Impact of the NHSaves Programs on Energy Consumption**

2        Since 2002, the energy efficiency programs Liberty has implemented have saved customers  
3        over 1.3 million electric kilowatt-hours over the life of the energy efficiency measures  
4        installed, and over 1,000 kW in annualized peak capacity reduction, which translates into  
5        customer savings of over \$140 million. Liberty’s programs have also served over 14,500  
6        participants per year on average during that time span. Table 6.1 summarizes Liberty’s  
7        annual and lifetime megawatt hour savings, customer participation, program costs, and  
8        benefits from 2002 through 2019.

9        Also, since 2012, Liberty has measured customer awareness of its energy efficiency  
10       programs. During this period, customer awareness of the programs has nearly doubled,  
11       increasing from 30% in 2012 to 58% in 2019<sup>28</sup>.

---

28       Luth Research (2019, December). Liberty Utilities – Customer Satisfaction Tracking New Hampshire Electric. Q. “Are you aware that Liberty Utilities offers energy efficiency programs to help you reduce your energy costs?”

1

**Table 6.1. NHSaves Program Results – Liberty Utilities, 2002–2019**

Year	Annual MWh Savings	Lifetime MWh Savings	EE Measures/ Participants	Expenses (000's)	Benefits (000's)
2002	5,035	64,825	4,648	\$1,190	\$4,554
2003	4,990	74,322	8,338	\$1,252	\$6,053
2004	4,019	61,104	6,733	\$1,148	\$5,122
2005	3,559	53,821	4,584	\$1,298	\$4,343
2006	4,001	56,958	4,441	\$1,599	\$5,726
2007	2,962	34,884	5,281	\$1,311	\$3,904
2008	6,120	74,641	22,649	\$1,379	\$7,894
2009	5,395	66,942	14,147	\$1,673	\$8,077
2010	5,848	72,485	17,550	\$1,407	\$8,847
2011	5,361	64,788	19,504	\$1,458	\$6,481
2012	5,644	74,465	7,595	\$1,473	\$6,245
2013	5,591	73,283	20,669	\$1,417	\$8,181
2014	5,347	71,943	18,476	\$2,145	\$9,285
2015	9,265	125,431	23,463	\$2,789	\$11,361
2016	7,308	110,029	9,318	\$1,960	\$11,183
2017	6,299	83,062	12,608	\$2,157	\$9,166
2018	7,545	91,009	21,428	\$2,577	\$10,016
2019	10,179	116,700	29,868	\$3,721	\$13,836
<b>Total</b>	<b>104,468</b>	<b>1,370,692</b>	<b>251,300</b>	<b>\$31,954</b>	<b>\$140,274</b>

2

Table 6.2 details Liberty’s annual and lifetime kilowatt-hour savings, customer participation,

3

program cost, and benefits, by customer program and sector, for its most recently completed

4

program year of 2019. Based on these results, Liberty’s average cost of 2019 savings was

1 3.36 cents<sup>29</sup> per lifetime kilowatt-hour, as compared to the current average retail price per  
2 kilowatt-hour of 16.34 cents, as of December 9, 2020.<sup>30</sup> This represents a simple net benefit  
3 ratio on program investments of 4.87 to 1.

4 **Table 6.2. Liberty Programs' Results — 2019**

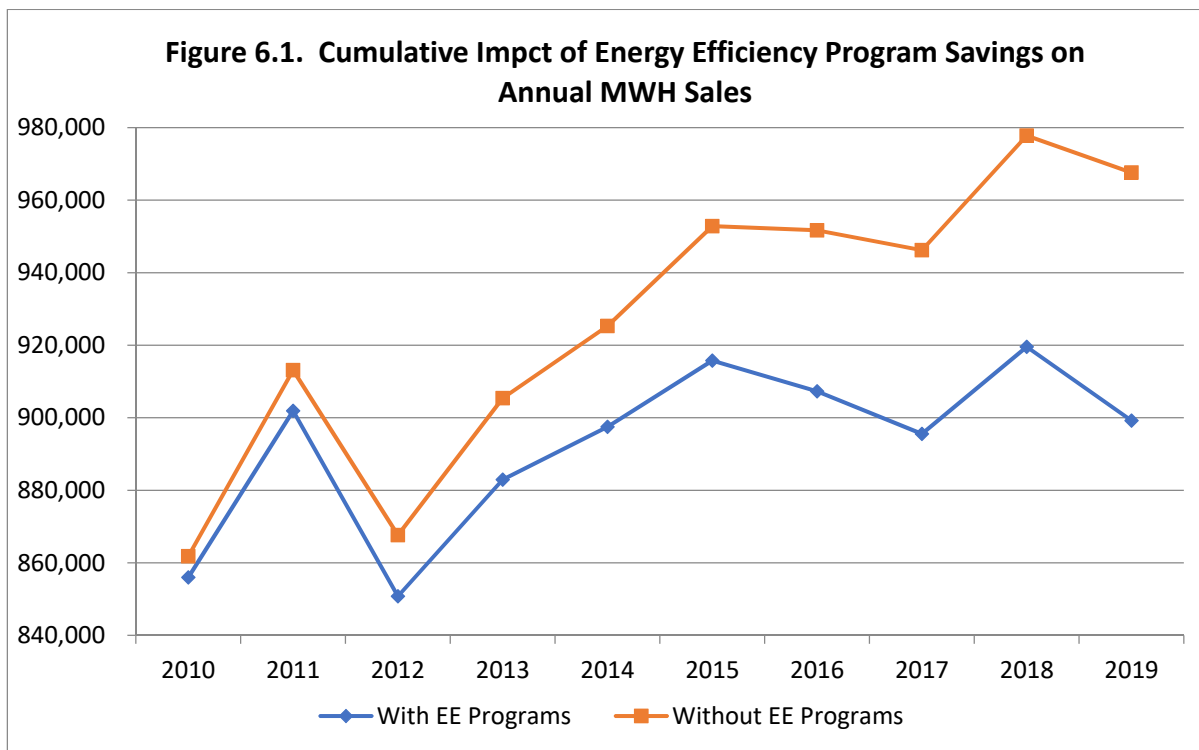
Sector/Program	Annual kWh Savings	Lifetime kWh Savings	EE Measures / Participants	Expenditures	Benefits
<b>Residential</b>					
ENERGY STAR Homes	130,469	2,908,931	40	\$167,964	\$1,837,722
ENERGY STAR Products	1,312,687	8,776,072	19,138	\$318,447	\$988,215
Home Energy Assistance	198,796	2,722,154	168	\$670,522	\$610,449
Home Energy Reports	1,210,000	3,509,000	10,289	\$130,924	\$282,239
Home Performance w/ENERGY STAR	105,608	1,876,918	62	\$314,424	\$1,098,773
<b>Residential Total</b>	<b>2,957,560</b>	<b>19,793,075</b>	<b>29,698</b>	<b>\$1,602,281</b>	<b>\$4,817,397</b>
<b>Commercial &amp; Industrial</b>					
Large Business	4,337,869	57,940,088	33	\$968,272	\$5,237,713
Municipal	541,529	7,551,764	19	\$166,842	\$708,441
Small Business	2,342,105	31,415,220	118	\$886,127	\$3,072,876
C&I Education	-	-	-	\$54,316	-
<b>C&amp;I Total</b>	<b>7,221,503</b>	<b>96,907,071</b>	<b>170</b>	<b>\$2,075,557</b>	<b>\$9,019,029</b>
Forward Capacity Market	-	-	-	\$43,182	-
<b>Overall Total</b>	<b>10,179,064</b>	<b>116,700,147</b>	<b>29,868</b>	<b>3,721,019</b>	<b>\$13,836,427</b>

5 The 2019 annual kilowatt-hour savings are approximately 1.13% of Liberty's total billed  
6 delivery kilowatt-hour sales in 2019 (10,179,064 / 899,231,963). The average life of the  
7 installed energy efficiency measures is 11.46 years. As a result, the savings associated with

29 Value calculated by dividing the total program costs and utility performance incentive (\$2,167,931,721,019 + \$196,915,000) by Lifetime kWh savings achieved (71,943,030 / 116,700,147).

30 New Hampshire Office of Energy and Planning Strategic Initiatives (December 14, 2020). Average Fuel Prices in New Hampshire – Electricity. Retrieved from [http://www.nh.gov/oep/energy/energy-nh/fuel-prices/index.htm#note\\_2](http://www.nh.gov/oep/energy/energy-nh/fuel-prices/index.htm#note_2) <https://www.nh.gov/osi/energy/energy-nh/fuel-prices/index.htm>

1 the measures installed in 2019 will continue well into the future and the cumulative impact of  
 2 the programs will become more significant over time. As illustrated in Figure 6.1, the  
 3 cumulative impact of the NHSaves Programs over the past ten years has resulted in a decline  
 4 of delivered MWh sales of 7.6% in 2019.



5

*Impact of the Energy Efficiency Programs on Capacity or Peak Reduction*

6

7 In addition to the kilowatt-hour energy savings, the Liberty energy efficiency programs also  
 8 provide capacity or peak demand reductions. Table 6.3 summarizes the average annual  
 9 capacity reduction coincident with the New England peak resulting from the programs  
 10 efficiency measures installed by customers between January 1, 2010, and December 31,  
 11 2019. As shown, the energy efficiency programs implemented by Liberty reduced New

1 England’s peak load (which currently occurs in the summer) by 1,113 kW, which is  
2 approximately 0.54% of Liberty’s system peak load<sup>31</sup> in New Hampshire.

3 **Table 6.3. NHSaves Programs Capacity Reduction Based on Operable Measures**  
4 **Installed Between January 1, 2010, and December 31, 2019**

Year	Coincident with ISO-NE Peak		
	Residential	C&I	Total
2010	117	898	1,015
2011	84	762	846
2012	94	844	938
2013	173	635	808
2014	192	855	1,047
2015	918	476	1,394
2016	459	1,032	1,491
2017	382	528	910
2018	341	627	969
2019	465	1,249	1,714
<b>Total</b>	<b>3,226</b>	<b>7,906</b>	<b>11,132</b>
<b>Average kW/mo</b> (120 months in period)	<b>26.88</b>	<b>65.89</b>	<b>92.77</b>
<b>Annualized Capacity Reduction</b>	<b>323</b>	<b>791</b>	<b>1,113</b>

5 The New Hampshire electric utilities, including Liberty, are the only energy efficiency  
6 providers in New Hampshire participating in the ISO-NE’s forward capacity market. The  
7 proceeds obtained through participation in this market have totaled \$3,010,787 from 2010  
8 through 2019. These proceeds are utilized as a funding source for the NHSaves Programs,  
9 and the amount obtained in 2019 represented approximately 19.8%<sup>32</sup> of Liberty’s NHSaves  
10 Program expenditures in 2019. In order to qualify for payments from the ISO-NE, Liberty

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

32 ISO-NE FCM Proceeds in 2019 were \$738,156 as compared to Total Energy Efficiency program expenditures of \$3,721,019 in 2019.



1 must certify to the ISO-NE's satisfaction that the capacity reductions are operational during  
2 hours of peak electrical usage. Liberty has developed the necessary reporting, measurement,  
3 and verification plans needed to evaluate the impact of the efficiency measures at the time of  
4 the New England peak and the resulting capacity reduction load value that qualifies for  
5 payment from the ISO-NE. Liberty has met the rigorous reporting standards and  
6 requirements to participate in the forward capacity market. As a result, the estimated  
7 capacity reductions summarized above are an accurate representation of the capacity  
8 reductions resulting from the NHSaves Programs as they have been thoroughly reviewed by  
9 ISO-NE and independently certified.

10 *State Energy Policy - Energy Efficiency Resource Standard (EERS)*

11 In August 2014, the New Hampshire Public Utilities Commission (PUC) initiated an  
12 informal, non-adjudicative stakeholder process to develop a framework, the EERS, within  
13 which the NHSaves Programs would be implemented. The process resulted in an eighteen-  
14 month dialogue among the Commission, the NH Utilities, and numerous stakeholders. In  
15 2016, the state's first EERS was established through a settlement agreement filed with the  
16 Commission.<sup>33</sup> The EERS is the framework within which the NHSaves Programs have been  
17 implemented since 2018, and requires the NH Utilities to file triennial plans, to pursue annual  
18 savings goals, and to achieve the long-term objective of achieving all cost-effective energy  
19 efficiency.

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33 State of New Hampshire Public Utilities Commission. DE 15-137. *Order No. 25,392: Energy Efficiency Resource Standard*, Aug. 2, 2016. Available at: <https://www.puc.nh.gov/Regulatory/Orders/2016orders/25932e.pdf>.

1 Coincident with the EERS, the Commission also established a recovery mechanism to  
2 compensate the NH Utilities for lost revenue resulting from the implementation of NHSaves  
3 Programs under the EERS. The NH Utilities file annual updates with the Commission  
4 regarding any necessary changes that need to be made to the Systems Benefit Charge  
5 (“SBC”) or Local Delivery Adjustment Clause (“LDAC”), the primary funding mechanisms  
6 for the NHSaves Programs. The SBC and LDAC are nominal charges on customers’ electric  
7 and natural gas utility bills, respectively.

8 During the state’s transition to the EERS, the Commission extended for an additional year  
9 the approved 2015–2016 NHSaves Programs (i.e., the program implementation and  
10 established annual savings targets for the 2017 program year). On January 2, 2018, the  
11 Commission approved the implementation of the NH Utilities’ first three-year plan (“2018–  
12 2020 Plan”).<sup>34</sup> The NH Utilities filed plan updates in September 2018 (“2019 Plan Update”)   
13 and September 2019 (“2020 Plan Update”) to realign energy-saving goals and program  
14 budgets with the Commission-approved 2018–2020 Plan. The 2021–2023 Plan is the second  
15 triennial plan filed by the NH Utilities under the EERS via Docket No. DE 20-092 on  
16 September 1, 2020.<sup>35</sup>

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34 State of New Hampshire Public Utilities Commission. DE 17-136. *Order No. 26,905: 2018-2020 New Hampshire Statewide Energy Efficiency Plan*, Jan. 2, 2018. Available at: <https://www.puc.nh.gov/Regulatory/Orders/2018orders/26095e.pdf>.

35 New Hampshire Electric and Natural Gas Utilities (2020, September 1). 2021-2023 New Hampshire Statewide Energy Efficiency Plan. Retrieved from [https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092\\_2020-09-01\\_NHUTILITIES\\_EE\\_PLAN.PDF](https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092_2020-09-01_NHUTILITIES_EE_PLAN.PDF)

1           **6.3    Energy Efficiency Resource Plan (EERS) Plan: 2021–2023**

2           In preparation of the 2021–2023 EERS Plan, Liberty and the NH Utilities reviewed energy  
3           efficiency portfolios across North America to determine additional opportunities to modify,  
4           improve, and lead the NHSaves Programs toward cost-effective, comprehensive energy  
5           savings over the next three years. Liberty and the NH Utilities also engaged in a  
6           collaborative stakeholder process to capture feedback from key experts, constituents, trade  
7           allies and customers in New Hampshire and that feedback is also reflected in the plan.

8           Market trends, new federal regulations and policies, changing state building codes, emerging  
9           technologies, and baseline studies were also incorporated into the NH Utilities’ planning  
10          process. In addition, the NH Utilities used evaluation results during the 2018–2020 term to  
11          help steer the NHSaves Programs toward greater efficacy while driving energy savings, GHG  
12          emissions reductions, and increased economic benefits.

13          *Plan Highlights*

14          As part of the 2021–2023 Plan, Liberty and the NH Utilities are focused on increasing the  
15          scale of the energy savings and broadening customer participation in the NHSaves Programs.

16          To accomplish this, the 2021–2023 Plan includes the continuation of many of the  
17          successfully deployed programs from prior years as well as the introduction of several new  
18          offerings, all designed to increase New Hampshire’s leadership in energy efficiency and  
19          demand management. For example:

- 20                 • For residential customers, Liberty will introduce or more heavily promote several  
21                 program pathways, including: code-plus initiatives, online platforms, single-measure  
22                 rebates, energy kits, and visual audits.

- 1           • For C&I customers, Liberty will encourage additional participation through the  
2 expansion of the “Main Street” efforts and community outreach initiatives, as well as  
3 the creation of standard marketing collateral targeting C&I customers and market  
4 segments. Liberty will also continue to market and make available its customer On-  
5 Bill Financing program, which has proven to be a key resource for driving customer  
6 activity, particularly with municipal and small business customers during the  
7 COVID-19 pandemic.
- 8           • Liberty and the NH Utilities intend to focus on delivering tailored, comprehensive  
9 solutions to customers that will drive electric savings. At a high-level, “tailored,  
10 comprehensive solutions” for C&I customers will involve testing various channels,  
11 incentive models, and strategies to identify more precisely what motivates customers  
12 and contractors to implement comprehensive energy-saving projects.
- 13          • Liberty and the NH Utilities will explore offering a tiered incentive design focused on  
14 the delivered energy savings of an entire project, rather than the current approach of  
15 incentivizing single measures.
- 16          • Liberty and the NH Utilities will continue to offer cost-sharing comprehensive audits  
17 and determine if this incentivizes more C&I customers to invest in deeper energy-  
18 saving projects.
- 19          • For residential customers, Liberty and the NH Utilities will promote  
20 comprehensiveness through the introduction and heavy promotion of multiple “on  
21 ramps” to energy efficiency that will be utilized to encourage investment in multiple-  
22 measure projects.
- 23          • Liberty and the NH Utilities are deliberately expanding the programs to focus on  
24 measures beyond lighting, which have provided an inexpensive and relatively easy  
25 means of reducing electricity for many years. Despite the recent federal roll-back of  
26 minimum lighting technology efficiency standards, the lighting market has continued  
27 to rapidly transform and transition to the widespread adoption of LEDs. In order to  
28 help maintain and accelerate the strong demand for high-efficiency ENERGY STAR  
29 LED technologies, Liberty and the NH Utilities will continue to aggressively support  
30 and incentivize energy-efficient bulbs and fixtures for the NHSaves Residential  
31 Programs through the end of 2021. However, beginning in 2022, and depending on  
32 how the marketplace responds to the relaxed federal standards, Liberty and the NH  
33 Utilities will transition program support to discount retailers focused on reaching the  
34 last-to-adopt and hard-to-reach customer segments. Sizeable program potential still

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1 remains in capturing retrofit lighting applications for commercial small, large and  
2 municipal customers, particularly when coupled with advanced control technologies,  
3 and this area will continue to be a focus throughout the next three year term.

- 4 • To scale up customer participation and drive deeper energy savings, Liberty and the  
5 NH Utilities are making a concerted effort to develop a comprehensive workforce  
6 development strategy. The goal here is to expand the universe of potential energy  
7 efficiency service providers in the state as well as increase the available talent pool  
8 from which the existing service providers in the state can leverage.

9 Table 6.4 summarizes the NHSaves program offerings scheduled to be available in 2021 with  
10 the assumption that the Settlement Agreement in Docket No. DE 20-092 is approved. In the  
11 event that the Settlement Agreement is not approved, these tables may be updated during this  
12 adjudicative proceeding to provide the approved program offerings.

1

**Table 6.4. NHSaves Program Offerings**

Program	Example Measures	Incentives
<b><i>Residential Sector</i></b>		
1. ENERGY STAR Products	LED lighting, ENERGY STAR appliances and HVAC measures	Instant discounts via retail, equipment distributor and online marketplace channels
2. Home Performance with ENERGY STAR	Audit, air sealing, weatherization and HVAC measures	75% rebate up to \$8,000; 3 <sup>rd</sup> party and On-Bill Financing
3. ENERGY STAR Homes	New construction measures beyond current building code standards	Builder training and verification of code + measure installations
4. Home Energy Assistance	Air sealing, weatherization, appliances, lighting and HVAC measures	Up to \$20,000 in services, at no cost, depending on income eligibility.
5. Home Energy Reports	Personalized energy usage reports detailing normative comparisons	No cost service
6. Energy Optimization (Pilot)	Cold-climate Air-Source Heat Pumps (ductless & mini-splits) when displacing existing fossil-based heating source w/Integrated Controls	\$1,250 per Ton
<b><i>Non-Residential Sector</i></b>		
6. Small Business	Interior and exterior lighting, refrigeration, compressed air, controls, electric hot water heating	Prescriptive & custom incentives up to 75% of project costs; Midstream channels; Technical assistance; Free energy audits; On-bill financing
7. Large Business	Interior and exterior lighting, process manufacturing, custom controls, retro-commissioning, VFDs	Prescriptive & custom incentives up to 50% of project costs; Midstream channels; Technical assistance; On-bill financing
8. Municipal	Interior and exterior lighting, HVAC and thermal savings	Up to 75% of project costs; Midstream prescriptive incentives; Technical assistance; Free energy audits; On-bill financing
9. Load Curtailment	Temporary reduction in facility kW load upon signal, during times of peak electric demand	\$ per kW Reduction

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1 Table 6.5 summarizes the specific Liberty energy efficiency program and sector savings  
2 targets and budgets for NHSaves program offerings scheduled to be available in 2021  
3 through 2023. Liberty plans to invest over \$23 million in energy efficiency programs and  
4 services (expressed in 2021 dollars) during the next three year period, as compared to just  
5 over \$13 million invested during the 2018 through 2020 term, a 80% increase. The Liberty  
6 energy efficiency programs are projected to generate 41,172 annual MWhs of customer  
7 energy savings, as compared to 29,183 annual MWhs of savings during the 2018 through  
8 2020 term, a 41% increase.

9 **Table 6.5. Liberty 2021–2023 Energy Efficiency Program Portfolio, Key Metrics**

Program	Program Benefits (\$000)	Utility Costs (\$000) <sup>1</sup>	Customer Costs (\$000) <sup>1</sup>	Annual MWh Savings	Lifetime MWh Savings	Winter kW Savings	Summer kW Savings	# Customers Served
<b>Residential Programs</b>								
Energy Star Homes	6,085.8	893.1	112.1	397.2	9,178.7	86.0	6.8	210
Energy Star Products	4,543.9	2,572.0	234.0	4,275.3	37,978.1	789.1	624.5	65,807
Home Energy Assistance	12,236.2	4,788.4	0.1	1,335.8	21,329.4	236.8	145.7	1,020
Home Energy Reports	452.0	378.3	-	3,862.9	3,862.9	833.9	537.9	30,768
Home Performance with Energy Star	3,548.7	1,755.8	345.8	320.6	4,985.3	86.2	61.0	207
Energy Optimization ( <i>Pilot</i> )	-	130.8	-	-	-	-	-	-
Residential Market Education	-	139.7	-	-	-	-	-	-
Res ISO FCM Expenses	-	116.5	-	-	-	-	-	-
<b>Sub-Total Residential</b>	<b>26,866.6</b>	<b>10,774.6</b>	<b>692.1</b>	<b>10,191.7</b>	<b>77,334.4</b>	<b>2,032.0</b>	<b>1,375.9</b>	<b>98,012</b>
<b>Commercial, Industrial &amp; Municipal</b>								
Large Business Energy Solutions	17,891.4	6,123.2	6,252.5	16,166.6	200,445.8	1,336.9	1,524.5	788
Load Curtailment	3,538.2	1,199.3	-	-	-	-	-	162
Municipal Energy Solutions	1,005.8	516.2	565.1	1,066.5	12,882.1	97.6	51.2	279
Small Business Energy Solutions	16,947.1	4,959.2	3,680.4	13,747.0	182,808.5	1,882.4	1,603.6	1,077
C&I Market Education	-	135.9	-	-	-	-	-	-
C&I ISO FCM Expenses	-	154.4	-	-	-	-	-	-
<b>Sub-Total Commercial &amp; Industrial</b>	<b>39,382.5</b>	<b>13,088.2</b>	<b>10,498.0</b>	<b>30,980.0</b>	<b>396,136.5</b>	<b>3,317.0</b>	<b>3,179.3</b>	<b>2,306</b>
<b>Total</b>	<b>66,249.1</b>	<b>23,862.8</b>	<b>11,190.0</b>	<b>41,171.7</b>	<b>473,470.9</b>	<b>5,349.0</b>	<b>4,555.2</b>	<b>100,318</b>

<sup>1</sup>Utility and Customer Costs Expressed in 2021 Dollars

10 Complete details of the 2021–2023 EERS program offerings for Liberty and the NH Utilities  
11 can be found in the 2021–2023 EERS Plan submitted to the Commission via Docket No. 20-

1 092.<sup>36</sup> Some notable new program and pilot offerings as part of the plan are detailed in the  
2 next section.

### 3 **New Programs & Pilot Offerings**

#### 4 *Load Curtailment Program*

5 Effective demand-reduction strategies can help reduce energy prices and price spikes during  
6 summer. For the 2021–2023 term, Liberty intends to deploy an Active Demand Reduction,  
7 Load Curtailment program to its Commercial and Industrial customers program to help to  
8 flatten peak loads, improve system load factors, and reduce costs for electric customers.

9 Also referred to as Interruptible Load, the Load Curtailment offering provides an incentive  
10 for verifiable shedding of load by customers in response to communication from Liberty or  
11 its curtailment service providers (“CSPs”). The program is based upon the design of the  
12 Eversource and Unitil Electric pilot programs implemented during the 2018–2020 term. The  
13 Load Curtailment offering is technology agnostic, which means that customers are able to  
14 use any technology or strategy and earn an incentive based on their summer seasonal average  
15 curtailment performance.

16 With a technology agnostic approach, customers with on-site generation are allowed to  
17 participate in the Load Curtailment offering. However, the NH Utilities have established  
18 certain criterion in order to not increase emissions, including prohibiting participation by

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36 New Hampshire Electric and Natural Gas Utilities (2020, September 1). 2021-2023 New Hampshire Statewide Energy Efficiency Plan. Retrieved from [https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092\\_2020-09-01\\_NHUTILITIES\\_EE\\_PLAN.PDF](https://www.puc.nh.gov/Regulatory/Docketbk/2020/20-092/INITIAL%20FILING%20-%20PETITION/20-092_2020-09-01_NHUTILITIES_EE_PLAN.PDF)



1 “emergency only” back-up generators. Allowed generators in the program must pass local,  
2 state, and federal guidelines for participation in demand response programs. These  
3 permitting procedures mean this class of generator (typically EPA Tier 4) can operate a  
4 higher number of hours per year and produce little emissions, especially when compared to  
5 electrical grid emissions during peak hours.

6 The Load Curtailment offering provides an incentive to C&I customers to temporarily reduce  
7 facility load upon a signal from Liberty or its CSP during times of peak electric demand  
8 (referred to as “events”). Generally, curtailment events will last three hours and occur during  
9 July and August. Typically, there will be between one to eight events per summer season  
10 depending upon ISO-NE load conditions.

11 Liberty, with assistance from its CSPs, will identify customers with curtailable load, assess  
12 curtailment opportunities, process and approve customer enrollment applications, manage the  
13 relationship with participants, call and manage curtailment events, oversee customer  
14 performance, and calculate payments.

15 Table 6.6 details the projected customer benefits, costs, kW savings, and number of  
16 customers served through the program during the 2021–2023 term for Liberty. In summary,  
17 over \$3.5M in customer benefits will be generated through the program, as compared to costs  
18 of just under \$1.2M, for a benefit cost ratio of 2.95. Liberty plans to serve 162 participants  
19 and generate in average of 5,293 in Summer kW savings per year.

1 **Table 6.6. C&I Load Curtailment Program, 2021–2023: Key Metrics**

Year	Benefits (\$000)	Costs (\$000)	Summer kW Savings	# Participants
2021	\$ 726.2	\$ 271.6	3,343.2	34
2022	\$ 1,112.2	\$ 376.9	5,014.8	51
2023	\$ 1,699.8	\$ 550.8	7,522.2	77
<b>Total</b>	<b>\$ 3,538.2</b>	<b>\$ 1,199.3</b>	<b>15,880.3</b>	<b>162</b>

2 *Energy Optimization Pilot*

3 Energy Optimization (“EO”) is an energy resource framework that seeks to minimize  
 4 customers’ total energy usage across all energy sources while maximizing customers’  
 5 benefits. In particular, EO often focuses on conversions from delivered fossil-fuel heating  
 6 systems to higher efficiency electric systems. EO strategies account for both equipment  
 7 efficiency, as well as the mix of fuels used, which distinguishes it from fuel switching and  
 8 beneficial electrification, which focus primarily on fuel type but do not necessarily prioritize  
 9 overall energy efficiency.

10 Beginning in 2021, Liberty and the NH Utilities plan to implement an EO pilot based on the  
 11 New Hampshire Electric CoOp (NHEC) Social Responsibility Heat Pump program as well as  
 12 offerings in other New England states. The EO pilot will focus on displacing residential  
 13 delivered fossil fuel through the adoption of cold climate air source heat pumps (“ASHPs”),  
 14 including central and mini-split systems. The pilot will provide Liberty and the NH Utilities  
 15 with a more comprehensive understanding and experience of the benefits of heat pumps to  
 16 the electric system, as well as the impact on emissions from GHGs and nitrogen and sulfur

1 oxides. Liberty and the NH Utilities will also investigate customer experience and optimal  
2 program delivery standards related to this offering.

3 To be eligible for the EO pilot, customers must be willing and able to displace their existing  
4 heat source for at least one heating zone(s) of their home for a substantial portion of the  
5 heating season (see requirements below regarding switchover set points). For the EO pilot,  
6 Liberty and the NH Utilities will recommend, but not require, that the home be weatherized  
7 in advance of participation to ensure optimal sizing of the ASHP. Liberty and the NH  
8 Utilities will also recommend that customers maintain a backup automatic feed heating  
9 system. In these cases, customers must allow for the installation of integrated controls that  
10 will automatically assign the most efficient heating system to operate during the heating  
11 season, based on the outdoor temperature. Homes in which a backup heating system is  
12 deemed unnecessary will not be required to have integrated controls. Since the vast majority  
13 of the installations in the pilot are projected to have a backup system, the narrative focuses on  
14 these installations.

15 *Existing Heat Pump Program*

16 For more than a decade, Liberty and the NH Utilities have provided incentives for the  
17 installation of high-efficiency ASHPs and have adopted best practices when cold climate heat  
18 pumps became commercially available. To date, heat pump units have typically been treated  
19 as a “lost opportunity” in which it was assumed that the customer was making a choice  
20 between the program-incented high-efficiency unit and a less expensive, standard-efficiency

1 unit. The kWh and kW savings were therefore calculated based on a comparison between the  
2 high-efficiency and standard-efficiency unit and assumed both heating and cooling savings.

3 *Pilot Purpose*

4 The EO pilot is designed to gather information on both program design elements and key  
5 regulatory questions, including how Liberty and the NH Utilities should account for fossil  
6 fuel and electricity savings (positive and negative). The EO pilot will be accompanied by an  
7 impact and process evaluation to guide future program design should Liberty and the NH  
8 Utilities recommend that the pilot expand to a full-scale program. The impact and process  
9 evaluation will also assess issues raised by the Commission in Order No. 26,322, as  
10 described in Section 7.6.

11 *Target Population*

12 The pilot has a goal of 100 participants per year across all utilities over the 2021–2023 term,  
13 of which Liberty would have an annual goal of nine participants. The pilot will target homes  
14 with existing HVAC configurations that are well-suited for ASHP conversions, but where the  
15 homeowners are not already planning to install ASHPs for heating (which are already  
16 incented by the existing ES Products program). The pilot will target customers heating with  
17 oil and propane furnaces and boilers. The target population will include:

- 18 • Customers who are not actively considering heat pumps but who have central A/C  
19 systems, that are failing or old;
- 20 • Customers who are not actively considering heat pumps but who use window A/C  
21 units;

- 1       • Customers who are actively considering the installation of a central A/C system and  
2       who currently have window A/C units or no cooling system; and
- 3       • Customers who are currently interested in heat pumps only for cooling, but not  
4       heating.

5       While not part of the target population, those heating with auto-fed wood pellet stoves and  
6       boilers will also be eligible on a limited basis provided they meet other pilot requirements for  
7       integrated controls and provision of fuel data.

8       *Customer and Contractor Outreach*

9       The EO pilot will leverage existing pathways for incentivizing high-efficiency heat pump  
10      technologies, as well as design new outreach efforts for the target population and  
11      technologies. Liberty and the NH Utilities will engage customers through online and in-  
12      person education, targeted incentives, marketing, and financing solutions (e.g., on-bill  
13      financing and third-party loan programs). Customer education will focus on how to optimize  
14      their heating system's efficiency and proper maintenance and upkeep.

15      A cornerstone of the EO pilot will be a broad promotional outreach effort, including training  
16      for HVAC and energy efficiency contractors on the benefits of ASHP technologies, and the  
17      need for integrated HVAC controls to optimally operate the ASHP with the building's  
18      existing heating system. Customers' existing heating systems will generally be expected to  
19      provide backup heating during the heating season's coldest temperatures while the ASHP  
20      will meet customers' full heating needs for the rest of the season.

1 Liberty and the NH Utilities will market the program to the following customers through  
2 personal outreach, direct marketing, collaboration with interested stakeholders, and other  
3 methods:

- 4 • HPwES program customers (past, present, and future);
- 5 • Existing customers of HVAC contractors;
- 6 • NH Electric Utility net metering Solar PV customers; and
- 7 • Customers who have installed battery storage on their own or through the Company's  
8 pilot.

9 *Customer Eligibility*

10 Customers may participate in the EO pilot if they meet the following eligibility guidelines:

- 11 • Are willing to allow for the installation of integrated controls (not required if a  
12 customer removes the existing heat source for a whole zone(s) within the home);
- 13 • Are willing to provide data on their delivered fuel consumption, including data from  
14 no less than one year prior to the installation of the heat pump. This data will enable  
15 evaluation of fossil fuel and electricity usage, both before and after the installation of  
16 the heat pump technology. The customer can provide the fossil fuel records directly,  
17 or sign a release form that allows evaluators to obtain the data directly from the  
18 customer's fuel company;
- 19 • Agree to meet a maximum outdoor temperature set point (determined by the Utilities)  
20 for the switch over from the backup heating system to ASHPs; and
- 21 • Agree to implement a full heating zone(s) displacement. Partial heating zone  
22 installations are not eligible.
- 23 • Backup heating systems must be automatic feed systems. These include boilers,  
24 certain types of stoves, and furnaces.

1     *Incentive Structure*

2     Incentives for EO are designed to move a customer away from their current primary fossil  
3     fuel heat source to use high-efficiency ASHPs as their primary heat source instead. This  
4     proposition differs from a standard ASHP program offering, which incentivizes a customer  
5     who is already purchasing an ASHP to buy a more efficient unit, rather than a typical unit. In  
6     the EO framework, the customer cost barrier is higher and the overall MMBtu savings are  
7     greater than a standard ASHP program offering. The incentive levels for the EO pilot are  
8     designed to help overcome the customer barriers and achieve the displacement of the fossil  
9     fuel heating source. The initial incentive level for the EO pilot will be \$1,250/ton, which  
10    aligns with a similar offering in Massachusetts. This level may be adjusted as Liberty and  
11    the NH Utilities gain experience and customer feedback during the pilot.

12    *Post Inspections and Survey*

13    Post-installation inspections will be conducted for all EO pilot participants. An EM&V  
14    survey will be provided during each inspection. The inspectors will collect the following  
15    information:

- 16       • If the number of installed HP tons (1 ton = 12,000 Btuh) meets the customer's heating  
17       needs;
- 18       • If the existing heating system and heat pump set points are within the pilot  
19       parameters;
- 20       • If there are working integrated controls (if required as listed above); and
- 21       • If the heat pump technologies installed were designed to provide heat to a whole  
22       heating zone(s).

1     *Evaluation Plan*

2     The pilot will be accompanied by an evaluation to measure the impacts on total energy  
3     consumption (for both heating and cooling, and across all fuels) and to assess program  
4     processes, customer behavior, and workforce capacity. Results of the evaluation will guide  
5     future decisions on expanding the pilot to a full-scale program. Design of the evaluation can  
6     leverage experience gained through similar evaluations happening in other states, such as the  
7     EO Impact and Process evaluation currently underway in Massachusetts. The NH EO  
8     evaluation will include both impact and process components:

- 9             • Pilot Impacts. The evaluation will measure impacts and refine methods for  
10            accounting for unregulated fuel savings and electric load increases for fuel-to-electric  
11            measures, to support modelling net MMBtu savings that could be claimed under a  
12            holistic accounting framework. The evaluation may include analysis of heat pump  
13            usage data from integrated control systems, delivered fuels billing data, where  
14            available, and whole home electric usage data from the NH Utilities. Requirements  
15            for integrated controls and customer releases to obtain delivered fuel records will  
16            support these efforts. This analysis will also help determine the extent to which EO  
17            could, at scale, lead to load factor improvements by increasing load during times  
18            when the transmission and distribution systems are not operating at peak capacity. As  
19            noted by the Commission in Order No. 26,322, such load factor improvements may  
20            present an opportunity for ratepayers, as non-participants may stand to benefit from  
21            increased electricity sales that do not significantly increase transmission and  
22            distribution system costs.
- 23             • Pilot Processes. The evaluation will assess the pilot design and offerings for tailored  
24            ASHP measure bundles, including weatherization and integrated controls, to  
25            understand customer behavior and satisfaction, contractor technical capacity and  
26            training needs, and equipment configurations and baselines. Post-inspections will be  
27            utilized to confirm installation configurations and setpoints, and to survey customers  
28            on their plans for using the heat pumps and modifying set points, alternative  
29            equipment baselines they considered, and their satisfaction with contractors, the  
30            installation processes, and the rebate fulfillment process. The evaluation is also



1 expected to include surveys or interviews with contractors to obtain feedback on  
2 issues such as training or capacity needs.

3 Although the pilot is not subject to cost-effectiveness requirements and Liberty and the NH  
4 Utilities have not modelled planned savings, average project savings are expected to be in  
5 line with those from the EO study done under the oversight of the NH Benefit Cost Working  
6 Group.<sup>37</sup> This study and its associated planning model were based on a Massachusetts EO  
7 model and adapted to include New Hampshire specific inputs such as fuel cost data, weather  
8 data, saturation of various air conditioning technologies, and the regional electric generation  
9 mix. Table 6.7 provides estimated fossil fuel and electric impacts for the four scenarios  
10 expected to comprise the majority of pilot projects: oil and propane furnaces displaced by a  
11 central ASHP and oil and propane boilers displaced by ductless heat pumps.

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37 Navigant, Energy Optimization. Sep. 12, 2019. See [https://puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136\\_2019-10-31\\_STAFF\\_NH\\_ENERGY\\_OPTIMIZATION\\_STUDY.PDF](https://puc.nh.gov/Regulatory/Docketbk/2017/17-136/LETTERS-MEMOS-TARIFFS/17-136_2019-10-31_STAFF_NH_ENERGY_OPTIMIZATION_STUDY.PDF) and <https://puc.nh.gov/Electric/Reports/20190805-PUC-Electric-NH-Energy-Optimization-Model.xlsx>.

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**Table 6.7. EO Estimated Energy Impacts**

Baseline Equipment	Replacement Equipment	Annual Energy Savings on MMBtu Basis (MMBtu/yr)	Propane Annual Savings (MMBtu/yr)	Oil Annual Savings (MMBtu/yr)	Electric Annual Savings (kWh/yr)	Electric Heating Savings (kWh/yr)	Electric Cooling Savings (kWh/yr)	Electric Heating Peak Demand Savings (kW)	Electric Cooling Peak Demand Savings (kW)
<b>Oil Furnace + Baseline A/C Blend</b>	Central HP + Oil Furnace	37.81	0.00	49.02	-3285	-3963	678	-1.630	0.610
<b>Propane Furnace + Baseline A/C Blend</b>	Central HP + Propane Furnace	51.67	68.83	0.00	-5027	-5705	678	-1.630	0.610
<b>Oil Boiler + Room A/C/No A/C Blend</b>	Ductless HP + Oil Boiler	46.11	0.00	57.82	-3433	-4231	799	-1.090	0.970
<b>Propane Boiler + Room A/C/No A/C Blend</b>	Ductless HP + Propane Boiler	63.53	81.19	0.00	-5176	-5975	799	-1.095	0.970

2 **Note:** Negative savings values reflect increased consumption. Cooling baselines are based on a statewide blend of  
3 A/C penetration for central and room A/C systems.

4 **7. CONCLUSION**

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

8 Key results and findings of the LCIRP include:

- 9 • Under the extreme weather scenario, Liberty’s summer peak demand is projected to  
10 grow an average of 0.87% per year over the 2021 to 2037 planning period. Winter  
11 peak demand is projected to grow 0.74% per year on average over the same time

- 1 period. These growth rates incorporate forecasted PV and electric vehicle charging  
2 projections for New Hampshire.
- 3 • The Company’s five-year capital budget is \$124 million, with spending on mandated  
4 and growth programs representing 41% of the budget, and spending on discretionary  
5 items representing 59% of the budget;
  - 6 • The Company’s distribution planning process integrates non-wires alternatives,  
7 although the Company’s pursuit of non-wires alternative solutions requires a more  
8 detailed analysis of the benefits and costs, including technical studies that would  
9 require additional resources;
  - 10 • The LCIRP assumes a “business as usual” scenario for energy efficiency, recognizing  
11 there is an ongoing Energy Efficiency Resource Standard (“EERS”) proceeding that  
12 may affect future energy efficiency programs;
  - 13 • The LCIRP includes known Distributed Generation (“DG”) interconnections;
  - 14 • The key impacts of the Company’s LCIRP on environmental, economic, and energy  
15 price and supply impact on the state include the following:
    - 16 ○ The Company’s competitively sourced energy supply procurement process,  
17 consistent with the Settlement Agreement approved by the Commission in  
18 Order No. 24,577 (Jan. 13, 2006), ensures energy supply is delivered to  
19 customers at the lowest reasonable cost, while considering certain financial  
20 and qualitative criteria.
  - 21 • The Company’s renewable energy credit procurement, energy efficiency programs,  
22 and net metering program provide economic and environmental benefits to the state  
23 by supporting jobs in the renewable energy industry and reducing reliance on sources  
24 of electric generation produced outside the state that emit greater amounts of  
25 pollutants.
  - 26 • The integration of non-wires alternatives into the Company’s distribution planning  
27 process has the potential to provide economic and environmental benefits to the state  
28 through lower costs to the customer and the reduction of peak loads.

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

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**Appendix A. LCIRP Statutory Requirements**

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**Figure A-1. LCIRP Compliance with Statutory Requirements**

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

1           **Consistency with the Federal Clean Air Act**

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

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

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

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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](http://www.iso-ne.com/static-assets/documents/2015/01/stateofgrid_presentation_01212015.pdf)

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

### 11 **Consistency with the New Hampshire State Energy Plan**

12 RSA 378:38 requires an LCIRP to include “an assessment of plan integration and  
13 consistency with the state energy strategy under RSA 4-E:1.” As described below,  
14 Liberty’s LCIRP is consistent with the New Hampshire 10-year State Energy Strategy  
15 (“SES”), released by the New Hampshire Office of Energy and Planning in September  
16 2014, and implemented by Governor Hassan on July 8, 2015.

17 The SES provides recommendations regarding New Hampshire’s energy policies and  
18 programs organized into four categories: (1) Electric Grid of the Future, (2) Energy  
19 Efficiency (3) Fuel Diversity and Choice, and (4) Transportation Options.<sup>4</sup> As the first

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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

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

3 *Electric Grid of the Future*

4 The SES recommends the Commission open an investigation into Grid Modernization.<sup>5</sup>  
5 Pursuant to House Bill 614, the Commission opened Docket No. IR 15-296 *Electric*  
6 *Distribution Utilities Investigation into Grid Modernization* on July 30, 2015. The  
7 purpose of the proceeding is to gather information and “give stakeholders a chance to  
8 learn about grid modernization and to explore to what extent that grid modernization is  
9 workable in New Hampshire.”<sup>6</sup> The Commission has suspended the docket as it decides  
10 on Eversource’s Motion for Reconsideration and/or Clarification filed in response to the  
11 Commission’s Order No. 26,358 whereby the Commission supported Staff’s position in  
12 their recommendation filed on February 12, 2019. As described in Section 4, Liberty is  
13 proposing a Least Cost Integrated Resource Plan with Grid Modernization Plan elements  
14 based on assessment of Smart Grid technologies working with CMG Consulting. This  
15 Plan will significantly improve Liberty’s ability to integrate Distributed Energy  
16 Resources (DERs) and manage the grid more efficiently, reducing the growth in  
17 centralized transmission and generation resources (See Section 5 and Appendix E) for  
18 details on the costs and benefits of this Plan. Therefore, this LCIRP is consistent with the

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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.



1 SES’s recommendations with respect to grid modernization and the “electric grid of the  
2 future.”

3 *Energy Efficiency*

4 The SES recommends that the state prioritize capturing more energy efficiency in all  
5 sectors through (1) establishing an efficiency goal, (2) addressing utility disincentives, (3)  
6 improving program coordination, (4) increasing access to financing, and (5) increasing  
7 funding for low-income energy efficiency programs.<sup>7</sup> The recommendations also  
8 included increasing state “lead by example” programs, and adopting newest building  
9 codes, however these recommendations are not relevant to utility energy efficiency  
10 efforts. Liberty supports these recommendations, and will participate in efforts to address  
11 these recommendations.

12 With respect to establishing an efficiency goal, Liberty is an active participant in Docket  
13 No. DE 20-092, the Commission’s EERS proceeding. As of the date of this filing, the  
14 Settlement Agreement filed in the docket has not been approved. As described in Section  
15 6.5, Liberty supports the creation of an EERS and believes, if structured correctly, there  
16 can be significant benefits to businesses, residents and communities in increasing energy  
17 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.

1        *Fuel Diversity and Customer Choice*

2        The SES recommends fostering sustainable, diverse energy development through  
3        enabling policies and regulatory frameworks.<sup>8</sup> One important aspect of this is  
4        encouraging distributed generation.<sup>9</sup> As noted in Section 4.9, Liberty has experienced a  
5        significant increase in the amount of distributed generation being interconnected to its  
6        distribution system in New Hampshire through the installation of customer-sited  
7        generation. In fact, Liberty reached its net metering cap on July 28, 2015. In addition, as  
8        described in Section 5.3, Liberty is in the process of evaluating investment in a renewable  
9        distributed energy resource, although such discussions are in the infancy stage. Should  
10       Liberty determine the benefits of a particular company-owned distributed generation  
11       project outweigh the project's cost, the Company will submit a filing to the Commission  
12       pursuant to RSA 374-G:5, and would treat Company-owned or contracted DG option on  
13       an equal footing with other wires and non-wires alternatives when selecting the least cost  
14       alternative to reducing demand on a particular feeder or group of feeders serving an area.  
15       Therefore, Liberty's distribution planning process currently considers and incorporates  
16       distributed generation, and has begun the evaluation process of owning distributed  
17       generation, in light of the current net metering cap.

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

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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		Winter month	Wthr Adj	
		Peak Mw	Growth		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 Model		PV and EV			Winter Model		PV and EV		
	month	Peak	Peak	Peak Mw	Growth	month	Peak	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 computed 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 Model		PV and EV			Winter Model		PV and EV		
	month	Peak	Peak	Peak Mw	Growth	month	Peak	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			Winter		
	month	Peak Mw	Growth	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			Winter		
	month	Peak Mw	Growth	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			Winter		
	month	Peak Mw	Growth	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			Winter		
	month	Peak Mw	Growth	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:

$$\text{THI} = .55 * \text{maximum temperature} + .2 * \text{average dew point temperature} + 17.5$$

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

$$\text{WTHI} = .7 * \text{THI on the peak day} + .2 * \text{THI day before} + .1 * \text{THI two days before}$$

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

$$\text{WTHI\_SUMMER} = \text{WTHI} * \text{summer period}$$

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:

$$\text{WTHI\_SUMMER\_T} = \text{WTHI\_SUMMER} * \text{time trend}$$

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:

$$WTMAX = .7 * \text{max temp on peak day} + 2 * \text{max temp day before} + .1 * \text{max temp 2 days before}$$

The term HDD was defined as

$$HDD = (55 - WTMAX), \text{ or } 0 \text{ if the value of } WTMAX \text{ was greater than or equal to } 55$$

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:

$$\text{TIME} = \log(\text{time trend value} + 1)$$

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:

$$\text{CDD} = (\text{average temp} - 60), \text{ or } 0 \text{ if the average temp was less than or equal to } 60.$$

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:

$$\text{Annual kWh} = a + b * \text{TIME} + c * \text{CDD}$$

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.

Month	Weather Values Used in Forecast			
	Normal	Extreme	Normal	Extreme
	WTHI	WTHI	HDD	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.

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



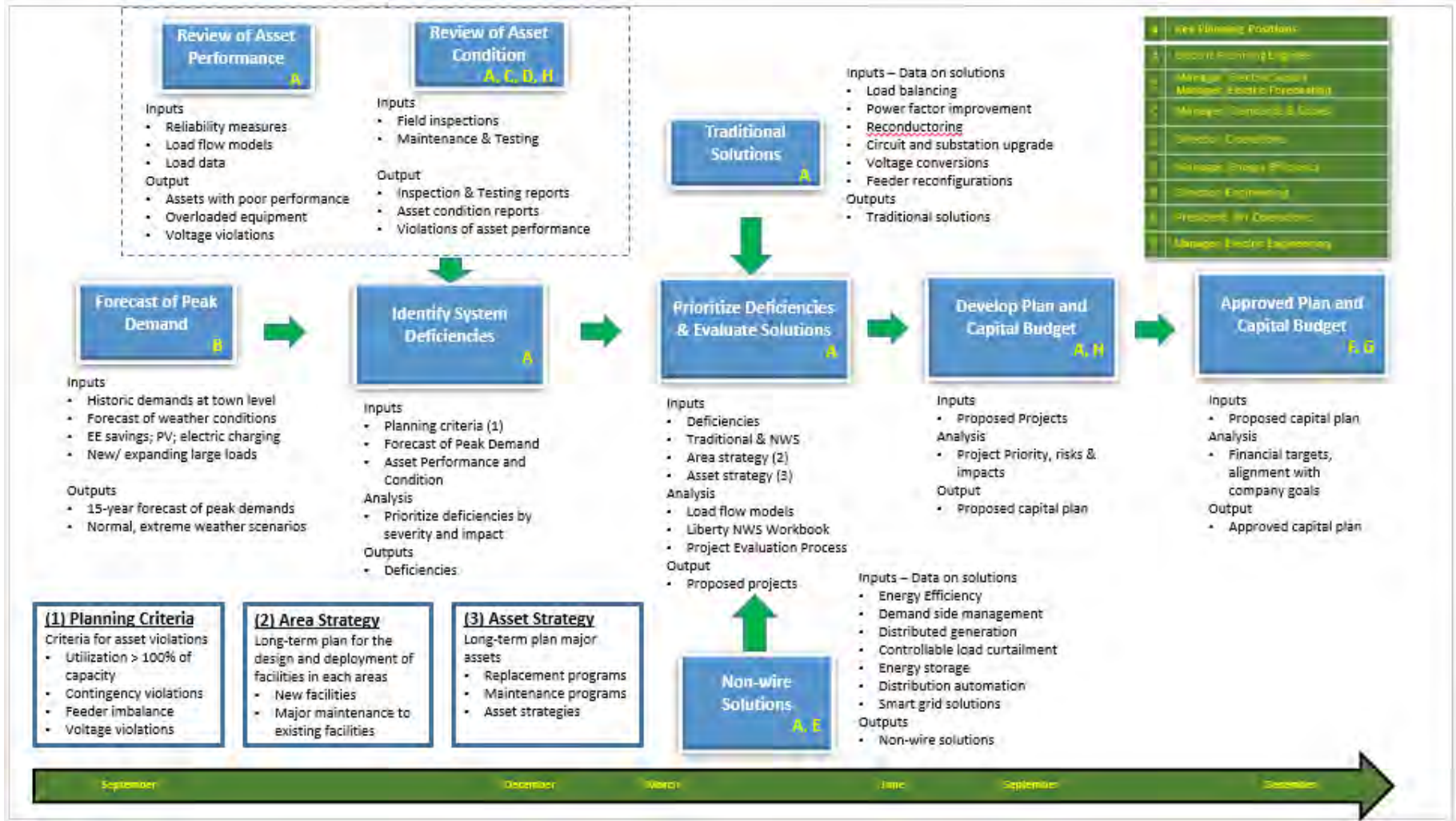
## Appendix C

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%	

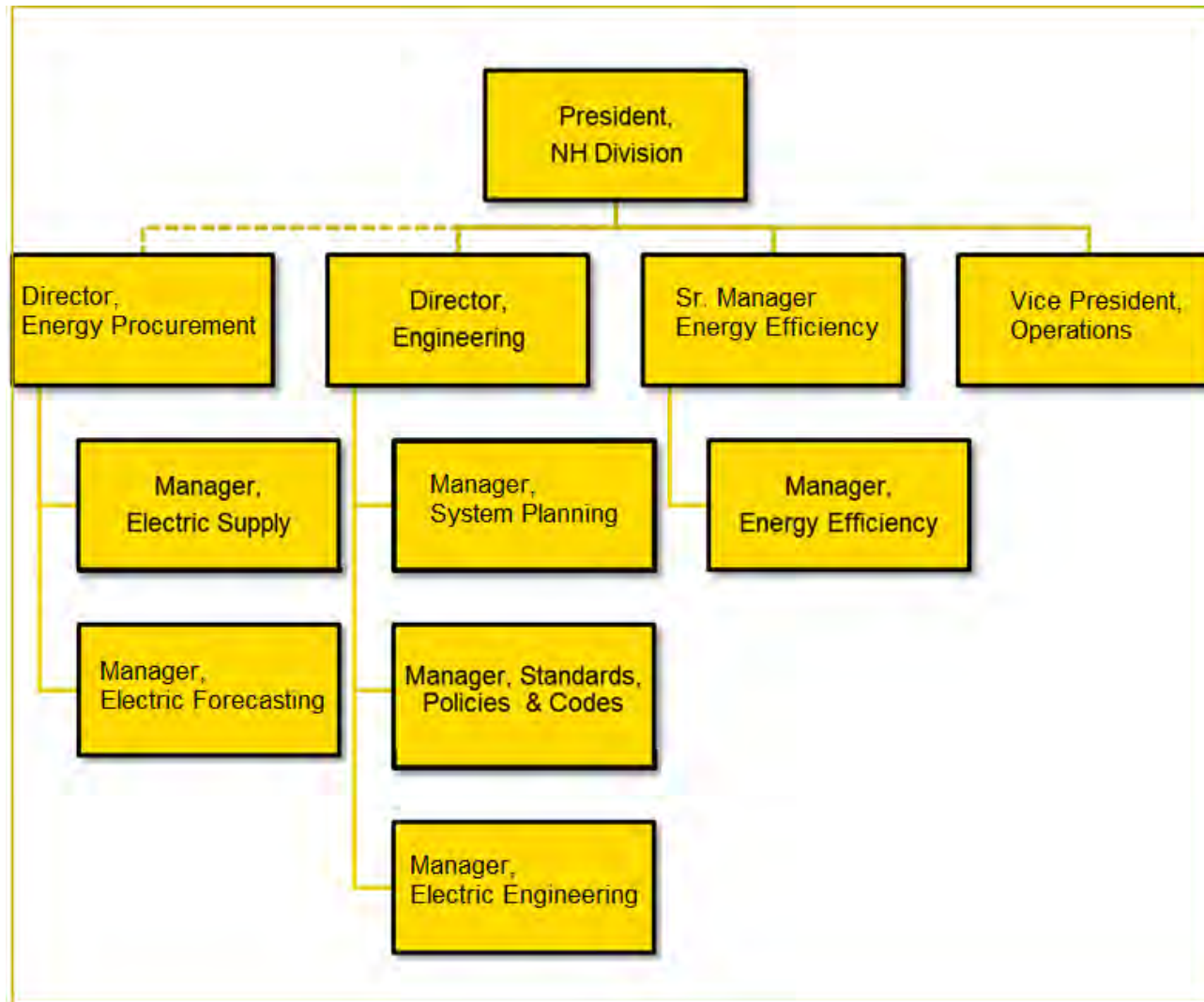
2017	1	9	18	143.485	143.4859	67	76.4859	46.69%	53.31%
2017	2	7	19	134.572	134.5725	62.075	72.4975	46.13%	53.87%
2017	3	4	19	127.668	127.6675	59.331	68.3365	46.47%	53.53%
2017	4	11	16	124.478	124.4777	53.157	71.3207	42.70%	57.30%
2017	5	18	16	162.931	162.9316	80.043	82.8886	49.13%	50.87%
2017	6	12	17	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%

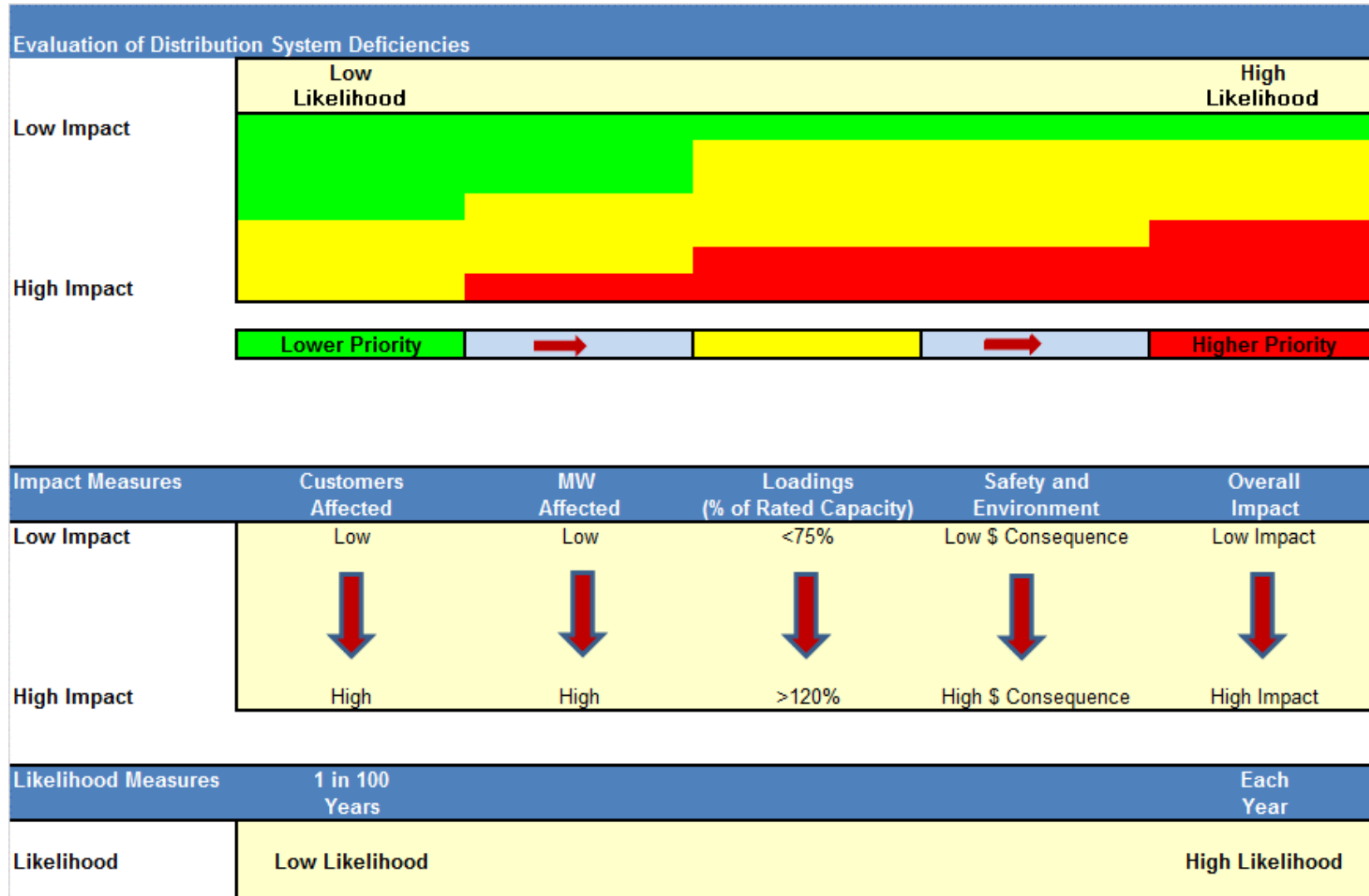
### Appendix C. Distribution Planning Process Map and Timeline




**Appendix C. Distribution Planning Organizational Chart and Key Positions**



**Appendix C. Prioritization of System Deficiencies**




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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



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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
<ul style="list-style-type: none"> <li>Load Balancing</li> <li>Power Factor Improvement</li> <li>Reconductoring/Recabbling</li> <li>Circuit and Substation Equipment Upgrades</li> <li>Voltage Conversions (e.g. 4kV to 13.2kV)</li> <li>Feeder reconfigurations</li> </ul>	<ul style="list-style-type: none"> <li>Distributed Generation</li> <li>Controllable Load Curtailment</li> <li>Energy Efficiency</li> <li>Energy Storage Devices</li> <li>Demand Side Management</li> <li>Distribution Automation</li> <li>Smart Grid Solutions (Ex: Dynamic Ratings, Real Time Load Transfers and Capacitor Activation, etc.)</li> </ul>

### 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.

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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.

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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

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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

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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 reconducted 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 reconducted 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

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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

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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



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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:



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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:

55°C INSULATION SYSTEM				65°C 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

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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

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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
<b>Feeders</b>	Continuous	24 Hours	As Needed, Typically 15 Minutes
<b>Sub Transmission lines</b>	Continuous	24 Hours	As Needed, Typically 15 Minutes
<b>Transformer</b>	Continuous	1 - 300 Hours	15 Minutes

**Table 4. Equipment Rating Criteria Summary**

Condition	Overhead Conductors		Underground Cables		Transformers	
	Duration	Design Criteria	Duration	Design Criteria	Duration	Design Criteria
Normal	Continuous	<ul style="list-style-type: none"> <li>The maximum value for normal peak loads on all new and rebuilt feeders</li> <li>Temperature limit for 100% ampacity for normal operating conductor is <u>176°F/80°C for bare conductors</u> and <u>167°F/75°C for spacer cable, tree wire, &amp; covered conductors</u></li> </ul>	Continuous	<ul style="list-style-type: none"> <li>Maximum loading that does not cause the conductor temperature to exceed its design value <u>at any time</u> during a 24-hour load cycle</li> <li>Normal cable ampacities are based on a 90° insulation operating temperature.</li> </ul>	Continuous	<ul style="list-style-type: none"> <li>Level for the peak hour in the 24-hour load cycle causes a cumulative (24 hour) 0.2% loss of Transformer life, or</li> <li>The Top Oil Temperature <u>exceeds 110 °C</u>, or</li> <li>The Hot Spot Copper temperature <u>exceeds 180 °C</u></li> </ul>
LTE	24 Hours	<ul style="list-style-type: none"> <li>The absolute maximum ampacity allowed for a given conductor and <u>should not be exceeded at any time.</u></li> <li>Temperature limit for 100% ampacity for operating at an elevated temperature during emergency conditions limited to a 24 hour period is <u>194°F/90°C for both bare and spacer cable, tree wire, &amp; covered conductors</u></li> </ul>	100 - 300 Hours	<ul style="list-style-type: none"> <li>Maximum loading that does not cause the conductor temperature to exceed its design value <u>over several consecutive</u> 24-hour load cycles.</li> <li>Emergency cable ampacities are based on 130° insulation operating temperature.</li> </ul>	24 Hours	<ul style="list-style-type: none"> <li>Level for the peak hour <u>with the emergency load added</u> in the 24-hour load cycle causes a cumulative (24 hour) <u>3.0% loss</u> of Transformer life, or</li> <li>the Top Oil Temperature <u>exceeds 130 °C</u>, or</li> <li>the Hot Spot Copper temperature <u>exceeds 180 °C</u></li> </ul>
STE	As Needed	<ul style="list-style-type: none"> <li>Estimated conservatively using seasonal ambient data along with circuit specific information by the Engineering Department</li> </ul>	1 - 24 Hours	<ul style="list-style-type: none"> <li>Maximum loading that does not cause the conductor temperature to exceed its <u>allowable emergency value at any time</u> during a 24-hour load cycle.</li> <li>Emergency cable ampacities are based on 130° insulation operating temperature.</li> </ul>	15 minutes	<ul style="list-style-type: none"> <li>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) <u>3.0% loss</u> of Transformer Life, or</li> <li>A hot spot copper temperature <u>exceeding 180°C.</u></li> <li>Maximum STE rating is limited to twice the transformer's "nameplate" rating (200%).</li> </ul>

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## 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

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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

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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**

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

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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:

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

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

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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.

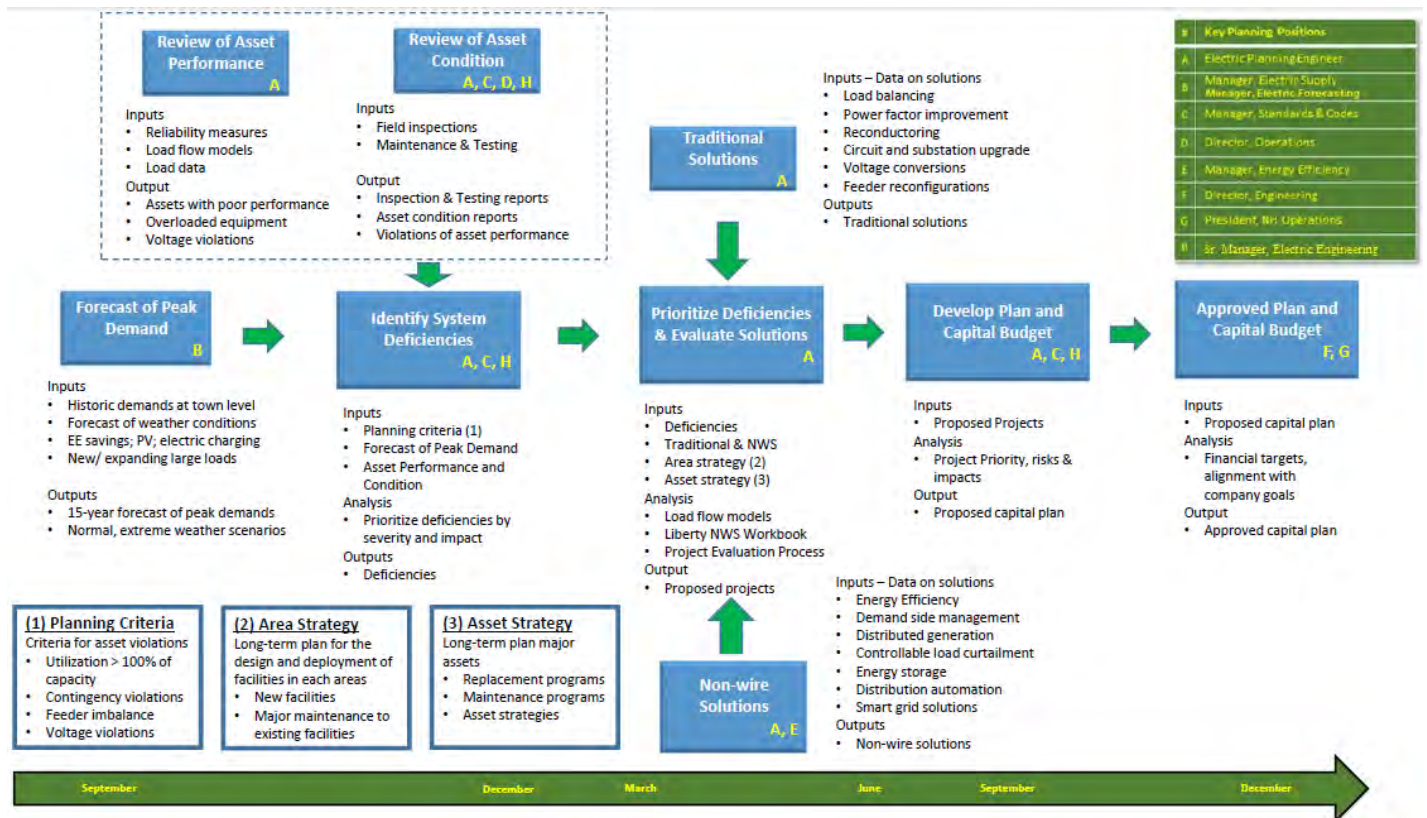
Liberty conducts an annual capacity planning process covering a 5 year period with inputs from various stakeholders that is intended to meet future customer demands, identify thermal capacity constraints,




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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**



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## 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

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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.

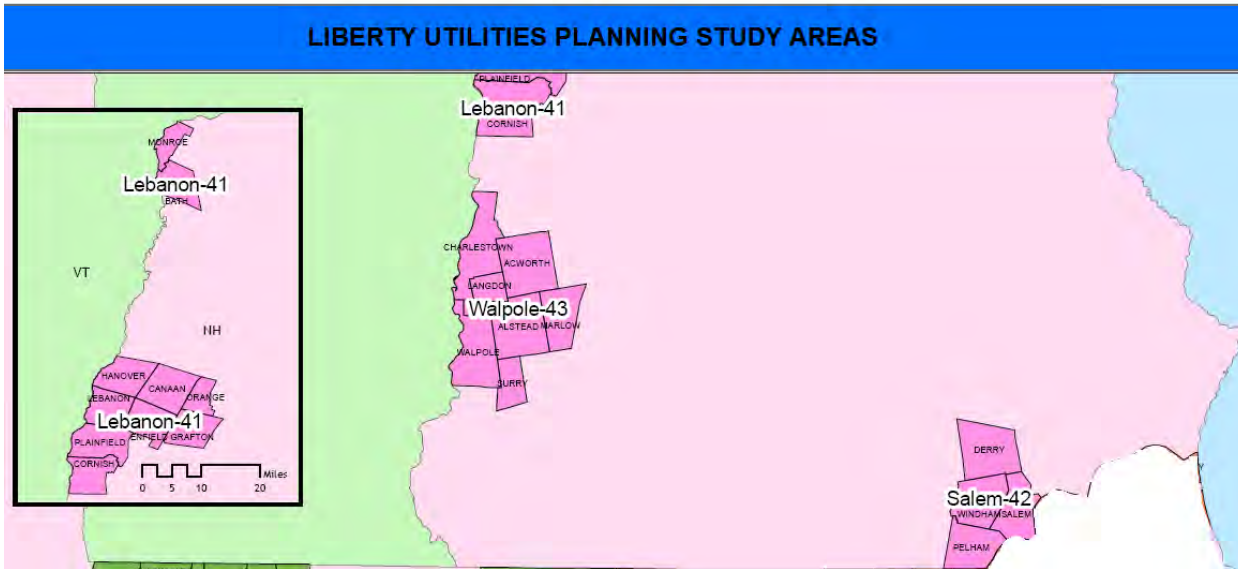
## 11.0 BENEFITS OF PLANNING CRITERIA STRATEGY





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.

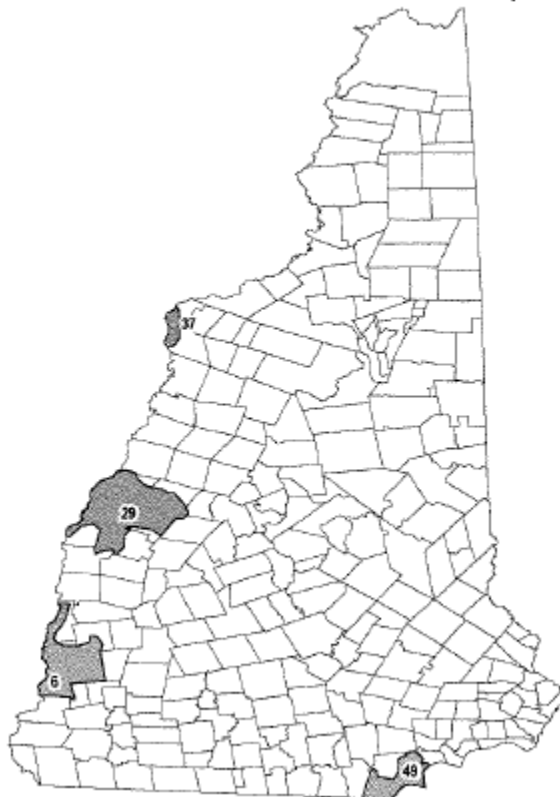
		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	<b>Electric Distribution Planning Criteria</b>	Revision #:	3.0	Page 22 of 24


## Attachment A – Liberty Utilities Planning Study Area Map



-  6 - Bellows Falls
-  29 - Lebanon
-  37 - Monroe
-  49 - Salem

**Liberty Utilities Study Area Map**



		Liberty Utilities 15 Buttrick Rd Londonderry, NH 03053		
Description:	<b>Electric Distribution Planning Criteria</b>	Revision #:	3.0	Page 23 of 24

## 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.



**Liberty Utilities**  
 15 Buttrick Rd  
 Londonderry, NH 03053

Description:	<b>Electric Distribution Planning Criteria</b>	Revision #:	3.0	Page 24 of 24
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<b>Every effort must be made to return the failed sub-transmission line to service within 12 hours.</b>	<b>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.</b>	Every effort must be made to return the failed sub-transmission line to service within 24 hours.
<b>N/A</b>	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: \_\_\_\_\_

Charles Rodrigues  
 Director of Engineering  
 Liberty Utilities

Date: \_\_\_\_\_





# 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 3<sup>rd</sup> 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

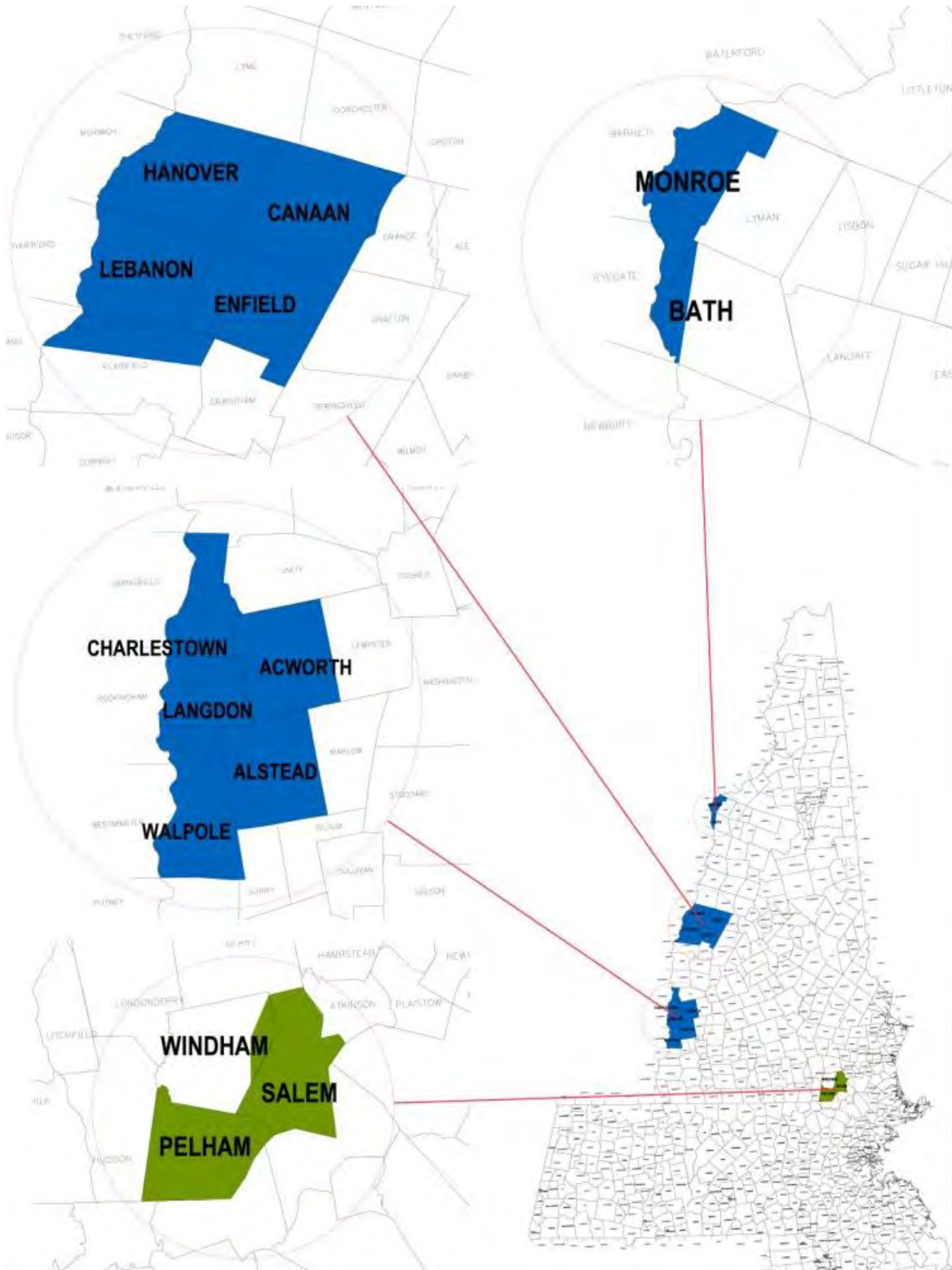
Liberty NH distribution serves approximately 44,600 customers in 21 towns. A breakdown of assets is listed in the following table:

<b>Liberty Utilities Electric Distribution/Subtransmission Line and Service Area Statistics</b>	
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 Subtransmission 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 <b>per DA controlled location</b> =	total	\$65,000
(includes cost of standard recloser)	material	\$45,000
	labor	\$3,000
	contingency	\$11,000



	misc	\$6,000
ave cost per <b>DA controlled fdr or ckt</b> =	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 Lockhaven 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



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## **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.

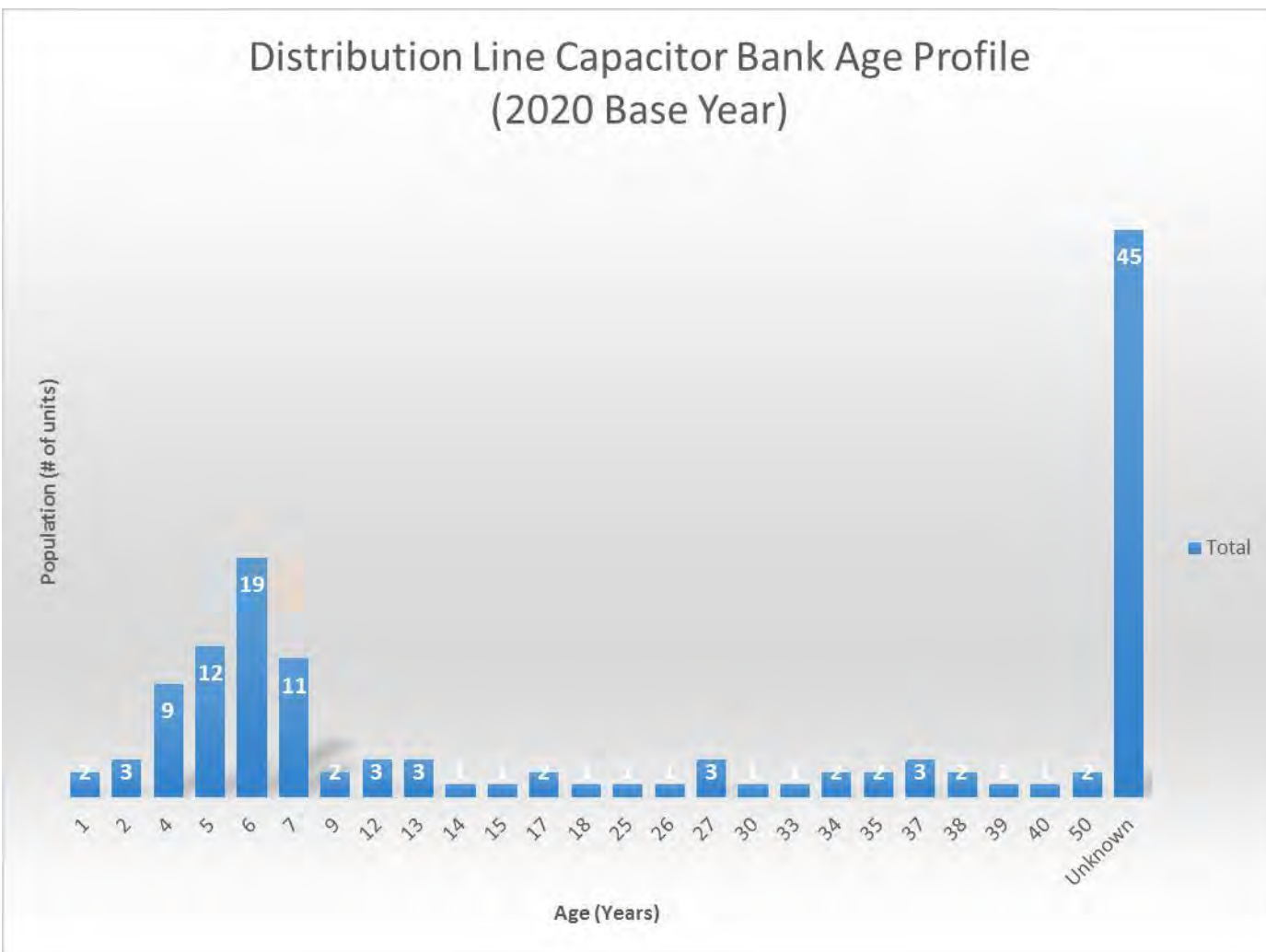
### **2.0 Strategy Description**

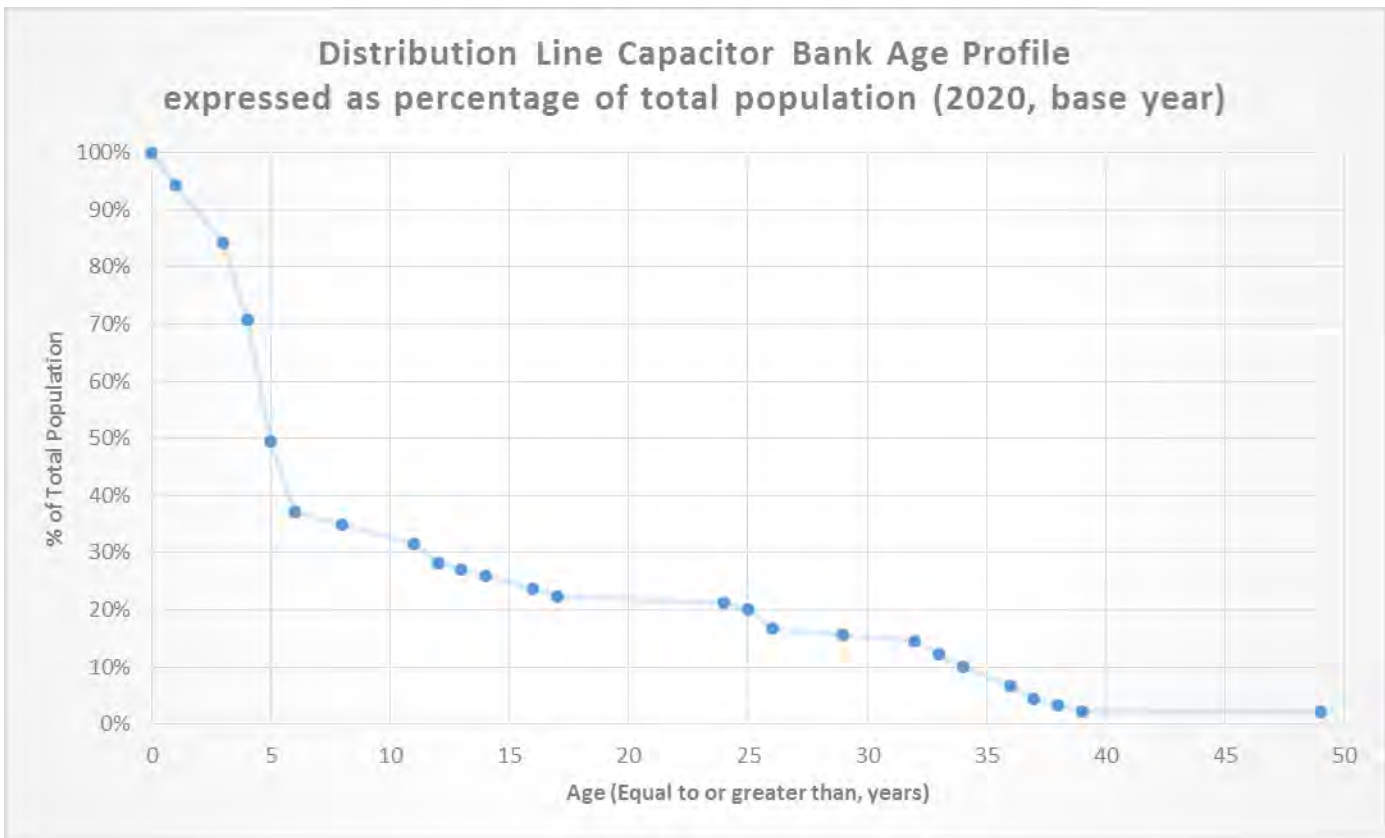
#### **2.1 Background**

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)





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:

	<u>CAPITAL</u>	<u>O&amp;M</u>	<u>REMOVAL</u>	<u>TOTAL</u>
<b>Existing banks—Inspection &amp; Maintenance</b>	\$75,000	\$8,000	\$8,000	\$91,000

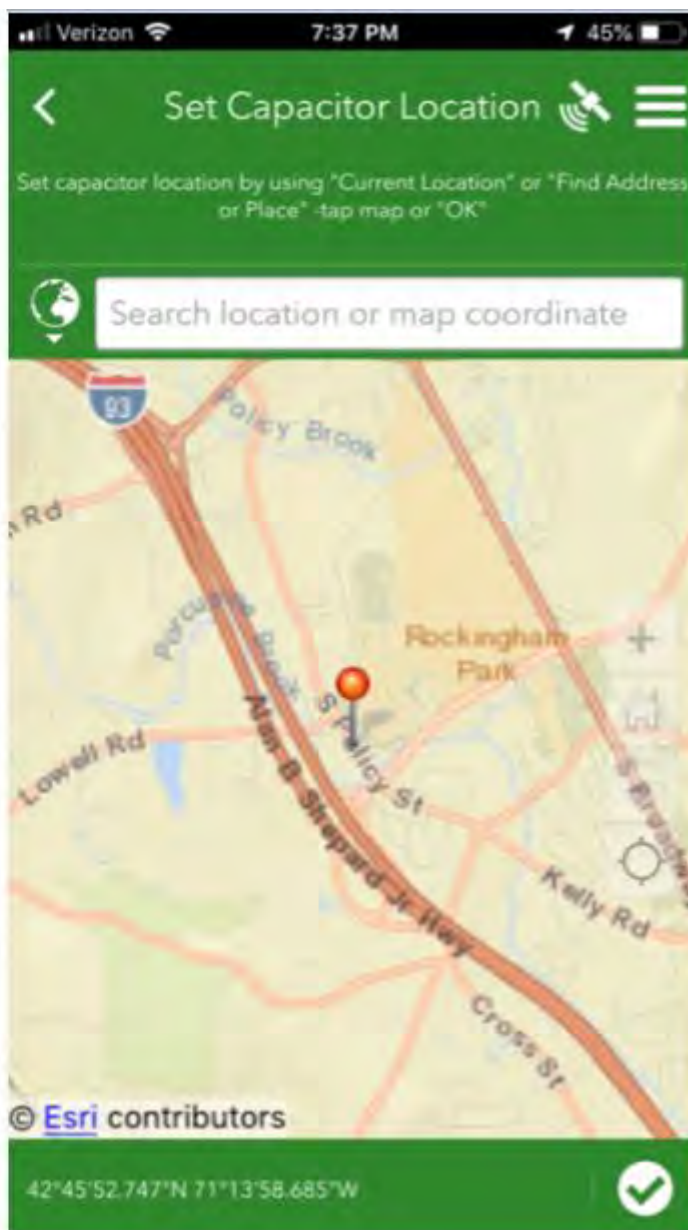
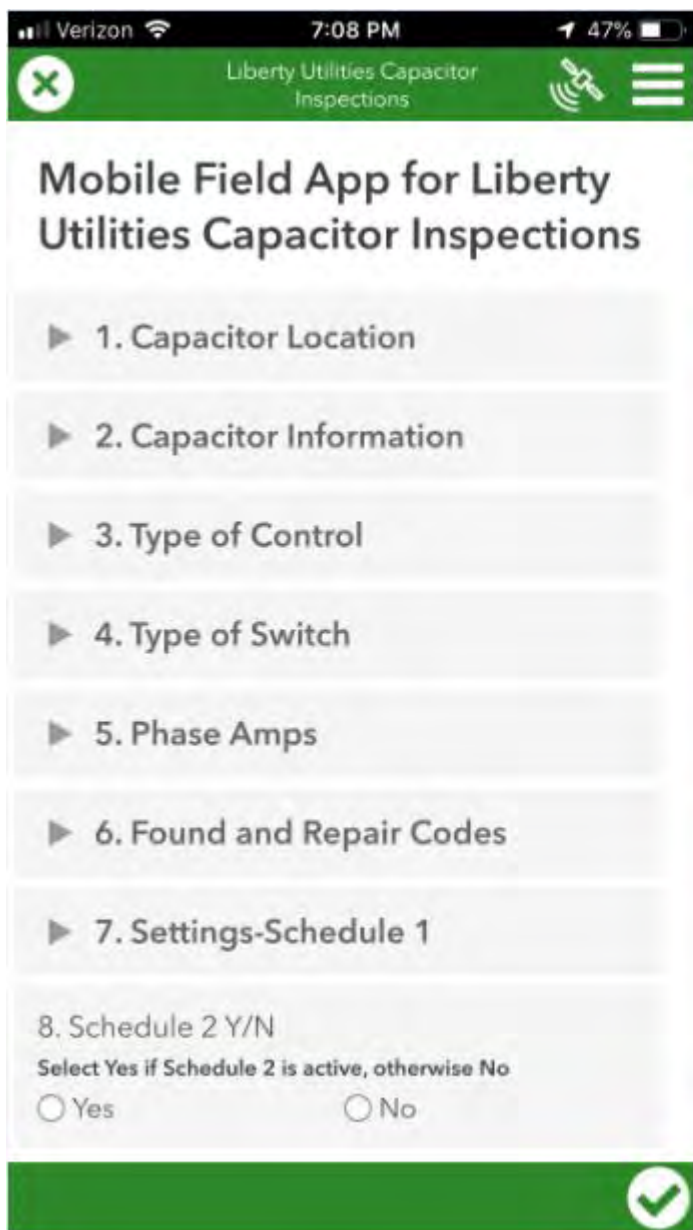


<b><u>New banks—Load Growth</u></b>	<u>45,000</u>	<u>5,000</u>	<u>5,000</u>	<u>55,000</u>
<b>TOTAL</b>	\$120,000	\$13,000	\$13,000	\$146,000

## 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:

	<u>CAPITAL</u>	<u>O&amp;M</u>	<u>REMOVAL</u>	<u>TOTAL</u>
<b>Distribution Line step-down transformers</b>	\$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

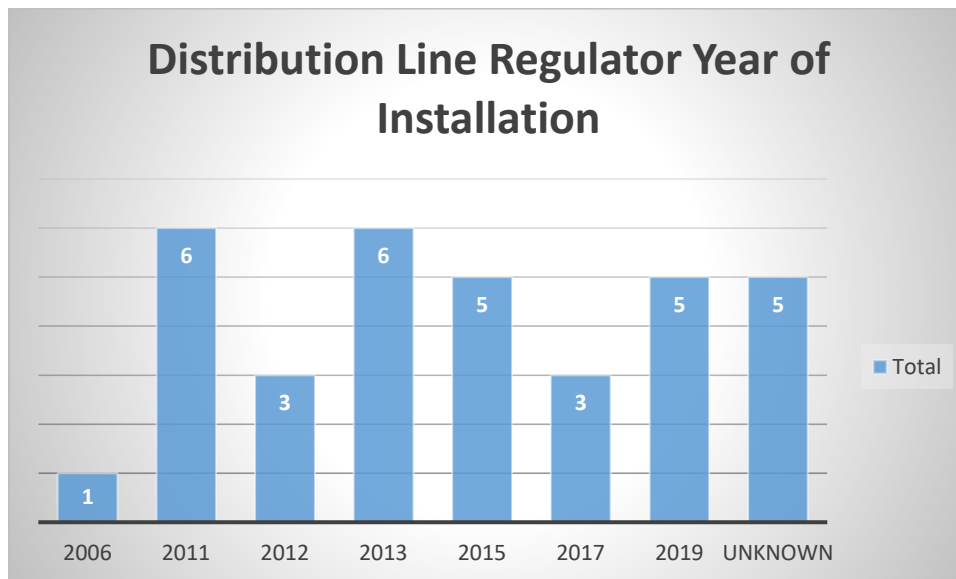
This policy sets forth the asset management philosophy for distribution line voltage regulators with the intent of maximizing system performance while minimizing safety, environmental, reliability and regulatory impacts to the company.

### 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).

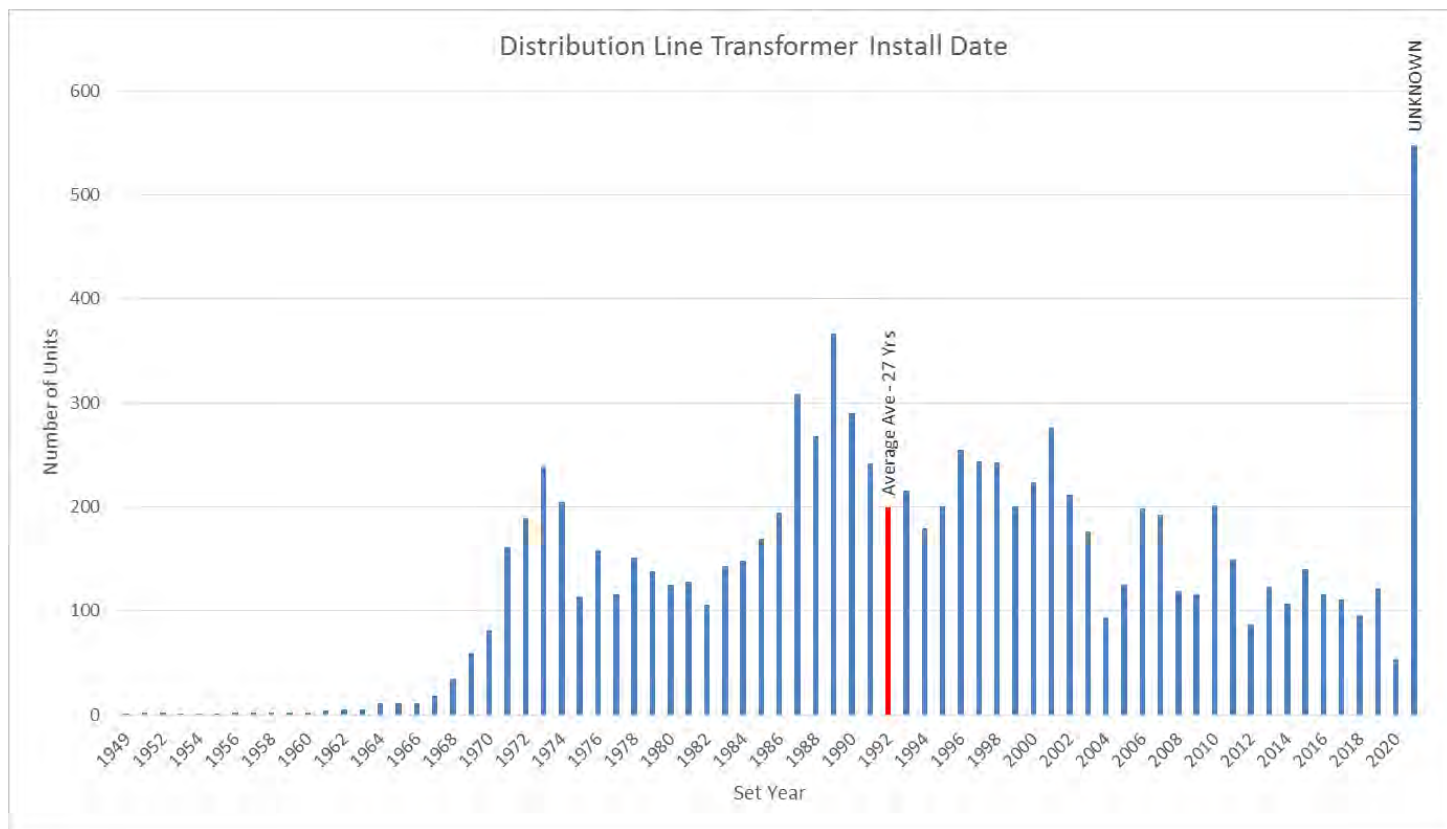


Figure 1

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.

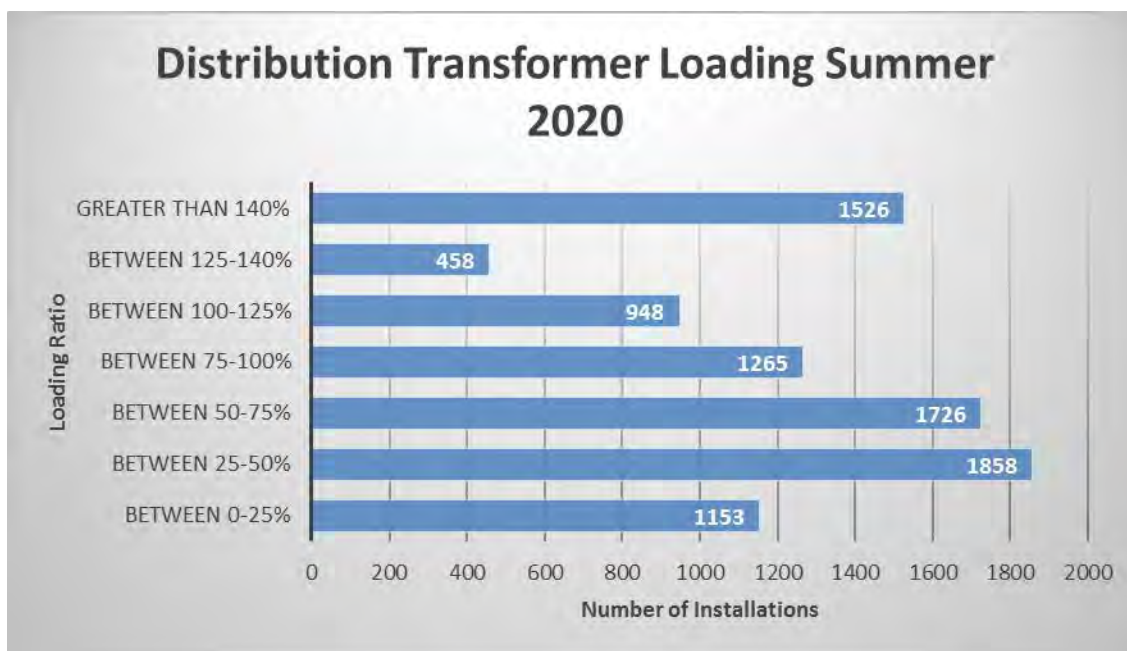


Figure 2

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	<u>\$1,500</u>



---

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

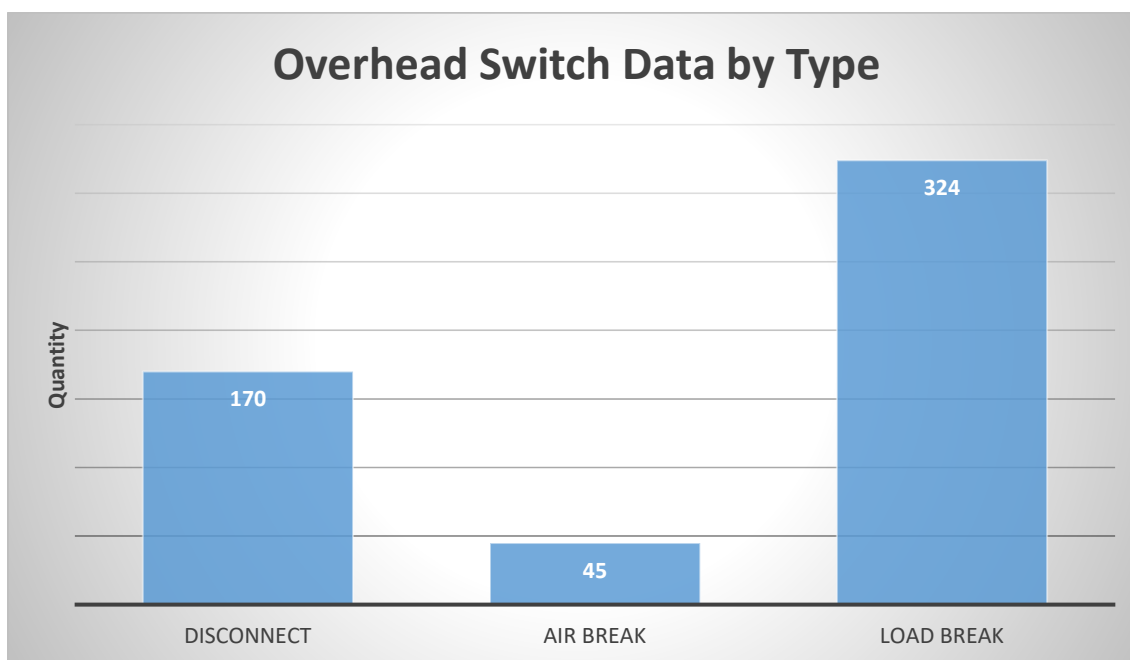
### 1.0 Purpose and Scope

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 in 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 ~~\$1020~~,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 ~~\$450900~~,000. Executing this plan over a ten year period would cost approximately ~~\$4590~~,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

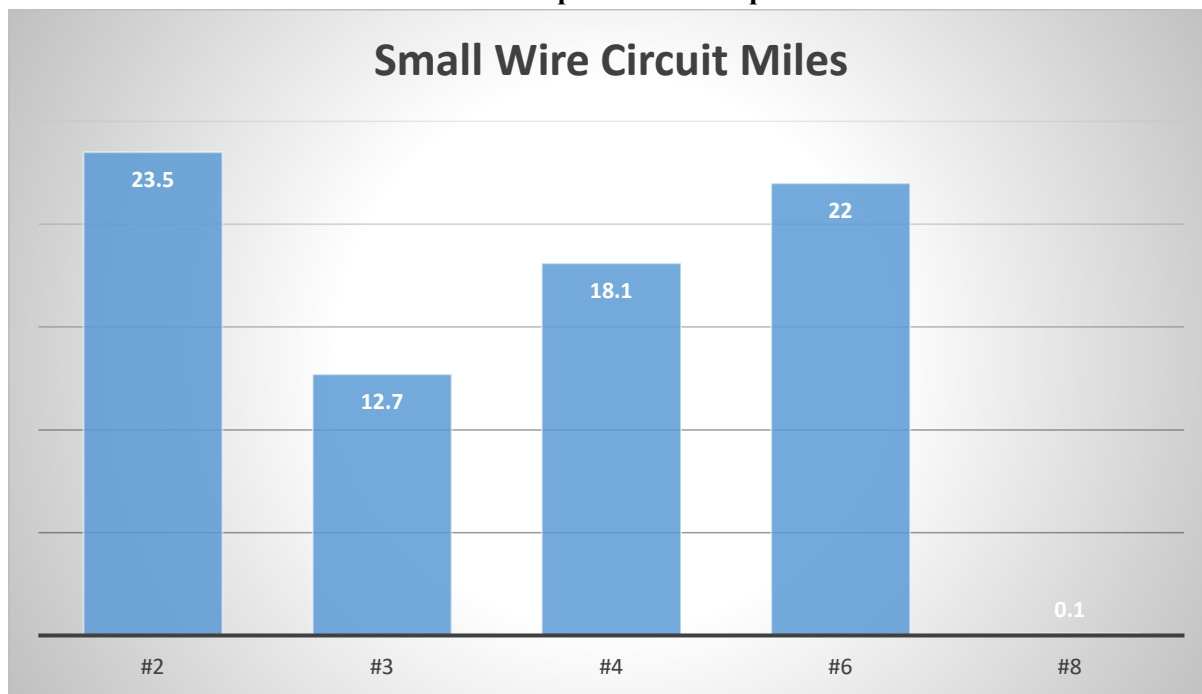
The intent of this strategy is to replace all “small” (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

### 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

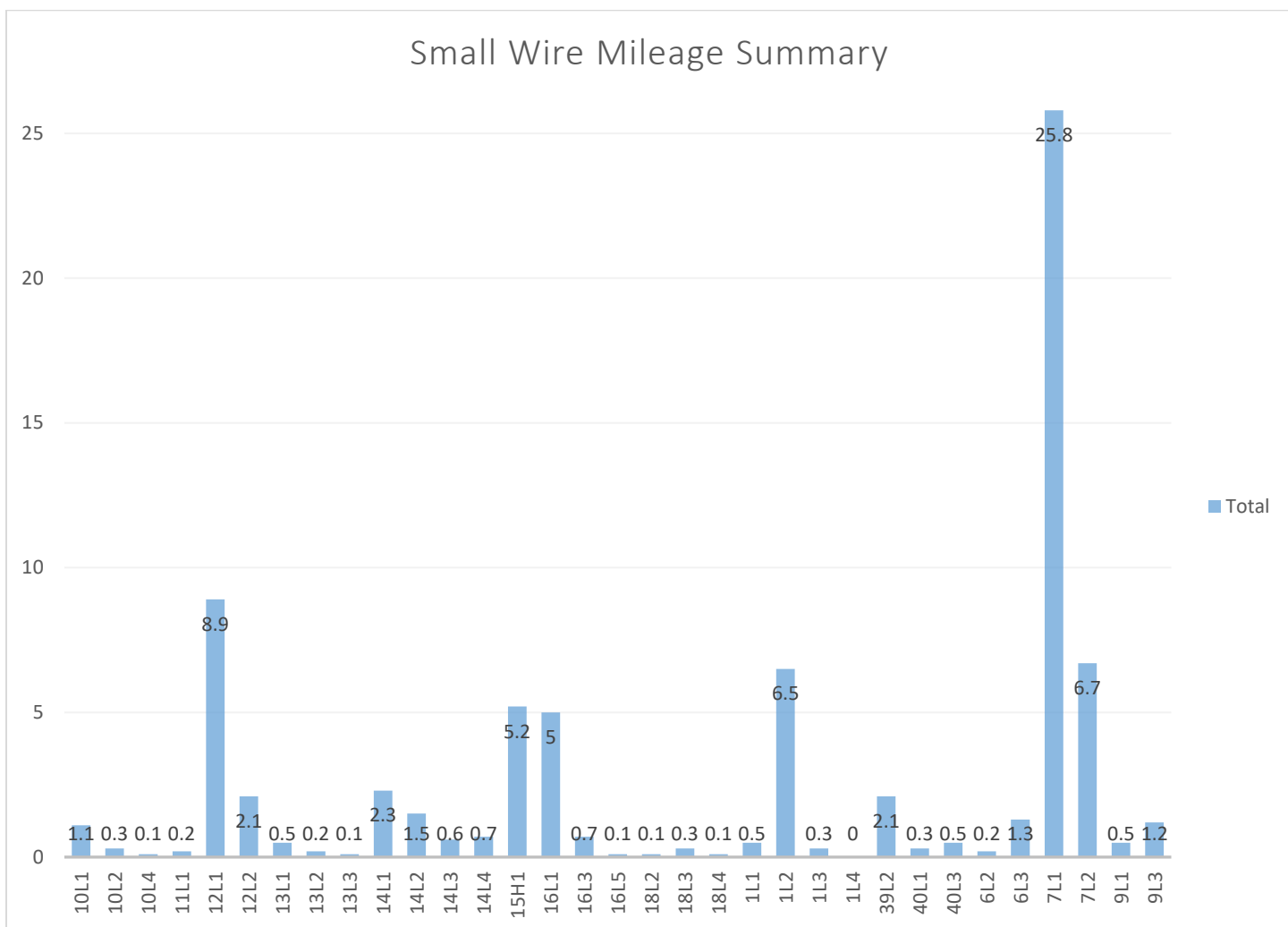
Three strategies are proposed to address the replacement of small wire across the system:

### 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

**Table 1 - Amendments Record**



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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 CKAIID or CKAIIF value for a reporting year that is among the highest 4-6 of all of Liberty's feeders. CKAIID measures the average duration of a power outage that a customer connected to a feeder experiences during a year. CKAIIF 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 CKAIID and CKAIIF. CKAIID/CKAIIF annual target thresholds are set as the 5 YR average of the CKAIID and CKAIIF 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

**Table 1 - Amendments Record**



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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 CKAIID or CKAIIF 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. CKAIID/CKAIIF annual target thresholds are set as the 5 YR average of the CKAIID and CKAIIF 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 CKAIID or CKAIIF 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 CKAIID or CKAIIF 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 CKAIIFI of each feeder will be tracked monthly against the annual company threshold. CKAIIDI and CKAIIFI annual threshold are set as the 5 year average of the CKAIIDI and CKAIIFI 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			Color Codes:
	Target	Projected Results*	Problem Feeder	Target	Projected Results*	Problem Feeder	
N/A	1.815	N/A	N/A	233.201	N/A	No	 Below Target
MT SUPPORT 16L1	1.815	N/A	N/A	233.201	230.242	No	 At Risk of Exceeding Target
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	 Above Target
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	 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 power 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 power outage during a year.
- \* Poor Performing Feeder is a feeder that possesses a CKA DI or CKA FI 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 two 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 two standard deviations.
- \* The Vilas Bridge 12L2 was a chronic feeder in 2018 being among the worst 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.

## 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

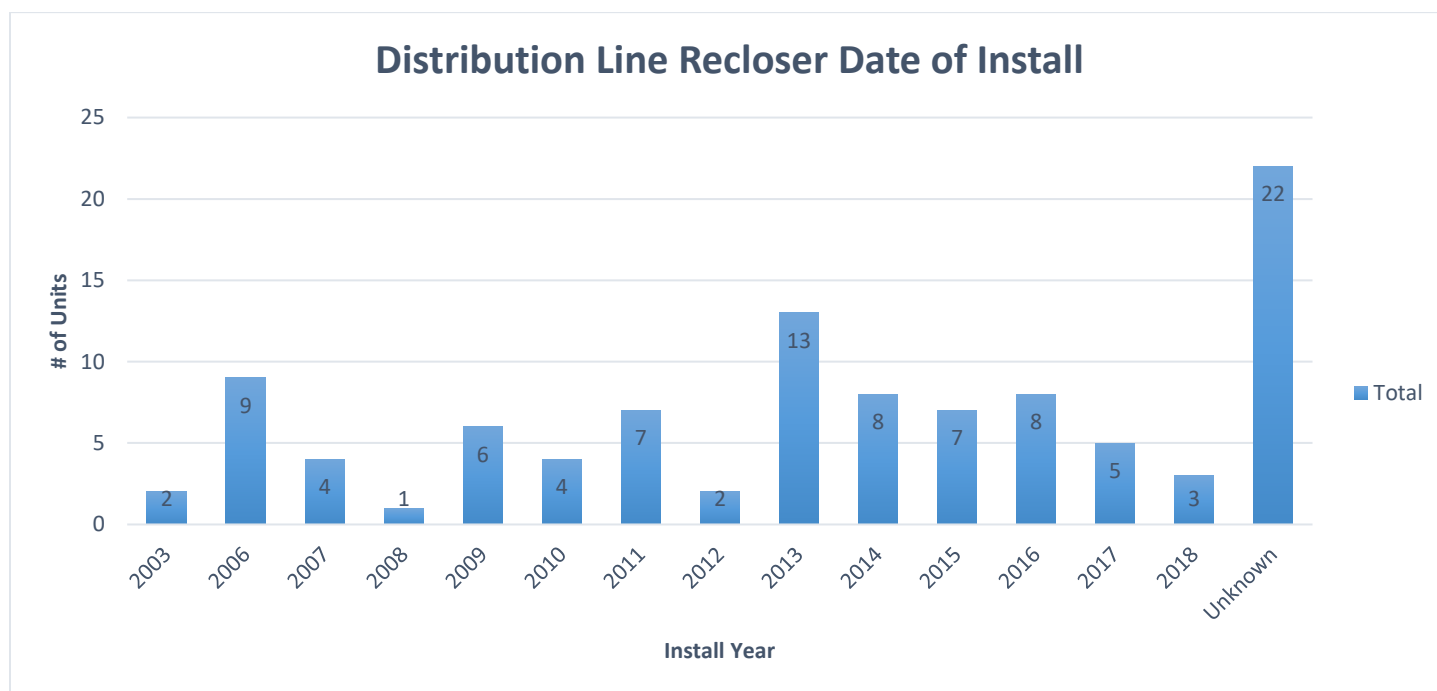
### 1.0 Purpose and Scope

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**

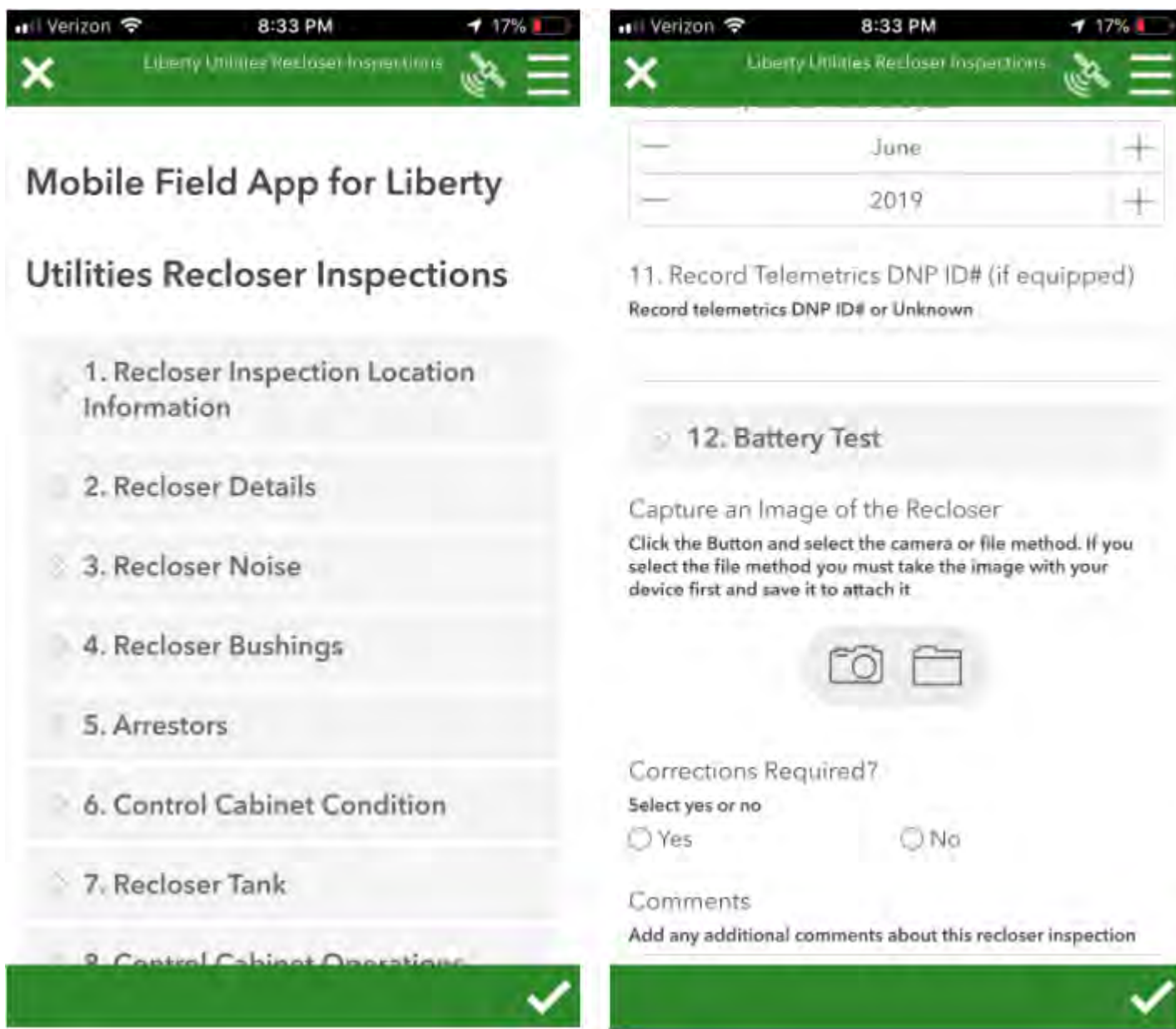
An estimated cost of \$75,000 capital per recloser is assumed for this strategy. At the present time the number of units in need of replacement is unknown. Based on the results of the inspection program an estimate of the number of units approaching their end of life can be collected.

### **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 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**



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## 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

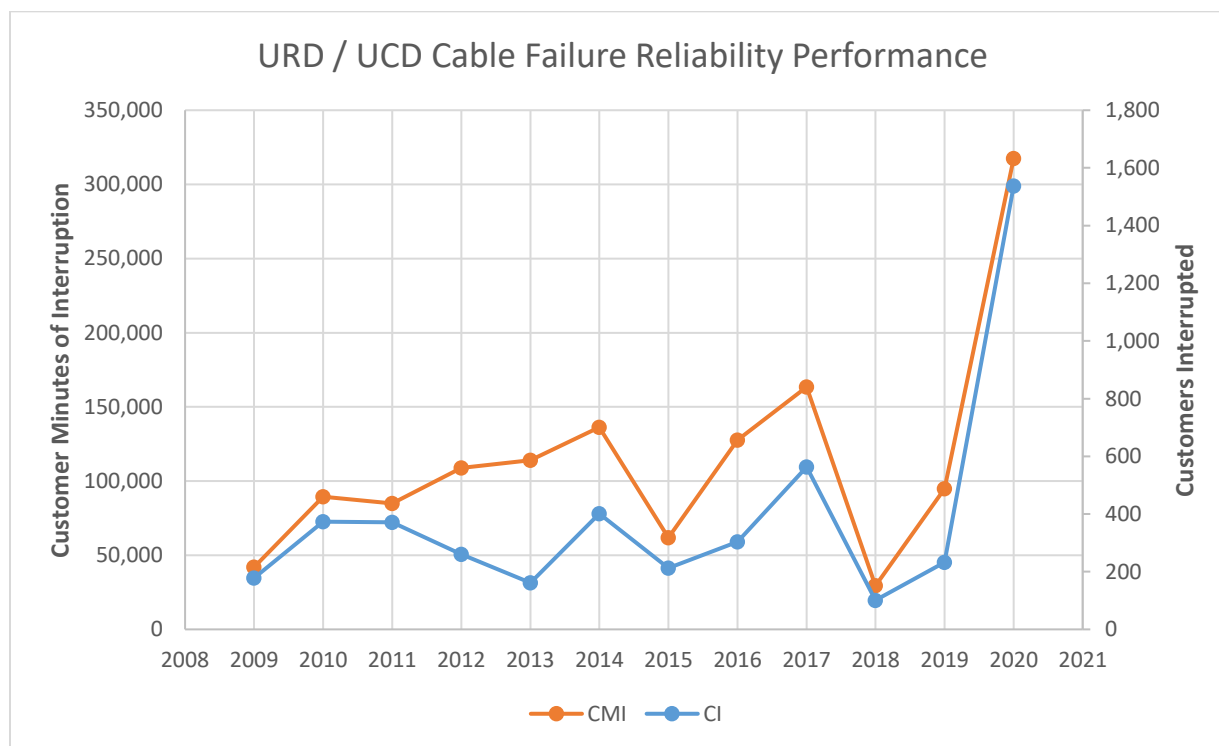
#### 2.1 Background

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
<b>Total</b>	<b>8</b>	<b>6</b>	<b>5</b>	<b>4</b>	<b>3</b>



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

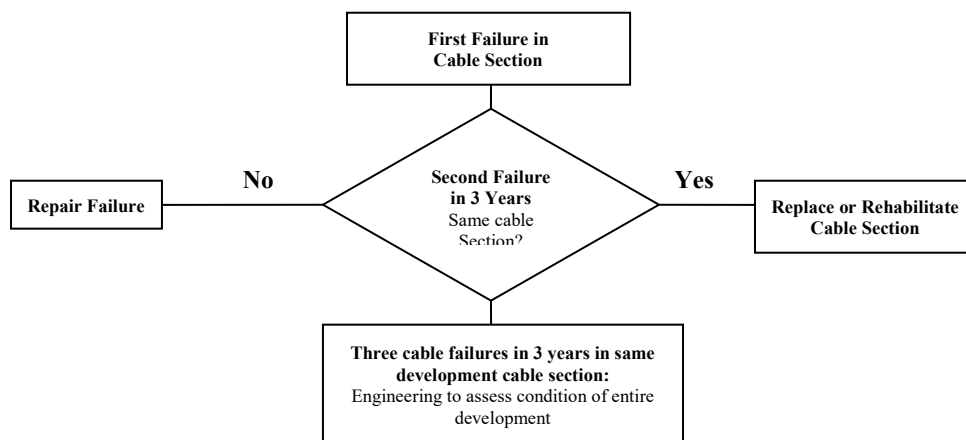
This strategy limits the number of repeated interruptions in a given development. This will generally limit the potential damage to the company's reputation with the public, state regulators or other governmental authorities.

### 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.

\$M	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Total
	2021	2022	2023	2024	2025	
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
<b>Total</b>	\$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:

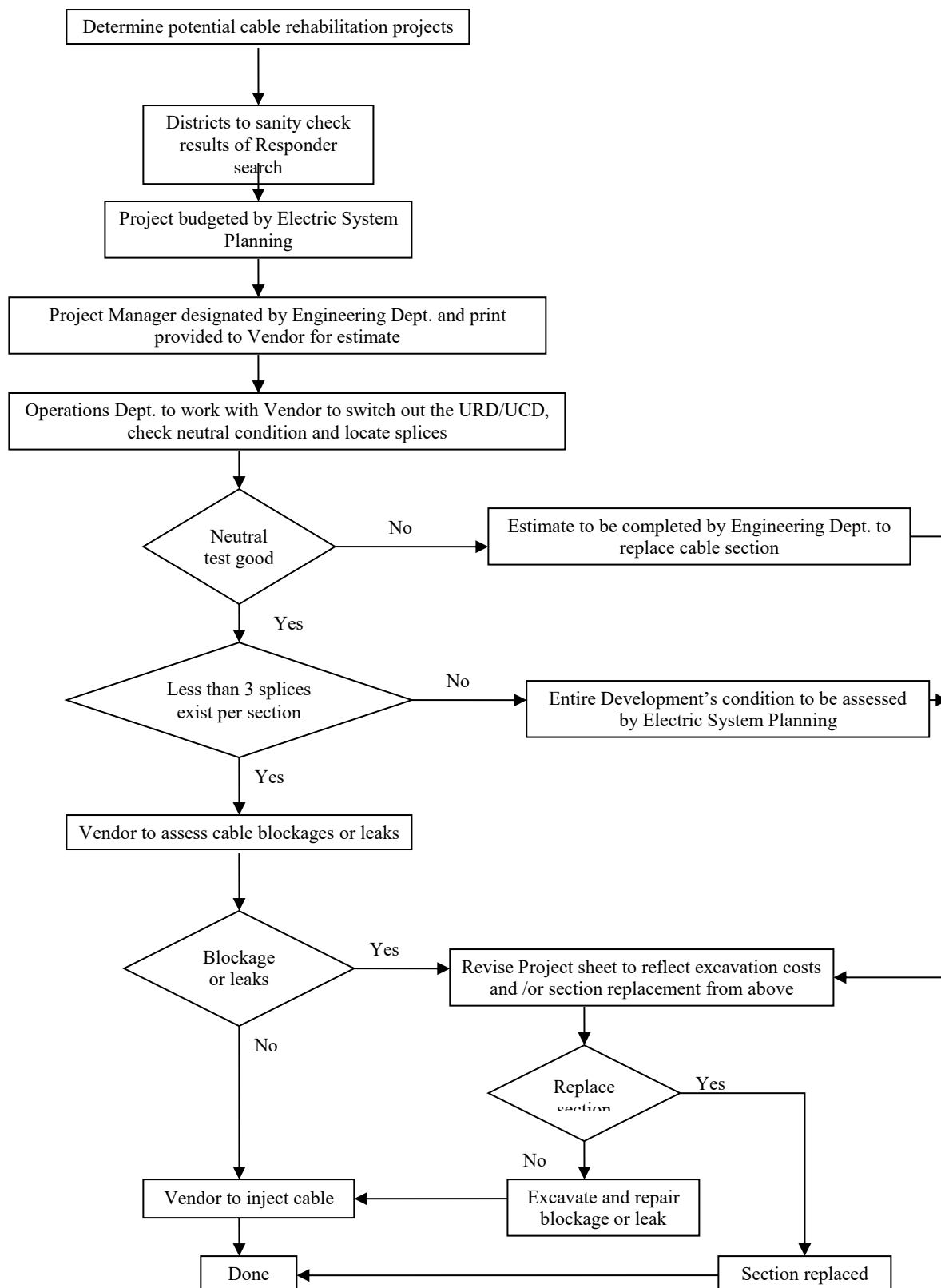
ArcGIS Desktop / ADMS

## 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.

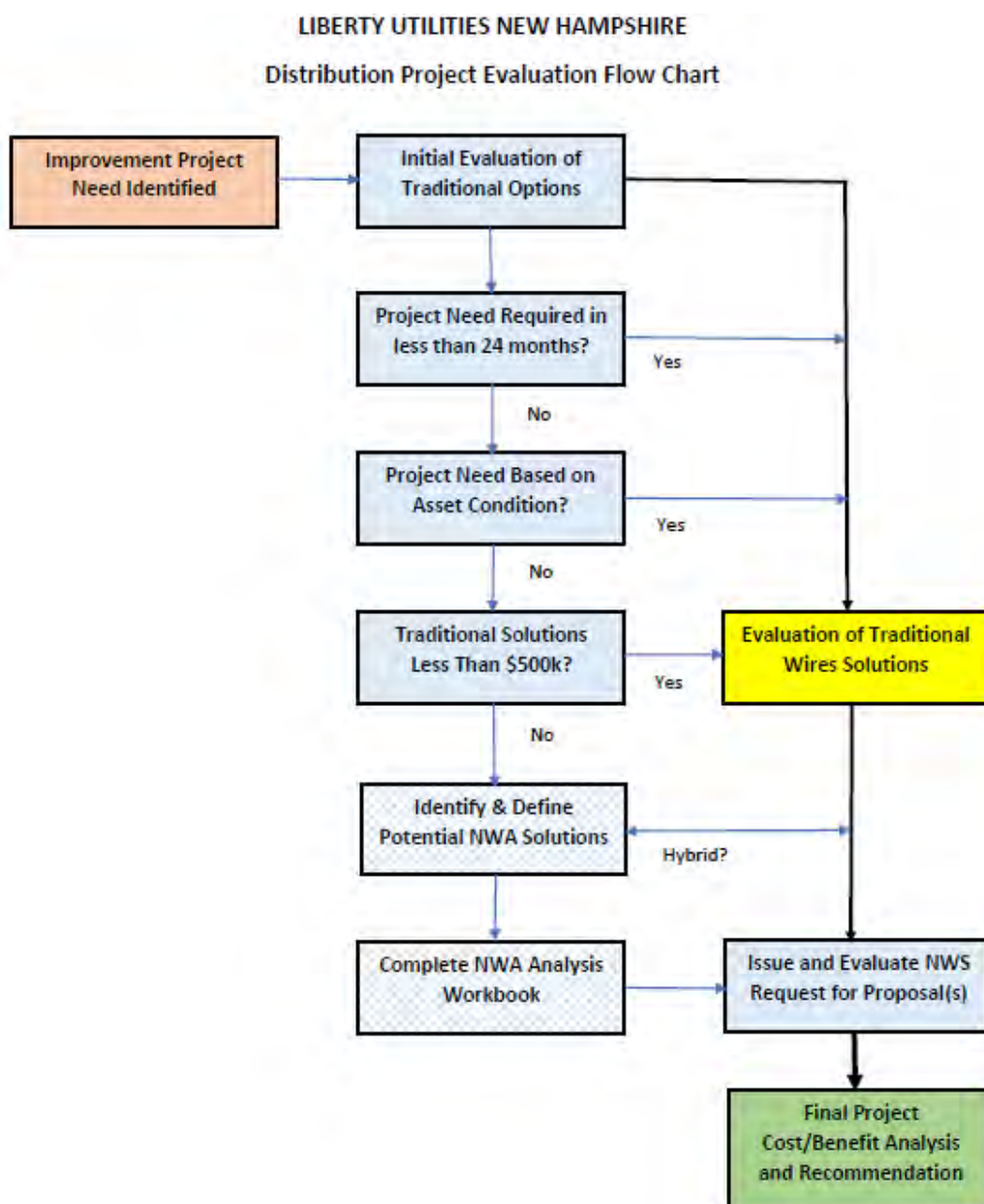


Figure 1: Overview of Project Evaluation Process



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
<b>Identified Problem:</b>						
Project Need Year:						
Brief Project Description/need:						
<b>Project Scope</b>		<b>Option</b>				
		1				
		2				
		3				
		4				
<b>Scoring Values</b>						
Marginal with mitigation		1				
Marginal without mitigation		2				
Acceptable		3				
Best Solution		4				
<b>Evaluation Summary</b>						
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	
<b>Total Assessment</b>		<b>100%</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>
		<b>Ranking</b>	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>



**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%					
<b>Totals</b>	<b>100%</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	
	<b>Ranking</b>	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	

**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 duration (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%					
<b>Totals</b>	<b>100%</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	
	<b>Ranking</b>	<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	

**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%					
<b>Totals</b>	<b>100%</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	
<b>Ranking</b>		<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	

**DEFINITIONS**

**Availability:** historical and predicted 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%					
<b>Totals</b>	<b>100%</b>	<b>0</b>	<b>0</b>	<b>0</b>	<b>0</b>	
<b>Ranking</b>		<b>1</b>	<b>1</b>	<b>1</b>	<b>1</b>	

**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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## 1 **Executive Summary**

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

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

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

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

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

- 12 • Metering
  - 13 ○ Advanced Metering
  - 14 ○ Connect/Disconnect
- 15 • Distribution Automation
  - 16 ○ Fault Detection
  - 17 ○ Conservation Voltage
  - 18 ○ Load Forecasting
  - 19 ○ Asset Management
  - 20 ○ Islanding
- 21 • Customer Connections
  - 22 ○ Energy Management
  - 23 ○ Distributed Energy Resources
- 24 • Smart City
  - 25 ○ LED Lighting

26

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- 1 Liberty Utilities proposes to begin a pursuit of a Grid Modernization effort that
- 2 incorporates elements of all ten of these programs, with the following as the guide path
- 3 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

#### 4 Chapter 1: Grid Modernization Trends

##### 5 *The Electric Utility View*

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

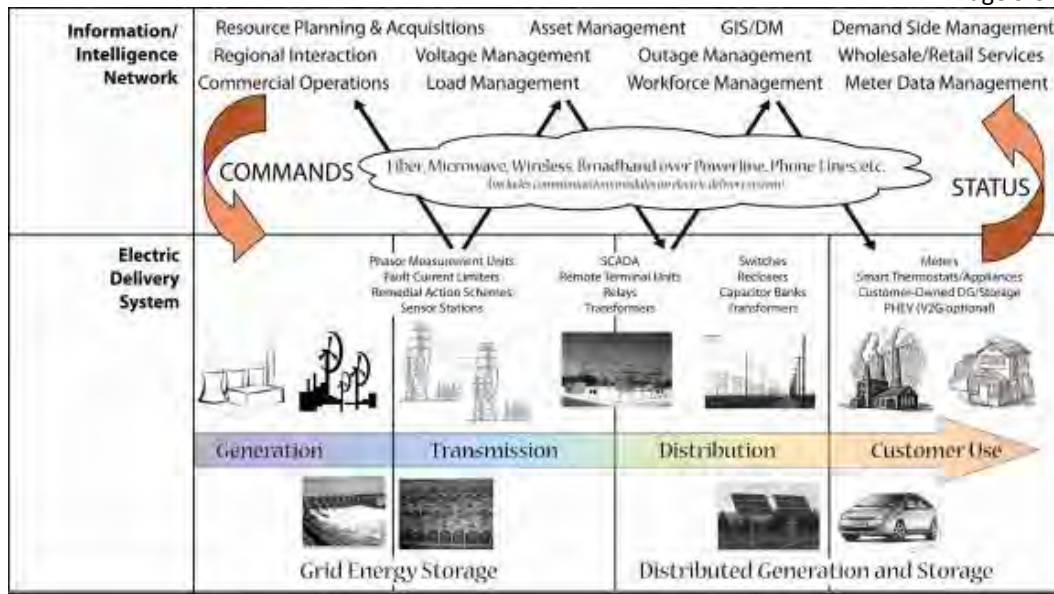
9 In the coming years, energy demand is projected to continue to increase due to  
10 further electrification (e.g. data centers, electric vehicles), a significant percentage of  
11 the industry’s skilled workforce is scheduled to retire with job experience and  
12 knowledge that cannot be replaced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

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

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

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



1 **Market Trends**

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

5 **The Utility of the Future**

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

11 The five sets of technologies are as follows:

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

- 1 information and control of the grid and thus allowing every component  
2 to both ‘talk’ and ‘listen’.
- 3 2. Sensing and Measurement – Devices that sense and measure various  
4 aspects of grid operation and thus support faster and more accurate  
5 response such as remote monitoring of voltage, current, phase angles,  
6 etc.
- 7 3. Advanced Components – Applying the latest technologies for  
8 superconductivity that reduce line losses, storage that allows for the use  
9 of off-peak generation to meet peak period requirements, and power  
10 electronics and diagnostics that will improve the operation and efficiency  
11 of the grid.
- 12 4. Advanced Controls – Monitoring essential components in real-time and  
13 thus, enabling early detection and rapid diagnosis in order to provide  
14 precise solutions appropriate to any event before they can cascade into  
15 bigger problems.
- 16 5. Improved Interfaces and Decision Support – Improving human decision –  
17 making by providing grid operators and managers with the information  
18 and ability to enable them to operate as visionaries when it comes to  
19 seeing into their systems.

## 1 **Chapter 2: Use Cases**

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

### 6 **Metering**

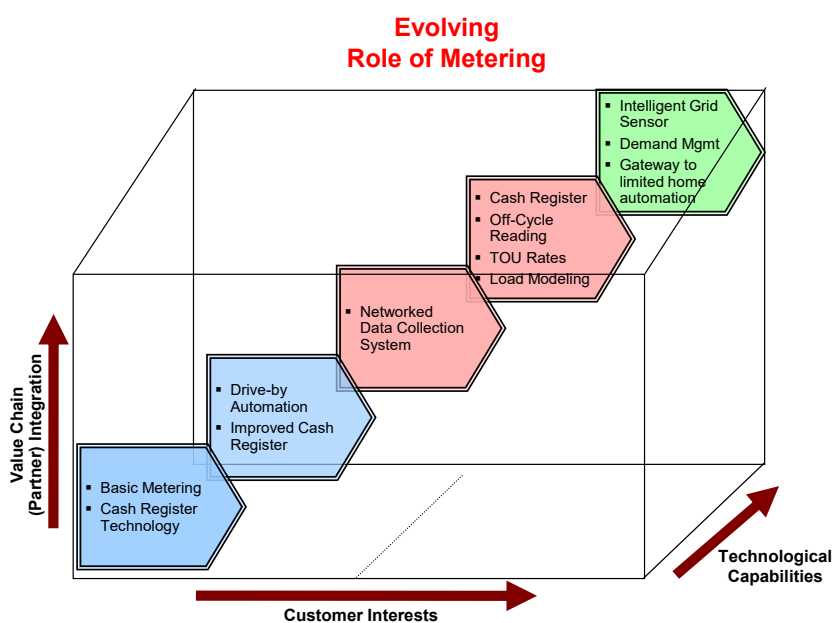
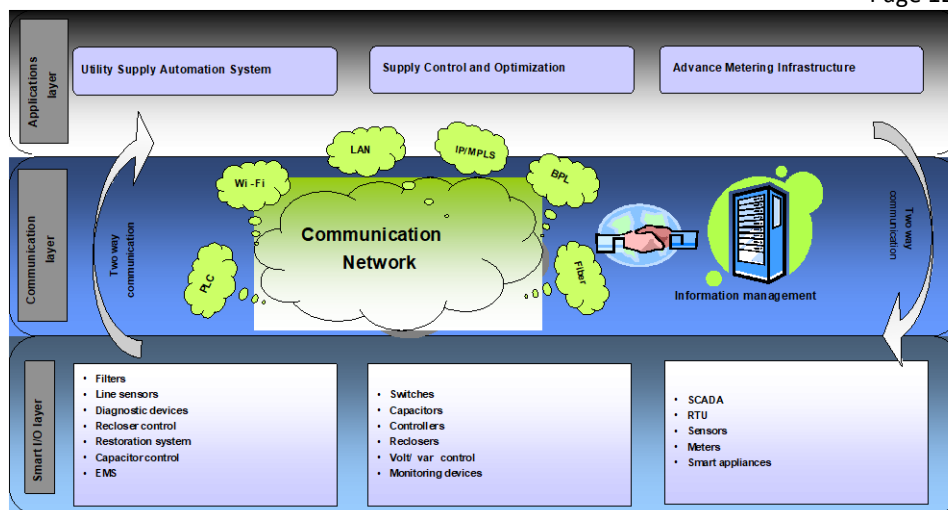
7 The first set of benefits involves the advanced metering components of a Grid  
8 Modernization effort. The smart meters, and the data they report, create multiple  
9 benefits involving labor savings, improved back-office efficiencies, and revenue  
10 assurance.

### 11 **Advanced Metering**

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



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- 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

1 **Connect/Disconnect**

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



This arrangement probably includes a service disconnect.



Meter socket with main breaker, 120/240V, hot sequence

This arrangement might include a service disconnect.



Meter socket, 480Y/277V, with unfused meter disconnect switch, cold sequence

8 **Distribution Automation**

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

1           **Fault Detection**

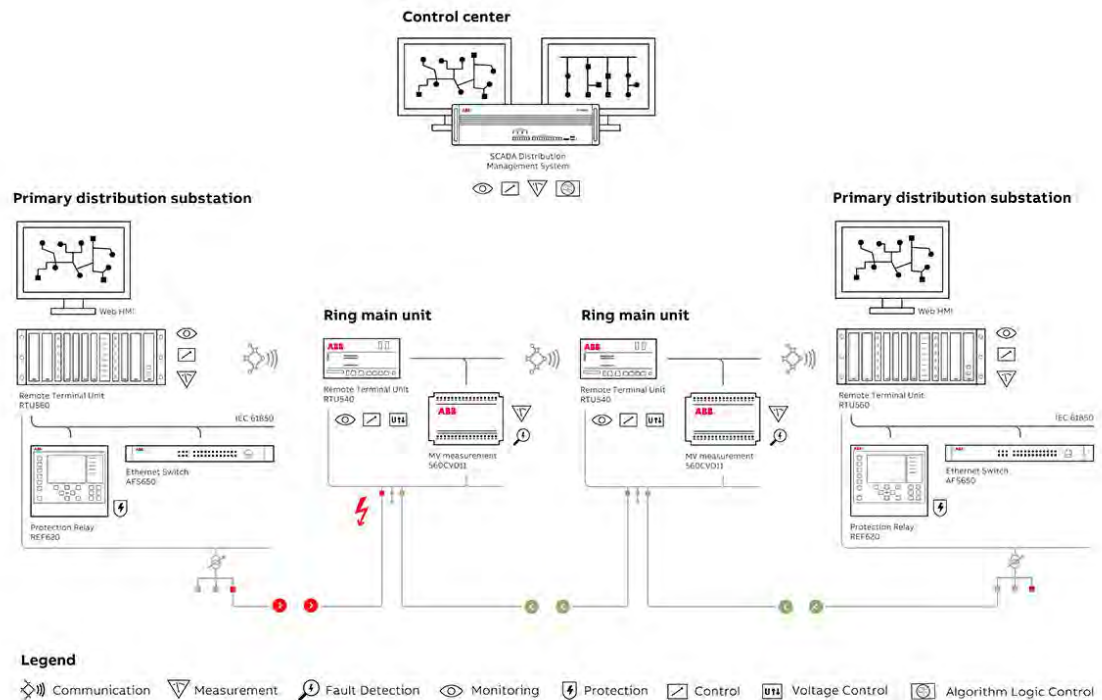
2           A significant grouping of benefits involves improved capabilities for responding  
3           to electrical faults in the utility’s electric delivery system. The automation  
4           schemes would provide improved capabilities for activating protective relays  
5           (e.g., tripping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

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

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

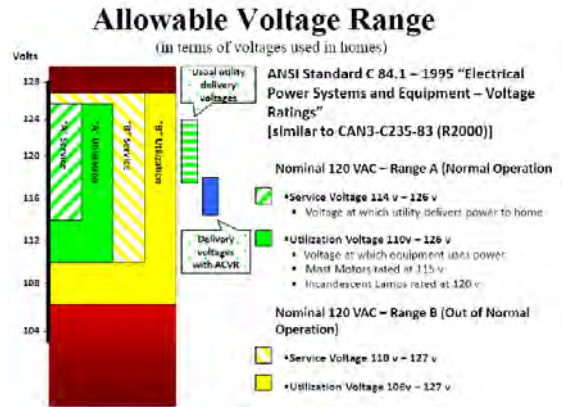
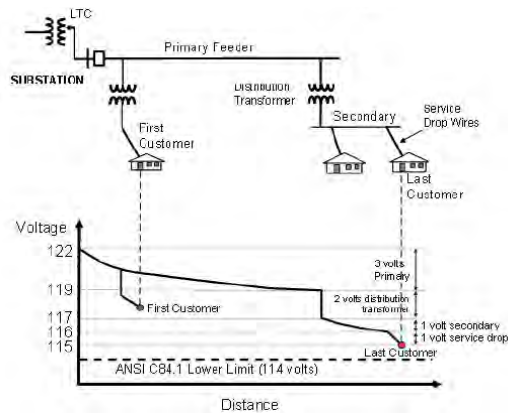
30          The development of a robust outage management/fault detection program  
31          often depends upon the deployment of an advanced distribution management  
32          system (ADMS). An ADMS is the software platform that supports the full suite of  
33          distribution management and optimization. An ADMS includes functions that

- 1 automate outage restoration and optimize the performance of the distribution
- 2 grid. ADMS functions being developed for electric utilities include fault location,
- 3 isolation and restoration; volt/volt-ampere reactive optimization; conservation
- 4 through voltage reduction; peak demand management; and support for
- 5 microgrids and electric vehicles.



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

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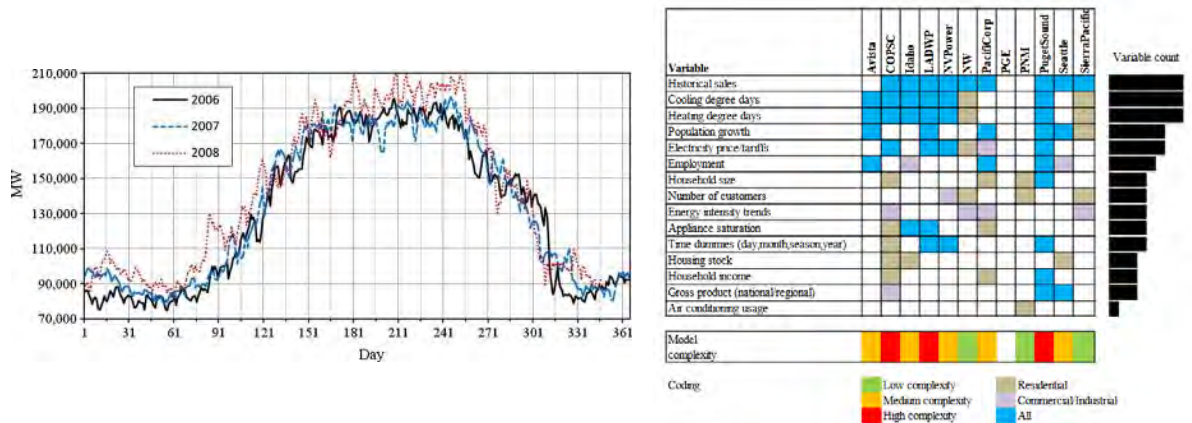
- 1 There are a number of deployment options that Liberty Utilities could consider in
- 2 the ultimate design of its conservation voltage program. Below are three
- 3 options it may want to consider:

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

1 **Load Forecasting**

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

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



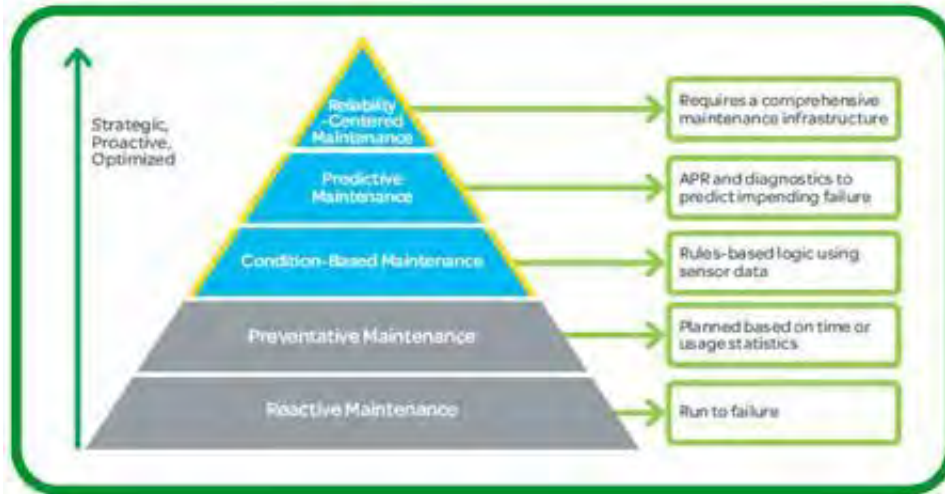
13 **Asset Management**

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

19 Utility companies frequently struggle with balancing the need to invest in  
20 modern equipment and infrastructure with demands to minimize costs for  
21 customers. One of the most effective ways to avoid substantial rate hikes is to



1 maximize the lifetime value of every existing asset. Automated asset  
2 management tools enable utilities to blend forecasting and business intelligence  
3 with traditional enterprise asset management capabilities.

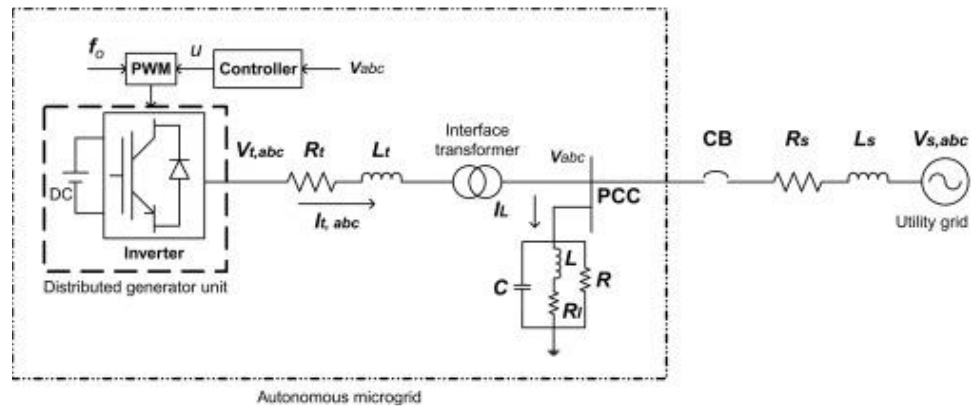


4 Part of the recommended asset management system would involve automated  
5 systems to ensure power quality analysis on a dynamic basis. Power quality  
6 analyzers are the most commonly used tools to observe real-time readings and  
7 also collect data for downloading to computers for analysis. While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

### 11 **Islanding**

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

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



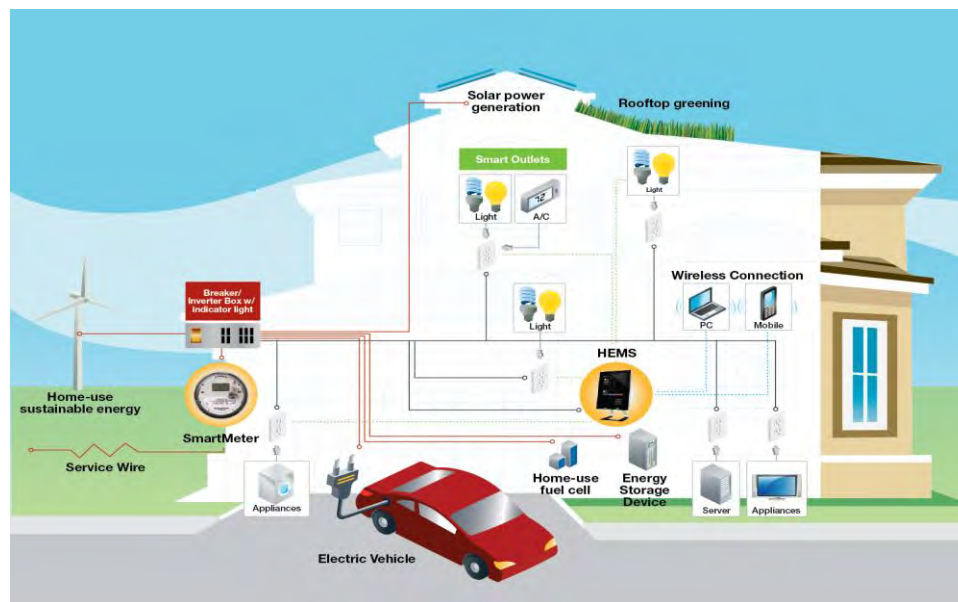


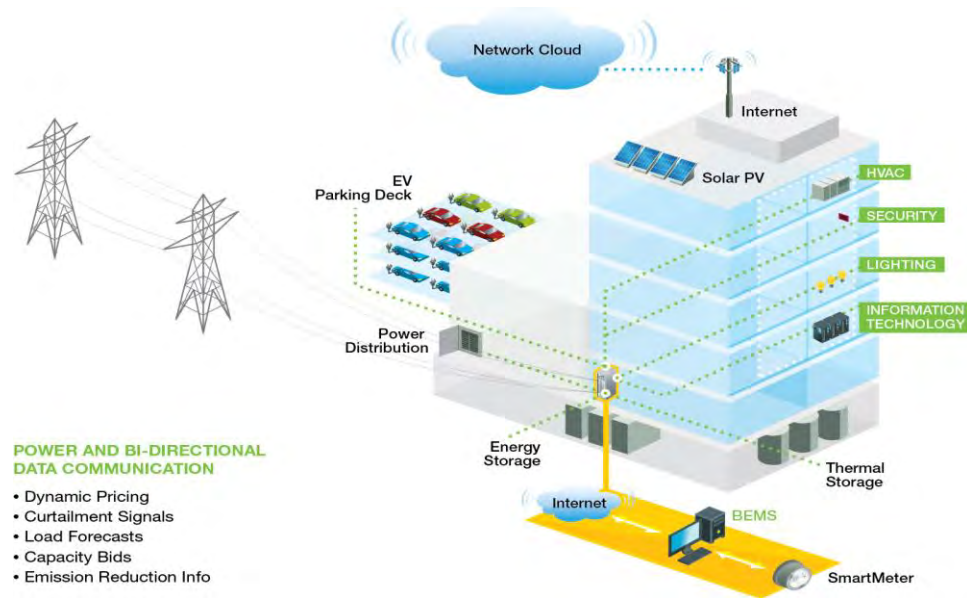
1 **Customer Connections**

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

9 **Energy Management**

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





1 **Distributed Energy Resources**

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

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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

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



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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.

9

### **Smart City**

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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.

13

### **LED Lighting**

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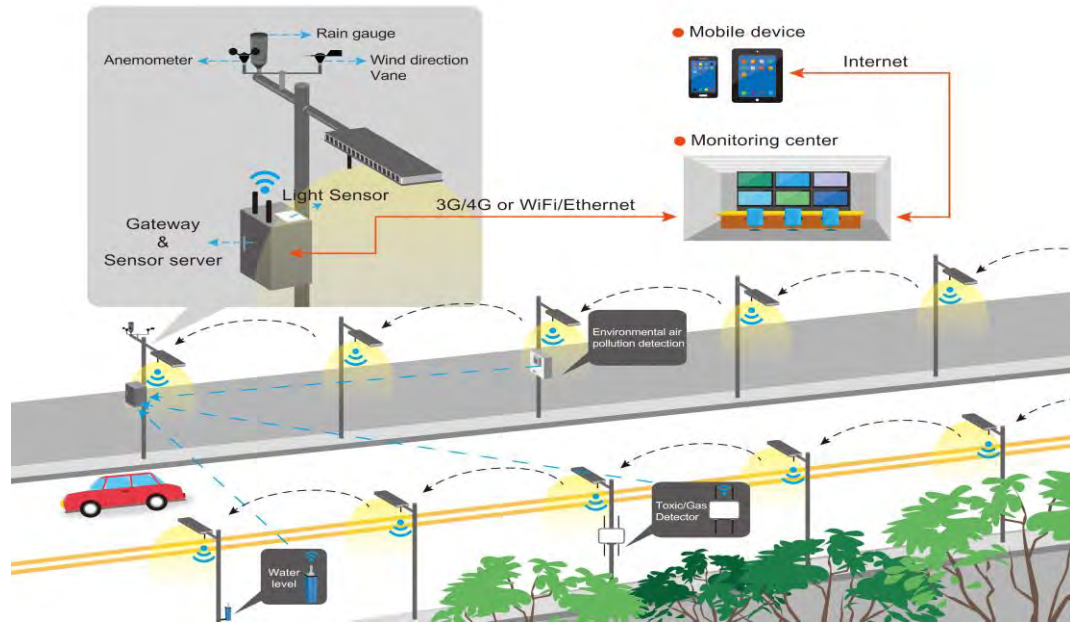
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18

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.

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## 1 Chapter 3: Business Case

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

### 8 *Summary*

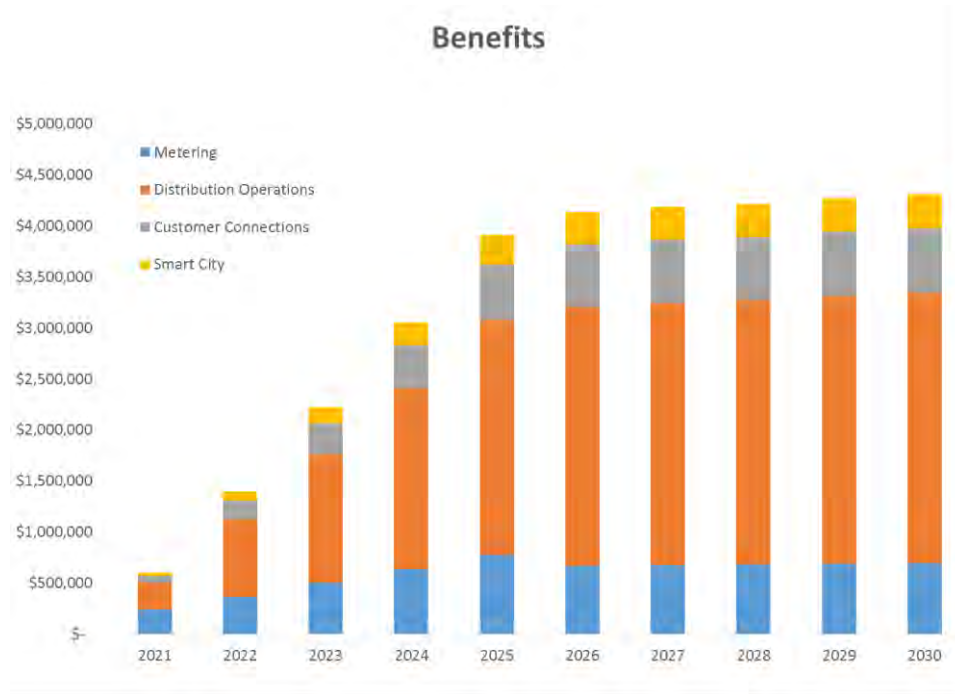
9 In order to assess the viability of the different grid modernization use cases under  
10 consideration, an evaluation of the forecasted economics of each program was  
11 evaluated. Included in the analysis were quantifications of the potential benefits for  
12 each program, the associated operating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

**Program Comparison - Ranked**

	<u>PV - Benefits</u>	<u>PV - CapEx</u>	<u>PV - OpEx</u>	<u>Terminal Value</u>	<u>NPV</u>	<u>Rank</u>
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	

1 **Benefits**

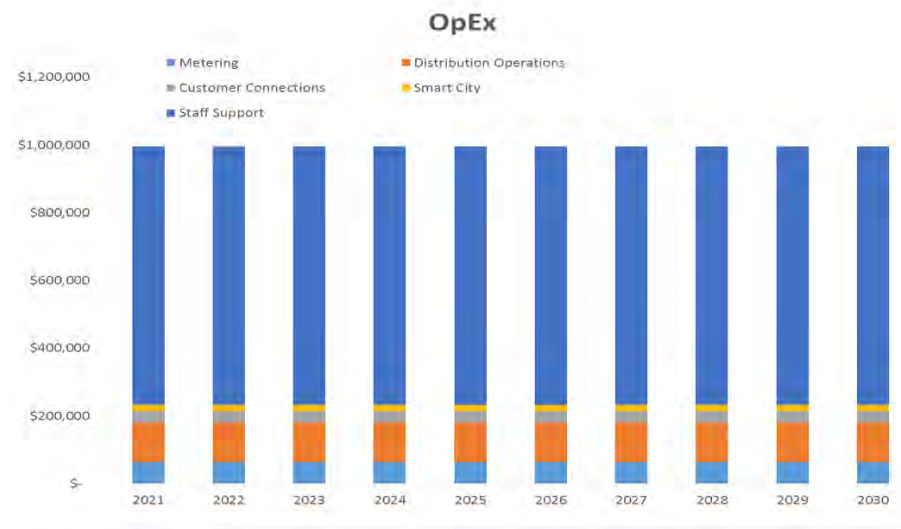
2 The annual benefits that are estimated from a grid modernization campaign are  
3 estimated to increase from \$600,000 in 2021 to \$4.3 million in 2030.



4 **Operating Expense**

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

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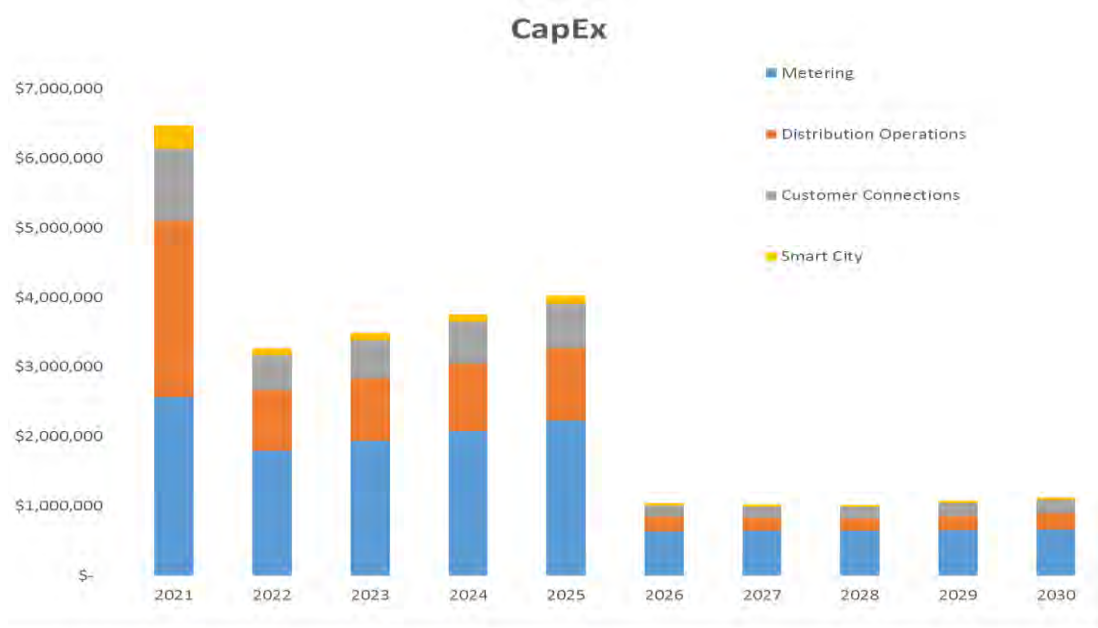


1 **Capital Expense**

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



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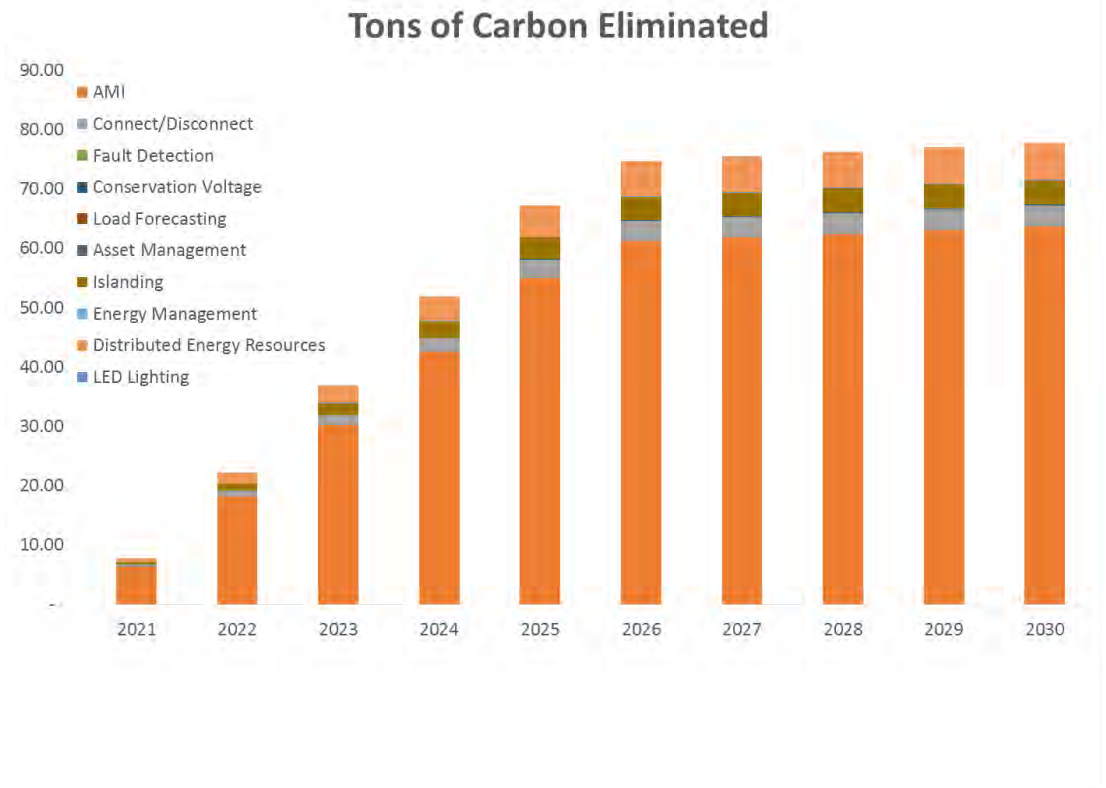


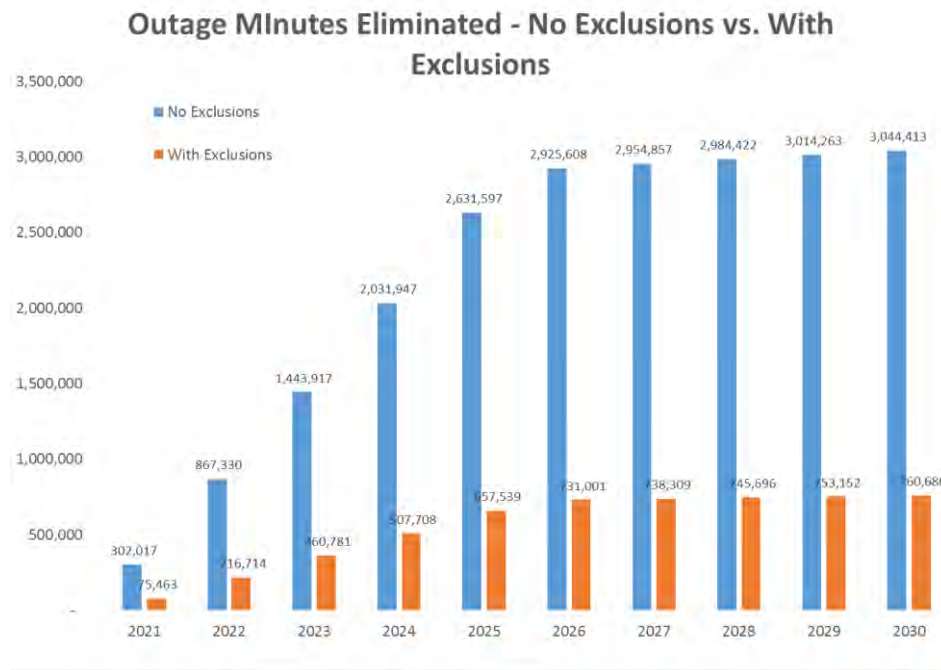
1 **Non-Financial Benefits**

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

- 7 • Carbon – It is estimated that a full grid modernization effort would eliminate  
8 a total of 567 tons of CO<sub>2</sub> over a period of ten years.
- 9 • Outage – It is estimated that a full grid modernization effort would offer the  
10 potential to reduce annual outage minutes by 3 million for Liberty’s  
11 customers. Using NH regulatory criteria, it has a potential to reduce annual  
12 outage by 760,000 minutes.

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1 **Chapter 4: Migration Strategy**

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

7 ***Proposed Pilot Programs***

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

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<u>Use Case</u>		<u>Pilot</u>
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
<b>Total</b>	<b>\$</b>	<b>2,526,976</b>

1           **Methodology**

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

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

- 11           1. In each case, the pilot needs to be large enough to establish a valid test of  
 12           the program under consideration.
- 13           2. At the same time, there is a desire to keep each pilot project to a reasonable  
 14           size so as not to overcommit resources to an as-yet unproven/unjustified  
 15           program.
- 16           3. Systems have been architected in such a way to make the test as reasonable as  
 17           possible. For example, the test of advanced meters is based on a targeted  
 18           meter route, while the test of conservation voltage is based on a feeder design.

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

7           **Pilot Budgets**

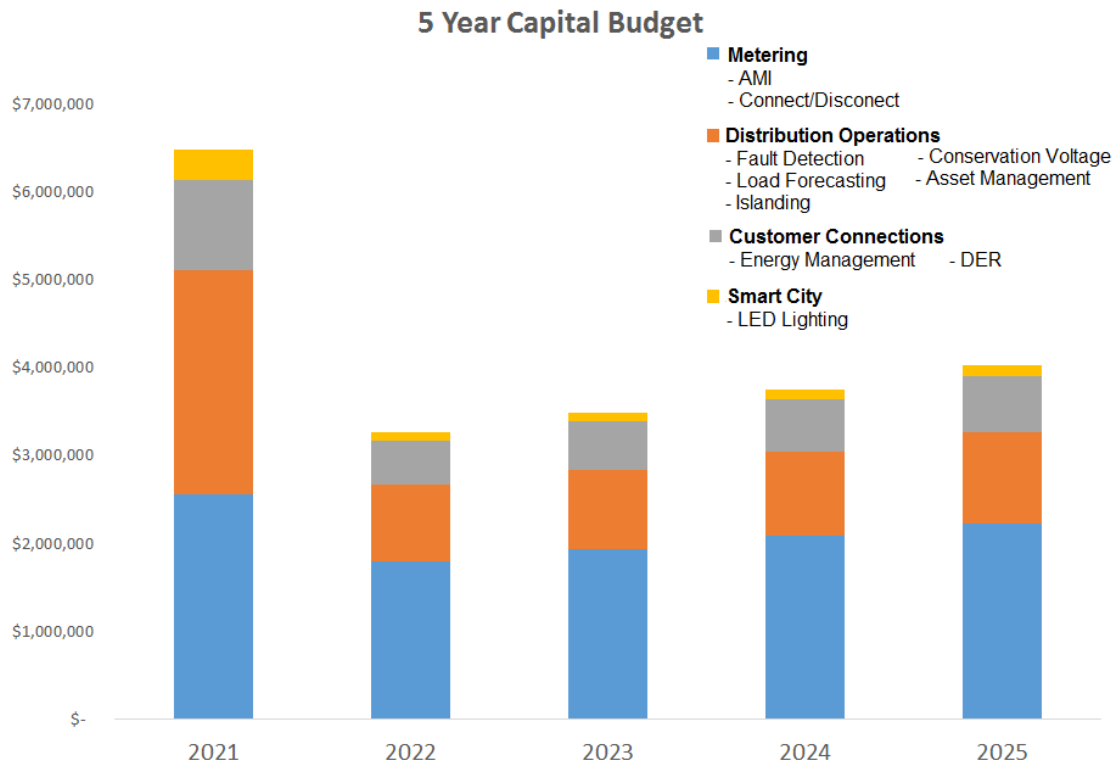
8           An initial set of plans and associated budgets have been developed to enable Liberty  
9           Utilities to prudently test the nine targeted use cases.

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

<u>Use Case</u>		<u>Pilot</u>		<u>Post-Pilot Full Deployment</u>		<u>Total Capex Investment</u>
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

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



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**CapEx - Annual**

	2021	2022	2023	2024	2025
<b>Metering</b>					
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
<b>Distribution Operations</b>					
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
<b>Customer Connections</b>					
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
<b>Smart City</b>					
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

- 1 For the pilot budgets, below is a listing of the core objective, proposed test focus and
- 2 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

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1 **Connect/Disconnect**

2 Program objectives include:

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

	Pilot				
	<u>Quantity</u>	<u>Unit Cost</u>	<u>Labor Hours</u>	<u>Labor Rate</u>	<u>Total Cost</u>
Remote Disconnects	418	\$ 77		\$	\$ 32,186
<b>Total</b>					<b>32,186</b>



1           **Conservation Voltage**

2 Program objectives include:

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

Pilot						
	<u>Quantity</u>	<u>Unit Cost</u>	<u>Labor Hours</u>	<u>Labor Rate</u>	<u>Total Cost</u>	
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
<b>Total</b>					\$	<b>126,610</b>

8           **Asset Management**

9 Program Objectives include:

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

Pilot						
	<u>Quantity</u>	<u>Unit Cost</u>	<u>Labor Hours</u>	<u>Labor Rate</u>	<u>Total Cost</u>	
Partial Discharge Tool	1	\$ 100,000			\$	100,000
Asset Management System	1	\$ 25,000			\$	25,000
<b>Total</b>						<b>125,000</b>

1           **Load Forecasting**

2   Program Objectives include:

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

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

10           **Islanding**

11   Program objectives include:

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

	<b>Pilot</b>				
	<u>Quantity</u>	<u>Unit Cost</u>	<u>Labor Hours</u>	<u>Labor Rate</u>	<u>Total Cost</u>
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
<b>Total</b>					<b>\$ 599,200</b>

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1 **Fault Detection**

2 Program objectives include:

- 3 • Evaluate fault detection capabilities
- 4 • Evaluate isolation recovery capabilities
- 5 • Assess viability of integration with AMI system
- 6 • Evaluate system integration into existing and proposed Company Electric
- 7 Dispatch and Control systems
- 8 • 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
<b>Total</b>					<b>\$ 290,410</b>

9 **Energy Management**

10 Program objectives include:

- 11 • Test responsiveness of residential customers to utilize smart thermostats
- 12 • Test responsiveness of commercial customers to engage with load control
- 13 devices.
- 14 • Test communications and AMI integration
- 15 • Evaluate rate mechanisms and other initiatives to incentivize the use of energy
- 16 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
<b>Total</b>					<b>\$ 85,770</b>

17

1 **Distributed Energy Resources**

2 Program objectives include:

- 3 • Test integration of distributed resources onto distribution grid.  
4 • Evaluate Hosting Capacity Analysis capabilities and potential.  
5 • Evaluate capabilities of different distributed generation and energy storage  
6 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

7 **LED Lighting**

8 Program objectives include:

- 9 • Evaluate capabilities of LED street lights, including control systems.  
10 • Assess economic impacts to stakeholders.  
11 • Evaluate capabilities to support other Smart City functions in the future  
12 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

1           **Pilot Implementation**

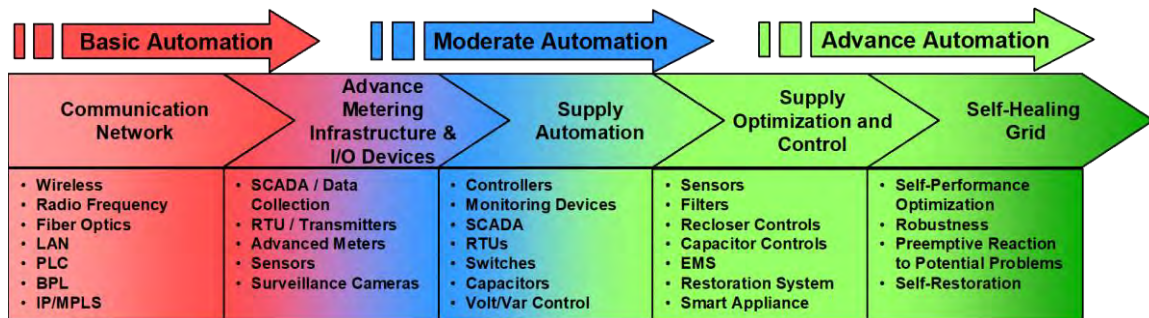
2   The proposed plan for Liberty Utilities’ Grid Modernization pilot test provides for a  
3   robust test of each program in a prudent and complete manner. The next steps going  
4   forward are:

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

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

4           ***Program Planning and Implementation***

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



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

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

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





4 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

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

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

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	Strategy Development	System Analysis & Design	Project Planning & Preparation	Network Deployment & Testing
<b>Inputs</b>	<ul style="list-style-type: none"> <li>Individual Program Plans</li> <li>Existing Infrastructure</li> <li>Stakeholder Hierarchy Diagram</li> </ul>	<ul style="list-style-type: none"> <li>Network Maps</li> <li>Input from Site Analysis (line crew, vendors, PM, etc.)</li> </ul>	<ul style="list-style-type: none"> <li>RFP Responses</li> <li>Installation Duration Estimating</li> <li>Resource Availability</li> </ul>	<ul style="list-style-type: none"> <li>Schedule Baseline</li> <li>Training</li> <li>Testing Plan</li> </ul>
<b>Outputs</b>	<ul style="list-style-type: none"> <li>Prioritized List of Technologies</li> <li>RFP Documentation</li> <li>List of Vendors</li> </ul>	<ul style="list-style-type: none"> <li>Approved Design</li> <li>List of Needed Equipment/Pre-Work</li> <li>Project Plan</li> </ul>	<ul style="list-style-type: none"> <li>Inventoried Equipment</li> <li>Schedule Mgmt Plan</li> <li>Test Goals &amp; Objectives</li> </ul>	<ul style="list-style-type: none"> <li>Working Network</li> <li>Performance Reporting</li> <li>Lessons Learned</li> </ul>
<b>Who</b>	<ul style="list-style-type: none"> <li>Smart Network Team</li> <li>Management</li> </ul>	<ul style="list-style-type: none"> <li>Project Manager</li> <li>Line Workers and IT Staff</li> <li>Vendors</li> </ul>	<ul style="list-style-type: none"> <li>Project Manager</li> <li>Purchasing</li> <li>Line Workers</li> <li>IT/Telecom Staff</li> <li>Vendors</li> </ul>	<ul style="list-style-type: none"> <li>Project Manager</li> <li>Testing Team</li> <li>Line Workers</li> <li>IT/Telecom Staff</li> <li>Vendors</li> </ul>
<b>Duration</b>	2 months	3 months	3 months	4 months
<b>Complexity</b>				

1 **Short Term Plan**

2 The first five years of the proposed program implementation covers the years 2021-  
3 2025. The following steps are planned during this time:

- 4
- 5
- 6
- 7
- 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.
- 8
- 9
- 10
- 11
- 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.
- 12
- 13
- 14
- 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.



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- 1           • Fault Detection – The core elements of the fault detection system will be  
2           deployed, allowing for full capabilities of an outage management system. It  
3           is anticipated that the fault detection system will leverage data from the  
4           metering system to identify locations of outages.
- 5           • Conservation Voltage – The goal is to deploy the conservation voltage system  
6           very quickly. In the short term, bellwether meters will be used to report on  
7           voltage levels across distribution feeders to ensure compliance with ANSI  
8           standards. As the AMI system is deployed across the entire service territory,  
9           these bellwether meters will be displaced by AMI meters.
- 10          • Load Forecasting – The backend systems supporting the load forecasting  
11          system will be deployed in the first year of the project. AMI meters and  
12          distribution assets deployed in the field will be utilized to report on load  
13          conditions on a real time basis as they are deployed.
- 14          • Asset Management – The backend systems supporting the asset  
15          management system will be deployed in the first year of the project. AMI  
16          meters and distribution assets deployed in the field will be integrated into  
17          the system as they are deployed.
- 18          • Islanding – The goal in the first phase will be to deploy enough islanded  
19          resources in order to defer one or two capital projects currently under  
20          budget for fiscal years 2022 and 2023. Currently there are three projects  
21          that offer the potential for deferral, including (a) the installation of Lebanon  
22          1L2 Feeder Tie in Plainfield (\$1.3 million); (b) the installation of Vilas Bridge  
23          12L1-12L2 Feeder Tie in Charlestown (\$1.3 million); and (c) the rebuild of  
24          Lockhaven Rd Enfield Phase 1&2 (\$1.51 million).
- 25          • Energy Management – Liberty Utilities proposes to monitor system  
26          development and continue to evaluate the viability of deployment. Within  
27          the first five years, Liberty Utilities plans to implement an initial pilot to  
28          further test the viability of a dedicated program.
- 29          • Distributed Energy Resources – Liberty Utilities is seeking to have a total of  
30          3% of system peak under management of a dedicated DER program by the  
31          end of 2024.

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

3           ***Long Term Plan***

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

- 8           • Advanced Metering – Continue deploying AMI meters in areas of growth  
9           within the service territory. In addition, Liberty Utilities will also seek to  
10          capture maximum value from the AMI system by looking to optimize the  
11          data mapping to ensure that departments can access information in the  
12          optimal methodology while also redesigning internal workflows to ensure  
13          that work processes are aligned with the new system.
- 14          • Connect/Disconnect – Alongside the AMI system, Liberty Utilities will seek to  
15          develop learnings from the initial stage of the connect/disconnect program  
16          to evaluate how to optimize operations.
- 17          • Fault Detection – Liberty Utilities will see to expand the outage management  
18          system by incorporating elements of isolation recovery to the fault detection  
19          system, enabling automated switching of circuits during major outage  
20          events.
- 21          • Conservation Voltage – The goal of the long-term conservation voltage  
22          program will be to optimize operations by testing and implementing  
23          automated voltage management systems.
- 24          • Load Forecasting – Liberty Utilities will identify and implement advanced  
25          systems to utilize meter and distribution automation data in load forecasting.
- 26          • Asset Management – Liberty Utilities will identify and implement advanced  
27          systems to utilize meter and distribution automation data in asset  
28          management.

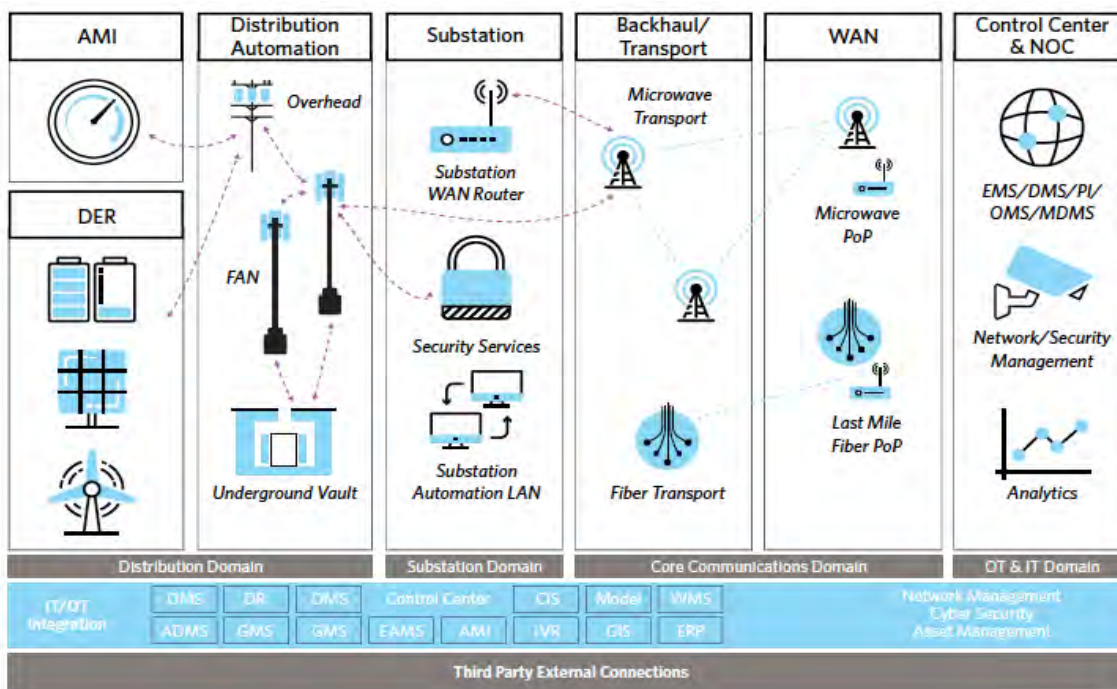
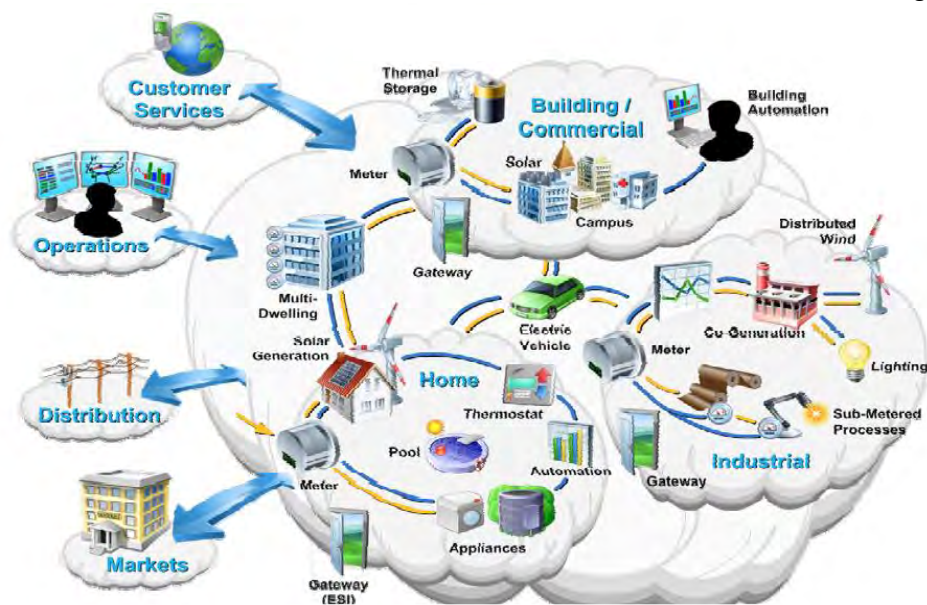
- 1           • Islanding – The goal in the second phase will be to deploy enough islanded  
2 resources in order to defer three to four capital projects by one or more  
3 years.
  
- 4           • Energy Management – Liberty Utilities plans to implement an initial  
5 deployment involving customers with a mix of smart thermostats and energy  
6 management systems.
  
- 7           • Distributed Energy Resources – Liberty Utilities is seeking to have a total of  
8 6% of system peak under management of a dedicated DER program by the  
9 end of 2029.
  
- 10          • Smart City – The goal is to ensure the complete installation of LED lights for  
11 additional cities within the service territory while also working with  
12 communities to evaluate and deploy additional smart city use cases beyond  
13 LED lighting controls.

#### 14           ***Implementation Approach***

15           Liberty Utilities seeks to implement programs to enable it to better serve customers  
16 and to become more operationally efficient. Grid modernization involves a non-  
17 stop, on-demand, re-design journey of the business models, business processes,  
18 technologies, organizational structures, and applied human capital to seamlessly  
19 leverage existing and new trends into a more profitable, faster growing, and more  
20 customer driven utility reality. Liberty Utilities believes that:

- 21           • Grid modernization delivers success by committing to pervasive performance  
22 management, which helps streamline processes by creating a smart, agile  
23 and aligned utility.
  
- 24           • Grid modernization enables the close monitoring of performance, flexible  
25 integrated planning, and re-establishes and/or enhances trust with  
26 stakeholders.
  
- 27           • Grid modernization also drives insight in divestments and investments, and  
28 offers techniques that help in rethinking strategies and managing innovation  
29 as a competitive advantage

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1 Ultimately, by developing these programs, it will enable the development of a host of  
2 new programs that are beneficial for a wide variety of stakeholders. For example,  
3 upgrades will be needed to host the inevitable growth in electric vehicles.

4 Electric vehicles have been discussed for a long time. The promise of achieving mass  
5 production of automobiles that could change the fueling paradigm – away from foreign  
6 dependence on oil and toward domestic production on electricity – is a promising one  
7 that has been championed by virtually all of the relevant stakeholders involved. Almost  
8 unanimously, we have heard the voices from the federal government, the automotive  
9 industry, and from consumers themselves stating that the time for electric vehicles to  
10 reach the market in a meaningful way is upon us. Now that the technology appears to  
11 be catching up the hype, there exists considerable optimism that we may be on the  
12 verge of the dawning of a new era – the electric vehicle era.

13 Some of the answers to these questions have been challenging to address for electric  
14 vehicle industry. Progress in some of the key areas is well under way and viable  
15 solutions appear to be at hand. Certain industry analysts have opined that progress will  
16 be slower and more gradual while others are more optimistic. However, one thing that  
17 almost no one debates is the ultimate impact of electric vehicles. Simply put, electric  
18 vehicles are a “game changer”. Consider the following impacts we can realistically  
19 expect to see once electric vehicles achieve mainstream status:

- 20 • Dependence on foreign oil to fuel our cars will be vastly diminished, thus  
21 reshaping foreign relations
- 22 • New industries that do not exist today, namely recharging stations and batter  
23 developers, will emerge
- 24 • Automobile manufacturers will be forced to respond to changing market needs  
25 and will need to support the delivery of volumes of electric vehicles not seen  
26 today
- 27 • Electric utilities will see their load profiles change dramatically – requiring new  
28 investments in distribution infrastructure to meet the growing and reshaped  
29 loads of the future

- 1 • Utilities that pursue smart grid investment may find that the electric vehicle  
2 becomes the “killer app” that many have been seeking
  
- 3 • Consumers will develop new relationships with their electric utilities, involving a  
4 confluence of smart metering, home automation, distributed energy resources,  
5 and electric vehicles

## 6 **Security**

7 No facet of our society can now afford to ignore the possibility of malicious  
8 interference with the normal operations of daily life, and this includes the  
9 operations of the utility industry’s critical infrastructures. Indeed, the very basic  
10 requirements for life are provided by the utility industry: power for heat and light,  
11 clean water supply and waste treatment. A secondary level of consideration is  
12 energy requirements for the successful functioning of a healthy economy including  
13 industrial production, transportation, construction and trade.

14 For utility companies, when we speak of cyber security we generally are referring to  
15 control systems such as DCS or SCADA. Typically Distributed Control Systems (DCS)  
16 are used within a single generating plant over a small geographic area while  
17 Supervisory Control and Data Systems (SCADA) are used for large, geographically  
18 dispersed distribution systems. It is the vitally important function of such systems to  
19 control, coordinate and monitor the operations of critical infrastructure including  
20 electric lines. In SCADA systems the supervisory control and monitoring station is  
21 connected to local control stations through a hard-wired network or through  
22 communications networks involving elements such as the Internet, the public  
23 switched telephone network, or internal cable or wireless networks.  
24 Telecommunications is the intricate nervous system that connects operational  
25 assets, providing the means by which control instructions are delivered.

26 As part of the Grid Modernization effort, we recommend the following practices be  
27 instituted:

- 28 • **Internal CI Protection Program Starts at the Top.** A critical infrastructure  
29 protection program should be initiated by upper management and included  
30 in the annual budget process. High-level leadership facilitates more

1 successful programs. Security initiatives need to be driven from the top of  
2 the organization, at the “C” level. There are two reasons for this. First,  
3 executive management is in the best position to work with legislators,  
4 Federal government contacts, policy makers, and powerful peers. At this  
5 level, pertinent information is quickly conveyed. Secondly, an authority  
6 within the organization is more likely to see security projects through to a  
7 successful conclusion.

- 8 • **Establish Formal Personnel Policies.** Well-defined personnel roles are  
9 essential to good security. Another key element of security is personnel  
10 policy. When individuals are left in charge of security without specific  
11 guidelines, likely results are inconsistency and ineffectiveness. Thus, even  
12 good security policies can be rendered ineffective without properly defined  
13 personnel roles and responsibilities. Improper training can also impair good  
14 security. If employees are properly trained for their roles in the security  
15 program, accidental disclosure of sensitive information as well as a host of  
16 other security breaches could ensue.
  
- 17 • **Assess Vulnerabilities.** Knowing weaknesses enables better security  
18 strategy. Before utilities can develop a strategy for protecting themselves  
19 against attack, they must be able to adequately identify their vulnerabilities.  
20 Knowing weak points in the system will enable utilities to provide additional  
21 protection where it is needed, rather than throughout the system.  
22 Ultimately, this will save valuable resources from being wasted.
  
- 23 • **Secure SCADA Connections.** The increasing trend towards systems that are  
24 more open and allow for more distributed communications environments  
25 along with the standardized technology sets that accompany them are  
26 leading to increasingly vulnerable systems that can be accessed from  
27 anywhere in the world. Because they are so essential to the function of the  
28 power grid, it is increasingly important that SCADA networks are  
29 appropriately isolated from corporate networks.
  
- 30 • **Work With Vendors.** There are some grid modernization systems that do not  
31 include security features. Using security devices that are provided is a good  
32 first step, yet additional security is necessary.

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- 1       • **Monitor the Systems.** The ability to quickly detect and eliminate any  
2       intrusion into the system will enable the quickest possible recovery of service  
3       in an emergency.
  
- 4       • **Format Disaster Recovery Plans.** Notification of security incidents is not  
5       enough. Utilities should also cultivate disaster recovery plans to cut off any  
6       incidents that arise as well as to allow for quick restoration of systems.
  
- 7       • **Perform Routine Audits.** In order to ensure that security measures are  
8       sufficient for actual protection, the security systems themselves should be  
9       audited regularly. Audits will expose weaknesses in security measures, and  
10      specifically they will reveal remaining vulnerabilities in the network.
  
- 11



1 **Chapter 5: Summary**

2 Regulatory compliance, support, and funding all have an impact on utility operations.  
3 As has been seen in the last few years, new security and environmental regulations are  
4 prompting reprioritization of projects and the implementation of new programs and  
5 technology. Energy efficiency and net metering are emerging in multiple areas of the  
6 country.

7 Every utility would like to have the fastest and most automated network, but a higher  
8 quality network comes at a higher price. That is why Liberty Utilities has developed a  
9 detailed business case to examine various factors—including budget—as part of a  
10 rigorous planning process to find the best fit for its operational requirements.

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1 **Exhibit A – Business Case Assumptions (General)**

<b>Growth Rate</b>	
Meters	1.0%
Substations	1.0%
Feeders	1.0%

<b>Meter Counts</b>	
Residential	41,350
Commercial	2,720
Industrial	144

<b>Annual Sales (\$MM)</b>	
Residential	\$ 51.6
Commercial	\$ 41.2
Industrial	\$ 7.4
Street Lighting	\$ 1.2

<b>Electric Delivery (kWh)</b>	
Residential	296,235,488
Commercial	492,762,561
Industrial	126,400,162
Street Lighting	4,168,594

<b>Summer Peak (MW)</b>	
Summer	197.8
Fall	141.0
Winter	154.3
Spring	121.8

<b>Infrastructure</b>	
Mainline Feeders	48
Distribution Transformers	9,340
Substations	15
Substation Transformers	13

<b>Financial Assumptions</b>	
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)

<b>AMI</b>		
<b>Read-To-Bill</b>		
Days to Accelerate Collection		3
<b>Reduction in Faulty Meters &amp; Loss</b>		
Percentage of Electromechanical Meters		65%
Inaccurate Meter Rate		1.0%
Digital Impact		50%
<b>Special Reads</b>		
Special Read Requests		1,000
Cost per Read	\$	95.00
AMI Impact		50%
<b>Vehicle Operations</b>		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		18,000
Cost per Mile	\$	0.580
<b>Emissions</b>		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		18,000
CO <sub>2</sub> Reduction per Mile (grams)		455
<b>Connect/Disconnect</b>		
<b>Labor Reduction</b>		
Annual Field Collector Expense	\$	65,000
Disconnect Reduction		25%
<b>Bad Debt Reduction</b>		
Annual Bad Debt	\$	1,000,000
Loss Reduction		15%
<b>Emissions</b>		
Meter Reading Vehicles Impacted		7
Average Number of Annual Miles per Vehicle		1,000
CO <sub>2</sub> Reduction per Mile (grams)		455

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**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 <sub>2</sub> emissions (grams) per kW	606
--	-----

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**Load Forecasting**

Capacity Reduction		
Peak Impact per Month		0.03%
Transmission Charge per kW-yr	\$	144

**Emissions**

Average CO <sub>2</sub> 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 <sub>2</sub> emissions (grams) per kW		606
--	--	-----

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**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 <sub>2</sub> emissions (grams) per kW		606

**Distributed Energy Resources**

Transmission 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 <sub>2</sub> emissions (grams) per kW		606

**LED Lighting**

Device Charge		
Target Devices		4,000
Annual Service Charge	\$	75.00

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1 **Exhibit C – Business Case Assumptions (Capital)**

<b>General</b>				
<b>Reinvestment</b>				
				Avg. Asset Life
Metering				15
Distribution Operations				20
Customer Connections				15
Smart City				15
<b>Metering</b>				
<b>AMI</b>				
	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
<b>Connect/Disconnect</b>				
	Dev: Cust Ratio	Device	Labor	Systems
Remote Disconnect	5.0%	\$ 77	\$ -	
Management System				\$ 50,000
<b>Customer Connections</b>				
<b>Energy Management</b>				
	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
<b>Distributed Energy Resources</b>				
	Dev: Cust Ratio	Device	Labor	Systems
Capacity Cost per kW		\$ 1,800	\$ 100	
Central Management System				\$ 400,000
<b>Smart City</b>				
<b>LED Lighting</b>				
	Dev: Cust Ratio	Device	Labor	Systems
Controllers	5.0%	\$ 150	\$ 20	
Radios	5.0%	\$ 10	\$ 5	
Management System				\$ 250,000

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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
<hr/>				
	Dev: Cust Ratio	Device	Labor	Systems
Conservation Voltage				
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
<hr/>				
	Dev: Cust Ratio	Device	Labor	Systems
Load Forecasting				
Sensors	0.1%	\$ 900	\$ 100	
Load Forecasting System				\$ 100,000
<hr/>				
	Dev: Cust Ratio	Device	Labor	Systems
Asset Management				
Sensors	0.5%	\$ 900	\$ 100	
Asset Management System				\$ 1,050,000
<hr/>				
	Dev: Cust Ratio	Device	Labor	Systems
Islanding				
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**

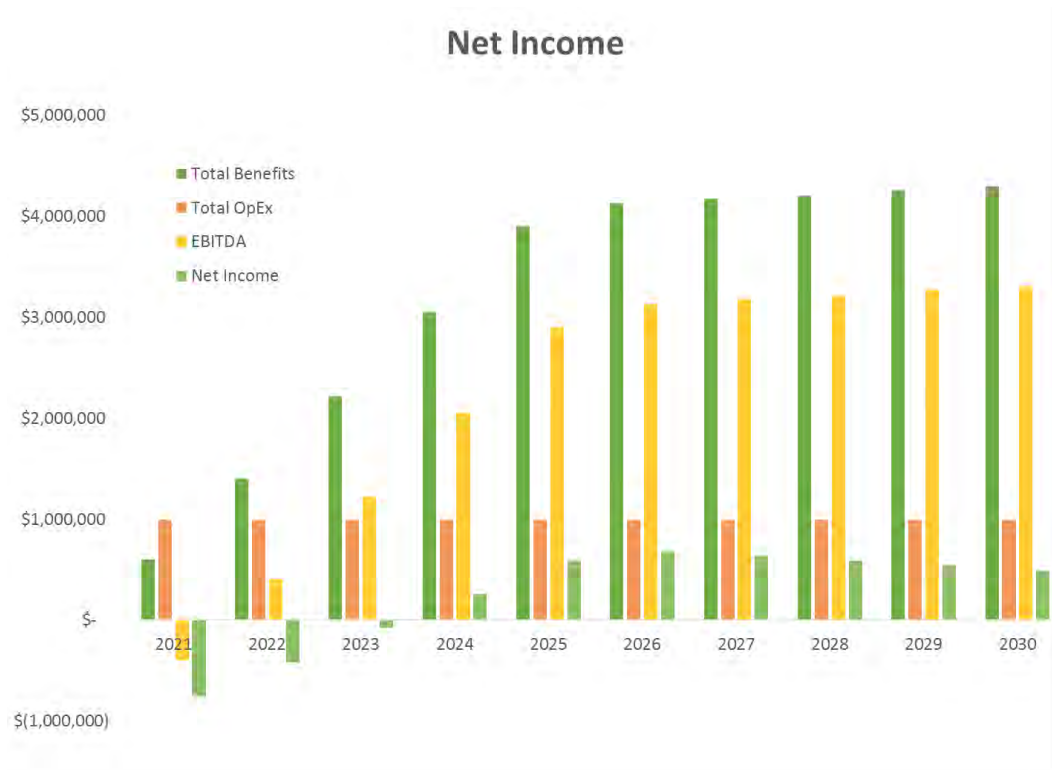
System Maintenance	
Annual System Maintenance	7.0%

**Support Staff**

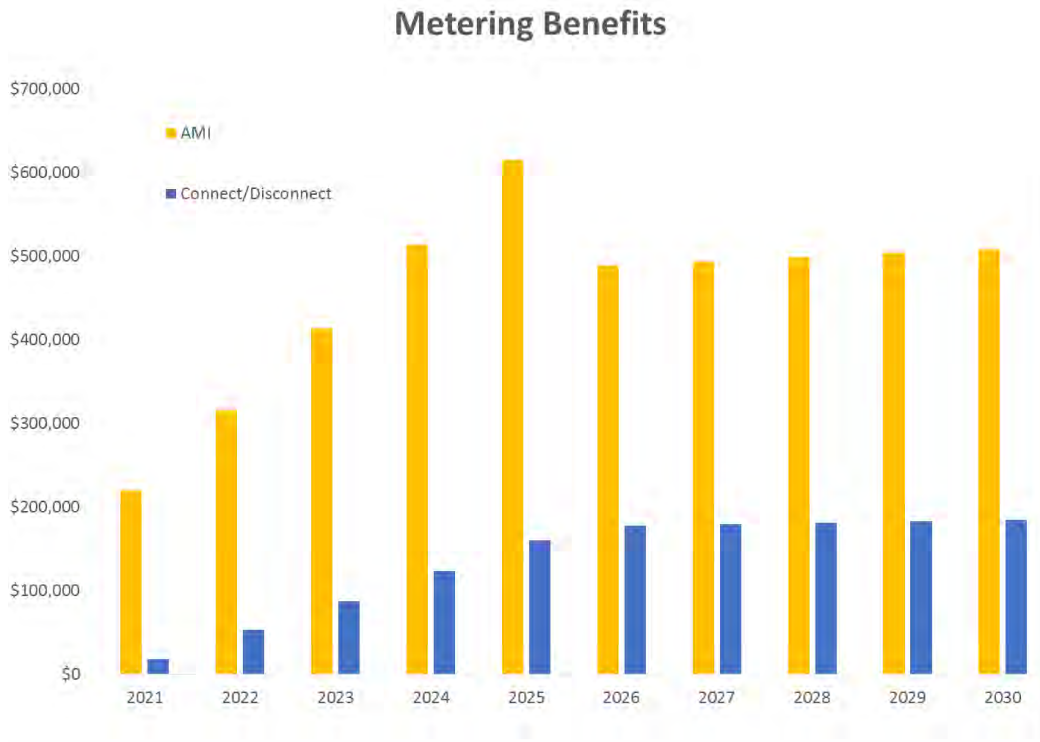
	Number	Salary
Communications Design Engineer	1	\$ 125,000
Field Support Engineer	1	\$ 85,000
Relay and Automation Engineer	1	\$ 125,000
System Infrastructure (Servers)	1	\$ 85,000
Grid Modernization Engineer	1	\$ 125,000

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1 **Exhibit E – Additional Graphs**

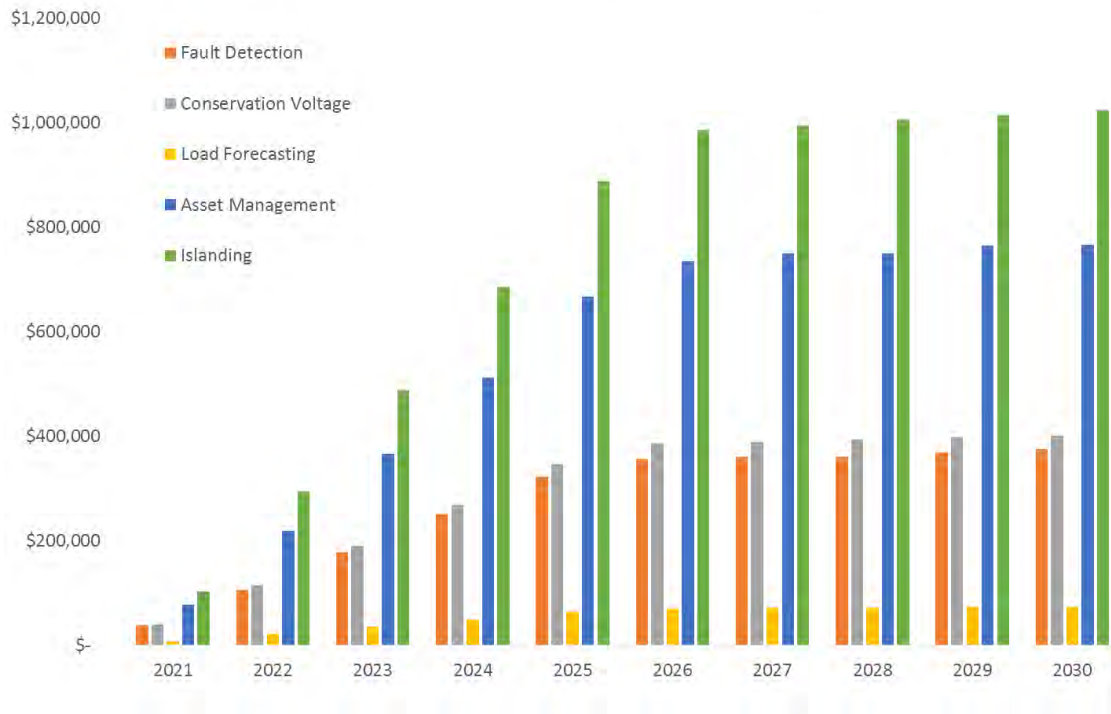


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### Distribution Operations Benefits



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### Customer Connections Benefits





**Bellows Falls Area**  
**System Planning Summary 2020**

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## 1    **1.0    Executive Summary**

2    Liberty Utilities completed the Bellows Falls Area system planning review for 2020. The revised  
3    Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System  
4    upgrades required to meet existing and future capacity requirements. The review focused on the  
5    distribution requirements needed to resolve deficiencies in system capacity, reliability, power  
6    quality or asset condition.

7    In 2014 the Michael Ave substation was installed to resolve asset conditions and retire the 46/13  
8    kV Charlestown Substation. It was also constructed to supply an expansion from Customer A  
9    Engineering, located in Charlestown NH. A new 115kV transmission line, one 115/13 kV  
10   transformer and two 13 kV feeders were installed.

11   The major concern in the Bellows Falls area is poor reliability and the load at risk that results from  
12   the inability to supply the Michael Ave substation load during contingency. Maintaining adequate  
13   voltages during contingencies is also a challenge given the long distances from the source.

## 14   **2.0    Introduction**

### 15       **2.1    Purpose**

16   The purpose of this review was to resolve all identified area concerns in the Bellows Falls Area  
17   through the 15-year 2020-2036 study horizon. An in-depth review of the area was performed that  
18   included the analysis of thermal loading, voltage, reliability, asset condition, power quality,  
19   environmental, safety and voltage performance. Both Traditional and NWS were considered to  
20   resolve the identified deficiencies presented in this report, using Liberty's project evaluation  
21   guidelines.

### 22       **2.2    Problem**

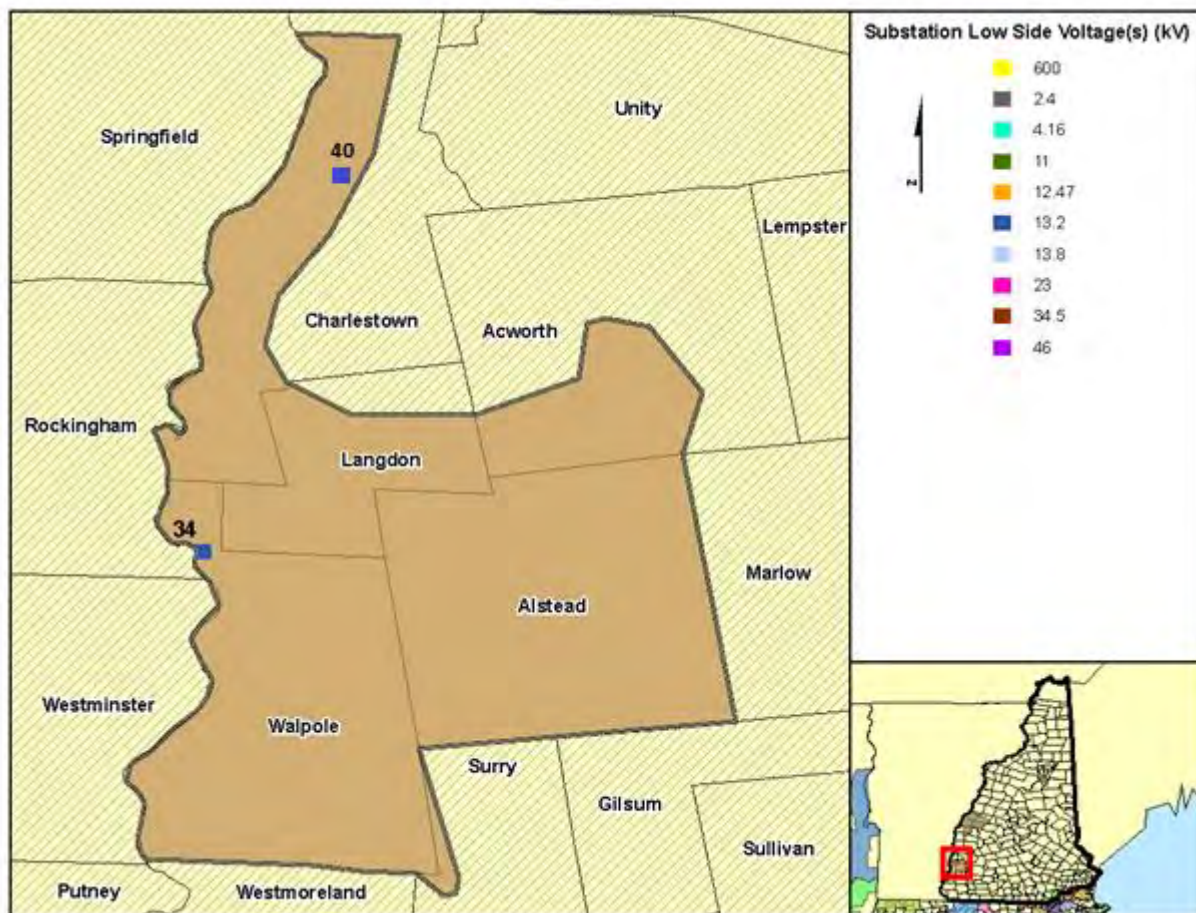
23   A study's initial system assessment is typically based on the needs identified through the problem  
24   identification process guided by the Company's Planning Criteria and Asset Strategies.

## 25   **3.0    Background**

### 26       **3.1    Geographic Scope**

27   The Bellows Falls area is rural residential with a few small commercial town centers. This area  
28   was historically supplied from the hydro generating plant developed at Bellows Falls by New  
29   England Power Company. There are two small load centers connected by a long feeder branch  
30   running along the Connecticut River. There are two substations in the Bellows Falls area: Michael  
31   Ave 40 and Vilas Bridge 34. Vilas Bridge is located in Vermont and is owned and operated by  
32   National Grid. Ownership of Michael Ave station is shared between Liberty and National Grid.

- 1 Liberty owns and maintains all distribution assets in the substation and National Grid is responsible
- 2 for the Transformer and Transmission assets. See Figure 1 below.
- 3 Supply to the area is from one radial 115 kV transmission line and two radial 46 kV sub
- 4 transmission lines originating at Bellows Falls. Distribution is at 13.2 kV.
- 5 Michael Ave 40 was installed in 2014 to retire the aging Charlestown 8 Substation and to support
- 6 a major expansion by Customer A.
- 7 Figure 1 Bellows Falls Geographical Map



8 **3.2 Electrical Scope**

9 The Bellows Falls Study Area includes one 115 kV transmission supply, two 46 kV supply lines  
10 and four 13.2 kV feeders interconnected through two area substations. Supply to Vilas Bridge and  
11 Michael Ave is at 46 kV and 115 kV respectively. The Table 1 below summarizes these  
12 interconnections:

1 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

2 The 115 kV transmission supply to the area originates from Bellows Falls and feeds one  
3 transformer at Michael Ave. Appendix A.1, Figure 5 - Bellows Falls 115 kV Transmission  
4 System, shows the 115kV supply to the area.

5 Two 46 kV sub transmission supply lines also originate from Bellows Falls. Table 2 below  
6 summarizes these interconnections and Figure 3 in Appendix A.1 – System One Lines shows the  
7 46 kV Supply System.

8 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)

9 Liberty Utilities serves 5,536 Customers in the Bellows Falls Area supplied by four 13.2kV  
10 distribution feeders. In 2020, the Planning Study Area generated a peak demand of 18 MVA. This  
11 area consists of approximately 14 miles of 46 kV three-phase supply line, 66 miles of 13.2 kV  
12 three-phase mainline and 164 miles of single-phase 7.62kV distribution. Figure 6, in Appendix  
13 A.1 – System One Lines shows the 13.2 kV Distribution System.

1           **3.3 Load and Load Forecast**

2    The Bellows Falls Study Area is a summer peaking area and is limited by summer equipment  
3    ratings. The study was conducted using load data beginning with the recorded 2020 peak load;  
4    refer to Table 3, below:

5                               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%

6    The Company developed an econometric model to forecast peak demands through 2036. The  
7    forecast model incorporates the impact of weather as well as demographic and local economic  
8    conditions on peak demands. The load was escalated through 2036 using the seasonal peak forecast  
9    under a 90/10 extreme weather scenario; refer to

10   , below:

11

1 Table 4 LUNH 2020-2036 90/10 Western PSA Growth Rate

<b>Year</b>	<b>% Increase</b>
<b>2020</b>	
<b>2021</b>	11.98%
<b>2022</b>	0.3%
<b>2023</b>	0.3%
<b>2024</b>	0.3%
<b>2025</b>	0.2%
<b>2026</b>	0.2%
<b>2027</b>	0.2%
<b>2028</b>	0.2%
<b>2029</b>	0.2%
<b>2030</b>	0.2%
<b>2031</b>	0.2%
<b>2032</b>	0.2%
<b>2033</b>	0.19%
<b>2034</b>	0.18%
<b>2035</b>	0.17%
<b>2036</b>	0.16%

2 The forecast model was then adjusted for spot loads to reflect new customer demands larger than  
3 300 kilowatts (“kW”), refer to Table 5 below. There are no known planned customer expansions  
4 above 300 kW for the Bellows Falls Area. The Distribution System was modeled and analyzed  
5 using the Synergi application to perform the load flow analysis.

6 Table 5 Bellows Falls Area Spot Loads

<b>Year</b>	<b>Feeder</b>	<b>Location</b>	<b>Load (MW)</b>
<b>None</b>	N/A	N/A	N/A

7 **3.4 Modeling and Criteria**

8 Synergi models were created for the Bellows Falls area 13.2 kV distribution system. Transformers,  
9 supply lines, and distribution circuits were evaluated and modeled for each year thru 2036. The  
10 peak load and the available tie capacity for each component of the system was determined.  
11 Contingencies for the loss of a major component of the electrical system (N-1) were developed,  
12 and the system consequences reviewed.

1 Distribution System Ratings were used to identify any station, supply line, and distribution circuit  
2 system capacity and reliability deficiencies, as applicable to Liberty Utilities Planning Criteria  
3 which is summarized below.

4 Table 6 Liberty Utilities Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>
N-1 Contingency, which results in facilities operating above their Long-Term Emergency (LTE) rating but below their Short-Term Emergency (STE) rating.	<p>Load must be transferred to other supply lines in the area to within their LTE rating.</p> <p>Repairs are expected to be made within 24 hours.</p> <p>Evaluate alternatives if more than <b>120 MWhr</b> of load at risk results following post-contingency switching.</p>	<p>Load must be transferred to nearby transformer to within their LTE rating.</p> <p>Repairs or installation of Mobile Transformer expected to take place within 24 hours.</p> <p>For transformers larger than 10 MVA nameplate, evaluate alternatives if more than <b>180 MWhr</b> of load at risk results following post-contingency switching.</p>	<p>Load must be transferred to nearby feeder to within their LTE rating.</p> <p>Repairs expected to be made within 24 hours.</p> <p>Evaluate alternatives if more than <b>16 MWhr</b> of load at risk results following post. (Guideline)</p>
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.

5 **4.0 Problem Identification**

6 The goal of system planning is to provide adequate capacity for safe, reliable, and economic  
7 service to customers with minimal impact on the environment. System Planning also includes

1 careful management of system assets; addressing asset conditions and protection issues where  
2 present to avoid failures, protect the equipment and provide a safe working environment for utility  
3 workers.

4 **4.1 Thermal Loading**

5 Analysis results in this section represent the 2020 peak base case. Planning criteria for normal and  
6 contingency load serving requirements are applied in concert with the thermal ratings of the  
7 facilities to identify capacity violations. Refer to the Company’s Distribution Planning Criteria  
8 for methodology on rating the equipment. The distribution system load is planned, measured, and  
9 forecasted with the goal to serve all customer electric load under system intact (normal conditions  
10 or “N-0”) and N-1 first contingency conditions.

11 **a. Normal Configuration**

12 **i. Sub-Transmission System**

13 Analysis under normal conditions resulted in no violations for the Supply System within the  
14 Planning Horizon.

15 Table 7 13.8kV Sub Transmission Loading – Normal Configuration

Circuit	Voltage (kV)	Line Section		Limiting Element	Element Specifics	Rating (MVA)		Actual		Projected Load			
		From	To			SN	SE	2020		2025		2036	
								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%

16 **ii. Transformers**

17 Analysis under normal conditions resulted in no violations for the Transformers within the  
18 Planning Horizon.

19 Table 8 Transformer Loading – Normal Configuration

Substation	Tranf. ID.	System Voltage (kV)		Maximum Nameplate Rating	Rating (MVA)		Actual Load			Projected Load					
		From	To		SN	SE	2020			2025			2036		
							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%



1 **iii. Feeders**

2 Analysis under normal conditions resulted in no violations for the Supply System within the  
3 Planning Horizon.

4 **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%

5 **➤ Phase Imbalance**

6 The feeders in the Bellows Falls Planning Study Area were reviewed for phase balance. The peak  
7 average phase loading between July 20 and August 2020 was selected for each feeder for phase  
8 imbalance review.

9 Liberty utilizes the following criteria for corrective action to phase imbalance:

- 10 • The calculated neutral current should not exceed 30% of the feeder ground  
11 relay pickup setting;
- 12 • The loading between the low and high phase should not exceed 100A.
- 13 • Liberty will strive to maintain phase balancing below 10% (guideline).

14 Any circuit violating these criteria will be monitored to get actual loading data, and will be  
15 corrected if the imbalance is verified.

16 Table 10 below identifies where the imbalance is greater than 10%, and provides recommended  
17 mitigation. These recommended mitigation aim to improve the poor voltage conditions that result  
18 from a contingency event. The cost to address these is minimal.



Liberty Utilities (Granite State Electric) d/b/a Liberty  
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1 Table 10 Feeder Phase Balance above 10%

Source	Amps						Loading		Criteria			Mitigation
	A	B	C	Avg	Max	N	% Rat	% Imb	Grnd Relay	% Relay	Dif Max / Min	
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	

2 **b. N-1 Contingency & Load-At-Risk**

3 **i. Supply System**

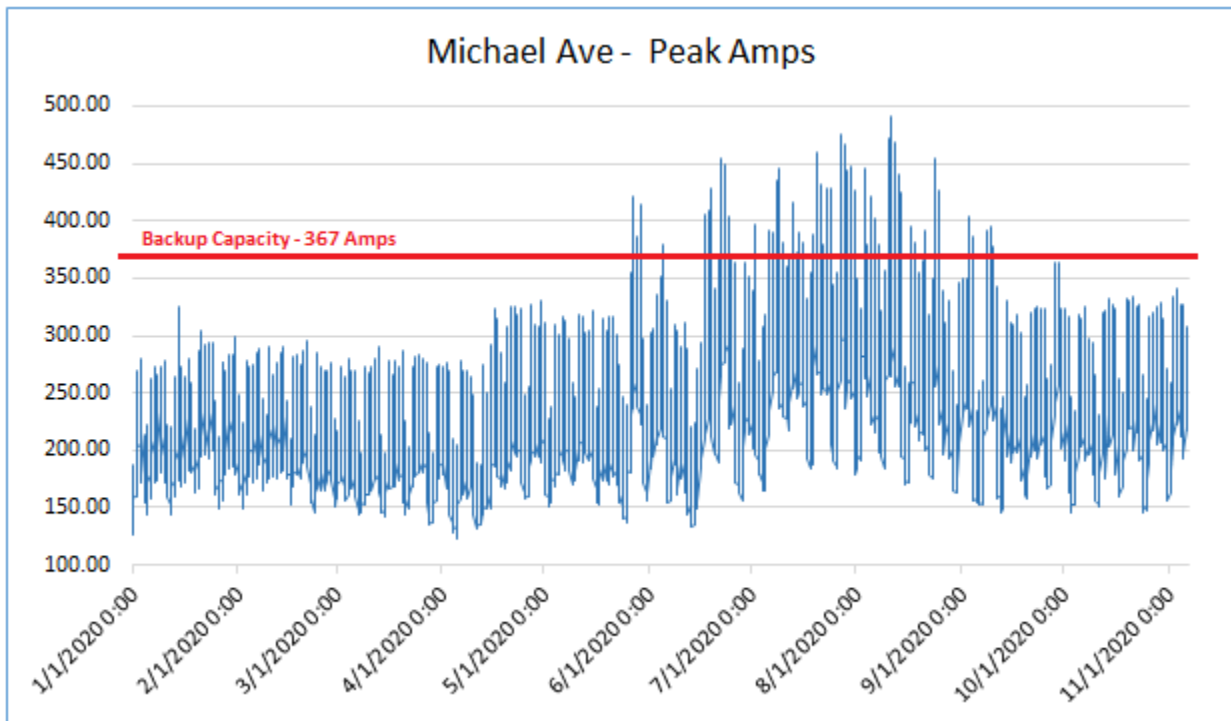
4 Contingency analysis for 46 kV supply lines resulted in no existing violations or predicted  
5 violations.

6 Table 11 13.8kV Sub Transmission Loading – Contingency Configuration

Circuit	Voltage (kV)	Line Section		Limiting Element	Rating (MVA)		Projected Contingency					
		From	To		SN	SE	2020		2025		2036	
							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%

1 The Michael Ave transformer is loaded to approximately 12MVA during peak. Contingency  
 2 analysis for the loss of the single 115 kV supply line feeding Michael Ave identified an existing  
 3 load at risk of 4.8 MVA. A loss of the 115 kV supply line W-149S results in an interruption to the  
 4 40L1 and 40L3 feeders. The Vilas Bridge 12L1 feeder does not have adequate capacity nor can it  
 5 provide adequate voltage support to supply both 40L1 and 40L3 feeders that are over 8 miles away.  
 6 The emergency rating of the Vilas Bridge 12L1 transformer is 9.6 MVA. After transferring most  
 7 of the 12L1 feeder load to the 12L2 feeder, approximately 8.4 MVA (367 amps) of capacity  
 8 remains to support the 12 MVA Michael Ave station. A review of the area load between 1/1/2020  
 9 and 11/7/2020 found that with the loss of the 115kV Supply Line, the loading for Michael Ave  
 10 Substation is above 8.4 MVA during 480 hours of the year. The graph below shows the Michael  
 11 Ave substation peak amps, for this time period.

12 Figure 2 2020 Michael Ave Coincident Demand (MVA)



13 An unserved load of 4.8 MVA for 12 hours could result in a load at risk of 58 MWhr. This load  
 14 at risk is projected to increase to 6.2 MVA and 74 MWhr in 2025 but is not projected to exceed  
 15 the 120 MWhr limit for Supply Lines. Larger commercial loads would likely be shed to maintain  
 16 the Vilas Bridge T1 transformer within limits. The Michael Ave substation also provides backup  
 17 power to the NH Electric Co-Op. Under this contingency scenario, supply to the NHEC cannot  
 18 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			
		From	To		Nameplate Rating	SN	SE	2020		2025		2036
				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.

1 The following table summarizes facilities which are expected to be loaded above 100% of  
2 emergency limits during the planning horizon. Additional information for each identified problem  
3 is provided in Appendix D.1 and E.1.

4 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

5 **4.2 Circuit Analysis**

6 **a. Voltage Performance during Normal Operation**

7 Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage  
8 on the feeders is controlled by the station load tap changer or station regulators on feeders, the  
9 application of distribution capacitor banks, and the application of pole mounted line regulators.  
10 The ultimate goal is to keep all customers’ service voltages within accepted limits.

11 The table below shows the areas where voltage is expected to exceed limits under normal  
12 configuration within the planning horizon. Refer to Appendix D.1 for additional details.

13 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

14 **b. Voltage Performance during Contingency Operation**

15 The figure below shows the areas where voltage is expected to exceed limits under contingency  
16 configuration within the planning horizon. Refer to Appendix E.1 for additional details.

17

1 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

2 With a loss of the Michael Ave Transformer or Transmission supply, load transfers to Vilas Bridge  
3 12L1 will need careful planning to avoid exceeding the emergency rating of two sets of 3-167  
4 kVA line regulators. These regulators require 10% regulation to maintain voltages within ratings.

5 **c. Power Factor**

6 Liberty will strive to maintain a 98% power factor at the substations to provide quality power to  
7 its customers and limit system losses via the addition of new capacitor banks. In addition, annual  
8 reviews for system power factor will allow Liberty to properly manage reactive support by  
9 adjusting settings from capacitor bank controls.

10 The table below identifies feeders where the power factor is lower than 98% and provides  
11 recommended mitigation.

12

1 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%

2 **d. Sector Report**

3 Where practical, Liberty’s goal is to limit feeders to 2,500 customers and sectionalized such that  
4 the number of customers does not exceed 500 or the load between disconnecting devices does not  
5 exceed 2,000kVA.

6 The Vilas Bridge 12L1 feeder supplies 2,482 customers in the towns of Walpole, Alstead,  
7 Langdon, Acworth and Marlow.

8 Liberty reviewed the load and customers between disconnecting devices to determine areas where  
9 these limits are exceeded. The table below summarizes these findings:

10 Table 17 Sector Report

# Sectors > 2 MVA	# Sectors > 500 Customers	Sector Average MVA	Sector Average Cust. Served
1	2	5.81	568

11 **4.3 Asset Condition**

12 Refer to Liberty Utilities Distribution Asset Strategy in Appendix D for details on the company’s  
13 plans.

14 **4.4 Reliability**

15 Refer to Liberty Utilities Reliability Report in Appendix H for details on the company’s results  
16 and plans.

17 **4.5 Protection Analysis**

18 The analysis identified 5 fuse replacements due to overload. With a loss of the Michael Ave  
19 Transformer or Transmission supply, load transfers to Vilas Bridge 12L1 will need careful  
20 planning to avoid exceeding the relay pickup setting on two reclosers. As part of the Distribution

1 Automation Program, Liberty will install additional protective devices to facilitate rerouting load  
2 in the area after interruptions and to improve outage durations. A protection review will be  
3 performed at this time.

## 4 **5.0 Problem Solutions**

5 The following section provides infrastructure improvement projects to address the deficiencies  
6 listed in Section 4, including potential non-wires solutions (NWS) to resolve the problem.

7 The project costs presented in this section are of investment grade. Project scope and estimates  
8 will be refined as part of detailed engineering activities.

### 9 **5.1 Thermal Loading**

#### 10 **a. N-1 Normal Configuration**

11 There are no identified thermal loading problems under Normal Configuration.

#### 12 **b. N-1 Contingency & Load-At-Risk**

13 While none of the contingency issues identified under Section 4.1.2 violate prescribed design  
14 limits, there does appear to be a convergence of several issues identified in this study (i.e. long  
15 distance from source, potential transformer overloading, voltage fluctuations, forced customer  
16 load shedding events) that deserves consideration of a creative NWS involving one or more  
17 modular battery storage installation(s) to better control power flows on these feeders and to  
18 improve the reliability and power quality issues in this area. Liberty has looked at an initial  
19 screening of traditional and Non-Wires solutions to address the deficiencies in the area and has  
20 determined that the proposed non-wires solutions should be pursued. For details refer to Appendix  
21 D – NWS Project Analysis.

22 Liberty is committed to working with Commission Staff and other stakeholders to identify a non-  
23 wires solution that best fits the needs of our Customers.

24 Project Cost: TBD

25 Risk Score: 49

### 26 **5.2 Circuit Analysis**

#### 27 **a. Voltage Performance**

28 The following projects aim to address existing and projected problems during normal and  
29 contingency conditions.

1           **b. Vilas Bridge 12L2 - 2022**

2   Feeder 12L2 could experience voltage deficiencies during normal and contingency conditions.

3   To mitigate, it is recommended to install one 600 kVAR capacitor bank at Prospect Hill Rd  
4   Walpole. In addition it is recommended to convert the 2.4 kV step down distribution area of March  
5   Hill Rd to 7.62 kV. This conversion is also recommended to improve reliability and to create a  
6   feeder tie between the 12L1 feeder at Valley Rd Walpole with the 12L2 feeder at March Hill Rd.  
7   For details on the Conversion and tie project refer to the Liberty Reliability Report.

8   Project Cost: \$15,000

9   Risk Score: 45

10           **c. Vilas Bridge 12L1 - 2022**

11   Feeder 12L1 could experience voltage deficiencies for a loss of Feeder 12L2. To mitigate, it is  
12   recommended to install one 900 kVAR capacitor bank at Route 123 and remove 600 kVAR  
13   capacitor bank 8938.

14   Feeder 12L1 could also experience voltage deficiencies for the contingency of loss of Michael Ave  
15   Station. This feeder cannot supply the entire Michael Ave substation load and would require  
16   shedding load to within the rating of the circuit. To improve voltage conditions during  
17   contingency, it is recommended to install one 900 kVAR capacitor bank at Route 12.

18   Project Cost: \$30,000

19   Risk Score: 45

20           **d. Michael Ave 40L1 - 2022**

21   To improve voltage performance during contingency and overall phase balance of the Michael  
22   Ave 40L3 feeder, it is recommended in 2022 to extend a three phase overhead line 650 feet and  
23   perform load transfers.

24   Project Cost: \$55,000

25   Risk Score: 45

26           **e. Power Factor Correction**

27   There are no identified concerns with poor power factor. The Michael Ave feeder 40L3  
28   experienced power factor lower than 98%. Capacitor CB26 was placed in service and is expected  
29   to improve the feeder's power factor to 99%.



1           **f. Sector Report**

2   A total of three locations have been identified exceeding number of customers or load between  
3   disconnecting devices. These locations will be reviewed for improved sectionalizing  
4   opportunities, reliability history and exposure. The scope of work will be to install one disconnect  
5   device to limit the exposure to customers and improve restoration times. Liberty expects to address  
6   these locations between 2022 and 2023. In general, Liberty assigns a risk score of 34 to these  
7   projects.

8   Project Cost: \$60,000

9   **6.0 Non-Wires Solution – Michael Ave**

10       **6.1 Grid Needs Assessment**

11   As part of the requirements of the approved Settlement Agreements in Docket Nos. DE 17-136,  
12   DE 17-189 and DE 19-120, the Company agreed to provide a grid needs assessment for projects  
13   with potential non-wires solutions whereby the wires solutions are \$500,000 or greater. Table 18  
14   provides the assessment:

1  
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

1       **6.2 Non-Wires Solution Candidate**

2       **Traditional Wires Solution**

3       Location: Bellows Fall NH Study Area – Figure 1 on page 5 of this document

4       Identified Need: A loss of the 115 kV supply line W-149S, owned by National Grid, at Michael  
5       Ave substation or the National Grid-owned Transformer could result in an interruption to the  
6       Liberty 40L1 and 40L3 feeders, or 1,751 customers including a large industrial customer. The  
7       Vilas Bridge #34 substation, also owned by National Grid located in VT, serves the 12L1 Liberty  
8       feeder and is the only alternate source for the area and does not have adequate capacity nor can it  
9       provide adequate voltage support to supply both 40L1 and 40L3 feeders during loss of supply line  
10      or transformer. This loss could result in approximately 4.8 MW of unserved load and could  
11      require shedding a large industrial load to maintain equipment within ratings. The expected loss  
12      of load in 2025 is 6.2 MW based on growth in the area.

13      Project Description (Traditional Wires Solution#1):

- 14              • Install 2nd 115 kV Transmission Line and 115kV in-line circuit breaker
- 15              • Install 2nd 115-13.2 kV 25 MVA Transformer
- 16              • Install new 40L2 13.2 kV feeder breaker and associated bus work
- 17              • Install new 40L2 circuit tie with 12L1

18      Engineering Start Date – Project Completion Date: 2022 – 2025

19      Estimated Cost of Traditional Solution (Investment Grade): \$8,000,000

20      Criteria Violation: There are no criteria violations. However, there are several contingency  
21      loss scenarios (e.g., 115kv supply line, Michael Ave Sub Transformer and other factors (e.g.,  
22      long distance from source, mobile lead time and voltage violations) that could result in long-  
23      term outages.

24      Benefits of Planned Wires Upgrade: Resolves load at risk resulting from loss of the Michael  
25      Ave 115 kV supply or Transformer and improves reliability for the Bellows Falls area.  
26      However, the Michael Ave Sub property presents an opportunity for PV and battery storage  
27      and/or Microgrid solution for this contingency issue and presents other benefits in cost  
28      savings.

29      Coincident Area Load in Need Year: 20,000 kVA

30      Annual Growth Rate: 0.2%

31

1 **Non-Wires Solution #1**

2 **Project Description:**

- 3 • Install Microgrid consisting of 1 MW solar with 4 MWh storage in front of  
4 the meter at Customer A's location in Charlestown
- 5 • Will provide islanding of Customer A, while still providing power to the  
6 residential customers in the area from the Vilas Bridge 12L1 during loss of  
7 supply or transformer
- 8 • Microgrid may also serve other purposes such as peak load reduction

9 **Engineering Start Date – Project Completion Date: 2022 – 2025**

10 **Estimated Cost of Non-Wires Wires Solution #1 (Investment Grade): \$2,900,000**

11 **Non-Wires Solution #2**

12 **Project Description:**

- 13 • Install Microgrid consisting of 1 MW solar and 4 MWh of storage at  
14 Michael Ave to serve the loss of a transformer or supply line at the  
15 substation
- 16 • Will provide flexibility to move load between the Vilas Bridge and Michael  
17 Ave substations and the Microgrid during loss of supply or transformer; for  
18 example, move the load from the industrial customer to the 12L1 feeder and  
19 serve other customers from Michael Ave with the Microgrid
- 20 • Microgrid may also serve other purposes such as peak load reduction

21 **Engineering Start Date – Project Completion Date: 2022 – 2025**

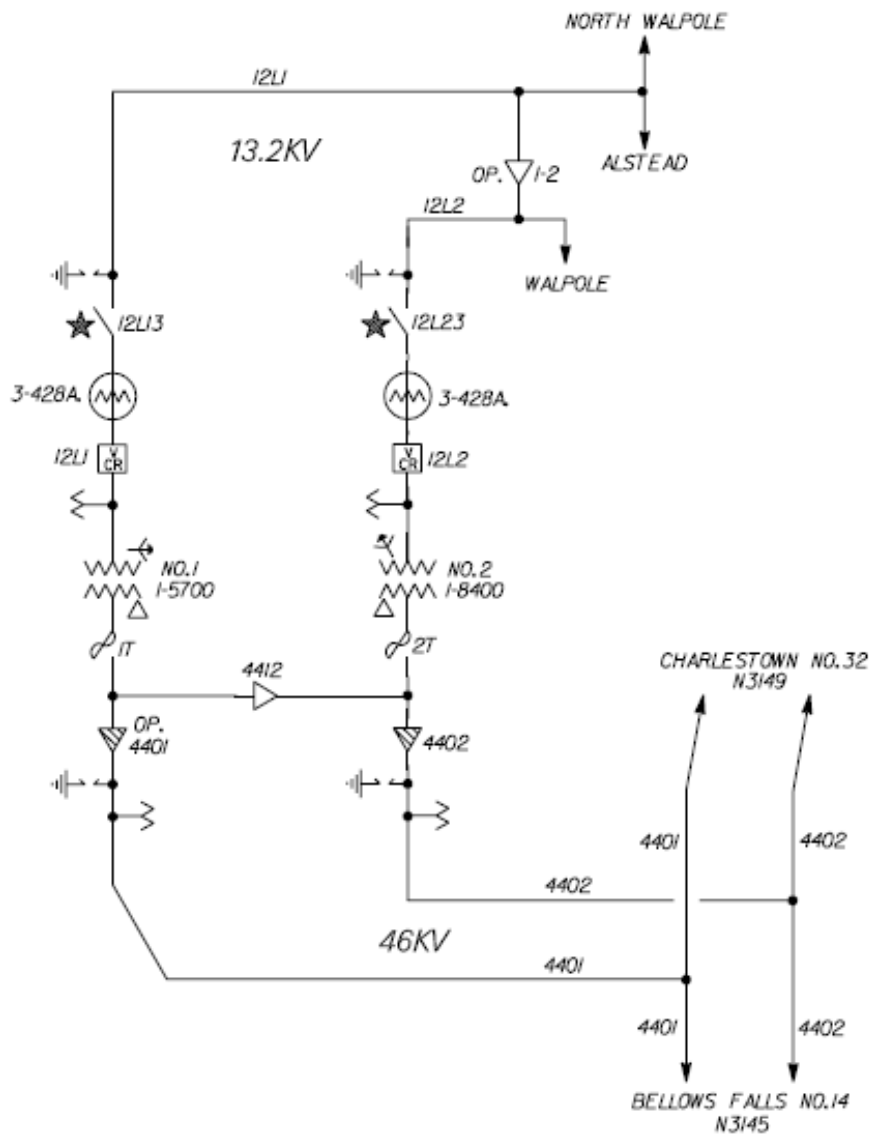
22 **Estimated Cost of Non-Wires Wires Solution #2 (Investment Grade): \$2,900,000**

23 The difference between the two solutions is the first solution provides that the customer will allow  
24 the Company to install the Microgrid at or near the premises of their business providing the  
25 opportunity to island the customer if the supply line is lost, and the other customers will be  
26 switched to another feeder. The second solution provides for the Microgrid to be sited at the  
27 Michael Ave substation instead, where the load in the area, minus Customer A, may be served  
28 with the Microgrid, and Customer A will be switched to another feeder. In both instances, the  
29 Company is looking to work with Customer A to reduce their load through energy efficiency and  
30 potentially demand response.

1 **7.0 Appendices**

2 **7.1 Appendix A.1 – System One Lines**

3 **Figure 3** [REDACTED]

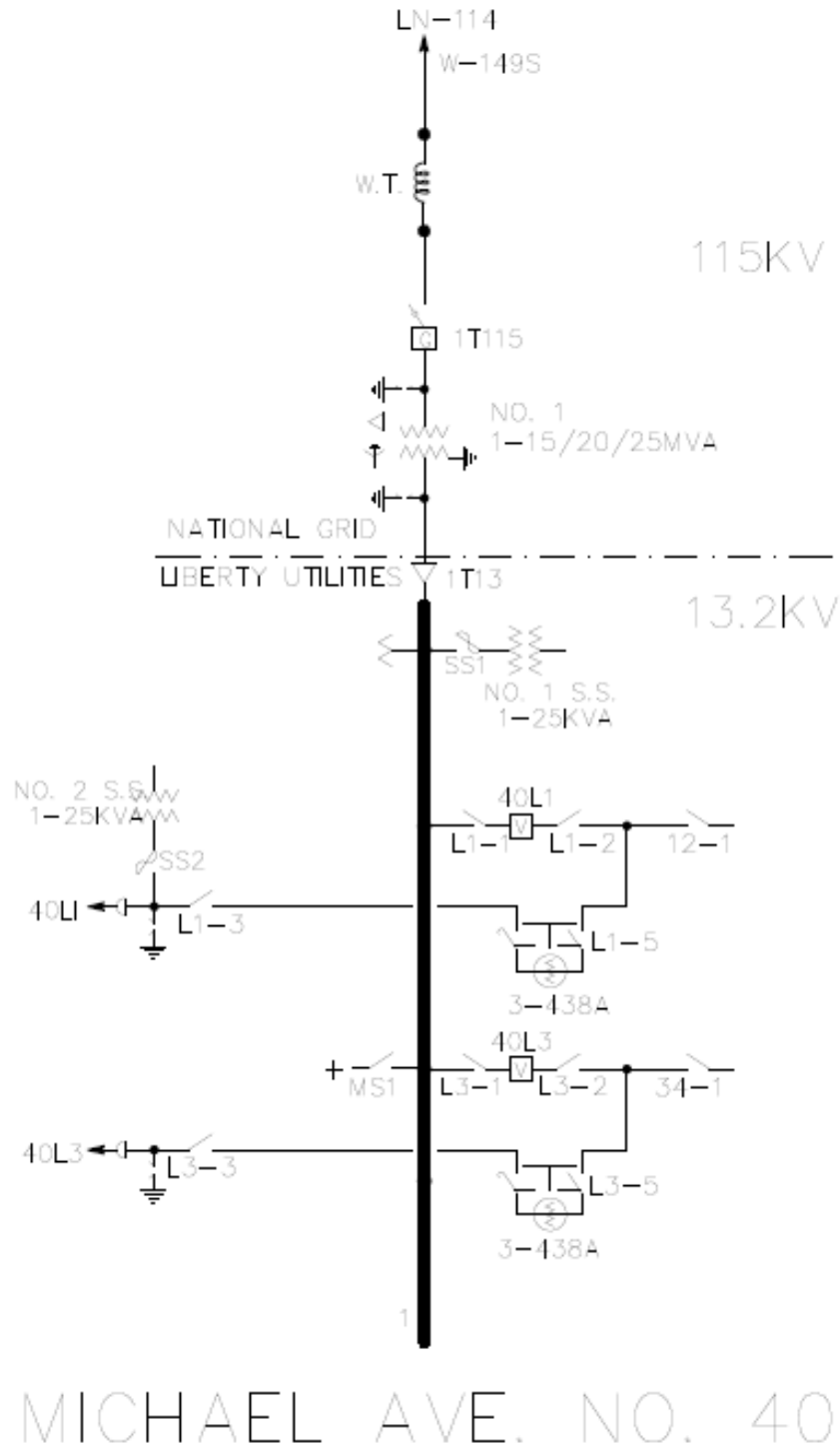


**VILAS BRIDGE NO. 34**

4

1

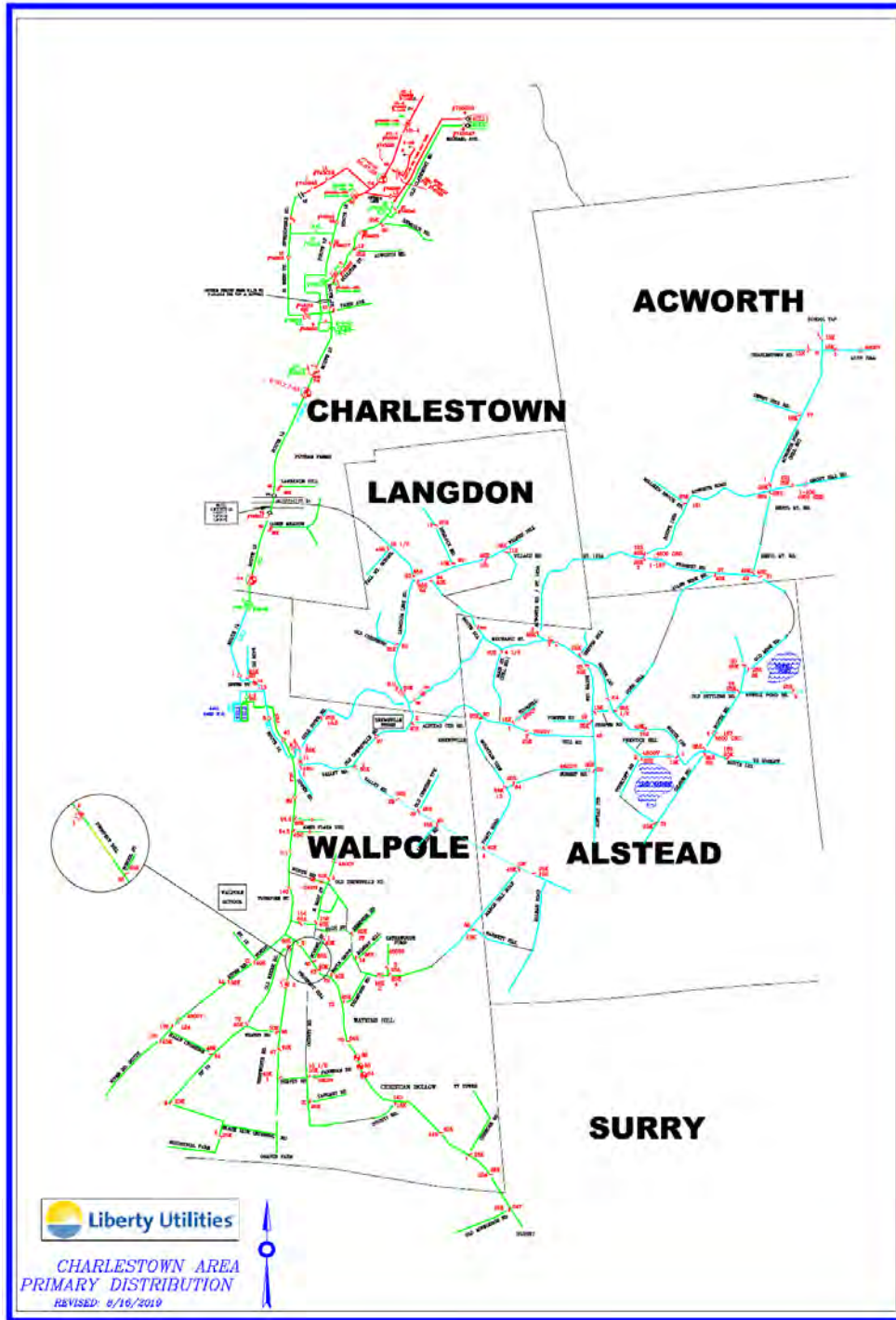
Figure 4 [REDACTED]



2

1

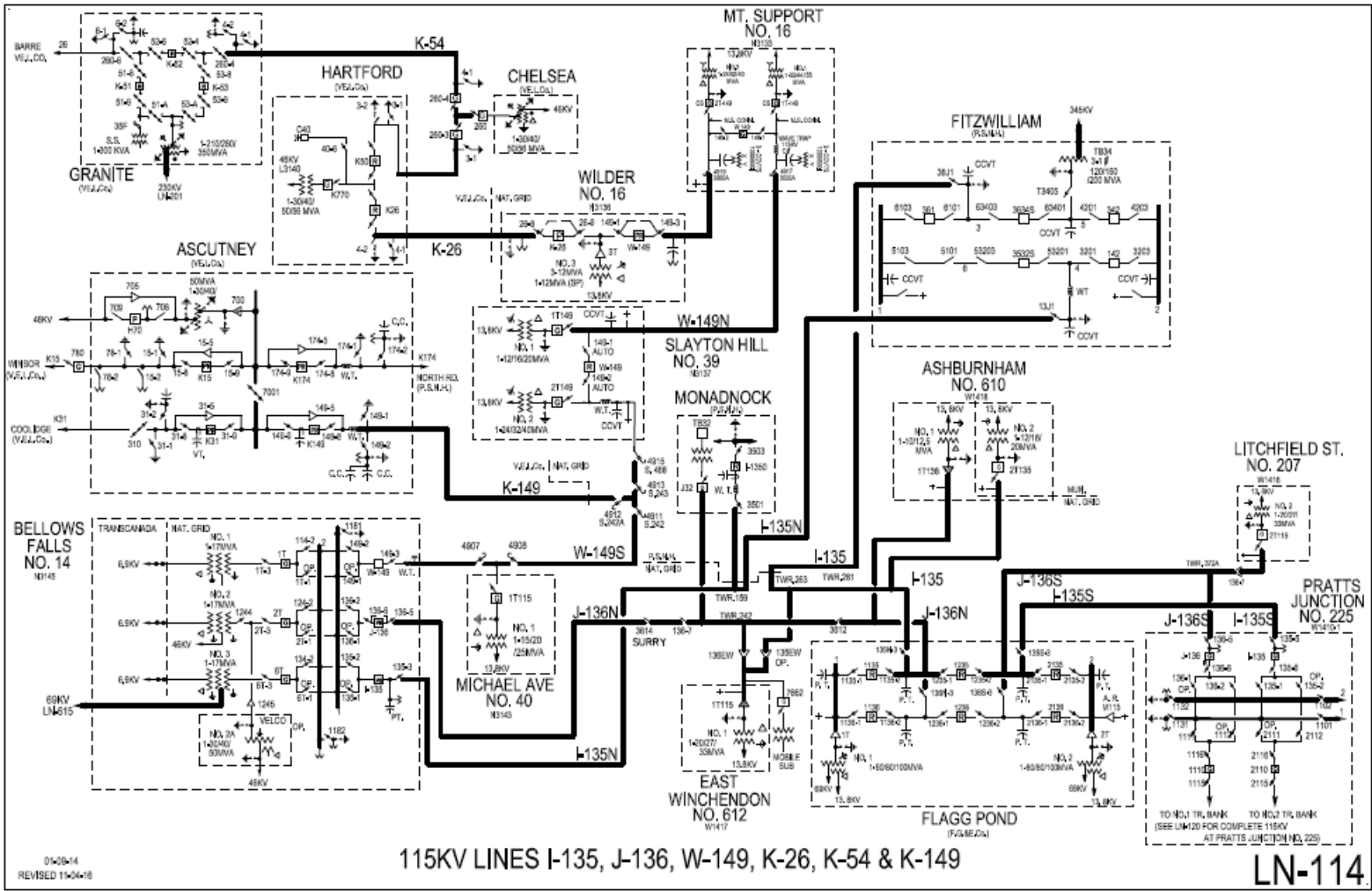
Figure 5



2

3

1  
 Figure 6





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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
<b><u>12L2 Feeder</u></b>										
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
<b><u>12L1 Feeder</u></b>										
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
<b><u>40L1 Feeder</u></b>										
0 - Open	40L1	40L1	284	14.9	470	---	---	---	---	No Issues
1 - Close	745021	---	---	---	---	40L3	287	14.9	470	
<b><u>40L3 Feeder</u></b>										
0 - Open	40L3	40L3	220	31.5	1117	---	---	---	---	No Issues
1 - Close	745021	---	---	---	---	40L1	220	31.5	1117	
<b><u>Michael Ave Station</u></b>										
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	
<b><u>Michael Ave Station with load shed</u></b>										
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 Link	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	

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1 **7.3 Appendix C.1 – Switch Plan 2025**

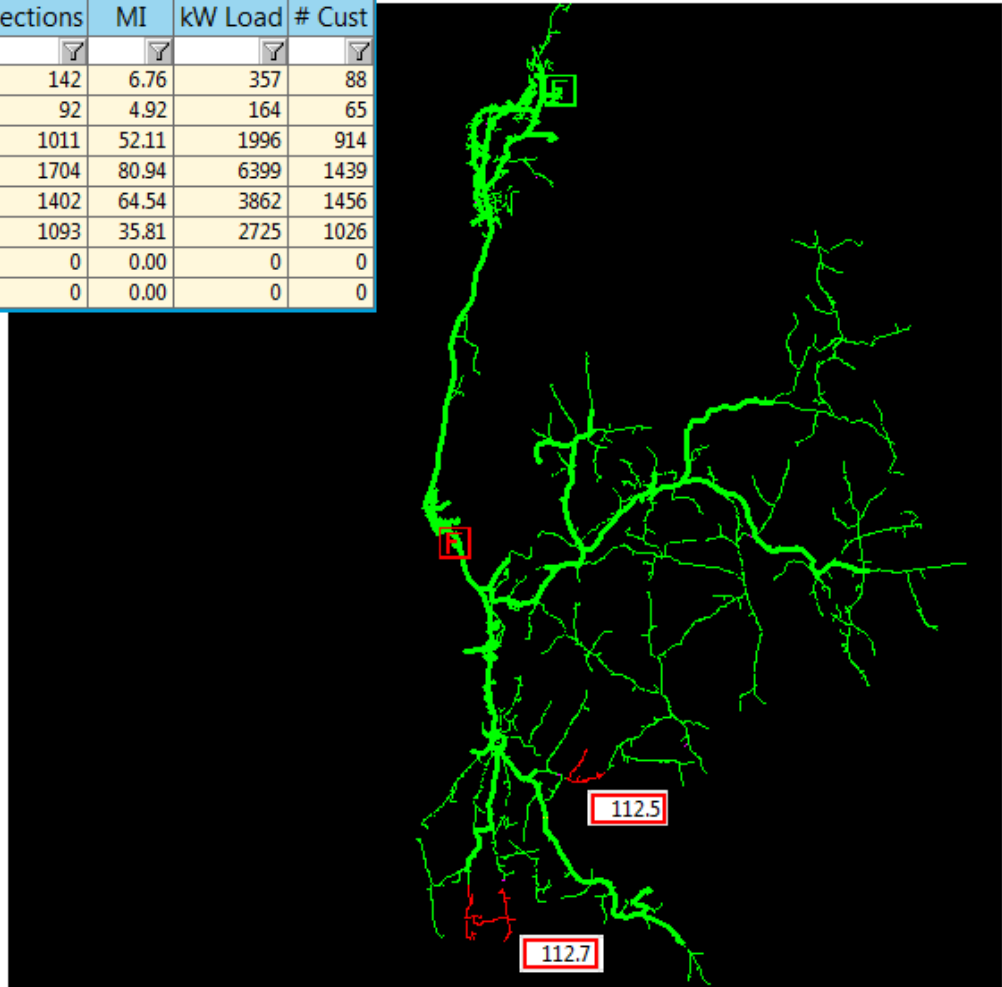
2 **Table 19 2025 Distribution Circuit Switch Plan**

Operation		Dropped				Picked Up				Problems
Action	Switch	From	Max Amps	Miles	Cust	To	Max Amps	Miles	Cust	
<b>Plan : 12L2</b>										
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
<b>Plan : 12L1</b>										
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
<b>Plan : 40L1</b>										
0 - Open	40L1	40L1	318	14 9	470	---	---	---	---	No Issues - Need additional switching to avoid overloading OH wires
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	
<b>Plan : 40L3</b>										
0 - Open	40L3	40L3	249	31 5	1117	---	---	---	---	No Issues - Need additional switching to avoid overloading OH wires
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	
<b>Michael Ave Station</b>										
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	
<b>Michael Ave Station with load shed</b>										
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	

1 **7.4 Appendix D.1 – Voltage Performance Normal Condition**

2 **Figure 7 2020 Voltage Performance 12L2 – Normal Configuration**

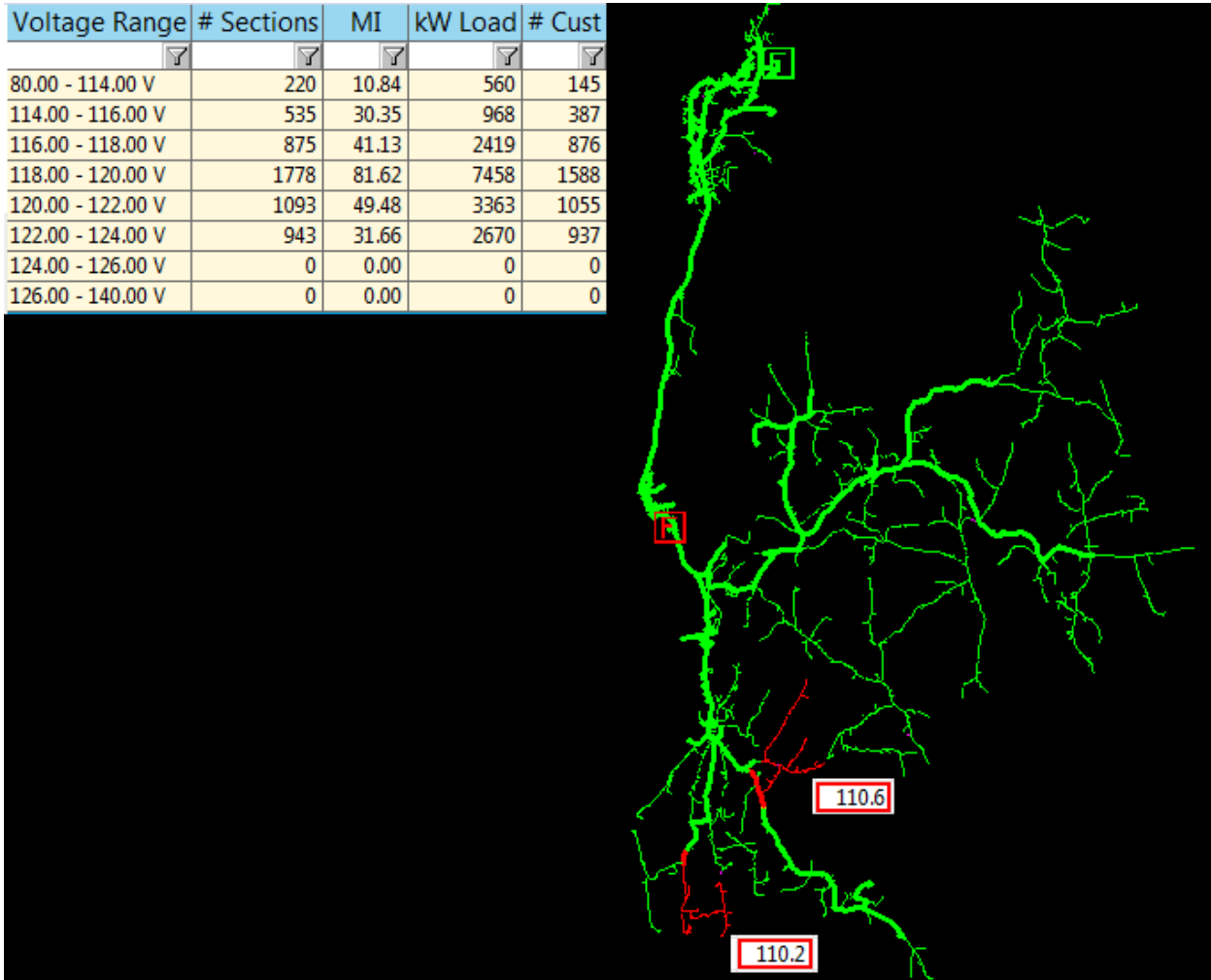
Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	142	6.76	357	88
114.00 - 116.00 V	92	4.92	164	65
116.00 - 118.00 V	1011	52.11	1996	914
118.00 - 120.00 V	1704	80.94	6399	1439
120.00 - 122.00 V	1402	64.54	3862	1456
122.00 - 124.00 V	1093	35.81	2725	1026
124.00 - 126.00 V	0	0.00	0	0
126.00 - 140.00 V	0	0.00	0	0



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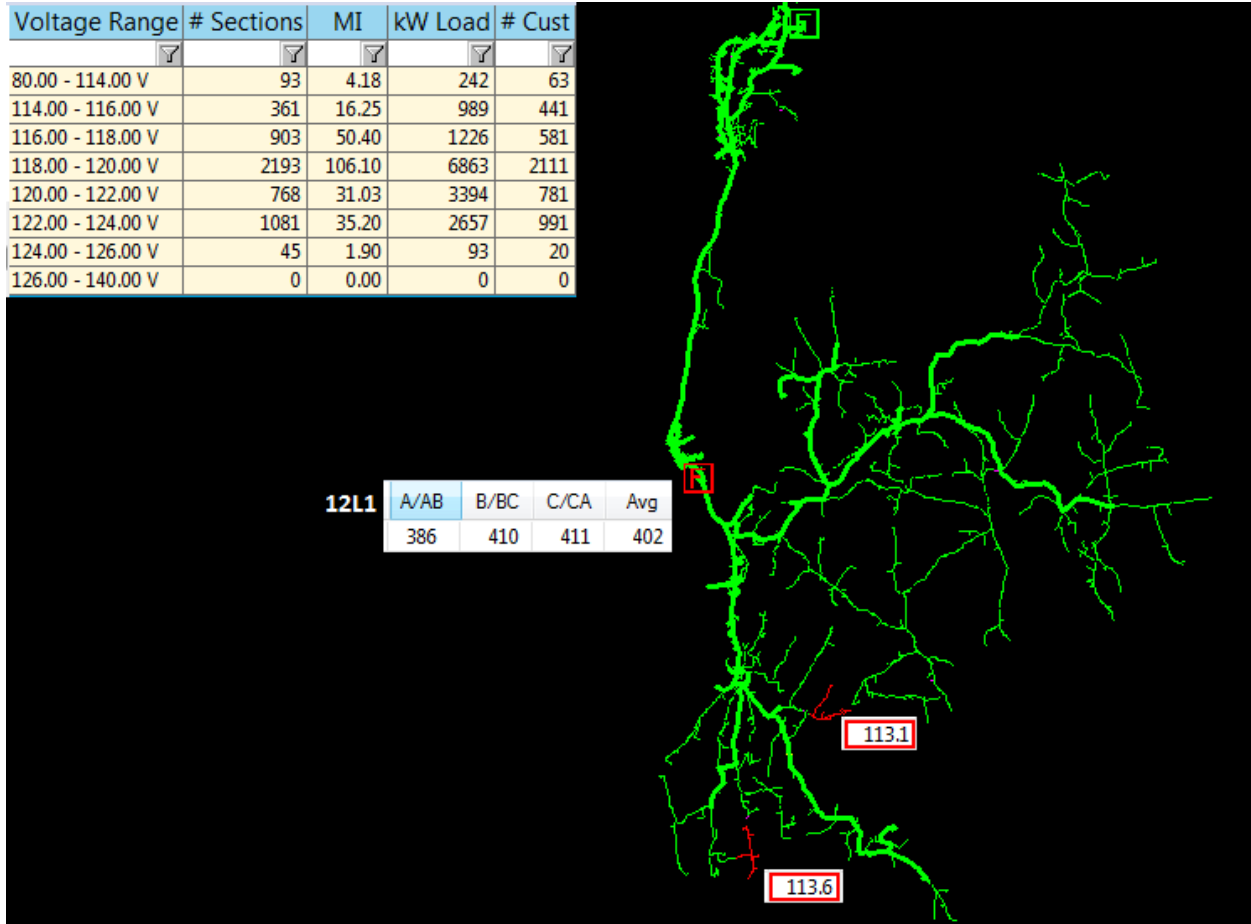
1 The figure below shows the areas where voltage is expected to exceed limits under normal  
2 configuration in 2025.

3 Figure 8 2025 Predicted Voltage Performance 12L2 – Normal Configuration



1 **7.5 Appendix E.1 – Voltage Performance Contingency Condition**

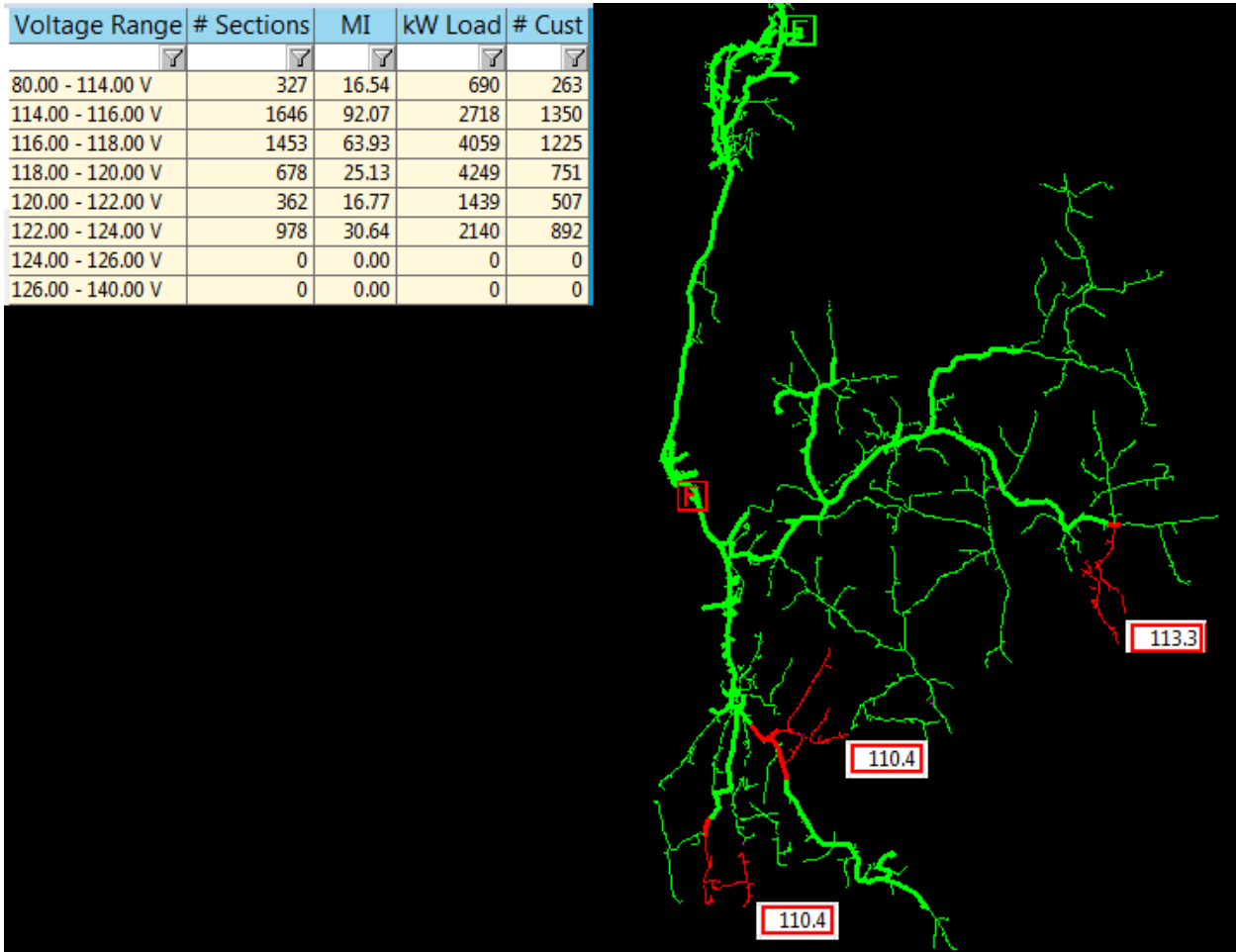
2 **Figure 9 2020 Voltage Performance 12L2 – Contingency Configuration**



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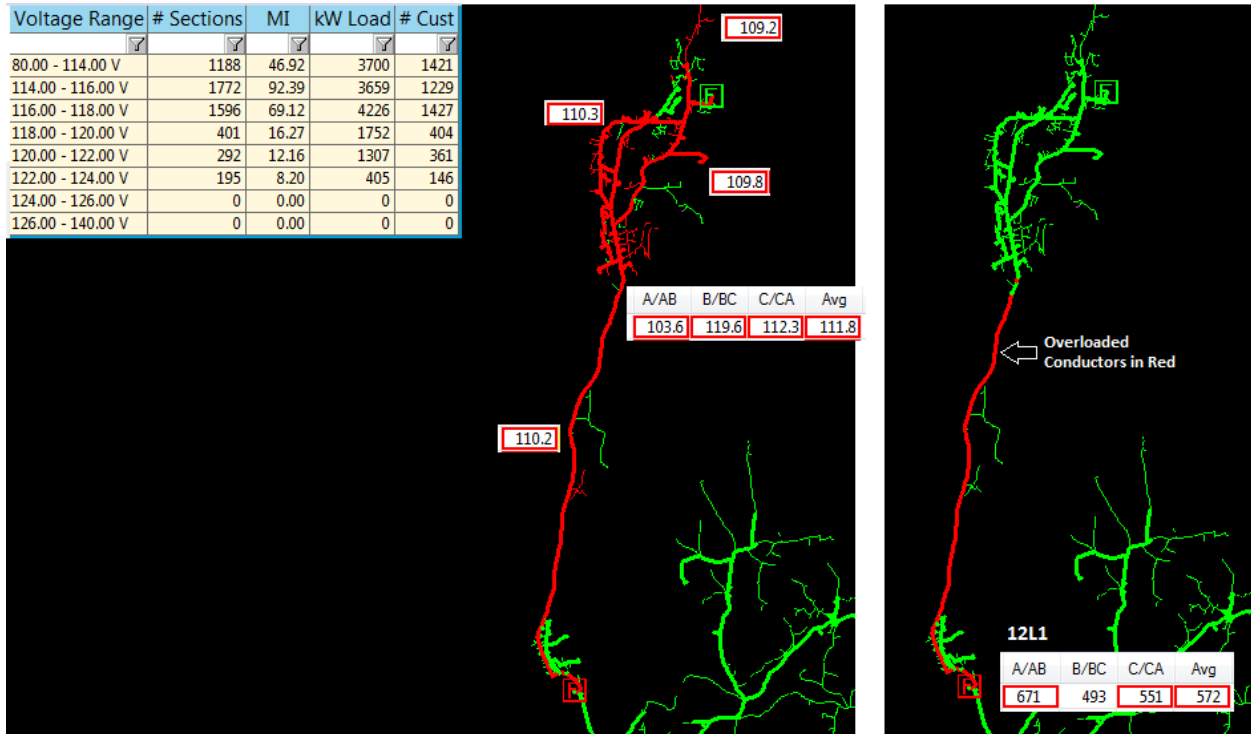
1 Figure 10 2020 Voltage Performance 12L1 – Contingency Configuration

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



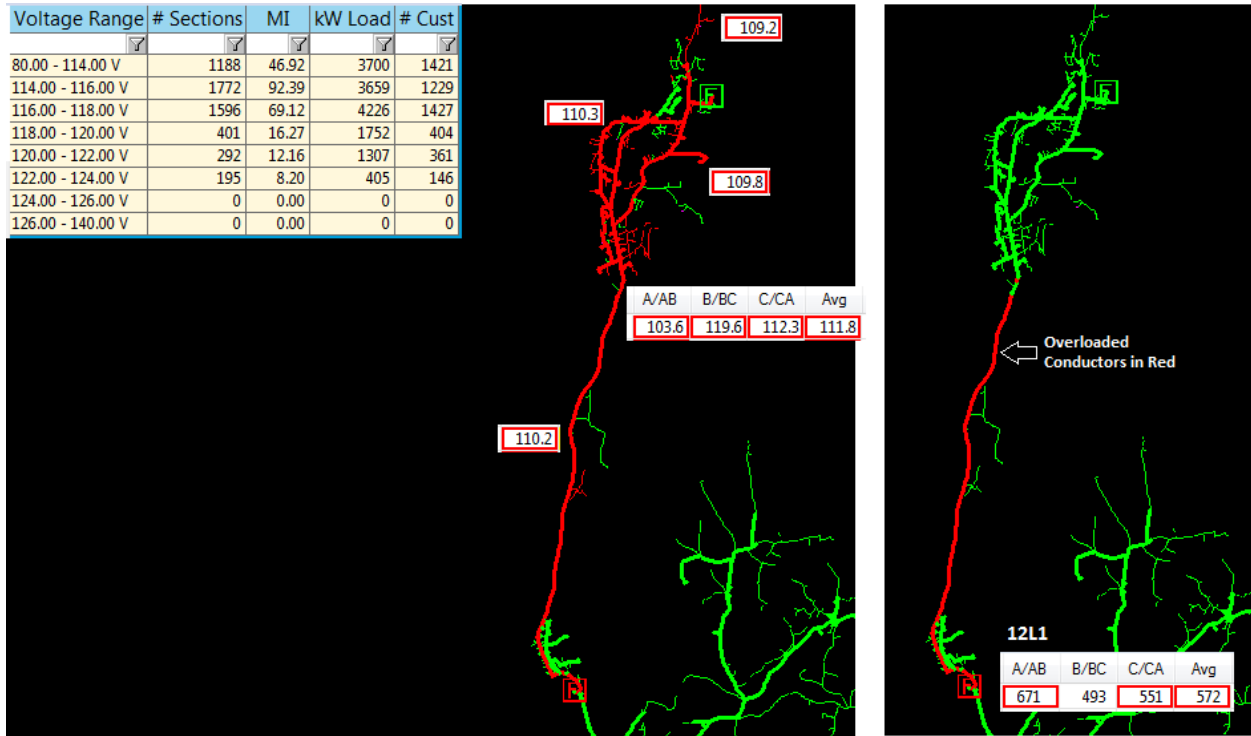
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1 Figure 11 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration



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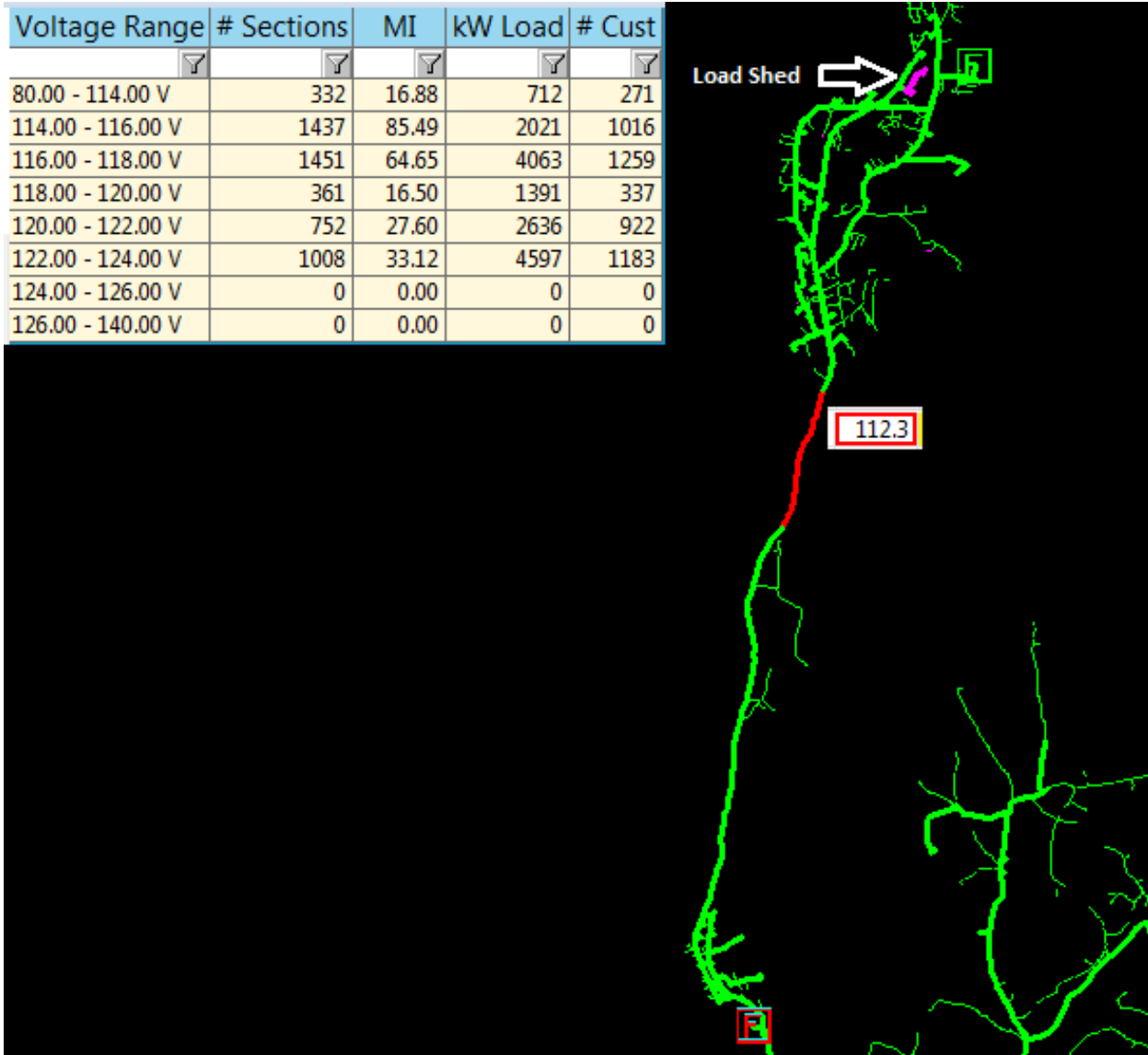
1 Figure 11 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration



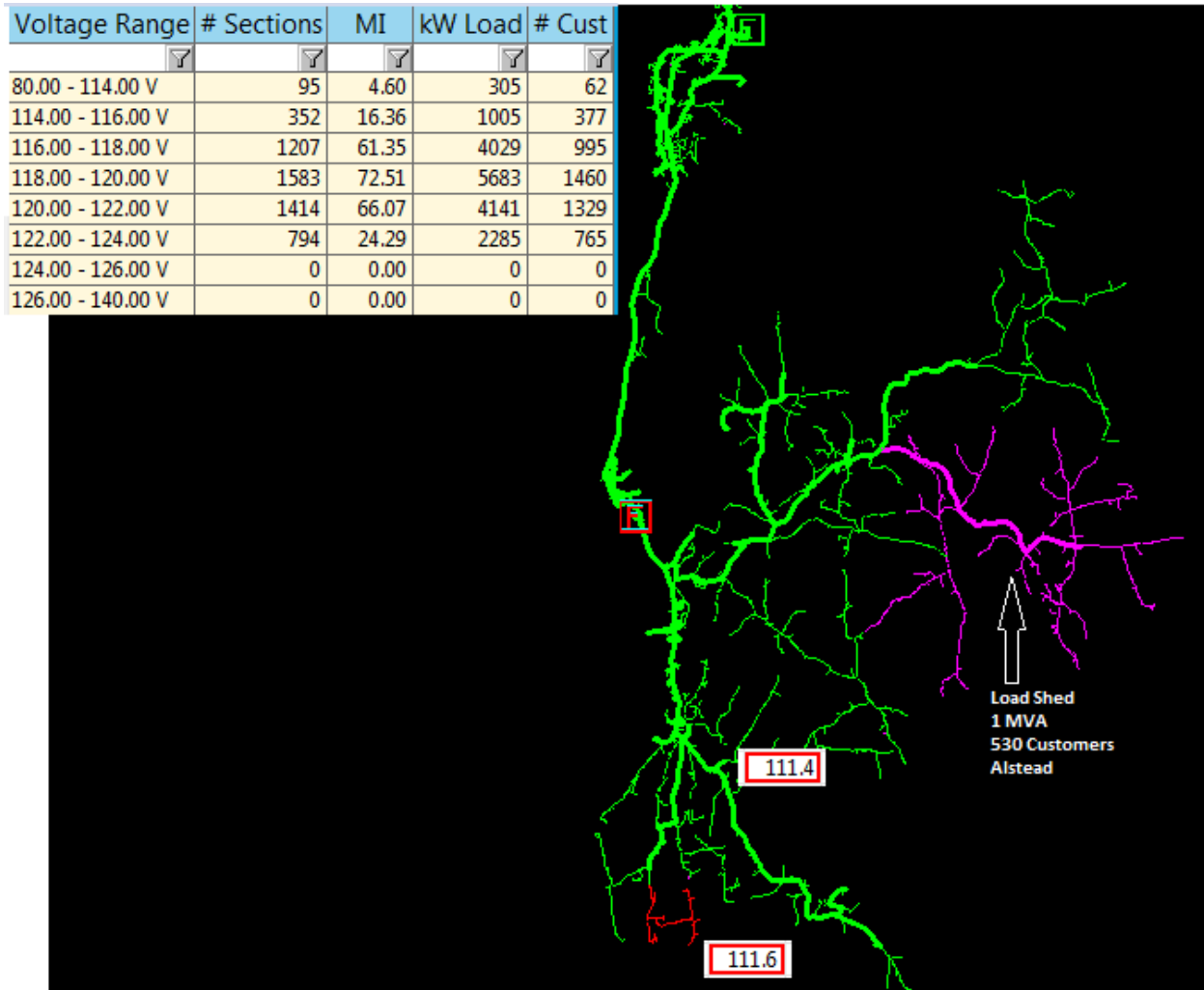


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1 Figure 8 2020 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration with  
2 load shed

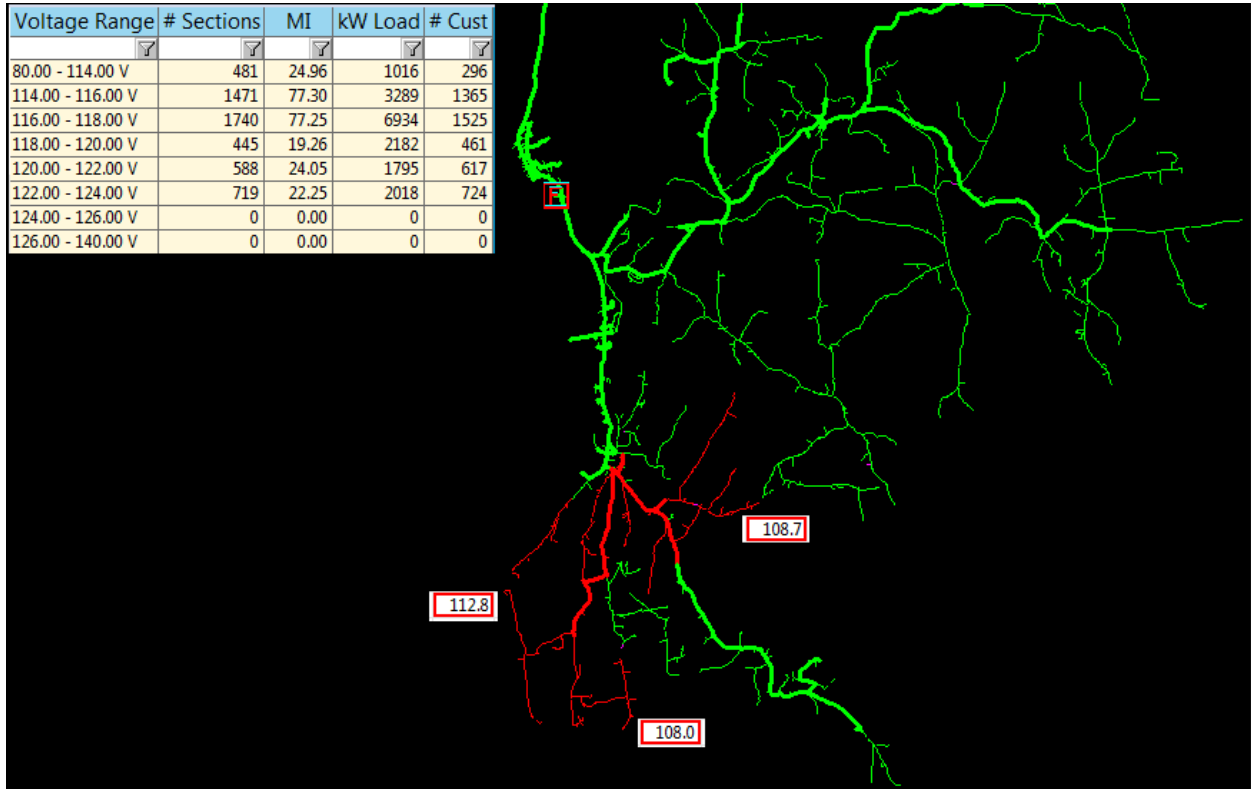


1 Figure 9 2025 Voltage Performance 12L2 – Contingency Configuration



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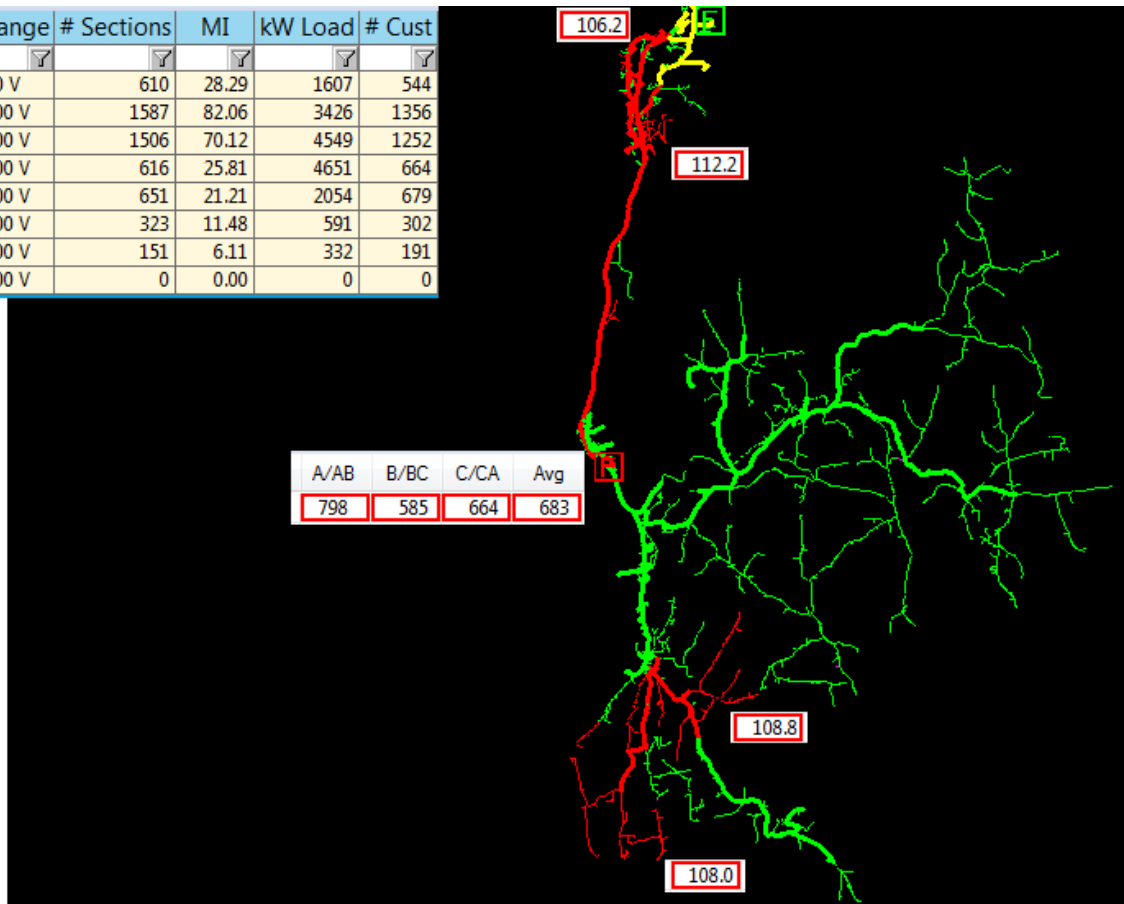
1 Figure 10 2025 Voltage Performance 12L1 – Contingency Configuration



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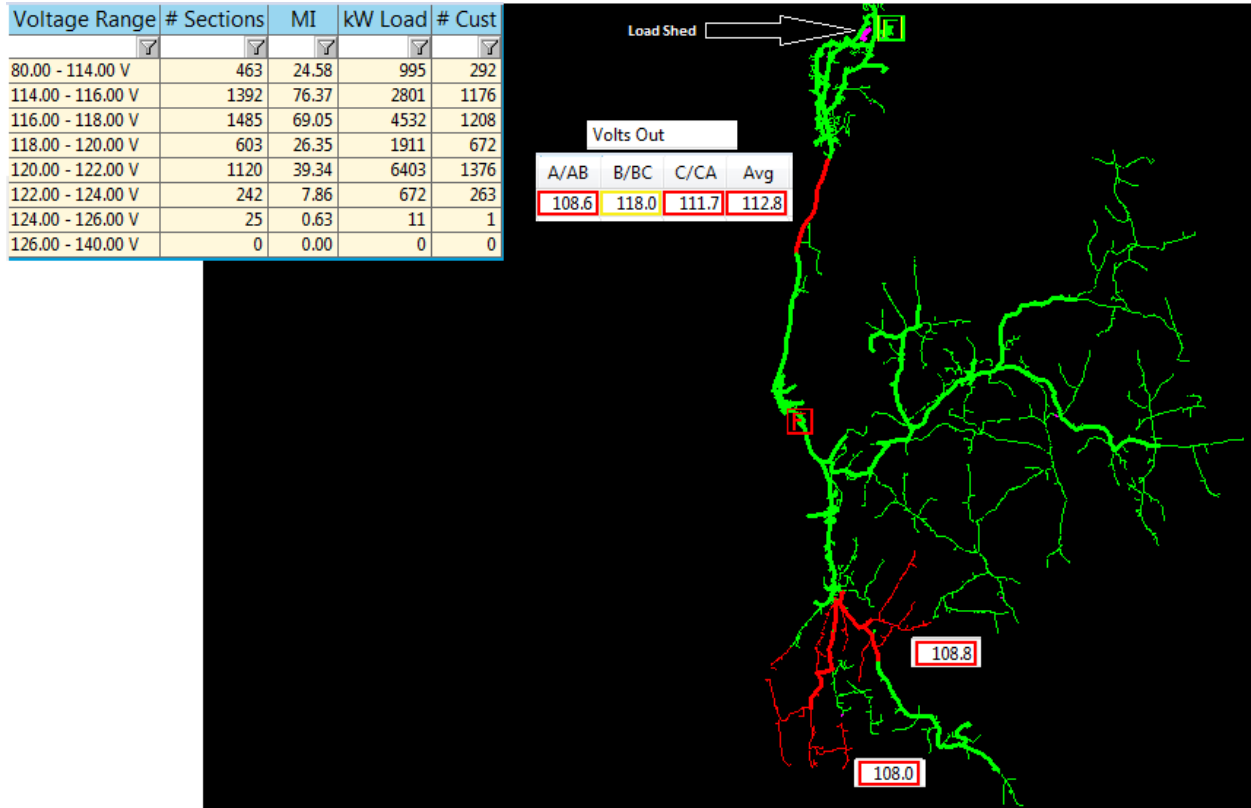
1 Figure 11 2025 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration

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



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1 Figure 16 2025 Voltage Performance Michael Ave 40L1/40L3 – Contingency Configuration  
2 with load shed



1 **7.6 Appendix F.1 – NWS Project Analysis**

NWA EVALUATION SUMMARY						
						11/2/2020
<b>Identified Problem:</b>	Contingency Loss Michael Ave Sta					
<b>Project Need Year:</b>	2025					
<b>Brief Project Description/need:</b>	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.					
<b>Project Scope</b>	<b>Option</b>					
Michael Station expansion	1					
Vilas Bridge Station rebuild	2					
PV + Storage	3					
DER - Large Customer	4					
<b>Scoring Values</b>						
Marginal with mitigation	1					
Marginal without mitigation	2					
Acceptable	3					
Best Solution	4					
<b>Evaluation Summary</b>						
<b>Evaluation Criteria</b>	<b>% Weight Factor*</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Comments</b>
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	
<b>Total Assessment</b>	<b>100%</b>	<b>2.48</b>	<b>2.45</b>	<b>2.50</b>	<b>2.82</b>	
	<b>Ranking</b>	<b>3</b>	<b>4</b>	<b>2</b>	<b>1</b>	

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**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
<b>Totals</b>	<b>100%</b>	<b>4</b>	<b>3</b>	<b>1.8</b>	<b>1.5</b>
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>

**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
<b>Totals</b>	<b>100%</b>	<b>2.4</b>	<b>2.7</b>	<b>2.6</b>	<b>2.65</b>
	<b>Ranking</b>	<b>4</b>	<b>1</b>	<b>3</b>	<b>2</b>

**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
<b>Totals</b>	<b>100%</b>	<b>2.4</b>	<b>2.7</b>	<b>2.6</b>	<b>2.65</b>
	<b>Ranking</b>	<b>4</b>	<b>1</b>	<b>3</b>	<b>2</b>

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**Identified Problem:** Contingency Loss Michael Ave Sta  
11/2/2020

<b>PERFORMANCE Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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
<b>Totals</b>	<b>100%</b>	<b>3.6</b>	<b>2.8</b>	<b>2.2</b>	<b>1.95</b>
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>4</b>

**Identified Problem:** Contingency Loss Michael Ave Sta  
11/2/2020

<b>ENVIRONMENTAL Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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
<b>Totals</b>	<b>100%</b>	<b>1.75</b>	<b>1.5</b>	<b>2.75</b>	<b>4</b>
	<b>Ranking</b>	<b>3</b>	<b>4</b>	<b>2</b>	<b>1</b>





**Lebanon Area**  
**System Planning Summary 2020**

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## 1 **1.0 Executive Summary**

2 Liberty Utilities completed the Lebanon Area system planning review for 2020. The revised  
3 Liberty Utilities Distribution Planning Criteria was used to determine any Electric Supply System  
4 upgrades required to meet existing and future capacity requirements. The review focused on the  
5 distribution requirements needed to resolve deficiencies in system capacity, reliability, power  
6 quality or asset condition.

7 In 2017 the Mount Support substation was expanded to add a second 115kV Transmission line, a  
8 second 115/13 kV Transformer and two new 13 kV feeders. This project addressed concerns with  
9 the lack of capacity on the sub transmission system and with load at risk that resulted from the  
10 contingency loss of the Mount Support Supply Line or Transformer.

## 11 **2.0 Introduction**

### 12 **2.1 Purpose**

13 The purpose of this review was to resolve all identified area concerns in the Lebanon Area through  
14 the 15-year 2020-2036 study horizon. An in-depth review of the area was performed that included  
15 the analysis of thermal loading, voltage, reliability, asset condition, power quality, environmental,  
16 safety and voltage performance. Alternative plans were developed and a preferred plan was  
17 recommended as being most prudent after detailed plan comparisons.

### 18 **2.2 Problem**

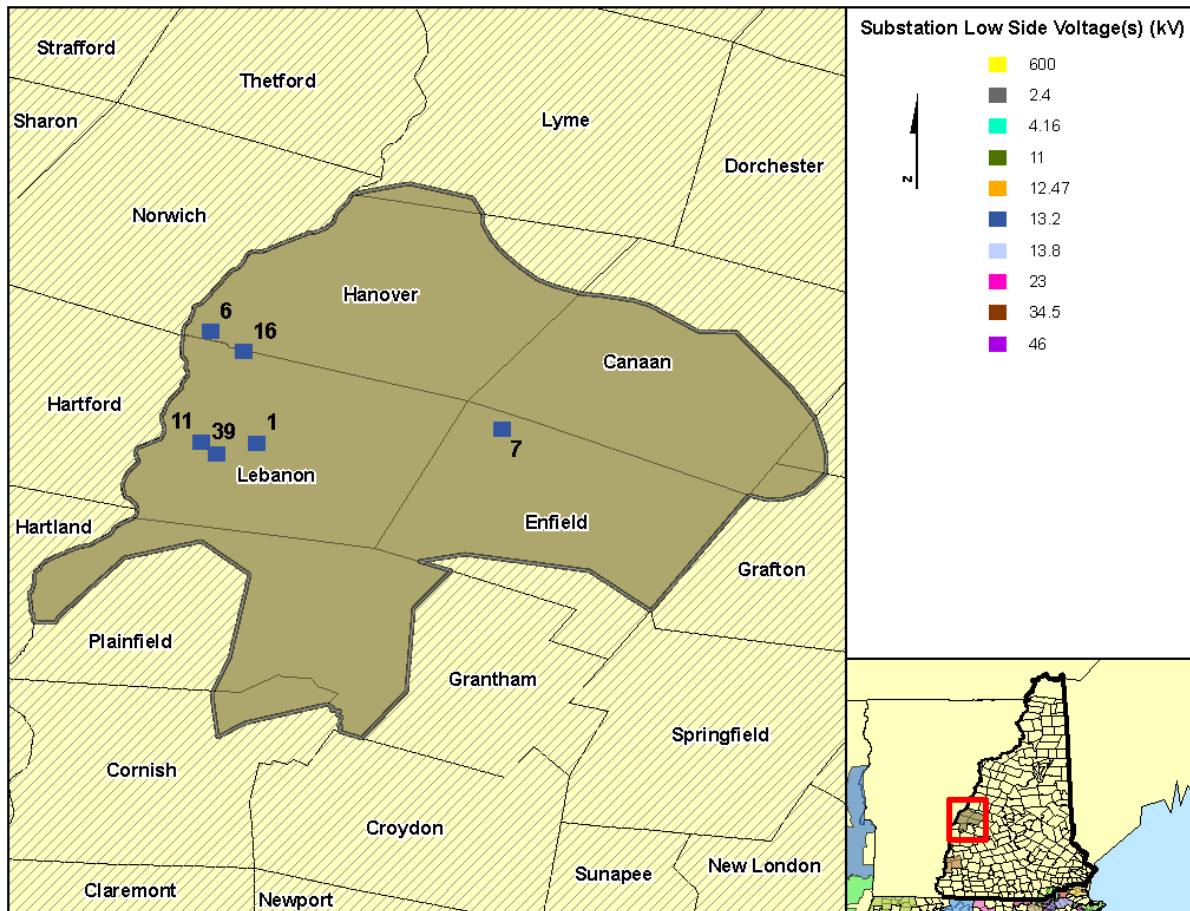
19 A study's initial system assessment is typically based on the needs identified through the problem  
20 identification process guided by the Company's Planning Criteria and Asset Strategies.

## 21 **3.0 Background**

### 22 **3.1 Geographic Scope**

23 The Lebanon study area is rural residential with commercial/industrial in scattered parks. This  
24 area was historically supplied from the Wilder hydro generating plant developed on the  
25 Connecticut River by New England Power Company. There are six substations: Craft Hill,  
26 Enfield, Hanover, Lebanon Mt. Support, and Slayton Hill. Mt. Support and Slayton Hill are jointly  
27 owned by the New England Power Company and Liberty Utilities. This area is confined to the  
28 towns of Lebanon, Hanover, Enfield and Canaan with small excursions into Orange, Lyme,  
29 Cornish and Grafton. See Figure 1 below:

1 Figure 1 Lebanon Geographical Map



2 **3.2 Electrical Scope**

3 The Lebanon Study Area includes 115 kV transmission supply, five 13.8 kV supply lines, and  
 4 eighteen 13.2 kV feeders interconnected through six area substations. Supply is from a network of  
 5 paralleled, radial 13.8 kV sub transmission lines originating at Wilder and Slayton Hill substations.  
 6 The Table 1 below summarizes these interconnections:

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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 <sup>1</sup>	39L1	86
			39L2	551
			1313	5398
			1333	2,282
W-149	W-149N	Mount Support 16 <sup>2</sup>	16L1	866
			16L2	405
			16L3	678
			16L4	1
			16L5	1070
			1363	830
W-149	K-26	Wilder <sup>3</sup>	1303	0
			1304	5,035

2 The 115 kV transmission supply is owned and operated by National Grid. These lines originate  
3 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.

1 transformers at Mount Support and at Slayton Hill Substations. Appendix A.1, Figure 5 - Lebanon  
2 115 kV Transmission System, shows the 115kV supply to the area.

3 The five 13.8kV sub transmission supply lines originate from Wilder, Slayton Hill and Mount  
4 Support Substations and supplies Hanover, Lebanon and Craft Hill regulating stations. Table 2  
5 below summarizes these interconnections and Figure 2 in Appendix A – System One Lines  
6 shows the 13.8 kV Supply System.

7 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

8 Liberty Utilities serves 17,202 Customers in the Lebanon Area supplied by eighteen 13.2kV  
9 distribution feeders. In 2020, the Planning Study Area generated a peak demand of 93.3 MW. This  
10 area consists of approximately 15 miles of 13.8 kV three-phase supply line, 420 miles of 13.2 kV  
11 three-phase distribution and 750 miles of 7.62 kV single-phase distribution. Figure 6, in Appendix  
12 A.1 – System One Lines shows the 13.2 kV Distribution System.

13

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1           **3.3 Load and Load Forecast**

2   The Lebanon Study Area is a summer peaking area and is limited by summer equipment ratings.  
3   The study was conducted using load data beginning with the recorded 2020 peak load; refer to  
4   Table 3, below:

5                                   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%



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1 The Company developed an econometric model to forecast peak demands through 2036. The  
 2 forecast model incorporates the impact of weather as well as demographic and local economic  
 3 conditions on peak demands. The load was escalated through 2036 using the seasonal peak forecast  
 4 under a 90/10 extreme weather scenario; refer to Table 4, below:

5 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%

6 The forecast model was then adjusted for spot loads to reflect new customer demands larger than  
 7 300 kilowatts (“kW”), refer to Table 5 below. The Distribution System was modeled and analyzed  
 8 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.

1

Table 6 Liberty Utilities Planning Criteria

Condition	Sub-Transmission	Substation Transformer	Distribution Circuit
Normal	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>	<p>Loading to remain within 100% of normal rating.</p> <p>Voltage at customer meter to remain within acceptable range.</p> <p>Circuit phasing is to remain balanced.</p>
N-1 Contingency, which results in facilities operating above their Long-Term Emergency (LTE) rating but below their Short-Term Emergency (STE) rating.	<p>Load must be transferred to other supply lines in the area to within their LTE rating.</p> <p>Repairs are expected to be made within 24 hours.</p> <p>Evaluate alternatives if more than <b>120 MWhr</b> of load at risk results following post-contingency switching.</p>	<p>Load must be transferred to nearby transformer to within their LTE rating.</p> <p>Repairs or installation of Mobile Transformer expected to take place within 24 hours.</p> <p>For transformers larger than 10 MVA nameplate, evaluate alternatives if more than <b>180 MWhr</b> of load at risk results following post-contingency switching.</p>	<p>Load must be transferred to nearby feeder to within their LTE rating.</p> <p>Repairs expected to be made within 24 hours.</p> <p>Evaluate alternatives if more than <b>16 MWhr</b> of load at risk results following post. (Guideline)</p>
N-1 Contingency, which results in facilities operating above their Short-Term Emergency (STE) rating.	<p>As Needed - Typically 15 min for OH conductors and 1-24 hours for UG cables.</p>	<p>Loads must be reduced within 15 minutes to operate within their LTE rating.</p>	<p>As Needed - Typically 15 min for OH conductors and 1-24 hours for UG cables.</p>

2 **4.0 Problem Identification**

3 The goal of system planning is to provide adequate capacity for safe, reliable, and economic  
 4 service to customers with minimal impact on the environment. System Planning also includes  
 5 careful management of system assets; addressing asset conditions and protection issues where  
 6 present to avoid failures, protect the equipment and provide a safe working environment for utility  
 7 workers.

1 **4.1 Thermal Loading**

2 Analysis results in this section represent the 2020 peak base case. Planning criteria for normal and  
3 contingency load serving requirements are applied in concert with the thermal ratings of the  
4 facilities to identify capacity violations. Refer to the Company’s Distribution Planning Criteria  
5 for methodology on rating the equipment. The distribution system load is planned, measured, and  
6 forecasted with the goal to serve all customer electric load under system intact (normal conditions  
7 or “N-0”) and N-1 first contingency conditions.

8 **a. Normal Configuration**

9 **i. Sub-Transmission System**

10 Table 7 13.8kV Sub Transmission Loading – Normal Configuration

Lebanon Supply Line Analysis														
Study Area	Circuit	Voltage	Line Section		Limiting Element	Element Specifics	Rating (MVA)		Projected Load					
			From	To			SN	SE	2020		2025		2036	
									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%

11 **ii. Transformers**

12 Analysis under normal conditions resulted in no violations for Transformers within the Planning  
13 Horizon.

14 Table 8 Transformer Loading – Normal Configuration

Lebanon Transformer Analysis																
Study Area	Substation	Tranf. ID.	System Voltage (kV)		Maximum Nameplate Rating	Rating (MVA)		Projected Load								
			From	To		SN	SE	2020			2025			2036		
								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%

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1            **iii. Feeders**

2 Analysis on feeder normal loading conditions, identified three violations within the planning  
3 horizon. By 2026 loading on the following feeders is projected to exceed 100% of summer normal  
4 rating:

- 5            • Craft Hill 11L1 – 105% SN
- 6            • Mount Support 16L4 – 119% SN
- 7            • Mount Support 16L5 – 102% SN

8            **Table 9 Feeder Loading – Normal Configuration**

Lebanon Feeder Analysis																
Study Area	Substation	Voltage (kV)	Feeder	Normal Limiting Element	SN Rating (Amps)	Emergency Limiting Element	SE Rating (Amps)	Projected Load								
								2020			2025			2036		
								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%

9            **iv. Phase Imbalance**

10 The feeders in the Lebanon Planning Study Area were reviewed for phase balance. The peak  
11 average phase loading between July 2020 and August 2020 was selected for each feeder for phase  
12 imbalance review.

13 Liberty utilizes the following criteria for corrective action to phase imbalance:

- 14            • The calculated neutral current should not exceed 30% of the feeder ground  
15 relay pickup setting;

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- 1                   • The loading between the low and high phase should not exceed 100A.
- 2                   • Liberty will strive to maintain phase balancing below 10% (guideline).
- 3 Any circuit violating these criteria will be monitored to get actual loading data, and will be
- 4 corrected if the imbalance is verified.
- 5 The table below identifies where the imbalance is greater than 10%, and provides recommended
- 6 mitigation. The cost to address these is minimal.

Table 10 Feeder Phase Balance above 10%

Source	Amps						Loading		Criteria			Mitigation
	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.

1 Table 12 13.8kV Transformer Loading – Contingency Configuration

Substation	Tranf. ID.	System Voltage (kV)		Maximum Nameplate Rating	Rating (MVA)		Projected Contingency					
		From	To		SN	SE	2020		2025		2036	
							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%

2 **iii. Feeders**

3 A switch plan has been developed for each feeder breaker for both 2020 and 2025 base case.  
4 Detailed results of this analysis can be found in Appendix B.1 – 2020 Switch Plan and Appendix  
5 C.1 – 2025 Switch Plan.

6 The following table summarizes facilities which are expected to be loaded above 100% of  
7 emergency limits during the planning horizon. The conductor size will be confirmed for accuracy.  
8 Additional information for each identified problem is provided in Appendix D.1 and E.1.

9 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



1       **4.2 Circuit Analysis**

2               **a. Voltage Performance during Normal Operation**

3 Voltage at the customer meter will be maintained within 5% of nominal voltage (120V). Voltage  
4 on the feeders is controlled by the station load tap changer or station regulators on feeders, the  
5 application of distribution capacitor banks, and the application of pole mounted line regulators.  
6 The ultimate goal is to keep all customers' service voltages within accepted limits.

7 The table below shows the areas where voltage is expected to exceed limits under normal  
8 configuration within the planning horizon. Refer to Appendix D.1 for additional details.

9                               Table 14 Voltage Performance – Normal Configuration

Year	Voltage (p.u.)	Affected Circuit	Reference
2020	0.95	16L1	Figure 6
2020	0.89	1L2	
2025	0.938	16L1	Figure 7
2025	0.93	16L5	
2025	0.875	1L2	

10               **b. Voltage Performance during Contingency Operation**

11 The figure below shows the areas where voltage is expected to exceed limits under contingency  
12 configuration within the planning horizon. Refer to Appendix E.1 for additional details.

1 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

2 **c. Power Factor**

3 Liberty will strive to maintain a 98% power factor at the substations to provide quality power to  
 4 its customers and limit system losses via the addition of new capacitor banks. In addition, annual  
 5 reviews for system power factor will allow Liberty to properly manage reactive support by  
 6 adjusting settings from capacitor bank controls.

7 The table below identifies feeders where the power factor is lower than 98% and provides  
 8 recommended mitigation.

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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%

1                 **d. Sector Report**

2         Where practical, Liberty’s goal is to limit feeders to 2,500 customers and sectionalized such that  
3         the number of customers does not exceed 500 or the load between disconnecting devices does not  
4         exceed 2,000kVA.

5         The Lebanon 1L2 feeder supplies 3,744 customers in the towns of Lebanon, Enfield, Plainfield  
6         and Cornish and is the only feeder that supplies over 2,500 customers.

7         Liberty reviewed the load and customers between disconnecting devices to determine areas where  
8         these limits are exceeded. The table below summarizes these findings:

9   Table 17 Sector Report

# Sectors > 2 MVA	# Sectors > 500 Cust.	Sector Average MVA	Sector Average Cust. Served
16	9	3.48	732

10                 **4.3 Asset Condition**

11         Refer to Liberty Utilities Distribution Asset Strategy in Appendix D for details on the company’s  
12         plans.

13         The major equipment to be addressed in the Lebanon Study Area within the planning horizon is:

- 14                         • Upgrade Hanover 6L3 circuit breaker and control
- 15                         • Upgrade Craft Hill 11L2 circuit breaker and control
- 16                         • Retire Enfield 7L1 circuit breaker and control
- 17                         • Retire Enfield 7L2 circuit breaker and control
- 18                         • Upgrade Monroe 15H1 breaker and voltage regulator.

19                 **4.4 Reliability**

20         Refer to Appendix F - Liberty Utilities Reliability Report for details on the company’s results and  
21         plans.

22                 **4.5 Protection Analysis**

23         The analysis identified 18 fuse replacements. An upcoming substation upgrade project by National  
24         Grid will impact the coordination and protection of the Lebanon Area and will require several

1 protection changes in the area. For details refer to Appendix E.1 - Liberty Utilities Lebanon Area  
2 Protection Review.

## 3 **5.0 Problem Solutions**

4 The following section provides infrastructure improvement projects to address the deficiencies  
5 listed in Section 4, including potential non-wires solutions (NWS) to resolve the problem.

6 The project costs presented in this section are of investment grade. Project scope and estimates  
7 will be refined as part of detailed engineering activities. Upon initial analysis, Liberty is evaluating  
8 potential NWA solutions for the Craft Hill 11L1 project – see below.

### 9 **5.1 Thermal Loading**

#### 10 **a. N-1 Normal Configuration**

##### 11 **i. Craft Hill 11L1 – 2023**

12 The Craft Hill 11L1 feeder is projected to be loaded to 105% of its summer normal rating in 2025  
13 mainly due to proposed new commercial development “River Park” in West Lebanon NH. It is  
14 projected that the feeder will exceed its summer normal rating in 2023.

15 Proposed Solution:

16 This commercial development is in its design phase and the Company continues to work with the  
17 development to meet expected in-service dates for the first phase of the project. The Company  
18 will continue monitoring the progress of the development and in the interim can transfer up to 1.6  
19 MVA of load to adjacent feeder Lebanon 1L3 to reduce loading within ratings while a permanent  
20 solution is employed.

21 This transfer would be considered temporary since the 1L3 feeder is part of an automated  
22 restoration scheme with the 16L5 and provides backup supply to the 1L2 feeder. Increasing the  
23 load on this feeder further constrains the available capacity to support the 16L5 feeder in the town  
24 of Lebanon and further worsens the voltage problems identified in this report. An existing bridge  
25 project from the Town could make this tie unavailable until construction is complete.

26 As more information becomes available Liberty will evaluate the installation of new feeder Slayton  
27 Hill 39L4 in 2025 to address this projected overload if needed. This project is estimated at  
28 \$600,000.

29 Since this project is expected to exceed its summer normal rating in 2023, and there is some  
30 uncertainty on the pace of the proposed commercial expansion, this feeder may lend itself to a  
31 potential non-wires solution, such as solar PV + storage solution or a hybrid solution. Liberty  
32 conducted an initial NWS Analysis for this project and evaluated the costs and risks of all solution  
33 options and determined that the traditional alternative is preferred. For details refer to Appendix

1 G. Liberty previously recommended a NWS as part of its Tesla battery program to reduce the 11L1  
2 feeder peak load but the plan was later discarded.

3 Liberty is committed to working with Commission Staff and other stakeholders to identify a non-  
4 wires solution that best fits the needs of our Customers.

5 Project Cost: \$600,000 – Pending NWS Consideration and Stakeholder Review

6 Risk Score: 34

7 **ii. Mount Support 16L4 – 2021**

8 The Mount Support 16L4 feeder is projected to be loaded to 103% of its summer normal rating  
9 mainly due to a 3 MW hospital expansion slated to be complete in 2021.

10 Proposed Solution (In Progress):

11 To resolve forecasted overloads it was proposed to install a new Mount Support 16L7 feeder.

12 Performing field transfers to adjacent feeders to provide additional capacity is not feasible due to  
13 the lack of spare capacity from adjacent feeders. The new 16L7 feeder will provide the customer  
14 with a second 13.2kV feeder for added supply redundancy and future growth. Non Wires Solutions  
15 was not evaluated because the need for solution is less than 24 months in the future.

16 Project Cost: \$740,000

17 Risk Score: 37

18 **iii. Mount Support 16L5 – 2022**

19 The Mount Support 16L5 feeder is projected to be loaded to 101% of its summer normal rating in  
20 2022 mainly due to customer growth in the town of Lebanon.

21 Proposed Solution:

22 It is recommended to transfer 2.3 MVA of load to adjacent feeder Lebanon 1L1 to reduce loading  
23 within ratings.

24 The 16L5 feeder is part of an automated restoration scheme with the 16L1 and 1L3 feeders and  
25 also provides backup to the 16L2 feeder. This transfer will improve voltage conditions during  
26 contingency.

27 Project Cost: Minimal

28 Risk Score: 37

1                    **iv. N-1 Contingency and Load-at-Risk**

2    The following conductors could experience thermal overloads under a contingency condition.  
3    These conductor sizes will be investigated in the field for accuracy prior to any design activities  
4    take place.

5                    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

6                    **5.2 Circuit Analysis**

7                    **a. Voltage Performance**

8    The following projects aim to address existing and projected problem issues during and normal  
9    and contingency conditions.

10                  **i. Mount Support 16L1 – 2022**

11    Feeder 16L1 could experience voltage deficiencies during normal and contingency conditions.  
12    This feeder is part of an automated restoration scheme with the 16L5 feeder.

13    To mitigate, it is recommended to install one 900 kVAR capacitor bank at Old Etna Rd in 2022  
14    and one 167 kVA voltage regulator at Great Hollow Rd in 2023.

15    Project Cost: \$90,000

16    Risk Score: 45

17                  **ii. Mount Support 16L5 - 2022**

18    Feeder 16L5 could experience voltage deficiencies during normal and contingency conditions.  
19    This feeder is part of an automated restoration scheme with the 16L1 feeder and the 1L3 feeder.

20    To mitigate, it is recommended to transfer 2.3 MVA of load to adjacent feeder Lebanon 1L1 in

1 2022. The installation of a new regulator and capacitor at Great Hollow Rd mentioned above, will  
2 also support emergency restoration of the 16L5.

3 Project Cost: Minimal

4 Risk Score: 45

5 **iii. Lebanon 1L2 - 2022**

6 Feeder 1L2 could experience voltage deficiencies during normal and contingency conditions. To  
7 mitigate, it is recommended to install one 167 kVA regulator at Connecticut Valley Hwy.  
8 Plainfield and one 600 kVAR capacitor bank at Eastman Hill Rd Enfield in 2022.

9 Project Cost: \$65,000

10 Risk Score: 48

11 **iv. Voltage Conversion – 2020 - 2025**

12 To address low voltage problems in step down areas, the following will be evaluated and  
13 prioritized for voltage conversion. These conversions are expected to cost between approximately  
14 \$50,000 and \$150,000 per location pending engineering design review. In general, Liberty assigns  
15 a risk score of 41 to voltage conversion projects.

- 16 • Old Route 10 Enfield - 2025
- 17 • Croydon Turnpike Plainfield - 2020
- 18 • Bonner Rd Plainfield - 2022
- 19 • Hopkins Rd Plainfield - 2024
- 20 • Route 120 Cornish - 2024
- 21 • River Rd Plainfield - 2020
- 22 • Dogford Rd Hanover - 2023

23 **b. Power Factor Correction**

24 In order to improve power factor for the Hanover 6L2 and Enfield 7L2 feeders, it is recommended  
25 to install a 1200 kVAR capacitor bank at Currier Pl Hanover and a 600 kVAR capacitor bank at  
26 Shaker Hill Rd Enfield in 2022.

27 Project Cost: \$25,000

28 Risk Score: 36



1           **c. Sector Problems**

2    In 2024 a new tie is planned to be constructed between the 1L2 and 1L3 feeders near Spencer St  
3    Lebanon to transfer 1.4 MVA and 430 Customers to the Lebanon 1L3 feeder. This tie will reduce  
4    the number of customers served from the 1L2 feeder and provide a new tie to support the eastern  
5    part of Lebanon and the northern part of Enfield where currently the only source is from the  
6    Slayton Hill Substation. The 1L3 tie to the area will provide an alternate source from the Wilder  
7    Substation which will provide additional flexibility to restore customers during emergencies. In  
8    general, Liberty assigns a risk score of 34 to these projects.

9    Project Cost: \$200,000

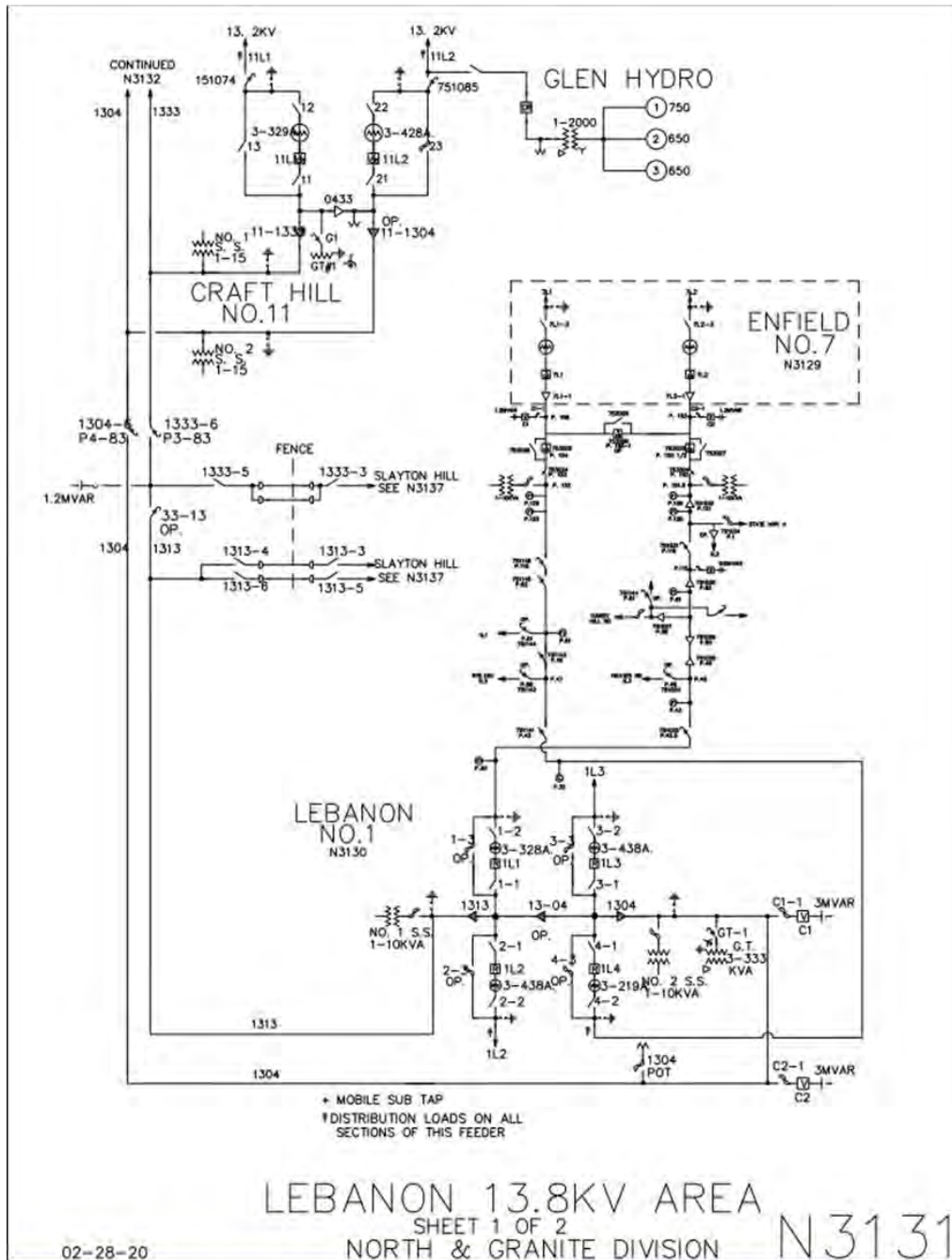
10   Liberty has prioritized the locations on the distribution system based on severity where there is  
11   over 2 MVA of load or 500 customers between disconnects. These locations will be reviewed for  
12   improved sectionalizing opportunities, reliability history and exposure. In order to limit the  
13   exposure to customers and improve restoration times, Liberty expects to address two locations per  
14   year between 2022 and 2025.

15   Project Cost: \$30,000/yr. (\$120,000 total)

1 6.0 Appendices

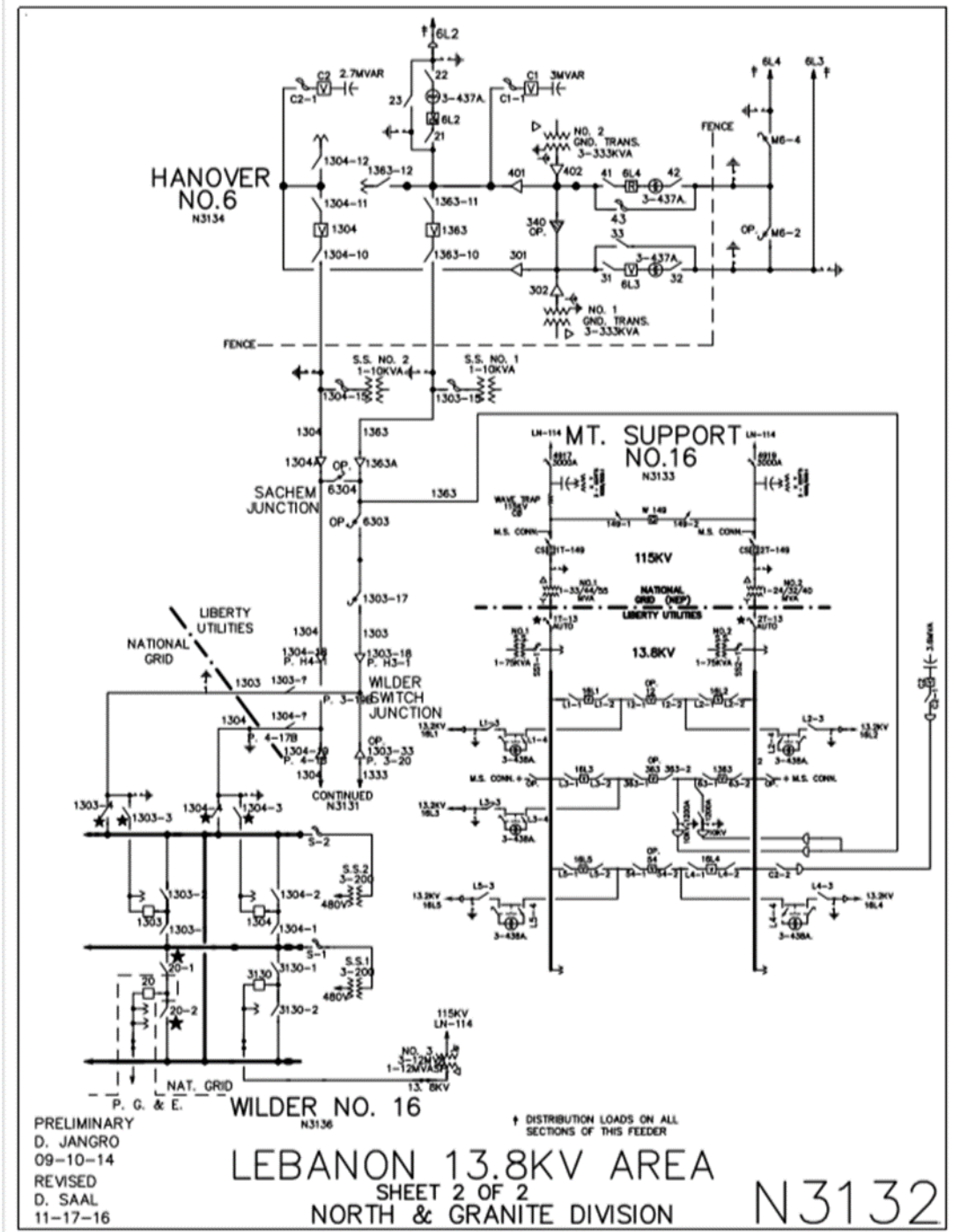
2 6.1 Appendix A.1 – System One Lines

3 Figure 2 [REDACTED]



1

Figure 3



1

Figure 4 [REDACTED]

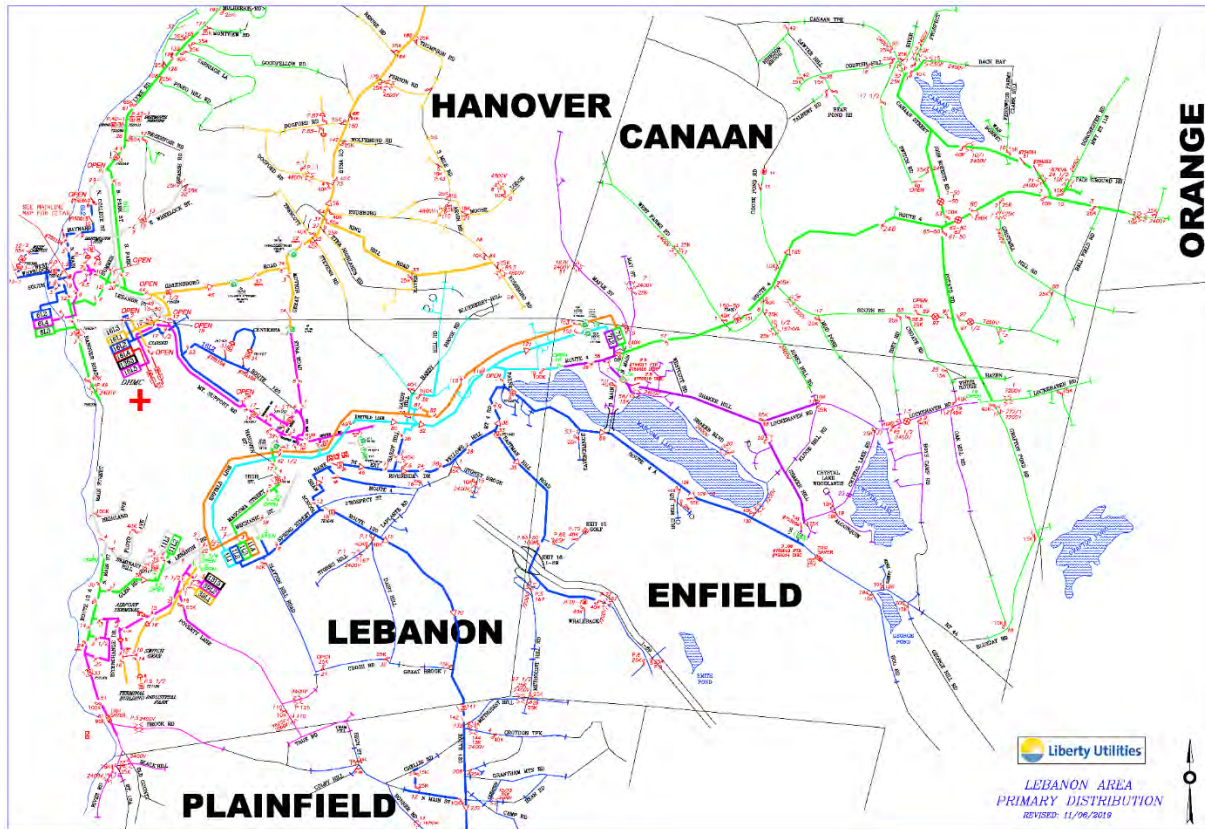
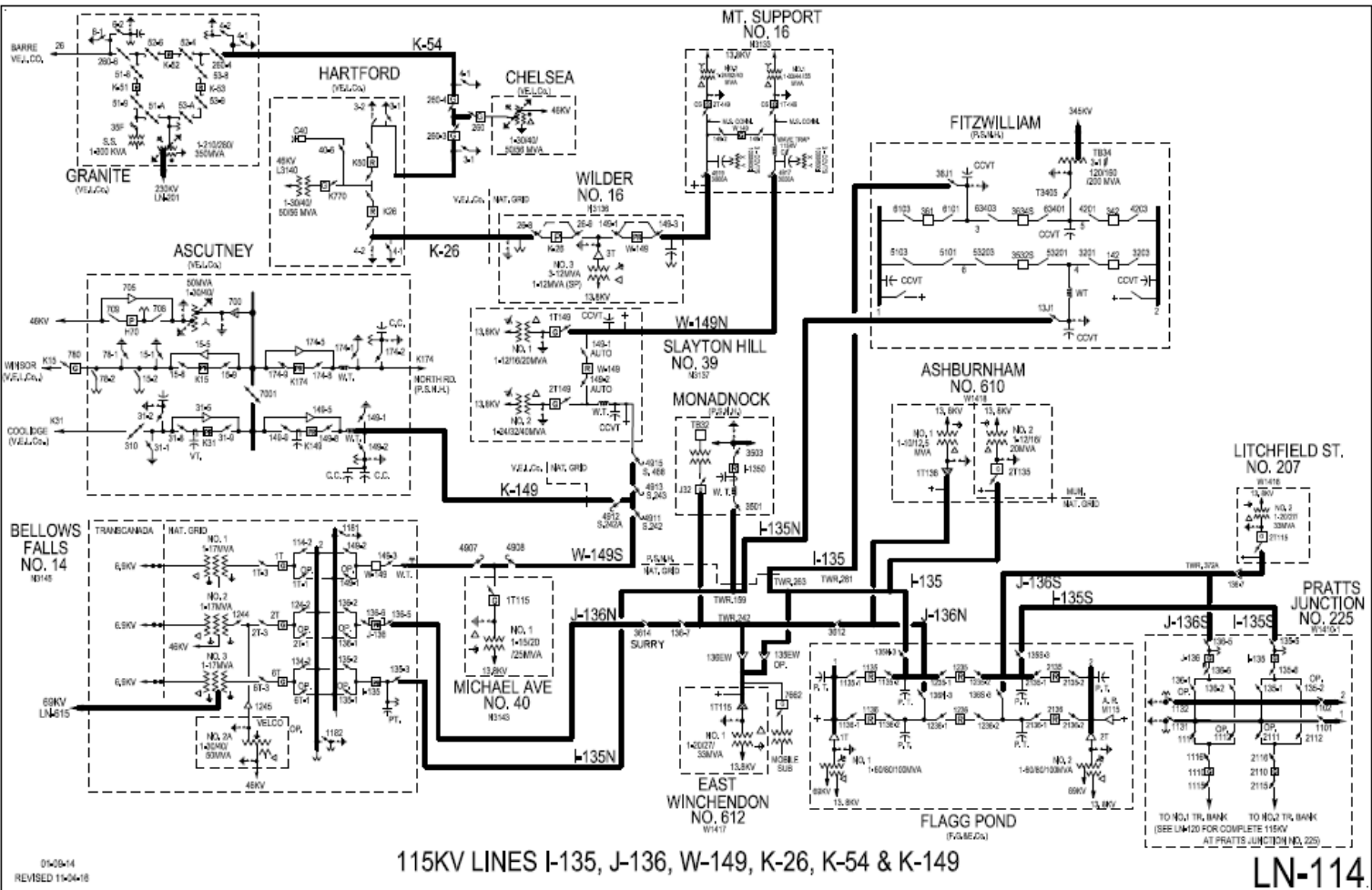


Figure 5



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1 **6.2 Appendix B.1 – Switch Plan 2020**

2 **Table 19 2020 Switch Plan Part 1**

Operation		Dropped				Picked Up				Problems
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	
<b><u>Plan : Feeder 11L1</u></b>										
0 - Open	PTR11L1	11L1	357	23.4	1717	---	---	---	---	
1 - Close	751065	---	---	---	---	1L3	358	23.4	1717	
<b><u>Plan : Feeder 11L2</u></b>										
0 - Open	PTR11L2	11L2	213	7.4	315	---	---	---	---	
1 - Close	751092	---	---	---	---	39L2	214	7.4	315	
<b><u>Plan : Feeder 16L2</u></b>										
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	
<b><u>Plan : Feeder 39L1</u></b>										
0 - Open	39L1	39L1	176	3.5	81	---	---	---	---	
1 - Close	751172	---	---	---	---	39L2	176	3.5	81	
<b><u>Plan : Feeder 39L2</u></b>										
0 - Open	39L2	39L2	249	39.2	499	---	---	---	---	
1 - Close	751172	---	---	---	---	39L1	249	39.2	499	
<b><u>Plan : Feeder 6L2</u></b>										
0 - Open	755027	6L2	108	7.3	543	---	---	---	---	
1 - Close	755010	---	---	---	---	16L3	108	7.3	543	
<b><u>Plan : Feeder 6L3</u></b>										
0 - Open	PTR6L3	6L3	326	41.9	1430	---	---	---	---	
1 - Close	755028	---	---	---	---	6L2	326	41.9	1430	
<b><u>Plan : Feeder 6L4</u></b>										
0 - Open	PTR6L4	6L4	187	2.4	127	---	---	---	---	
1 - Close	755007	---	---	---	---	6L2	187	2.4	127	
<b><u>Plan : Feeder 7L1</u></b>										
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
<b><u>Plan : Feeder 16L1</u></b>										
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	

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Table 19 2020 Switch Plan Part 2

Operation		Dropped				Picked Up				Problems
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	
<b><u>Plan : Feeder 16L3</u></b>										
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	
<b><u>Plan : Feeder 16L4</u></b>										
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
<b><u>Plan : Feeder 16L5</u></b>										
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	
<b><u>Plan : Feeder 1L1</u></b>										
0 - Open	1L1	1L1	54	25.8	313	---	---	---	---	
1 - Close	PTR753029	---	---	---	---	1L4	54	25.8	313	
<b><u>Plan : Feeder 1L2</u></b>										
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
<b><u>Plan : Feeder 1L3</u></b>										
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	
<b><u>Plan : Feeder 7L2</u></b>										
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	

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1 **6.3 Appendix C.1 – Switch Plan 2025**

2 **Table 20 2025 Switch Plan Part 1**

Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
<b><u>: Feeder 11L1</u></b>										
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	
<b><u>: Feeder 11L2</u></b>										
0 - Open	PTR11L2	11L2	239	7.4	315	---	---	---	---	
1 - Close	751092	---	---	---	---	39L2	241	7.4	315	
<b><u>: Feeder 16L2</u></b>										
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	
<b><u>: Feeder 39L1</u></b>										
0 - Open	39L1	39L1	195	3.5	81	---	---	---	---	
1 - Close	751172	---	---	---	---	39L2	195	3.5	81	
<b><u>: Feeder 39L2</u></b>										
0 - Open	39L2	39L2	277	39.2	499	---	---	---	---	
1 - Close	751172	---	---	---	---	39L1	277	39.2	499	
<b><u>n : Feeder 6L2</u></b>										
0 - Open	755027	6L2	116	7.3	543	---	---	---	---	
1 - Close	755010	---	---	---	---	16L3	115	7.3	543	
<b><u>n : Feeder 6L3</u></b>										
0 - Open	PTR6L3	6L3	362	41.9	1430	---	---	---	---	
1 - Close	755028	---	---	---	---	6L2	362	41.9	1430	
<b><u>n : Feeder 6L4</u></b>										
0 - Open	PTR6L4	6L4	208	2.4	127	---	---	---	---	
1 - Close	755007	---	---	---	---	6L2	208	2.4	127	
<b><u>n : Feeder 7L1</u></b>										
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
<b><u>: Feeder 16L1</u></b>										
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 0.85 pu
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	



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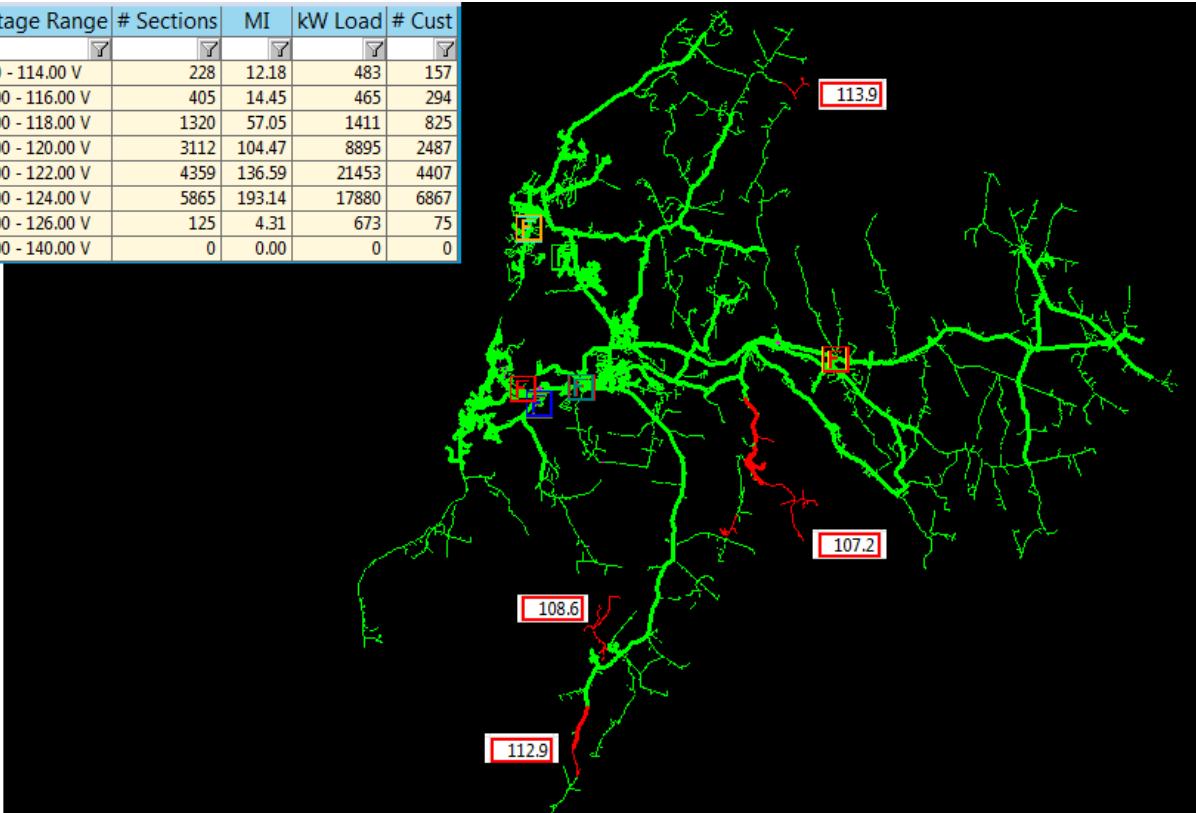
Table 20 2025 Switch Plan Part 2

Operation		Dropped				Picked Up				
Action	Switch	From	Amps	Miles	Cust	To	Amps	Miles	Cust	Problems
<b><u>Feeder 16L3</u></b>										
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	
<b><u>Feeder 16L4</u></b>										
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
<b><u>Feeder 16L5</u></b>										
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	
<b><u>Feeder 1L1</u></b>										
0 - Open	1L1	1L1	60	25.8	313	---	---	---	---	
1 - Close	PTR753029	---	---	---	---	1L4	60	25.8	313	
<b><u>Feeder 1L2</u></b>										
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 0.81 pu
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 0.82 pu
<b><u>Feeder 1L3</u></b>										
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	
<b><u>Feeder 7L2</u></b>										
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	

1 **6.4 Appendix D.1 – Voltage Performance Normal Condition**

2 **Figure 6 2020 Voltage Performance 1L2 – Normal Configuration**

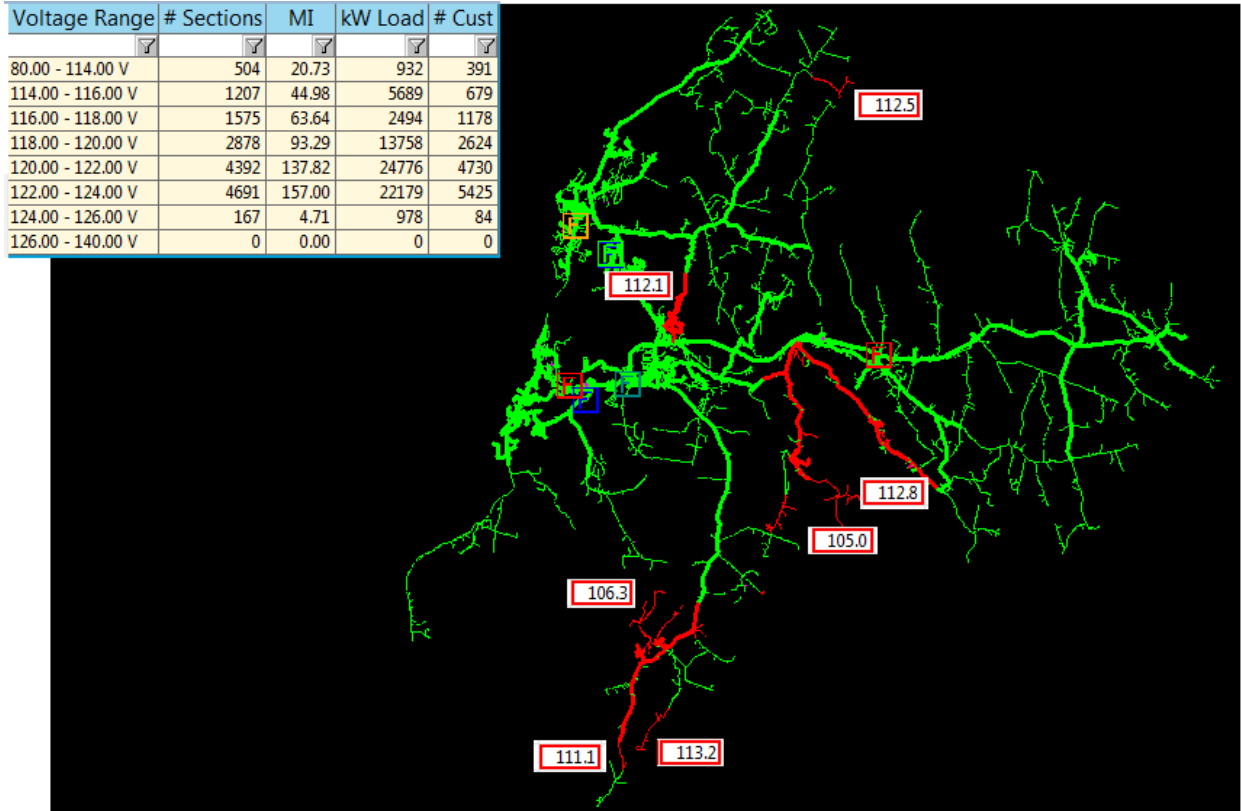
Voltage Range	# Sections	MI	kW Load	# Cust
80.00 - 114.00 V	228	12.18	483	157
114.00 - 116.00 V	405	14.45	465	294
116.00 - 118.00 V	1320	57.05	1411	825
118.00 - 120.00 V	3112	104.47	8895	2487
120.00 - 122.00 V	4359	136.59	21453	4407
122.00 - 124.00 V	5865	193.14	17880	6867
124.00 - 126.00 V	125	4.31	673	75
126.00 - 140.00 V	0	0.00	0	0



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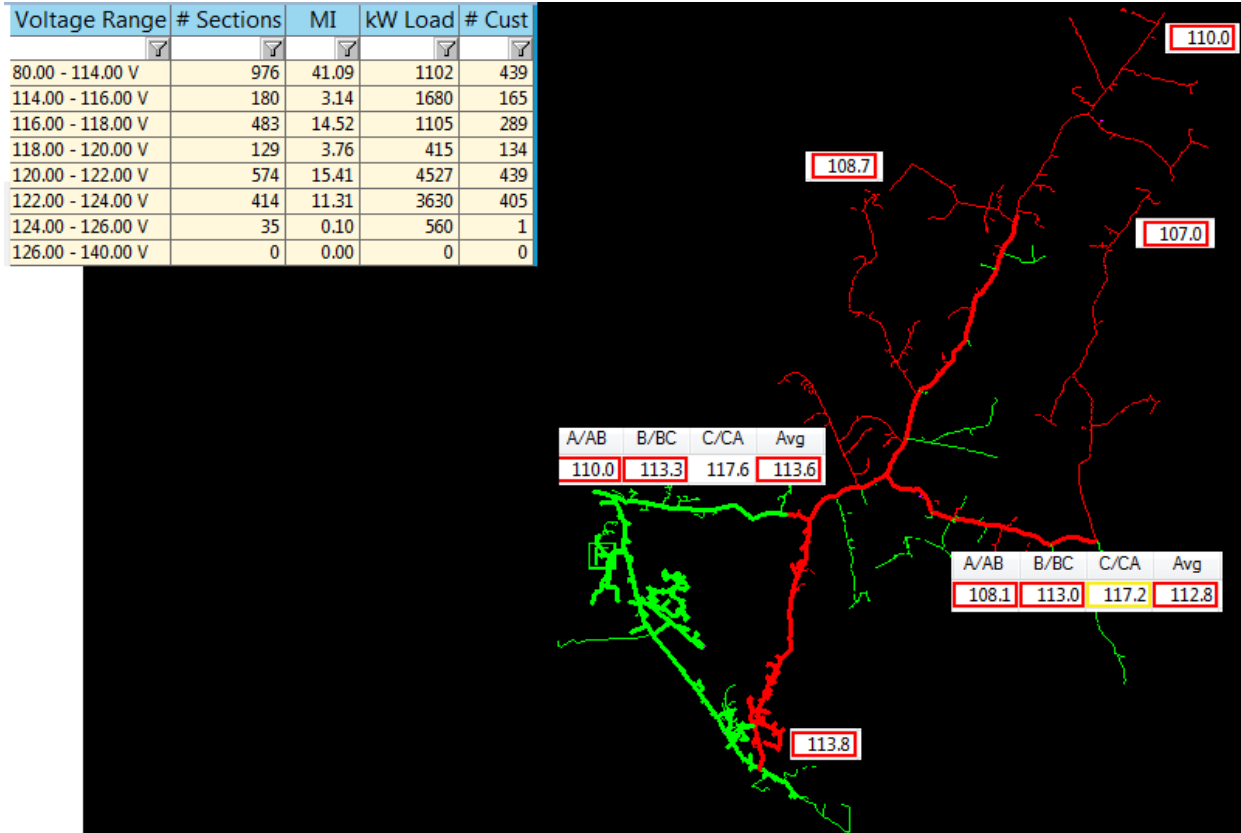
1 The figure below shows the areas where voltage is expected to exceed limits under normal  
2 configuration in 2025.

3 Figure 7 2025 Predicted Voltage Performance 1L2, 16L5, 16L1 – Normal Configuration

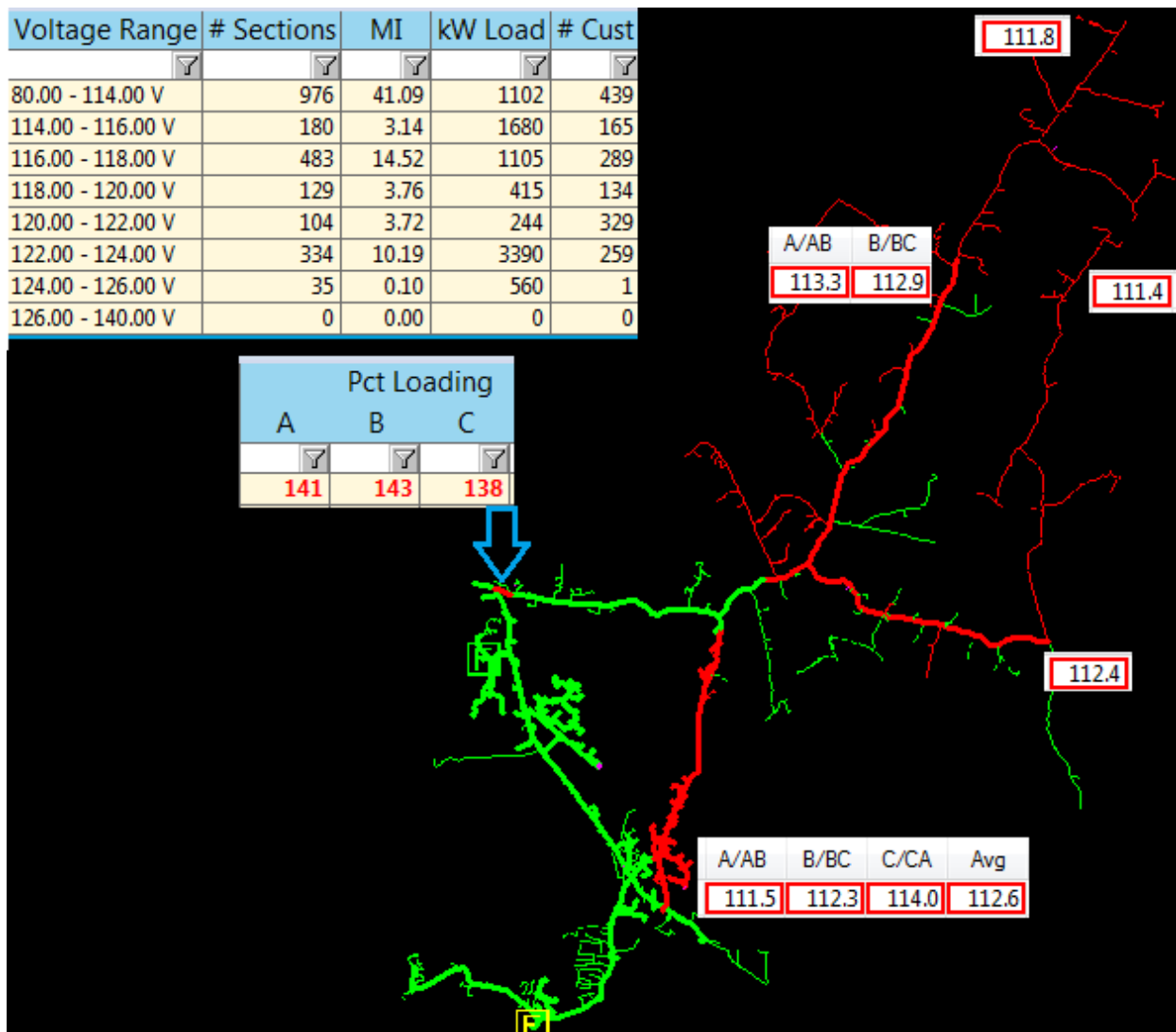


1 **6.5 Appendix E.1 – Voltage Performance Contingency Condition**

2 **Figure 8 2020 Voltage Performance 16L1 – Contingency Configuration**

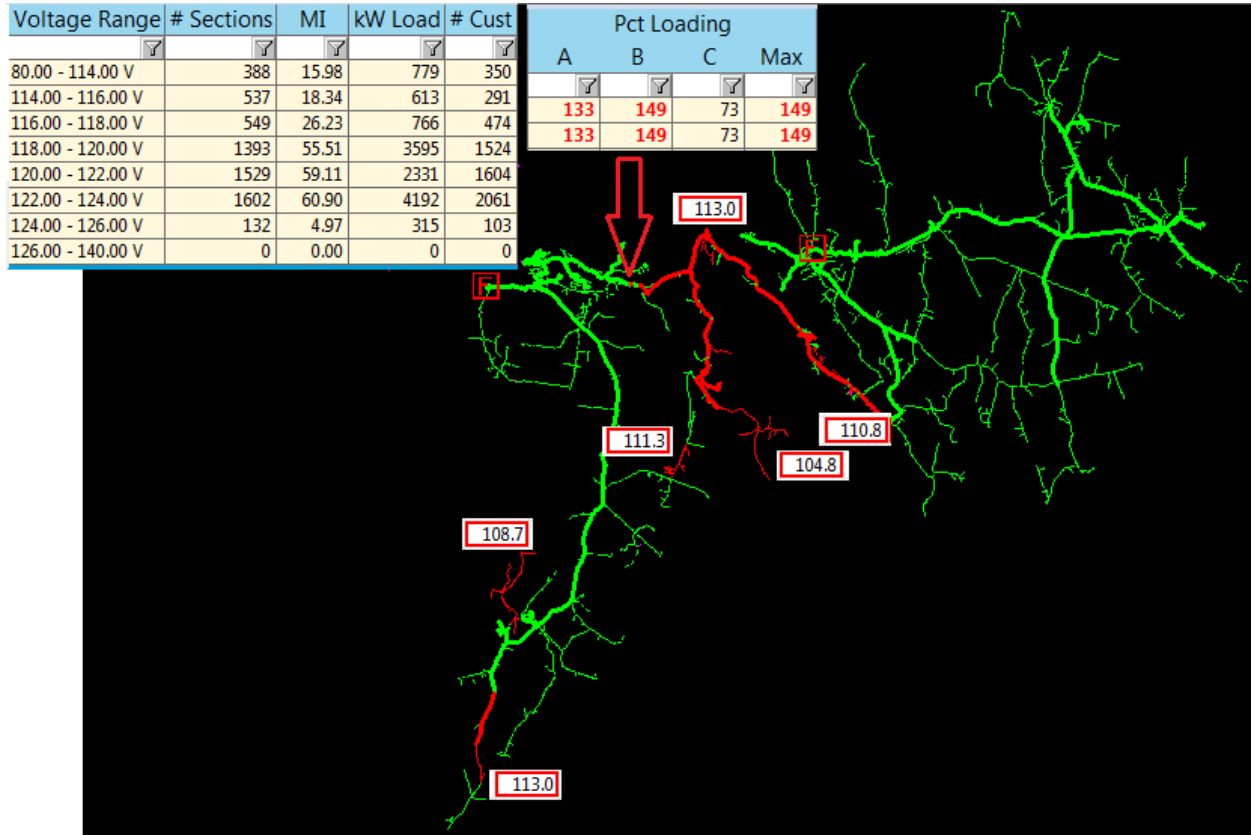


1 Figure 9 2020 Voltage Performance 16L5 – Contingency Configuration



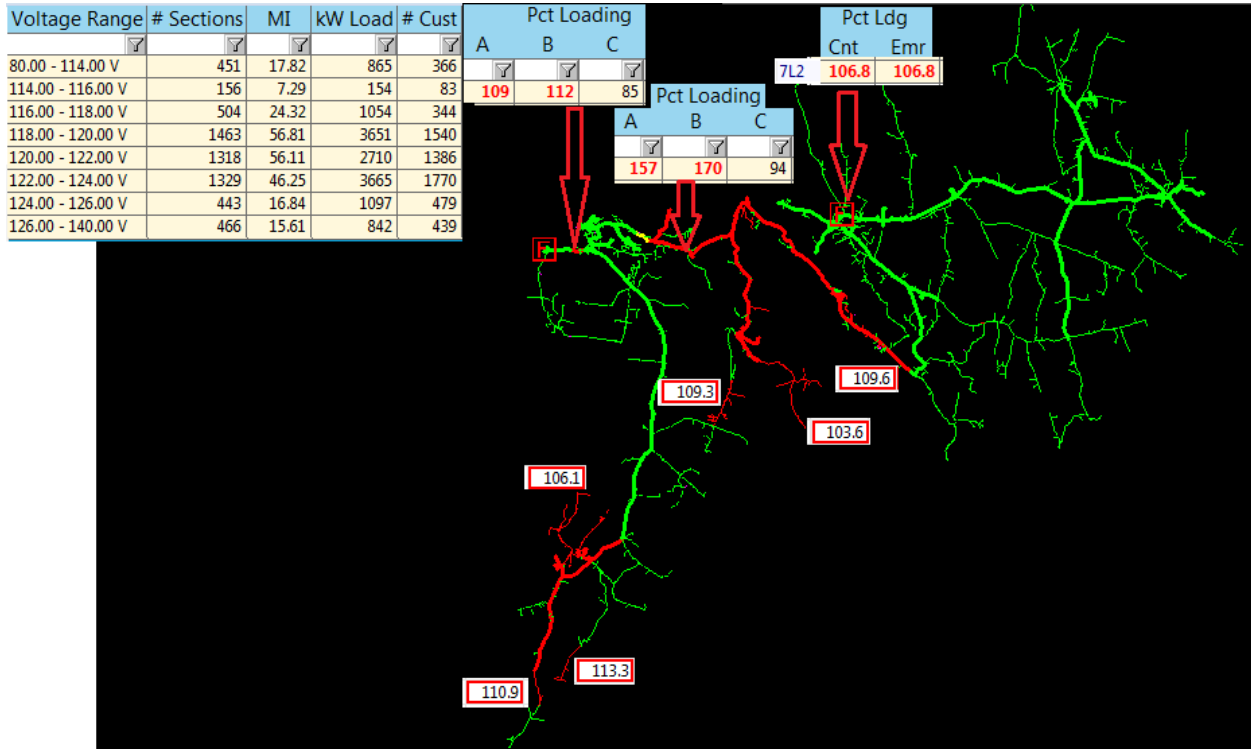
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1 Figure 10 2020 Voltage Performance 7L1 or 7L2 – Contingency Configuration



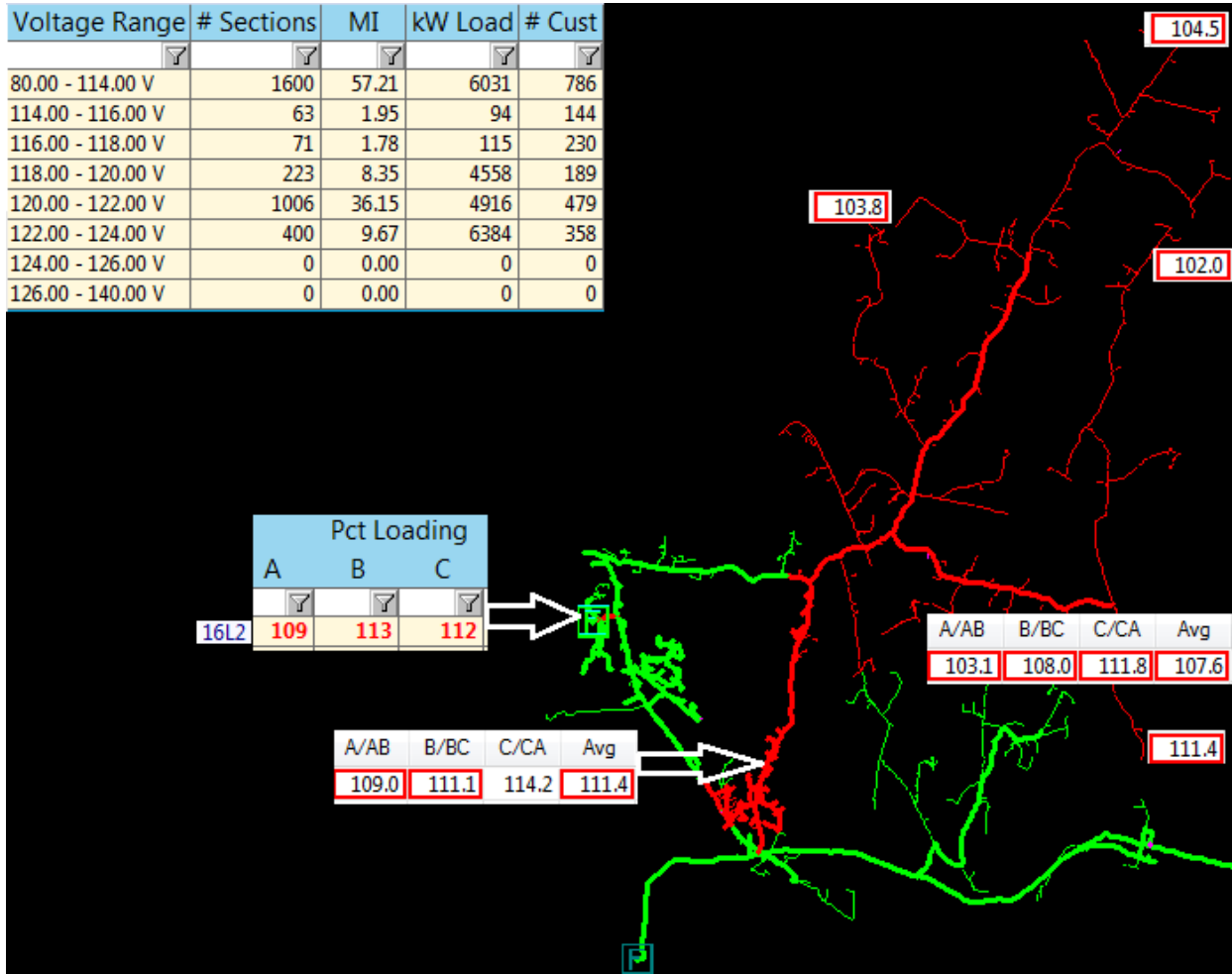
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1 Figure 12 2025 Voltage Performance 7L1 or 7L2 – Contingency Configuration



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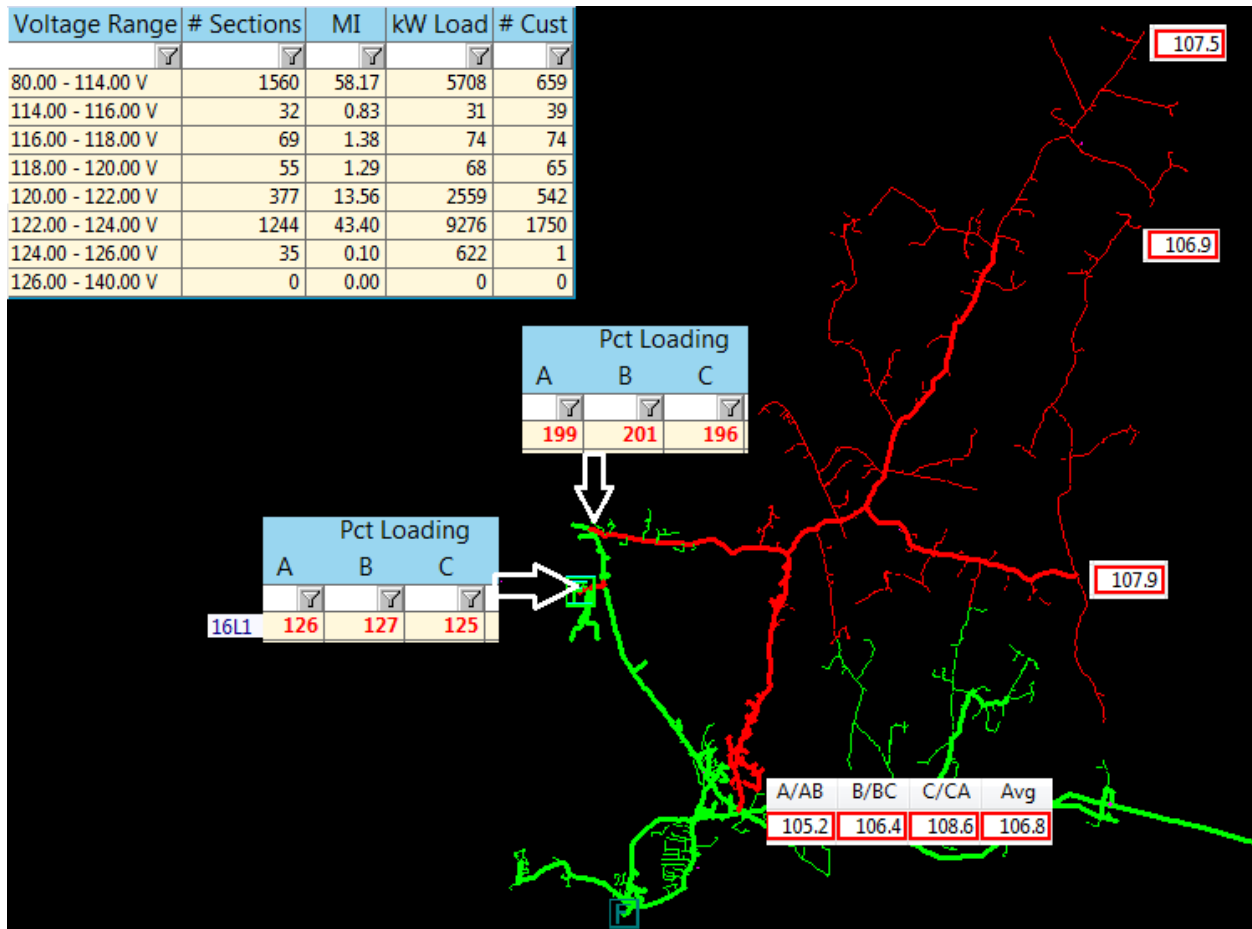
1 Figure 13 2025 Voltage Performance 16L1 – Contingency Configuration





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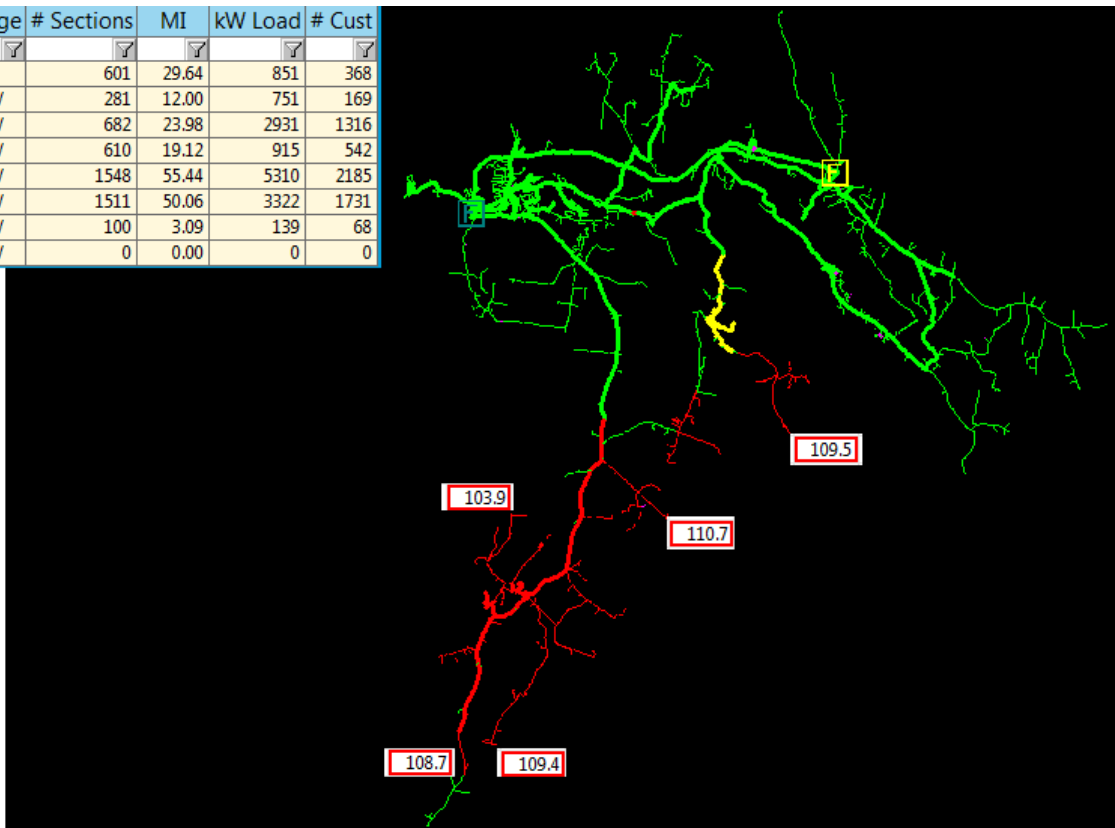
1 Figure 14 2025 Voltage Performance 16L5 – Contingency Configuration



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1 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



1           **6.6 Appendix F.1 – Lebanon Area Reliability Report**

2           **a. Executive Summary**

3 National Grid will be modifying their Wilder #16 substation and introducing a new 13.8 kV supply  
4 transformer that will supply Liberty’s 1303 and 1304 lines. The new transformer will have a  
5 different winding configuration and impedance than the existing and, consequently, fault current  
6 contributions will be different.

7 The existing transformer (3T) will become a backup for the new transformer. This will impact the  
8 operation of protective devices on the 1303 and 1304 lines and the protective devices on  
9 substations and circuits supplied by those lines.

10 The 1304 line provides the primary supply to Liberty’s Hanover 6L3, Lebanon 1L3 and 1L4  
11 feeders. The Lebanon 1L4 line, in turn, supplies Liberty Electric’s Enfield 7L1 circuit. The 1303  
12 line provides the backup supply to Liberty’s 1333 and 1363 lines.

13 The purpose of this Study is to review the Protection Coordination of the impacted protective  
14 devices and make recommendations for any required setting changes to mitigate potential issues  
15 with safety and mis-operation of protective equipment.

16 Cost Estimate

17 The total estimated cost for all required System Modifications is \$363,000.

18           **b. System Overview**

19 National Grid’s Wilder #16 substation’s existing 3T transformer bank, consists of three (3) single  
20 phase 12 MVA units, connected to form a three (3) phase bank. Each unit has a 66.4 kV primary  
21 and 13.8 kV secondary, with an impedance of  $Z = 8\%$  on a 12 MVA Base.

22 The 3T bank has been configured 115 kV Wye Grounded to 13.8 kV delta. The 3T is the current  
23 13.8 kV source for Liberty’s 1303 and 1304 lines. The 1304 line normally supplies Liberty’s  
24 Hanover 6L3, Lebanon 1L3 and Lebanon 1L4 line. The Lebanon 1L4, in turn, supplies Liberty’s  
25 Enfield 7L1 circuit. The 1303 Line normally does not carry load and is used as a backup for the  
26 1333 and 1363 line.

27 National Grid’s proposed modifications to Wilder #16 will include a new 13.8 kV supply  
28 transformer for the 1303 and 1304 lines consisting of a new three phase, 40 MVA, 115 kV Delta  
29 to 13.8 kV Wye Grounded supply transformer with an impedance of  $Z = 13\%$  on a 24 MVA base.  
30 The new transformer has a different winding configuration and impedance than the existing supply  
31 transformer bank and, consequently, its fault current contributions will be different and will impact  
32 the operation of protective devices downstream of it .

1           **i. Short Circuit & Protection Coordination Analysis**

2     The ASPEN OneLiner version 14.3 modeling program was used to model the substations, circuits  
3     and protective devices impacted by the new 1303/1304 supply transformer.

4     Substation and circuit protective devices associated with Liberty’s 1303, 1304, 1363, Hanover #6,  
5     Lebanon #1, Enfield #7, Mount Support, and Slayton Hill substations were reviewed.

6     The initial review determined that with the New 13.8 kV supply operational, and with the current  
7     settings in place, a good deal of mis-coordination between devices will exist, most protective  
8     devices will have much longer clearing times, and some protective devices will not operate for  
9     bolted faults that may occur within their zone of protection, which raises safety concerns.

10    To mitigate these issues, protection equipment and settings were analyzed for normal (“N-0”) and  
11    contingency (“N-1”) conditions at Hanover #6, Lebanon #1, and Enfield #7 substations and  
12    circuits, for both the existing and proposed new 13.8 kV supply at Wilder #16.

13    The ideal goal was to make all relayed protectives able to clear an end of zone bolted faults within  
14    one (1) second while maintaining adequate coordination with other series protective devices. Some  
15    leeway was given to the preferred 1.0 second or less end of zone clearing time due to the low fault  
16    current levels predicted on some of the impacted circuits. However, coordination between devices  
17    is maintained without the need for alternate settings for N-1 conditions.

18    The analysis determined that the existing grounding banks at the Hanover #6 and Lebanon #1  
19    substations should remain in service, even with the new 13.8 kV Wilder #16 Supply’s ability to  
20    source zero sequence fault current. These grounding banks are needed to facilitate sensing end of  
21    zone line to ground faults on the associated circuits, otherwise these faults may not be detected  
22    and cleared in in an acceptable manner.

23    The analysis also determined that a single set of protective device settings can be used for normal,  
24    N-1, and for both the existing and new 13.8 kV supply conditions. This will allow Liberty to  
25    perform necessary setting changes in anticipation of the changes at the Wilder Substation which  
26    are expected to be completed in the fourth quarter of 2024. Protective device modifications will  
27    be implemented at the substation level first then sequentially on downstream protective devices.

28                   ➤ **Wilder #16**

29    The Wilder #16 substation protective devices and settings associated with the 1303 and 1304 lines  
30    are National Grid’s responsibility. Liberty provides any recommended settings changes for the  
31    Hanover #6, and Lebanon #1 substation breakers to enable National Grid to coordinate with those  
32    settings.

1                   ➤ **Hanover #6**

2   The Hanover 6L3 circuit is normally supplied by the Wilder 1304 line, the backup supply is the  
3   Mount Support 1363 line. Setting changes and protective device modifications are recommended  
4   due to the impact of the new 13.8 kV supply transformer and from the addition transformation  
5   proposed at CRREL (Primary Metered Customer expanding to 9.5 MVA total). These  
6   modifications include the following:

- 7                   • Hanover #6 Substation 1363/Bus 1 and 1304/Bus 2 setting changes.
- 8                   • Hanover 6L2:
  - 9                   ○ Hanover #6 Substation 6L2 Recloser setting changes (to coordinate
  - 10                   with 1363/B1 setting changes)
  - 11                   ○ 6L2 PTR Pole #2-50 W. Wheelock Rd, Hanover (to coordinate with
  - 12                   1363/B1 setting changes)
- 13                  • Hanover 6L3:
  - 14                   ○ Hanover #6 Substation 6L3 Recloser setting changes (can
  - 15                   coordinate with 100K).
  - 16                   ○ 6L3 PTR Pole #2 West Lebanon Rd, Hanover setting changes.
  - 17                   ○ 6L3 PTR Pole #3 Lyme Rd, Hanover setting changes (can
  - 18                   coordinate with 100K).
  - 19                   ○ 6L3 Cooper Form 3A PTR Pole #40-1 Lyme Rd replacement with
  - 20                   Viper/SEL 651R control and new settings (CRREL PCC recloser).
  - 21                   This replacement is required to allow coordination with the 6L3
  - 22                   PTR Pole #3 Lyme Rd.

23                   ➤ **Lebanon #1**

24   The Lebanon 1L3 and 1L4 circuits are normally supplied by the 1304 line, with the backup supply  
25   is the Slayton Hill 1313 Line. The #1 Lebanon 1L1 and 1L2 are normally supplied by the Slayton  
26   Hill 1313 Line, with backup provided by the Wilder 1304 line, refer to Figures 2 & 5 Appendix  
27   A. The following protection modifications are recommended:

- 28                  • Lebanon #1 Substation 1L1 setting changes (can coordinate with 100K and
- 29                  Slayton Hill).
- 30                  • 1L1 PTR Pole #152.5 Enfield R.O.W. setting changes, add reclosing,
- 31                  replaces Enfield 7L2 (can coordinate with 100K).1

- 1                   • 1L1/1L4 PTR Pole # 155-1 Enfield R.O.W. setting changes,
- 2                   • Lebanon #1 Substation 1L2 setting changes (can coordinate with 100K and
- 3                   Slayton Hill).
- 4                   • 1L2 PTR Pole #18 School St Lebanon setting changes (can coordinate with
- 5                   80K).
- 6                   • 1L2 PTR Pole #141 Plainfield Rd Plainfield setting changes (can coordinate
- 7                   with 80K).
- 8                   • 1L2 PTR Pole #36 Bank St Lebanon setting changes (can coordinate with
- 9                   100K).
- 10                  • 1L2 PTR Pole #33 Eastman Hill Lebanon setting changes (can coordinate
- 11                  with 100K).
- 12                  • 1L2 PTR Pole #6 Route 4A Lebanon setting changes (can coordinate with
- 13                  65K).
- 14                  • 1L2 PTR Pole #106 Shaker Hill/Bishop Ln Enfield setting changes (can
- 15                  coordinate with 65K).
- 16                  • Lebanon #1 Substation 1L3 setting changes (can coordinate with 100K).
- 17                  • Lebanon #1 Substation 1L4 setting changes (can coordinate with 100K).
- 18                  • 1L4 PTR Pole #154 Enfield R.O.W. Lebanon setting changes, replaces
- 19                  Enfield 7L1 (can coordinate with 80K).1
- 20                  ➤ **Enfield #7**

21 The Enfield 7L1 is normally supplied by the Lebanon 1L4 circuit and the Enfield 7L2 is normally  
22 supplied from the Lebanon 1L1 circuit. There is a distribution automation scheme between the  
23 1L1 and 1L4 to provide backup to both the 7L1 and 7L2 for loss of either supply involving PTRs  
24 on Poles #s 152.5, 154, and 155-1 (N.O.P) in the Enfield R.O.W.

25 There is also a loop scheme between the 1L2 and 7L2 involving the N.O.P., 1L2 PTR on Pole  
26 #106 Shaker Hill/Bishop Ln Enfield and the 7L2 PTR Pole #8 South St, Enfield, where the 1L2  
27 picks up a portion of the 7L2 up to the Pole #8 PTR.

28 Due to the limitations of the existing Cooper Form 3A recloser controls used on both the 7L1 and  
29 7L2 breakers and their proximity to the Enfield R.O.W PTRs on Pole #152.5 and 154, It is  
30 recommended that the existing 7L1 and 7L2 breakers be retired. Protection of the 7L1 can be taken

1 over by the 1L4 PTR on Pole # 154 and 7L2 protection can be handled by the 1L1 pole # 152.5  
2 PTR, both in the Enfield R.O.W. Recommended protection modifications are as follows:

3 • 7L1 breaker Bypass remove from service, refer to 1L4 PTR Pole #154  
4 setting changes.

5 • 7L2 breaker Bypass remove from service, refer to 1L1 PTR Pole #152.5  
6 setting changes.

7 • 7L1 PTR Pole #150-50 Route 4 Canaan setting changes (can coordinate  
8 with 80K).

9 • 7L1 new PTR in vicinity of Pole #63 John Roberts Rd Canaan and new  
10 settings, to replace 100 K fuse (can coordinate with 80K). This new recloser  
11 is required to allow coordination with the 7L1 PTR Pole 150-50 Route 4  
12 and to improve the coordination further downstream at the Cardigan Mtn  
13 School Canaan.

14 • 7L2 PTR Pole #8 South St Enfield setting changes (can coordinate with  
15 80K).

16 **ii. Alternatives**

17 The existing protection device settings were developed to accommodate the fault current levels  
18 associated with the existing Wilder # 16, 13.8 KV supply, the proposed new 13.8 kV Wilder supply  
19 will deliver less fault current ,which will impact the operation of all the protective devices on all  
20 the circuits it ultimately supplies. If no action is taken, protective devices may not operate as  
21 intended, possibly impacting system reliability and the safety of both line personal and the public.

22 **iii. Cost Estimates**

23 The cost planning grade estimate for the Company's work associated with mitigating coordination  
24 and protection issues associated with the changes at the Wilder Substation, as identified in this  
25 report, are \$360,000 +/-25%, and includes the breakdown of items listed in Table 1 below:

26

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1 Table 1: Protection Cost Estimates +/-25%

Work Item		Conceptual Cost +/-25% Planning			Total Customer Costs
		Grade Cost Estimate			
	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



1           **iv. Conclusion**

2   Analysis concludes that certain protective device modifications are recommended to ensure proper  
3   protective device operation and coordination, as a result of National Grid’s proposed addition of a  
4   new 13.8 kV supply transformer that supplies Liberty’s 1303 and 1304 lines.

5   Additionally, the Hanover 6L3 circuit also is impacted by CRREL’S proposed facility expansion  
6   to include up to 9.5 MVA of Connected transformation. The recommended settings and protective  
7   device modifications, discussed in detail in the preceding Protection Review section, are  
8   acceptable for use with either the existing Wilder #16 13.8 KV supply or the proposed new 13.8  
9   kV supply in service for both normal and N-1 contingencies. This affords Liberty some flexibility  
10   in its ability to schedule the implementation of protection modifications prior to National Grid’s  
11   proposed Wilder #16 13.8 kV supply changes. The estimated planning grade cost for the  
12   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
<b>PROJECT NAME:</b>	Craft Hill 11L1					
<b>Project Need Year:</b>	2023					
<b>Brief Project Description/need:</b>						
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.						
<b>Project Scope</b>						
	<b>Option</b>					
Load transfer to Lebanon 1L3 circuit	1					
Install new Slayton Hill 39L4 feeder	2					
PV with storage	3					
DER - Large Customer	4					
<b>Scoring Values</b>						
Marginal with mitigation	1					
Marginal without mitigation	2					
Acceptable	3					
Best Solution	4					
<b>Evaluation Summary</b>						
<b>Evaluation Criteria</b>	<b>% Weight Factor*</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Comments</b>
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	
Environmental Risk	10%	4	3	2.25	3.5	
<b>Total Assessment</b>	<b>100%</b>	<b>2.85</b>	<b>3.37</b>	<b>2.10</b>	<b>2.61</b>	
	<b>Ranking</b>	<b>2</b>	<b>1</b>	<b>4</b>	<b>3</b>	

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**PROJECT NAME:** Craft Hill 11L1  
11/2/2020

<b>RELIABILITY Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
Customer Outage Experience	50%	1	4	2	2
Automated Restoration	30%	1	4	3	3
Power Quality	20%	1	2	4	4
<b>Totals</b>	<b>100%</b>	<b>1</b>	<b>3.6</b>	<b>2.7</b>	<b>2.7</b>
	<b>Ranking</b>	<b>4</b>	<b>1</b>	<b>2</b>	<b>2</b>

**PROJECT NAME:** Craft Hill 11L1  
11/2/2020

<b>FEASIBILITY Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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
<b>Totals</b>	<b>100%</b>	<b>3.25</b>	<b>3.65</b>	<b>2.3</b>	<b>2.65</b>
	<b>Ranking</b>	<b>2</b>	<b>1</b>	<b>4</b>	<b>3</b>

**PROJECT NAME:** Craft Hill 11L1  
11/2/2020

<b>PERFORMANCE Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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
<b>Totals</b>	<b>100%</b>	<b>2</b>	<b>3.6</b>	<b>2.85</b>	<b>2.95</b>
	<b>Ranking</b>	<b>4</b>	<b>1</b>	<b>3</b>	<b>2</b>

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**PROJECT NAME:** Craft Hill 11L1  
11/2/2020

<b>ENVIRONMENTAL Risk Evaluation Criteria</b>	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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
<b>Totals</b>	<b>100%</b>	<b>4</b>	<b>3</b>	<b>2.25</b>	<b>3.5</b>
	<b>Ranking</b>	<b>1</b>	<b>3</b>	<b>4</b>	<b>2</b>



## **Reliability Review 2020**

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## 1 **1.0 Executive Summary**

2 The purpose of this document is to report on the overall reliability performance of the Liberty  
3 Distribution System for calendar year 2019. This report identifies root cause and locations within  
4 the distribution system that are experiencing repeated interruptions. The information is  
5 summarized for each Area, feeder and poor performing sub sections of the feeders, including  
6 smaller pockets supplied by fuses.

7 In 2019, tree related interruptions contributed to approximately 50% of the reliability performance  
8 of the Company. In addition interruptions in radial areas contributed to approximately 40% of the  
9 SAIDI performance of the Company. The project recommendations made in this report support  
10 the Company's reliability and resiliency initiatives to reach top quartile performance and improve  
11 the resiliency of the distribution system.

12 Reliability metrics for CY2019 are presented in the table below based on both the PUC Standard<sup>1</sup>  
13 for excluding major weather events and the IEEE Standard 1366<sup>2</sup> method for excluding major  
14 event days. The metrics presented also exclude transmission supply outages, planned or notified  
15 outages, and all other applicable exclusions<sup>3</sup>. The metrics include customers interrupted ("CI"),  
16 customer minutes interrupted ("CMI"), system average interruption frequency index ("SAIFI"),  
17 system average interruption duration index ("SAIDI"), customer average interruption duration  
18 index (CAIDI), and customers interrupted per interruption index (CIII).

---

<sup>1</sup> 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.

<sup>2</sup> IEEE Major Event Days: Using IEEE criteria, no days were excluded in Calendar Year 2019.

<sup>3</sup> 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.

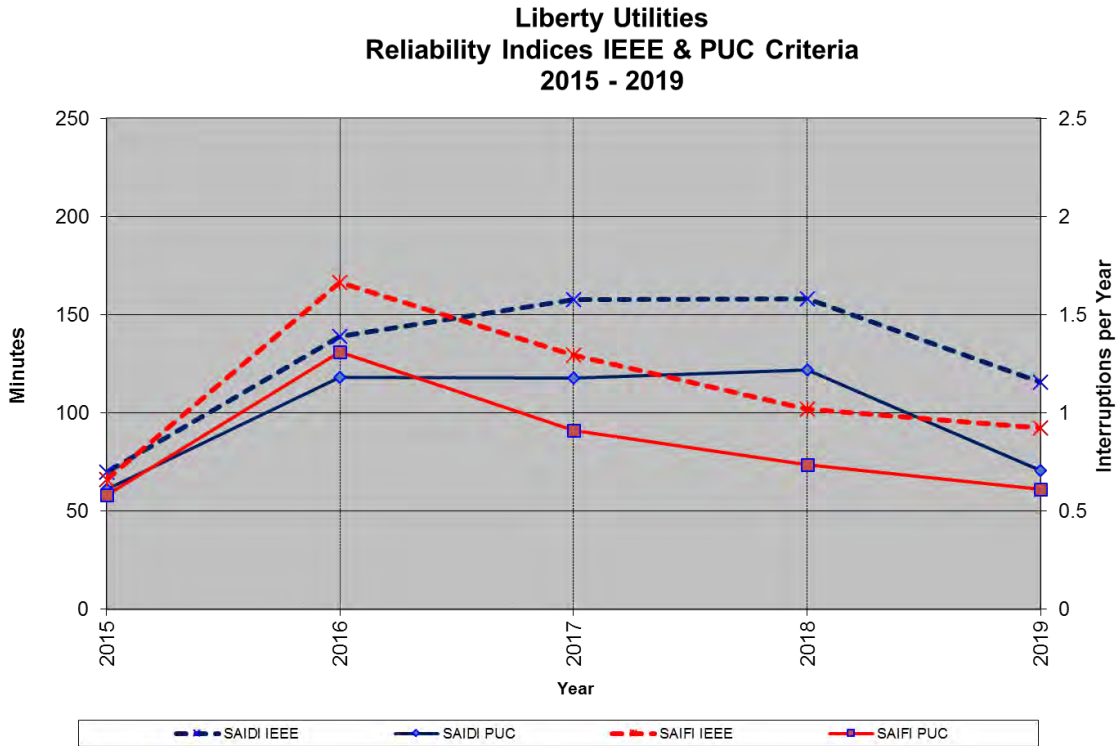
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<b>No Exclusions</b>								
Year	Events	Customers Interrupted	Customer Minutes Interrupted	Customers Served	SAIFI	SAIDI	CAIDI	CIII
2019	650	41,337	5,178,620	44,784	0.9236	115.689	125.28	63.60
<b>Excludes Only IEEE Major Events</b>								
Year	Events	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
<b>Excludes Only PUC Major Events</b>								
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
<b>Excludes Only Loss of Supply by Other Utility or Transmission Outage</b>								
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
<b>Excludes Only Planned Maintenance</b>								
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
<b>All Exclusions: IEEE Major Events, loss of supply, transmission, planned maintenance, Load Shedding, Single Customer Outages, Fire/Police Request</b>								
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
<b>All Exclusions: PUC MEDs, loss of supply, transmission, planned maintenance, Load Shedding, Single Customer Outages, Fire/Police Request</b>								
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

- 1 The historical reliability performance for the Company for the time period from 2015–2019 is
- 2 outlined in Figure 1 below. This chart displays annual SAIDI and SAIFI performance using IEEE-
- 3 1366 and PUC criteria.



1 Figure 1 Liberty Utilities 5 Year Reliability Performance

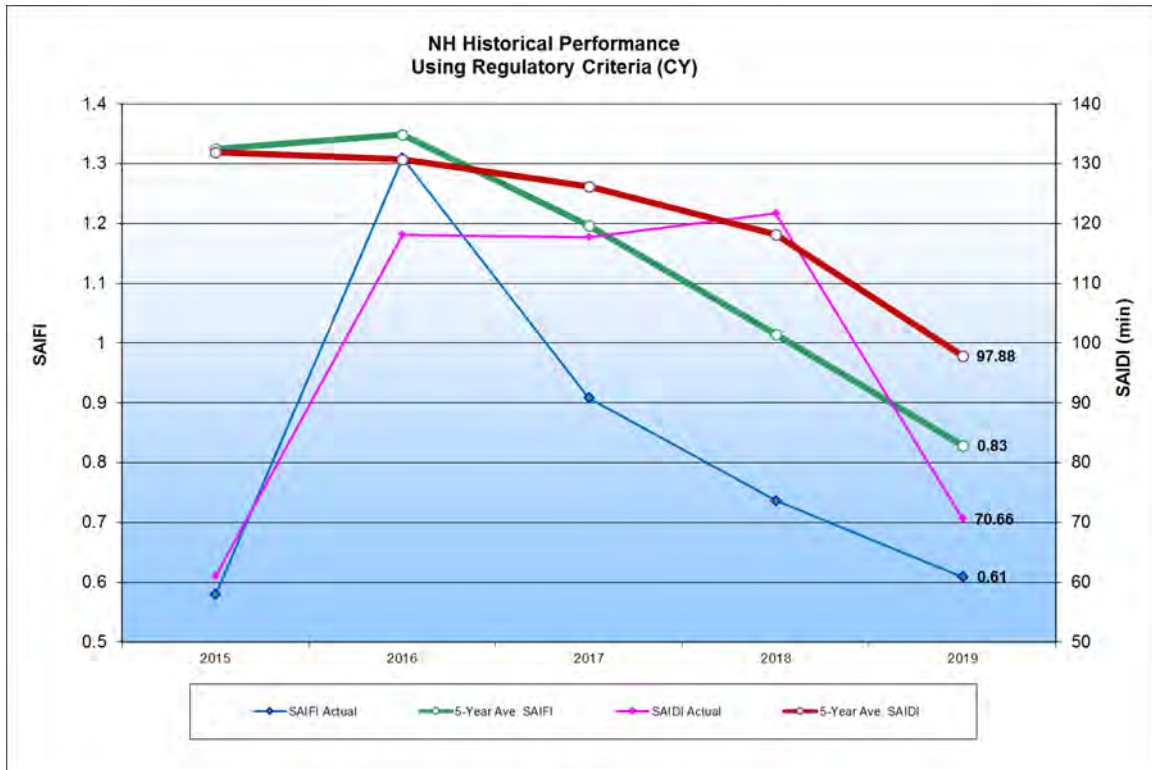


2 In terms of both SAIDI and SAIFI, the reliability performance for the Company in 2019 (based on  
3 IEEE-1366) was the second best performance in the last five years. The SAIDI performance of  
4 115.64 minutes in 2019 is lower than the five-year average of 128 minutes. The SAIFI  
5 performance of 0.923 is lower than the five-year average of 1.11 minutes.

6 Liberty’s annual reliability targets are determined by calculating the average of the previous five  
7 year SAIDI and SAIFI performance.

8 As shown on Figure 2 below, based on PUC criteria, the SAIFI performance of 0.61 and the SAIDI  
9 performance of 70.66 for CY2019 continue on an improving, downward trend, with the 2019  
10 SAIFI and SAIDI results being the second best in twenty years. Only calendar year 2015 resulted  
11 in a lower SAIFI and SAIDI performance.

1 Figure 2 Liberty Utilities 5 Year Rolling Average Reliability Performance

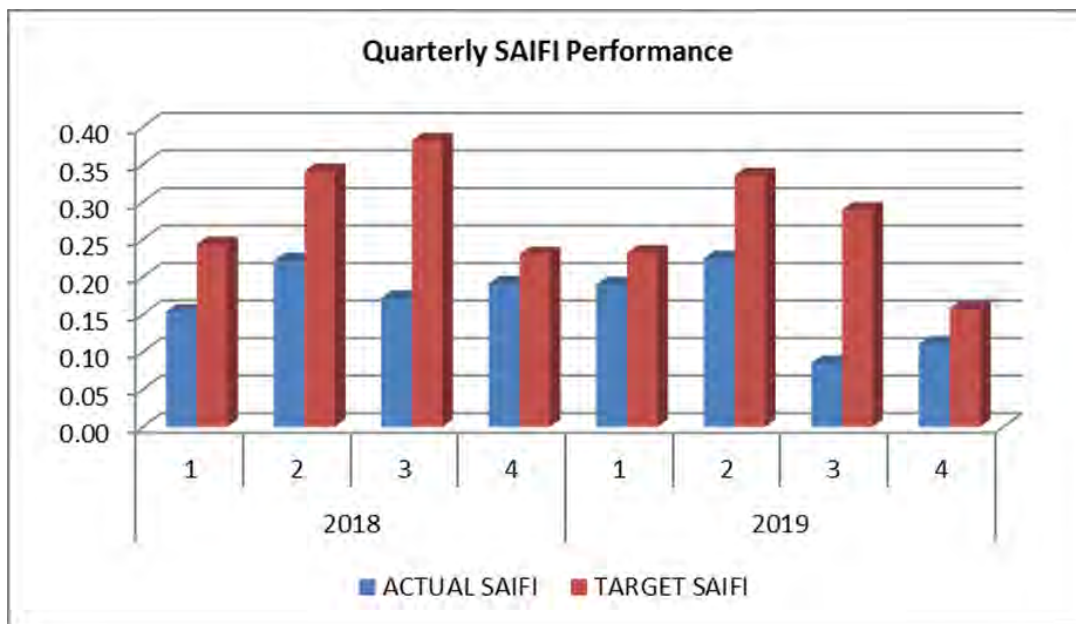


2 In summary, Liberty met its SAIFI and SAIDI targets of 1.01 and 118.17 minutes, respectively,  
 3 which are based on a five-year rolling average and has done so for five consecutive years (2014-  
 4 2019). Liberty expects this overall positive performance in SAIFI and SAIDI to continue as further  
 5 positive impacts from our reliability and vegetation management initiatives are experienced.

1 **2.0 Reliability Performance**

2 **2.1 Performance vs. Goals**

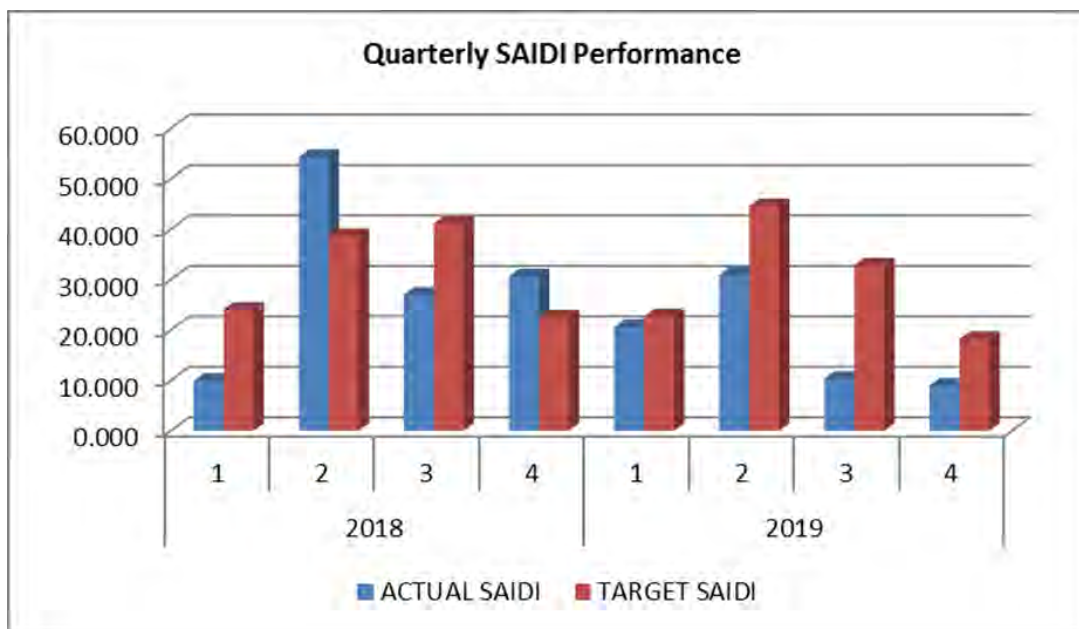
3 Figure 3 Liberty Quarterly SAIFI Performance



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5

Figure 4 Liberty Quarterly SAIDI Performance



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1 **2.3 Reliability Results by Area**

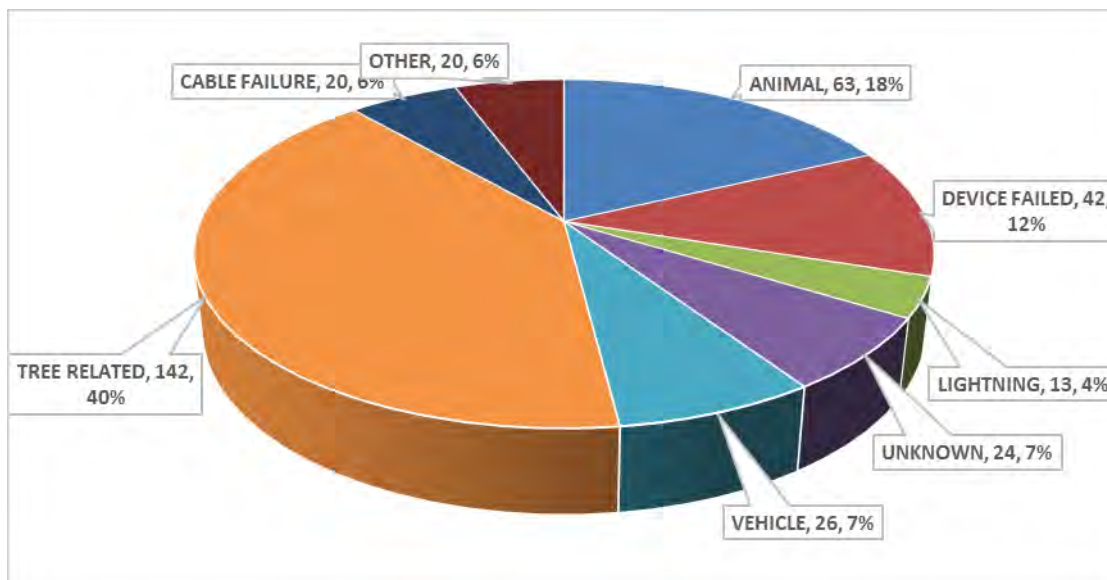
2 Table 2: Liberty Utilities Reliability Performance by Area

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 **3.0 Interruptions by Cause**

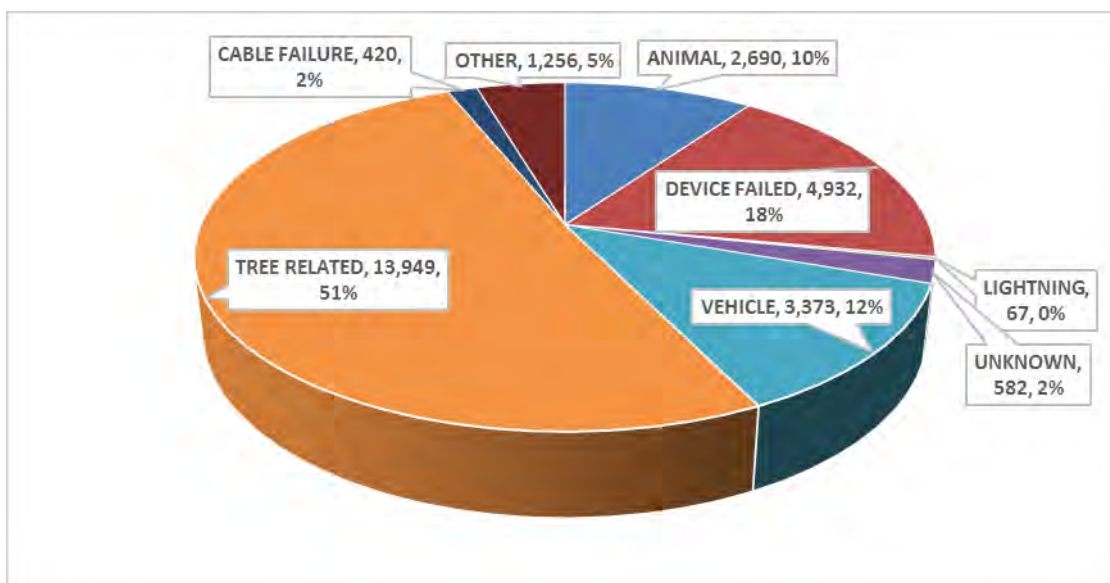
4 This section provides a breakdown of all outages by cause code experienced during 2019. Figures  
5 5, 6 and 7 show the number of interruptions, customers interrupted and customer minutes  
6 interrupted by cause, respectively. Tree related incidents contribute to over 50% of the reliability  
7 performance for the Company.

8 Figure 5 Number of Interruptions by Cause



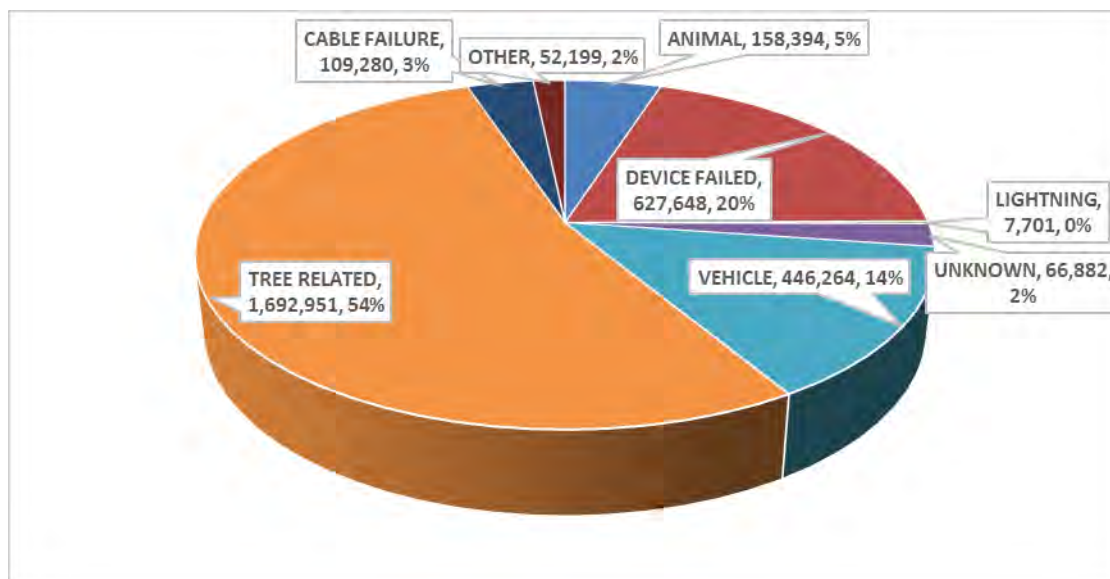
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Figure 6 Customers Interrupted by Cause



2

Figure 7 Customer Minutes Interrupted by Cause



1 **4.0 Interruptions by Tree Related Events**

2 **4.1 2019 Tree Related Reliability Performance**

3 The tree related reliability performance during the time period from January 1, 2019 through  
4 December 31, 2019 is summarized by area in Table 3 below.

5 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

6 The wind and weather statistics of the tree related interruptions is shown in the tables below. Table  
7 4 summarizes the tree related incident results by wind strength and Table 5 by weather events.  
8 Strong winds over 32 mph contributed to 46% of the customer minutes interrupted. In addition  
9 weather events contributed to 46% of the customers interrupted.

10 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



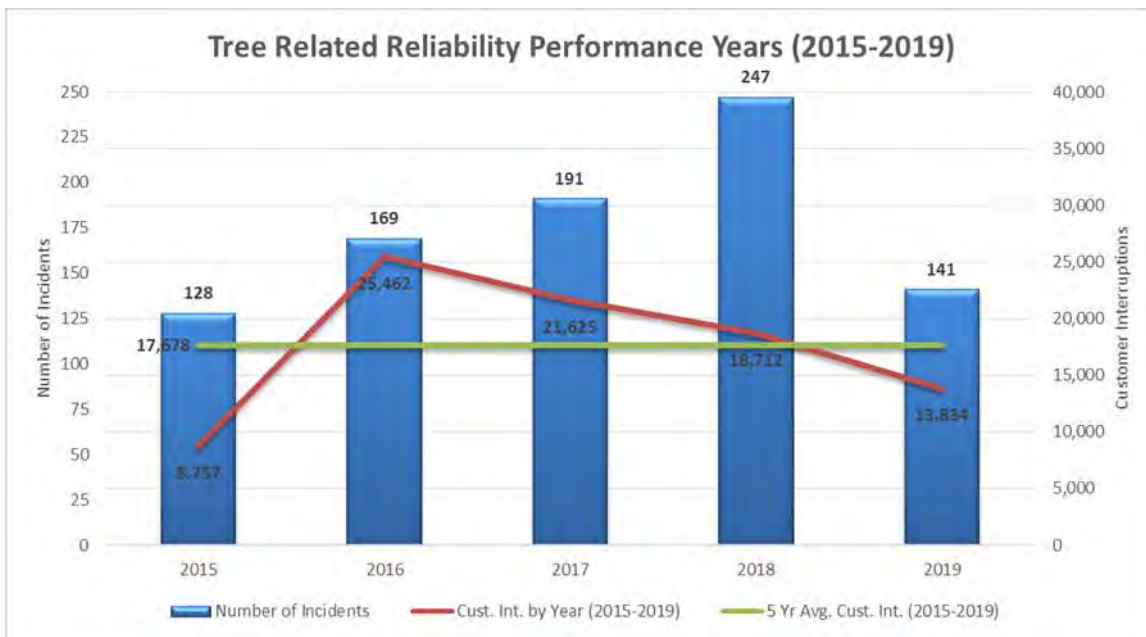
1 Table 5: 2019 Tree Related Reliability Performance by Weather Event Type

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

2 **4.2 2015-2019 Tree Related Reliability Performance**

3 The tree related reliability performance for the Company was reviewed using regulatory criteria.  
4 Figure 8 below displays the number of tree related incidents per year and the number of customers  
5 interrupted from tree related incidents from 2015 to 2019. For comparison the five-year average  
6 of number of customers interrupted from tree related incidents is also shown.

7 Figure 8 Customer Minutes Interrupted by Cause



8 **a. Tree Related Performance – Lebanon Area**

9 The tree related reliability performance of the Lebanon Area feeders during the time period from  
10 January 1, 2015 through December 31, 2019 is summarized in Table 6 below<sup>4</sup>. These are ranked  
11 by circuit SAIFI.

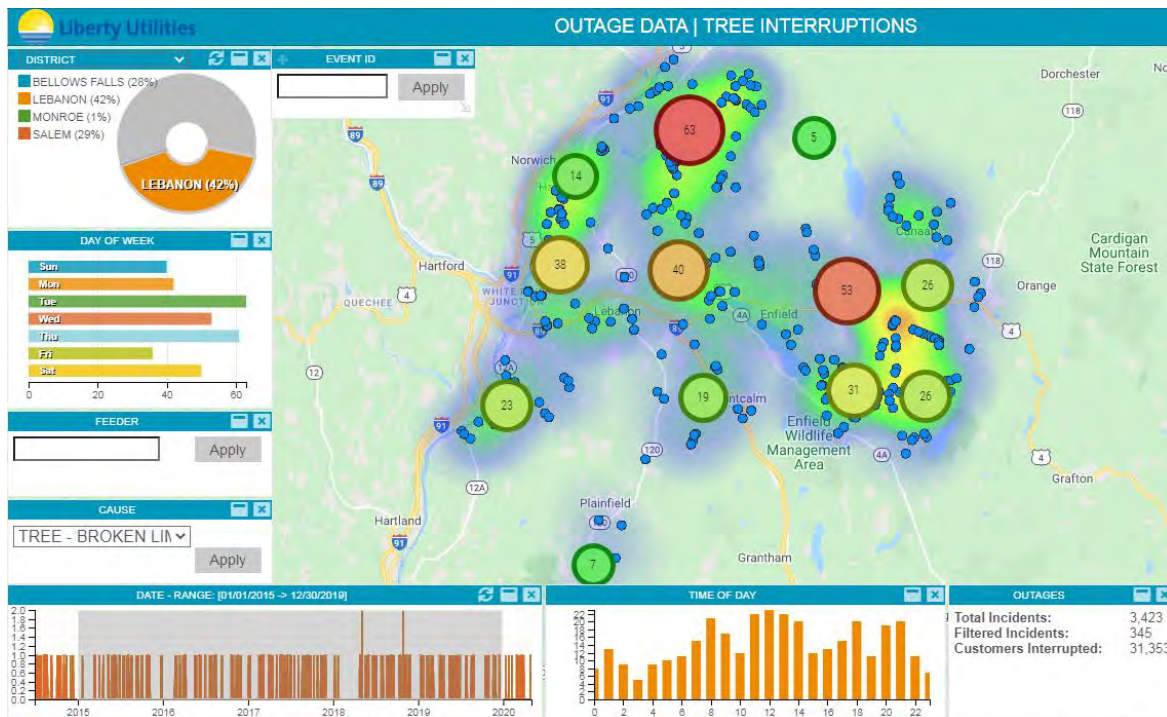
<sup>4</sup> The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

1 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

2 The location of tree related incidents that resulted in an interruption during the time period from  
3 January 2015 through December 31, 2019, using regulatory criteria, is shown in the map below.

4 Figure 9 Lebanon Area Tree Related Incidents





1           **b. Tree Related Performance – Salem Area**

2   The tree related reliability performance of the Salem Area feeders during the time period from  
3   January 1, 2015 through December 31, 2019 is summarized in Table 7 below<sup>5</sup>. These are ranked  
4   by circuit SAIFI.

5           Table 7: 5-Yr. Average Tree Related Reliability Performance – Salem Area

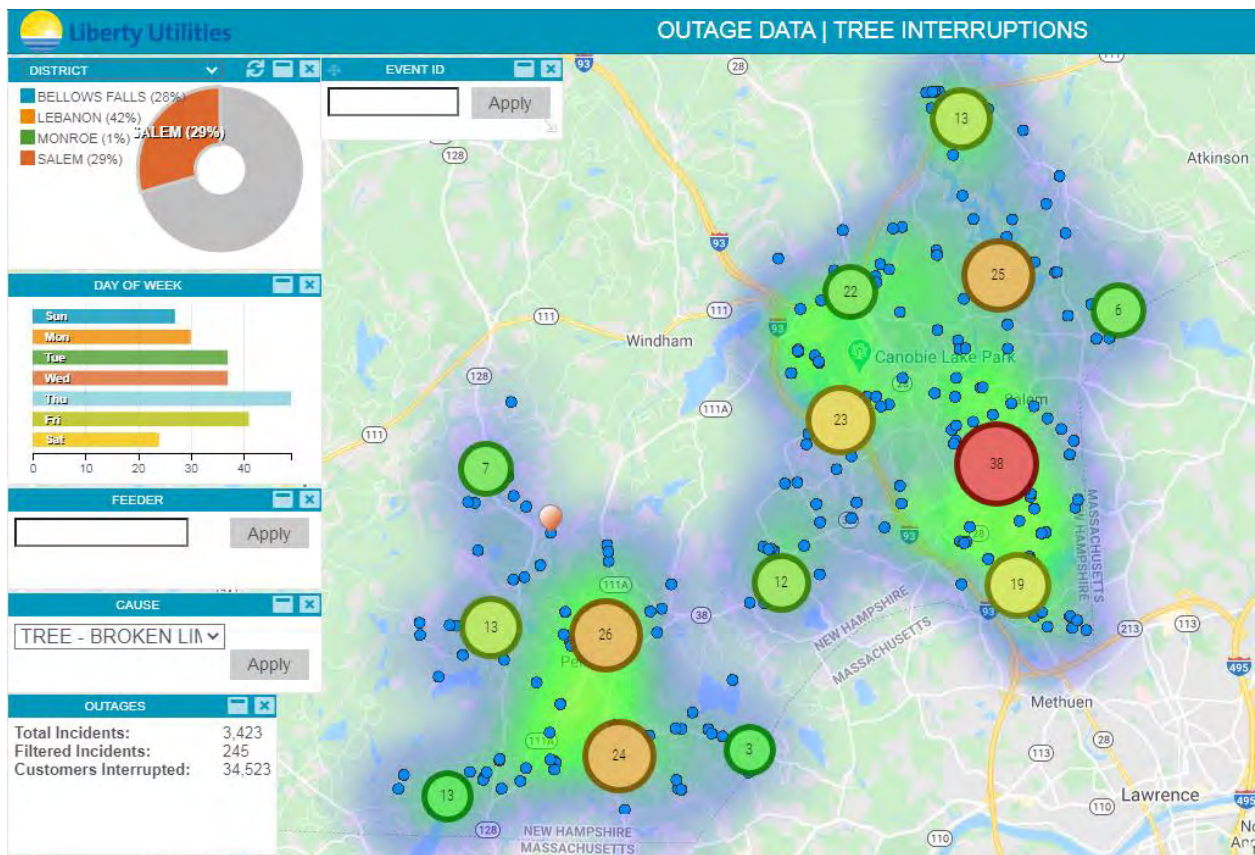
Feeder	# Incidents	cKAIFI	cKAIDI
42-18L4	2	0.65	30.92
42-14L2	8	0.63	71.35
42-9L3	5	0.58	88.17
42-14L3	6	0.50	39.29
42-18L3	1	0.41	14.75
42-13L3	6	0.40	39.43
42-10L2	2	0.37	34.99
42-14L1	7	0.35	47.87
42-10L1	2	0.22	36.56
42-13L2	5	0.21	12.96
42-13L1	5	0.19	21.68
42-10L4	3	0.15	21.11

6   The location of tree related incidents that resulted in an interruption during the time period from  
7   January 2015 through December 31, 2019, using regulatory criteria, is shown in the map below.

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<sup>5</sup>       The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

1 Figure 10 Salem Area Tree Related Incidents



2 **c. Tree Related Performance – Bellows Falls Area**

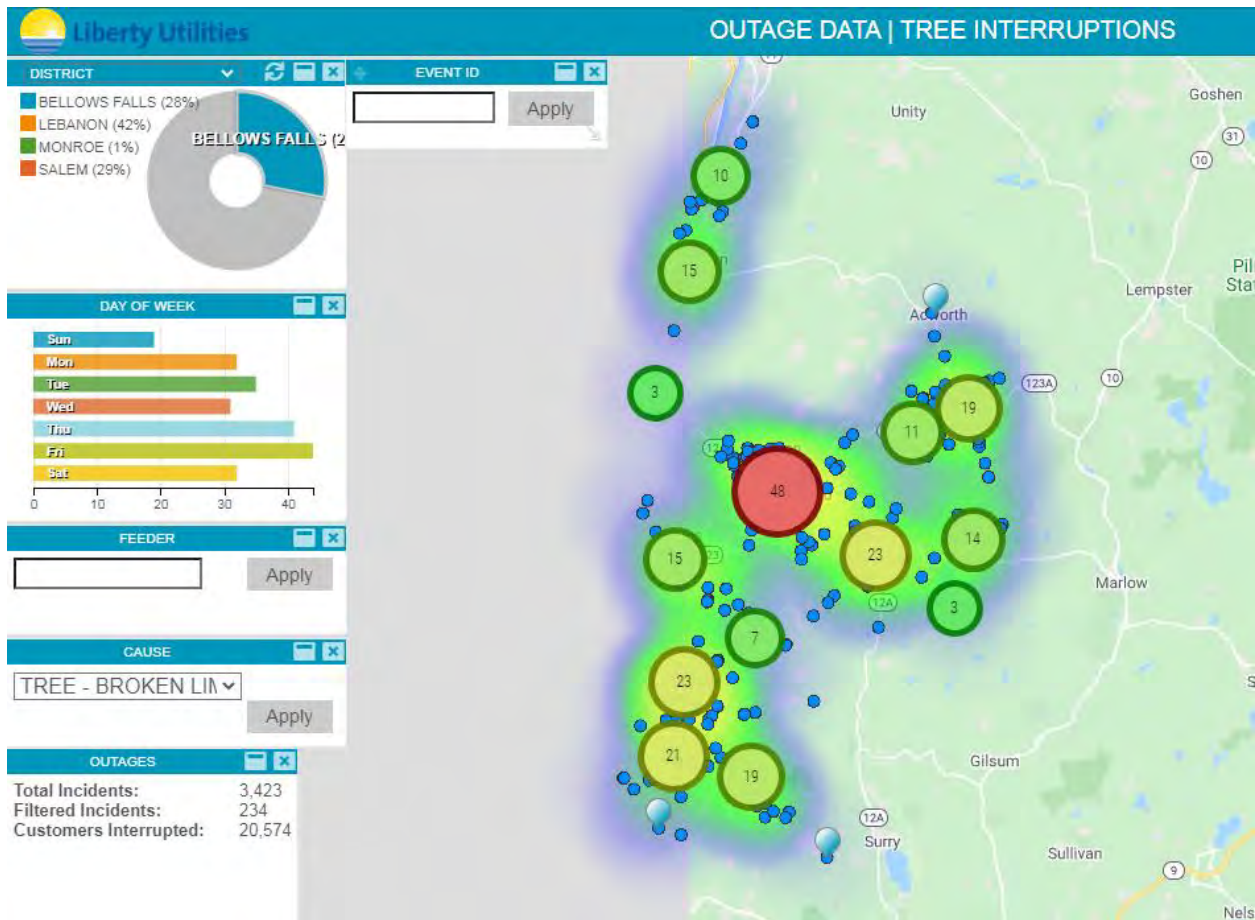
3 The tree related reliability performance of the Bellows Falls Area feeders during the time period  
4 from January 1, 2015 through December 31, 2019 is summarized in Table 8 below<sup>6</sup>. These are  
5 ranked by circuit SAIFI.

6 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

<sup>6</sup> The results presented are determined using the regulatory criteria. Only feeders that have experienced more than 10 interruptions in 5 years are included.

1 Figure 11 Bellows Falls Area Tree Related Incidents



2 **5.0 Poor Performing Feeders**

3 A distribution feeder that possesses a cKAIDI or cKAIFI value for a reporting year that is among  
4 the highest five of all of feeders is considered a Poor Performing Feeder. For additional details  
5 refer to Document DAS-010 Poor Performing Feeder Strategy.

6 **5.1 2019 Poor Performing Feeders**

7 Table 9 below shows the ten worst circuits ranked by the total number of Customer Minutes  
8 Interrupted during the time period between January 1, 2019 and December 31, 2019.

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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

2 Table 10 below provides detail on the major causes of the outages on each of these circuits.  
3 Number of Incidents, Customers Interrupted and Customer Minutes of interruption are given for  
4 the five most prevalent causes during 2019.

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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

2 Table 11 below provides the 3 worst incidents for the 5 worst performing feeders in 2019 ranked  
3 by Customers Minutes Interrupted.

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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



1 **5.2 2015 – 2019 Poor Performing Feeders**

2 The annual performance of the five worst feeders in terms of circuit SAIDI and SAIFI for each of  
3 the past five years is shown in the tables below using the regulatory criteria. Table 12 lists the five  
4 worst performing feeders ranked by circuit SAIDI and Table 13 lists the five worst performing  
5 feeders ranked by circuit SAIFI.

6 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

7 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

8 If a distribution feeder is among the highest five for two and three consecutive years, it is  
9 considered a Problem Feeder and Chronic Feeder respectively.

10 From a circuit SAIDI standpoint, there are no chronic feeders but feeders 12L1, 12L2 and 9L3 are  
11 currently Problem Feeders. From a circuit SAIFI standpoint, there are no chronic or problem  
12 feeders, however feeder 12L2 was a chronic feeder for being amongst worst 5 feeders between  
13 2016 and 2018.

1 **6.0 Radial Distribution Areas**

2 It is estimated that in 2019, only 4% of interruptions occurred in portions of the Liberty distribution  
3 system where there are no adjacent feeder ties to partially restore unaffected portions. However,  
4 given the longer restoration times in these areas, these incidents contributed to 40% of all customer  
5 minute interruptions for the year. Table 14 below shows for each Planning Area, the number of  
6 events, customers interrupted and customer minutes interrupted for interruptions occurring in  
7 radial areas. Table 15 shows the percent contribution that these incidents had on the area’s number  
8 of customers interrupted and customer minutes interrupted.

9 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

10 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%

11 **6.1 Problem Radial Areas**

12 Table 16 below shows for each Radial Location, the average number of customers interrupted, the  
13 average customer minutes interrupted and the percent that these contribute to their distribution  
14 feeder. The table also shows for each location, the load at risk, distance of overhead line exposure  
15 and amount of customers served. These factors coupled with the reliability performance are used  
16 to determine a relative ranking of impact for each location.

17 **7.0 Pockets of Poor Performance**

18 Table 17 below shows pockets of Liberty’s distribution system that have experienced more than 5  
19 interruptions since 2015. This table excludes Radial locations listed in Section 6.1. For additional  
20 details refer to Document DAS-009 Pockets of Poor Performance Strategy.



1

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

2 **8.0 Recommendations**

3 This following section describes recommendations to improve overall system reliability in the  
 4 underperforming areas presented in this document. The recommendations listed below will be  
 5 compared to other proposed projects on a system-wide basis. A risk analysis will determine the  
 6 priority of projects for inclusion in the capital budget. All project costs are of investment grade.  
 7 Project scope and costs will be refined during the detailed engineering process. Liberty’s NWS  
 8 Project Evaluation Process was used to determine if a NWS or a hybrid NWS-Traditional option  
 9 could defer or replace the Traditional option. Three traditional solutions were evaluated using  
 10 Liberty’s NWS initial screen to determine the risk associated with each proposed solution. For  
 11 details, refer to Appendix A – NWS Project Analysis. Liberty expects that the remaining projects  
 12 over \$500,000 with a need date of at least 24 months in the future, will have similar results.

13 **8.1 Bare Conductor Replacement Program**

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

20 The bare conductor replacement program prioritizes sections of feeder mainline for replacement  
 21 that are between the circuit breaker and the first protective device (Zone 1). It also looks to address  
 22 specific areas of the distribution system that have experienced repeated interruptions.

1 Table 18 below lists recommended locations for bare wire replacement and provides an estimate  
2 of the reliability benefits.

3 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

4 **8.2 Enhanced Bare Conductor Replacement Program**

5 The Enhanced Bare Conductor Replacement Program targets specific areas of the distribution  
6 system that are beyond the first protective device and have experienced repeated interruptions.

7 Table 19 below lists recommended locations for bare wire replacement and provides an estimate  
8 of the reliability benefits.

9 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

1       **8.3 Distribution Automation**

2       For details on the Company's distribution automation strategy refer to Document DAS-002  
3       Distribution Automation Strategy. In general, the Company gives DA projects a Risk Score of 34.

4       **8.4 Underperforming Feeder Program**

5       For details refer to Document DAS-010 Poor Performing Feeder Strategy. Table 20 below lists  
6       recommended projects to improve the reliability of Poor Performing Feeders.

7                       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       **8.5 Pocket of Poor Performance Program**

9       For details refer to Document DAS-009 Pockets of Poor Performance Strategy. Table 21 below  
10       lists recommended projects to improve the reliability of these pockets of poor performance.

11                      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

1 performance. If enacted, these will provide considerable reliability and resiliency benefits for our  
2 Customers.

3 **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			
<b>Total Assessment</b>	<b>100%</b>	<b>1.50</b>	<b>1.25</b>	<b>0.00</b>	<b>0.00</b>	
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>3</b>	

<b>RELIABILITY Risk</b> 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		
<b>Totals</b>	<b>100%</b>	<b>1.7</b>	<b>1.5</b>	<b>0</b>	<b>0</b>
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>3</b>

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**Identified Problem:** 12L2 Watkins Hill Rd P149 Tree Related Interruptions  
11/2/2020

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

**Identified Problem:** 12L2 Watkins Hill Rd P149 Tree Related Interruptions  
11/2/2020

<b>PERFORMANCE Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
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		
<b>Totals</b>	<b>100%</b>	<b>1.65</b>	<b>1.35</b>	<b>0</b>	<b>0</b>
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>3</b>	<b>3</b>

**PROJECT NAME:** 12L2 Watkins Hill Rd P149 Tree Related Interruptions  
11/2/2020

<b>ENVIRONMENTAL Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>
Wetland Impact	25%	1	2		
Tree Clearing	25%	1	2		
Community Impacts	25%	1	2		
Municipal Impacts	25%	2	1		
<b>Totals</b>	<b>100%</b>	<b>1.25</b>	<b>1.75</b>	<b>0</b>	<b>0</b>
	<b>Ranking</b>	<b>2</b>	<b>1</b>	<b>3</b>	<b>3</b>

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NWA EVALUATION SUMMARY							
<b>Identified Problem:</b> Meriden Rd Plainfield							11/2/2020
<b>Project Need Year:</b> 2024							
<b>Brief Project Description/need:</b> Reliability improvement - Meriden Rd Area							
<b>Project Scope</b>				<b>Option</b>			
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			
<b>Scoring Values</b>							
Marginal with mitigation				1			
Marginal without mitigation				2			
Acceptable				3			
Best Solution				4			
<b>Evaluation Summary</b>							
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	
<b>Total Assessment</b>	<b>100%</b>	<b>3.93</b>	<b>3.16</b>	<b>1.93</b>	<b>2.56</b>	<b>2.92</b>	
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>5</b>	<b>4</b>	<b>3</b>	

**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
<b>Totals</b>	<b>100%</b>	<b>5</b>	<b>2.6</b>	<b>2.1</b>	<b>1.5</b>	<b>3.8</b>
	<b>Ranking</b>	<b>1</b>	<b>3</b>	<b>4</b>	<b>4</b>	<b>2</b>

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**Identified Problem:** Meriden Rd Plainfield  
11/2/2020

<b>FEASIBILITY Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>4.65</b>	<b>4.45</b>	<b>2.3</b>	<b>2.35</b>	<b>2.35</b>
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>5</b>	<b>3</b>	<b>3</b>

**Identified Problem:** Meriden Rd Plainfield  
11/2/2020

<b>PERFORMANCE Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>4.1</b>	<b>2.85</b>	<b>2.5</b>	<b>2.05</b>	<b>3.45</b>
	<b>Ranking</b>	<b>1</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>2</b>

**PROJECT NAME:** Meriden Rd Plainfield  
11/2/2020

<b>ENVIRONMENTAL Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>2.75</b>	<b>2.75</b>	<b>2.5</b>	<b>4.75</b>	<b>4</b>
	<b>Ranking</b>	<b>3</b>	<b>3</b>	<b>5</b>	<b>1</b>	<b>2</b>



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NWA EVALUATION SUMMARY							
<b>Identified Problem:</b> Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield							11/2/2020
<b>Project Need Year:</b> 2024							
<b>Brief Project Description/need:</b> Improve reliability of customers supplied from 7L1 and 7L2 feeders in Enfield NH							
<b>Project Scope</b>		<b>Option</b>					
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					
<b>Scoring Values</b>							
Marginal with mitigation		1					
Marginal without mitigation		2					
Acceptable		3					
Best Solution		4					
<b>Evaluation Summary</b>							
<b>Evaluation Criteria</b>	<b>% Weight Factor*</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>	<b>Comments</b>
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	
<b>Total Assessment</b>	<b>100%</b>	<b>3.74</b>	<b>3.06</b>	<b>1.88</b>	<b>2.65</b>	<b>2.90</b>	
	<b>Ranking</b>	<b>1</b>	<b>2</b>	<b>5</b>	<b>4</b>	<b>3</b>	

**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
<b>Totals</b>	<b>100%</b>	<b>4.2</b>	<b>2</b>	<b>2.2</b>	<b>2.3</b>	<b>3.8</b>
	<b>Ranking</b>	<b>1</b>	<b>5</b>	<b>4</b>	<b>2</b>	<b>2</b>

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**Identified Problem:** Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield  
11/2/2020

<b>FEASIBILITY Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>4.4</b>	<b>4.45</b>	<b>1.95</b>	<b>2.35</b>	<b>2.35</b>
	<b>Ranking</b>	<b>2</b>	<b>1</b>	<b>5</b>	<b>3</b>	<b>3</b>

**Identified Problem:** Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield  
11/2/2020

<b>PERFORMANCE Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>4.2</b>	<b>2.95</b>	<b>2.5</b>	<b>1.85</b>	<b>3.45</b>
	<b>Ranking</b>	<b>1</b>	<b>3</b>	<b>4</b>	<b>5</b>	<b>2</b>

**PROJECT NAME:** Improve reliability for customers at Lockehaven Rd - Potato Rd Enfield  
11/2/2020

<b>ENVIRONMENTAL Risk</b> Evaluation Criteria	<b>Weighing Factor</b>	<b>Option 1</b>	<b>Option 2</b>	<b>Option 3</b>	<b>Option 4</b>	<b>Option 5</b>
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
<b>Totals</b>	<b>100%</b>	<b>2.75</b>	<b>2.75</b>	<b>2.5</b>	<b>4.5</b>	<b>3.75</b>
	<b>Ranking</b>	<b>3</b>	<b>3</b>	<b>5</b>	<b>1</b>	<b>2</b>