REVISED

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 19-XXX

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

DIRECT TESTIMONY

OF

ROBERT JOHNSON, JR.,

JOEL RIVERA,

ANTHONY STRABONE,

AND

HEATHER M. TEBBETTS

July 15, 2019

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I. INTRODUCTION AND BACKGROUND

Q. Mr. Johnson, please state your full name and business address.

A. My name is Robert Johnson, Jr. and my business address is 9 Lowell Road, Salem, New Hampshire.

Q. By whom are you employed and in what position?

A. I am employed as the Project Engineer - Electric by Liberty Utilities Service Corp. ("Liberty") which provides services to Liberty Utilities (Granite State Electric) Corp. ("Granite State" or "the Company"). In my capacity as Project Engineer - Electric, I am responsible to manage and coordinate the development and maintenance of distribution construction standards and material specifications, engineering policies and procedures, and engineering standards programs.

Q. Please describe your educational background and certifications.

A. I graduated from Northeastern University in 1986, earning a Bachelor's Degree in Electrical Engineering (BSEE). I also earned a Master's Degree in Power Systems Management from Worcester Polytechnic Institute in 2009.

Q. Please describe your professional experience.

A. In 1986, I began my engineering career as an Electrical Engineer with Metropolitan District Commission, Boston, Massachusetts, responsible for design, installation, and maintenance of electrical systems and equipment, lighting, and traffic control systems for the Division. In 1987, took a Field Engineer position with Massachusetts Electric ("NEES") in North Andover, Massachusetts, responsible for engineering design of overhead and underground distribution facilities and coordinating construction projects with internal and external stakeholders. In 1993, I was promoted to T&D Operations Manager, responsible for the coordination and supervision of all aspects of the Transmission and Distribution operations in the Tewksbury satellite of the Merrimack Valley District, Massachusetts Electric Co. I progressed through NEES T&D Operations Management with increasing responsibilities from 1996 through 2000 with Manager positions in Salem, New Hampshire (Granite State Electric) in 1996 and Weymouth, Massachusetts (Massachusetts Electric) in 1997. In 2000, I took a position as Coordinator Overhead Lines with O&M Support Services with National Grid Service Co., responsible for coordinating overhead practices and formulating consistent systems policies and procedures based on optimal practices. In 2002, I progressed to Lead Coordinator in Distribution Engineering Services responsible for planning, developing, and coordinating the implementation of policies and techniques for electric overhead and underground distribution standards, construction, operations, and maintenance for the distribution system. In 2009, I took a position as Manager, Transmission Scheduling for TLS and Substation Construction National Grid, responsible for ensuring that the Scheduling group developed a close working relationship with both the New York and New England In-House Construction team to provide an accurate construction schedule within an 18-month rolling work plan in Primavera. In 2011, I took a position at Liberty Utilities NH as Program Manager, Compliance, Quality, & EM – Standards, Policies and Codes, responsible for the development and maintenance of Liberty Utilities Overhead and Underground Distribution Construction Standards, Liberty Utilities Electric Material Specifications, and Electric Operating Procedures ("EOP").

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("the Commission")?

A. Yes, in 1997 in relation to a December 1996 storm and reliability hearings.

Q. Mr. Rivera, please state your full name and business address.

A. My name is Joel Rivera and my business address is 9 Lowell Road, Salem, New Hampshire.

Q. By whom are you employed and in what position?

A. I am employed as the Manager of GIS and Electric System Planning by Liberty . In my capacity as Manager of GIS and Electric System Planning, I am responsible for managing Granite State's electric system capacity, reliability, integrity, interconnections, protection systems, equipment and system upgrades, prioritization, and associated budget estimates.

Q. Please describe your educational background and certifications.

A. I graduated from Universidad Interamericana de Puerto Rico in 2003, earning a bachelor's degree in electrical engineering. I also earned a master's degree in electrical engineering from the University at Buffalo in 2017. I am a registered professional engineer in the state of New Hampshire.

Q. Please describe your professional experience.

A. In 2006, I began my engineering career as an associate engineer with National Grid USA ("National Grid") in Buffalo, New York. By 2009, I had progressed to senior engineer in the distribution planning department for National Grid's electric distribution system in Buffalo. In 2009, I was promoted to lead engineer and was responsible for distribution planning, asset management, protection, and reliability functions for National Grid's electric distribution system in both New England and New York. In 2013, I assumed the role of Planning Engineer - Electric for Liberty Utilities Service Corp. In 2018, I was promoted to Manager of GIS and Electric System Planning and I am responsible for electric and gas map records, and for developing and implementing the company's electric system planning initiatives in the electric delivery business.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("the Commission")?

A. Yes, I testified before the Commission on the Company's Reliability Enhancement Program for program years 2016, 2017, and 2018.

Q. Mr. Strabone, please state your full names, business addresses, and positions.

A. My name is Anthony Strabone and my business address is 9 Lowell Road, Salem, New Hampshire. I am the Manager of Electrical Engineering for Liberty and I am responsible for the electric capital work plan whereby I manage engineering and construction resources for capital projects.

Q. Please describe your educational background and training.

A. I graduated from Merrimack College in 2004 with a Bachelor of Science degree in Electrical Engineering. I received a Master's of Business Administration from Southern New Hampshire University in 2006. I received a Project Management Professional (PMP) Certification in 2017 from the Project Management Institute.

Q. Please describe your professional background.

A. I joined Liberty in November 2014. Prior to my employment at Liberty, I was employed by PSNH as a Substation Supervisor in Substation Maintenance from 2010 to 2014. Prior to my position in Substation Maintenance, I was a Substation Engineer in Substation Engineering from 2008 to 2010 and an Engineer in the System and Planning Strategy department from 2004 to 2008.

Q. Have you previously testified before the Commission?

A. Yes, I testified in support of the Company's 2019 step adjustment in Docket No. DE 16-383.

Q. Ms. Tebbetts, please state your full name, business addresses, and position.

A. My name is Heather M. Tebbetts and my business address is 15 Buttrick Road, Londonderry, New Hampshire. I am Manager of Rates and Regulatory Affairs for Liberty and am responsible for providing rate-related services for Granite State.

Q. Please describe your educational background and training.

A. I graduated from Franklin Pierce University in 2004 with a Bachelor of Science degree in Finance. I received a Master's of Business Administration from Southern New Hampshire University in 2007.

Q. Please describe your professional background.

A. I joined Liberty in October 2014. Prior to my employment at Liberty, I was employed by Public Service Company of New Hampshire ("PSNH") as a Senior Analyst in NH Revenue Requirements from 2010 to 2014. Prior to my position in NH Revenue

Requirements, I was a Staff Accountant in PSNH's Property Tax group from 2007 to 2010 and a Customer Service Representative III in PSNH's Customer Service Department from 2004 to 2007.

Q. Have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission.

II. PURPOSE OF TESTIMONY

Q. What is the purpose or your testimony?

A. Order No. 26,039 (July 10, 2017) in Docket No. DE 16-097 approved Granite State's LCIRP and established July 1, 2019, as the deadline for the Company to file its next LCIRP. RSA 378:38 prescribes the contents of the 2019 LCIRP that Granite State would file by that date. However, Staff's February 12, 2019, "Staff Recommendation on Grid Modernization" filed in Docket No. 15-296 proposed that the Commission substantially augment the existing LCIRP requirements through what Staff called an "integrated distribution plan," or IDP. The IDP, as proposed by Staff, would have some elements of the existing LCIRP statute plus many new requirements, the details of which would be refined through a working group process over the coming year. A comparison of the items listed in the LCIRP statute, RSA 378:38, with the items to be included in the proposed IDP, confirms that the IDP would be a far more comprehensive document than an LCIRP. Given these substantial differences, Staff also acknowledged that a waiver of the requirement to file the next LCIRP for Granite State and the other utilities would be appropriate. Accordingly, the Company requested a waiver of the requirement to file its LCIRP by July 1, 2019, for the "good cause" reason that a 2019 LCIRP filing would be a wasted effort because it would almost immediately be superseded (or satisfied) by the proposed 2020 IDP. The time spent evaluating and adjudicating the 2019 LCIRP through the second half of 2019 and into 2020 (Granite State's prior LCIRP proceedings took 18 months) would overlap with the working group schedule that Staff proposed to refine and establish the IDP process. And just when the Commission may be in a position to rule on the 2019 LCIRP, the Company would be filing the 2020 IDP, which would cause all involved to cast aside the 2019 LCIRP and focus on the 2020 IDP. With the Staff recommendation, the Company believed it would be a more efficient use of utility and Staff resources to delay or waive that LCIRP filing requirement to allow Liberty to file its first IDP in 2020. Staff has recommended that the electric utilities seek waivers of LCIRP filing requirements from the Commission to allow them to focus their efforts on preparing "more robust, integrated, and transparent IDPs." On June 14, 2019, the Company received Order No. 26,261 partially granting the request for a waiver but requiring the Company to make a more limited filing by July 15, 2019, with the following updates to its 2016 LCIRP:

1. Confirmation that the utility is currently following the process of system planning using established procedures, criteria, and policies outlined in its 2016 LCIRP, and achieving the objectives included its 2016 LCIRP.
2. Copies of adopted standard operating procedures for employees and managers integration day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning.

This testimony, which summarizes the Company's current practices for system planning and day-to-day activities, providew the information necessary to comply with Order No. 26,261.

The Company is providing the following attachments:

- Attachment 1: Distribution Asset Strategy and Distribution Asset Management documents
- Attachment 2: Planning Criteria
- Attachment 3: 2018-2034 Seasonal Peak Forecast
- Attachment 4: Bellows Falls Problem Identification example
- Attachment 5: 2016 & 2017 Capital Work Plan results
- Attachment 6: Electric Operating Procedures

III. CURRENT PRACTICES

A. System Planning

Q. Please describe the tools the Company provided in its last LCIRP to evaluate the distribution system.

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

- The SynerGee Electric 6.1 load flow program models supply system and distribution feeders. It also assists in determining coordination between protective devices and short circuit duty at all sub-transmission and distribution facilities.

- The Geographical Information System ("GIS") geographically maps supply and distribution lines and is used to store attribute data for different asset class of the distribution system. Using data contained in the Cogsdale system, the GIS allows to determine customer demands at a service point level and/or a supply transformer level. This data is exported to SynerGee Electric 6.1 to make part of the electric system model that is used for planning studies.
- The Supervisory Control and Data Acquisition ("SCADA") system provides real time loading and voltage data for monitored facilities such as substation breakers and line reclosers and provides historical load and voltage data for various electrical facilities.
- The Responder System serves as an outage management system and provides real time outage information and a consolidation and statistical analysis of historical reliability data.
- The Quadra system serves as a work management tool, as well as an estimation tool.

Q. Is the Company still using these tools to evaluate the distribution system for planning purposes?

A. Yes.

Q. Does the Company have documentation that it has established procedures, criteria and policies for employees and managers integration day-to-day and long-term planning consistent with the Company's objectives of Least Cost Planning?

A. Yes. Please see Attachment 1 for the guidance documents and strategies used to evaluate the distribution system for planning purposes. These documents have been in place since the Company was previously owned by National Grid and have been updated to reflect Granite State's most recent asset investments. Standard operating procedures are used by the operations department in the operation and maintenance of the system and are not considered planning documents. In addition, see Attachment 2 for the company's latest version of the Distribution Planning Criteria.

B. Day-to-Day Practices

Q. Please explain how the Company integrates planning into day-to-day practices.

A. The Electric System Planning Department at Granite State performs an annual planning process to determine what projects are necessary for adequate electric system performance, and includes reviews of: capacity, delivery voltage, reliability, asset condition, and power quality. This process is documented on Section 4.4 and Appendix C of the Company's 2016 Least Cost Integrated Resource Plan. Depending on the needs of the system and available funding, these projects may be completed either over the course of one year or multiple years. Once the projects are identified and prioritized, they are included in future years' capital budgets and depending on the available resources, are either assigned internally to the Operations department, or bid to external vendors. The Operations department follows Liberty Utilities' Distribution Overhead &

Underground Construction Standards and Electric Operating Procedures and any vendor working on the Company's system is required to follow the same standards & procedures, including industry best practices and OSHA guidelines.

Q. Has the Company achieved its main objectives as set forth in the 2016 LCIRP?

A. Yes. The purpose of the LCIRP is to provide the Commission with an understanding of the planning process employed by the Company to meet its obligation to provide safe, reliable, and least-cost electric service to its customers. To achieve that goal the system is planned and operated with the objective of providing safe and reliable service to customers under normal and contingency conditions incorporating existing planning criteria, area strategies, and asset strategies. When system deficiencies are identified from the annual planning review, the Company implements its processes to address those deficiencies to ensure safe, reliable, and economic service to customers.

The first step of the planning process is the development of a demand forecast that is used by planning engineers to project loading levels for distribution facilities. See Attachment 3 for the latest demand forecast used by the Company.

The second step of the planning process is to identify system deficiencies for capacity, asset condition, or asset performance. In this step, several inputs are utilized such as reliability data, loading data, power quality data, field inspections, maintenance and testing data, asset strategies, and voltage data. Using an example for capacity analysis, planning engineers apply the forecasted growth rates in Step 1 and load additions to each distribution feeder, supply line, and transformer to ensure that adequate capacity exists within the fifteen-year planning horizon. See Attachment 4 for a sample of the problem identification review for the Bellows Falls Planning Study Area using 2018 load and applied growth forecast. From this review, capacity concerns have been identified for the 12L1 transformer under normal and contingency scenarios. In addition, initial results for the Vilas Bridge feeders 12L1 and 12L2 indicate that in 2023 the contingency loading on these feeders approach the 16MWhr limit as they are estimated at 15.2 and 15.6 MWhr respectively.

The third step of the planning process develops solutions that aim to satisfy planning criteria and strategies whose main objective is to provide safe, reliable, and economic service to customers. These criteria and strategies are provided in Attachment 1 and Attachment 2. As part of this process, non-wires solutions are considered. The above example for the Vilas Bridge feeder and transformer deficiencies will be evaluated for a Non-Wire Alternative.

The fourth step of the planning process prioritizes all system deficiencies and given solutions via a prioritization matrix that considers the impact of the deficiency and the likelihood of occurrence. This matrix is shown in Appendix C of the 2016 LCIRP. Continuing to use the Vilas Bridge deficiency as an example, using a load at risk of 3.6 MVA for the 12L2 and a likelihood of occurring in three to five years, would result in a prioritization score of 34 from a maximum of 49. This method is used as a guide to prioritize projects that will be part of the capital plan. Other considerations for inclusion into the capital plan include budget constraints or changes that may occur during the year.

The fifth step of the planning process involves developing the Capital Plan. The Capital Plan is approved by Senior Management based on budgetary targets from the Finance department. See Attachment 5 for the Company's Distribution Work Plan results for the year 2016 and 2017 showing success in meeting the Capital Plan. In addition, the Company has met its reliability targets for both SAIDI and SAIFI for the past four years. Between 2014 and 2018, and using five-year rolling averages, the Company has reduced the outage duration by forty minutes for the average customer while reducing the probability of being interrupted by 0.55. This improvement in reliability can be directly attributed to the strategies and processes implemented by the Company.

Q. Is the Company submitting its Distribution Overhead & Underground Construction Standards and Electric Operating Procedures as part of this filing?

A. Yes. As required by the Order, the Company is providing the procedures in Attachment 6.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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DAS-001
Distribution Line Overarching Strategy
Table of Contents

Amendments Record

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

Strategy Justification

1.0 Purpose and Scope

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

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

It is the intent that this strategy be:
- Consistent with the company's organizational plan,
- Consistent with all organizational policies,
- Provide the framework for developing and enabling specific asset management strategies, and
- Be consistent with the company's overall risk management objectives.

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

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

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

2.0 Asset Management Objectives

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

- **Safety**
  - Achieve zero injuries every day
  - Continue to work on processes, systems and designs that improve safety, and to reinvigorate our safety culture to bring fresh effort to improving performance
  - Design for safety

- **Reliability**
  - Meet service quality requirements for frequency and duration of outages to our distribution system (SAIDI/SAIFI) using NH PUC regulatory criteria of 5 year rolling averages.
  - Achieving this objective, and making it sustainable, will require investments in the replacement of our aging infrastructure.
  - Building relationships with our regulatory bodies is required to achieve mutual understanding for the need to support long-term investment in a sustainable distribution network

- **Customer Service**
  - Achieve targeted customer service and satisfaction levels measured by a 3rd party survey company to evaluate how our customers fell 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
- Overhead Switch Strategy
- URD/UCD 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 for five years. Reliability data prior to 2014 is maintained in other spreadsheets and databases.

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

Future Recommendations – Reliability Reporting

➢ **ADMS (under development)**

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

5.4 Asset Condition Data

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

5.5 Risk Assessment

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

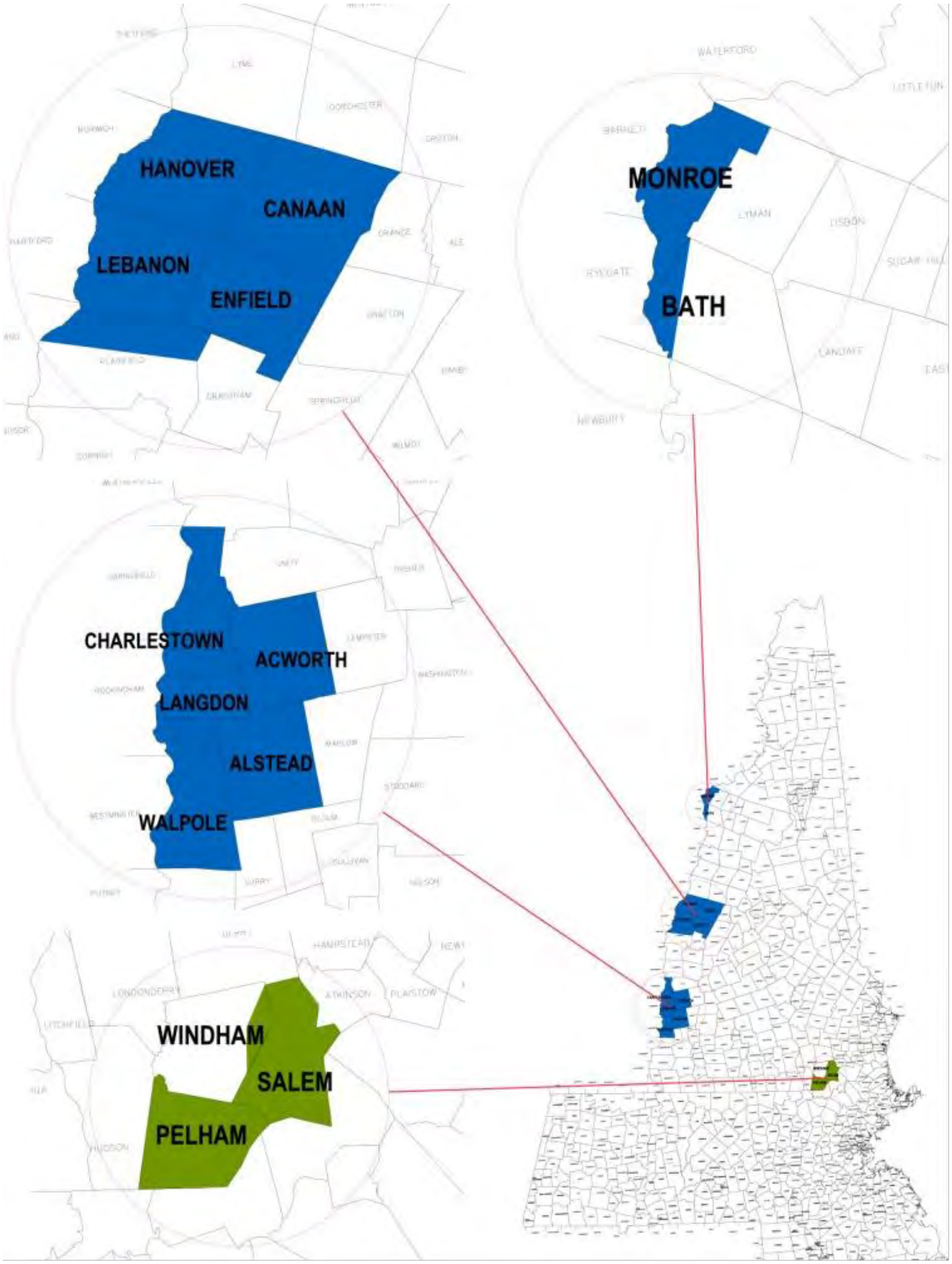
6.0 State of the System

6.1 Assets

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

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

6.2 Service Territory Graphics



6.3 Load Data

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

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

Company	Summer 2017 (MW)	Summer 2018 (MW)
Liberty - NH	181	179

DAS-002
Distribution Automation (DA) Strategy
Table of Contents

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.

The distribution system of the future (DSF) 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). This first version of the strategy is currently under development and is being aligned to serve as a company-wide strategy.

Amendments Record

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

Strategy Justification

1.0 Purpose and Scope

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

2.0 Strategy Description

2.1 Background

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

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

2.2 Coordination with Advanced Distribution Management System (ADMS)

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

2.3 What is encompassed by DA

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

3.0 Benefits

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

3.1 Safety & Environmental

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

3.2 Reliability

3.2.1. Distribution

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

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

3.3 Regulatory

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

3.4 Customer

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

4.0 Estimated Costs

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

average cost **per DA controlled location** =	total	$65,000
(includes cost of standard recloser)	material	$45,000
	labor	$3,000
	contingency	$11,000
	misc	$6,000
ave cost per **DA controlled fdr or ckt** =	total	$250,000
(includes cost of standard recloser)	material	$177,000
	labor	$11,000
	contingency	$40,000
	misc	$22,000

5.0 Implementation

While many of the DA applications apply to a broad range of systems, the distribution systems for each area may have different characteristics. This will require each area to develop and design its own DA system that brings positive value to their system. It is recommended that all new and large projects such as substations, feeders and expansions be evaluated by the Planning Departments for DA implementation.
In general DA is implemented incrementally rather than all at once. This allows each utility to develop its DA System at a rate that fits its resource capabilities and its financial constraints. At a conceptual level, the following table illustrates the suggested development process.

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

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

Application Area	Benefits	Applications
SCADA Applications	RTU, Detailed monitoring, Fault Location. Improves fault response and repair times	Substation SCADA, Feeder SCADA, Volt/Var SCADA

Advanced monitoring applications	Intelligent electronic devices (IEDs): relays, reclosers, capacitor controls, fault location, equipment diagnostics, sensors	Integration of data into common database platform. Fault Location, power quality identification, equipment diagnostics, asset management
Automatic system reconfiguration	Improved efficiency, reduced losses, prevent overloading, etc.	Automated switching for isolating faults during contingency, Automated switching for dynamic reconfiguration
Volt/Var Control and PQ Systems	Monitoring and control of cap banks and regulators for improved voltage control and minimize losses.	Remote switching of capacitors, regulators and load tap changers. Coordination with VAR compensation from DG.
AMI	Demand Response, load control systems, CIS, voltage reduction	Voltage reduction based on sensors, cap banks, regulators, customer facilities
Integration of DER	DG and storage	

The following table presents results from a survey of the Liberty electric utilities of existing and planned investments in distribution automation technologies. It also lists the major challenges facing each utility.

Area	Existing Applications	Future Applications	Challenges
GSE	Automatic switching systems (loop schemes)	S&C PME-9 Source Transfer Switchgear (Tuscan Village, Rockingham Mall, APD Hospital)	Communications
	Fault Indicators - Grid Sentry	Smart Fault Indicators (Aclara)	SCADA Integration
	S&C Trip Saver II	Implement comms for capacitor/reg controls regs for future Volt/Var control applications	Future ADMS Integration
	Distribution SCADA	Automatic switching systems	
	Single phase tripping	Pulse Reclosers	
		Distribution SCADA	
		MicroGrid	
		Battery Storage	

Empire	S&C Scadamates remote operation via SCADA	S&C Trip Saver II	Dual Sources
	S&C Vista Gear - source transfer at critical customers		Load Capacity
	Welch DA System		Lack of central dispatch
	S&C Intellirupter		
	PDP Fault Indicators		
	AMI Integration		
Calpeco	Addition of Viper reclosers with SCADA	Squaw Valley MicroGrid and Battery Storage	Fire Protection
	Migrate SCADA systems from MV Energy to NH Control	Battery Storage for long radial areas	Migration project complexities
	Smart Fault Indicators (Aclara)	Circuit Hardening and automated fire protection schemes for critical areas	

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. 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.

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 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

Table of Contents

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	June 2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager – Electric System Planning	Charles Rodrigues Director of Engineering
1	01/03/2008	Initial Issue	Brian Hayduk Distribution Field Engineering	John Pettigrew Executive Vice President, Electric Distribution Operations

Strategy Justification

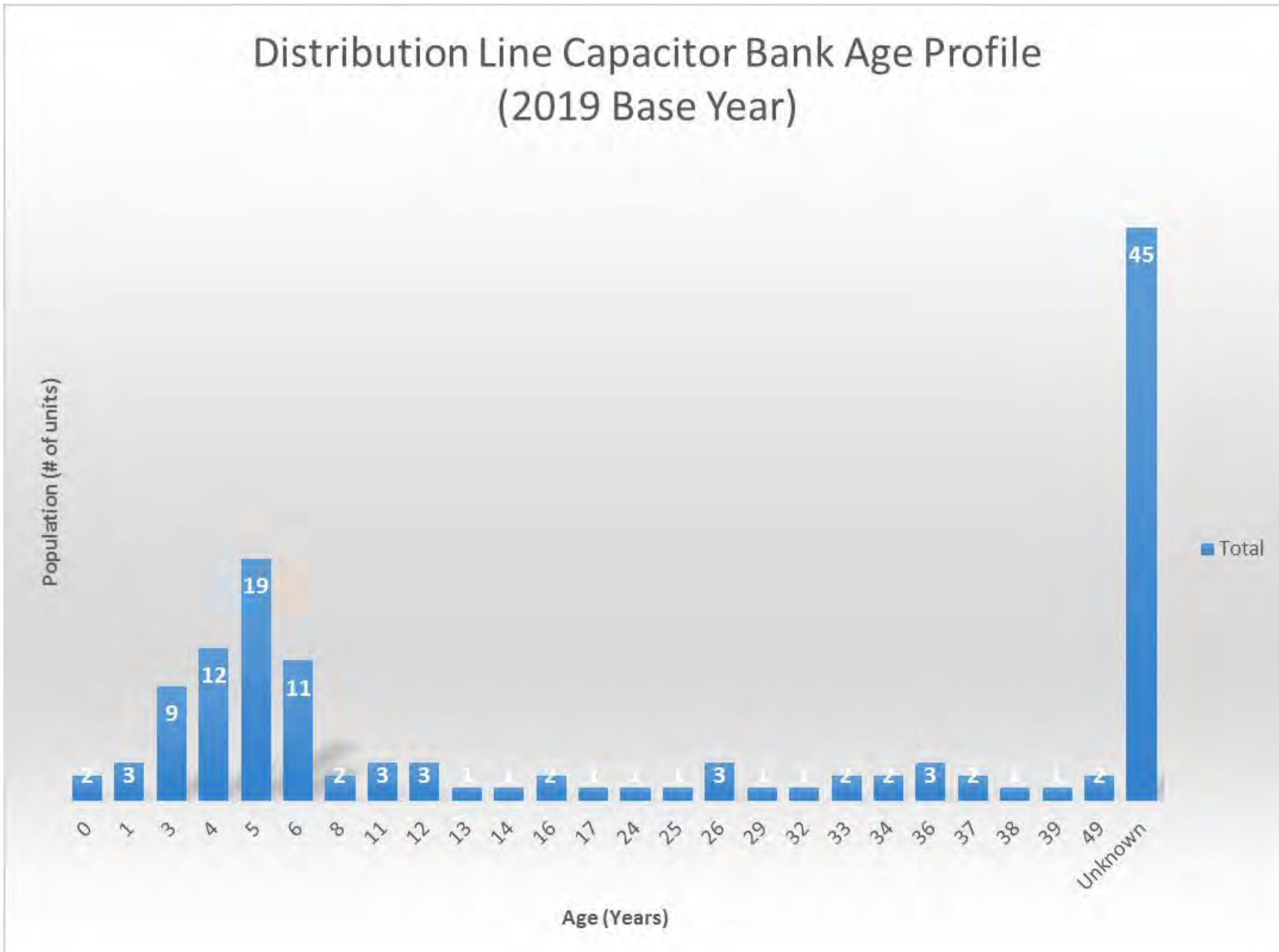
1.0 Purpose and Scope

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

2.0 Strategy Description

2.1 Background

Based on data obtained from the ArcFM GIS system including the year each capacitor bank was installed, 84% of the distribution capacitor plant in New Hampshire is under 30 years of age, with the average age being approximately 12 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
(2019 Base Year)
Population (# of units)
Age (Years)
Total
0
1
3
4
5
6
8
11
12
13
14
16
17
24
25
26
29
32
33
34
36
37
38
39
49
Unknown
2
3
9
12
19
11
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1
2
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1
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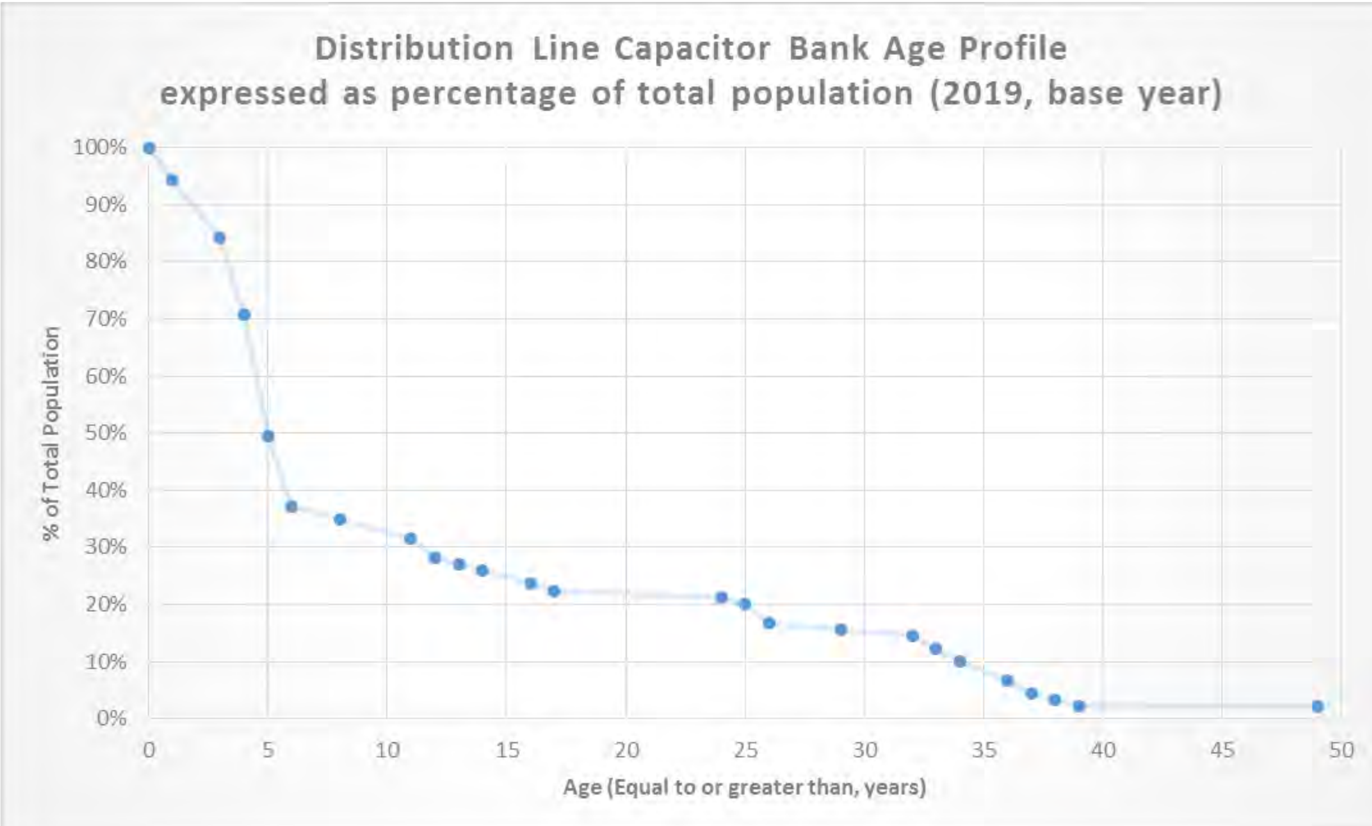
3
1
1
2
2
3
2
1
1
2
45



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

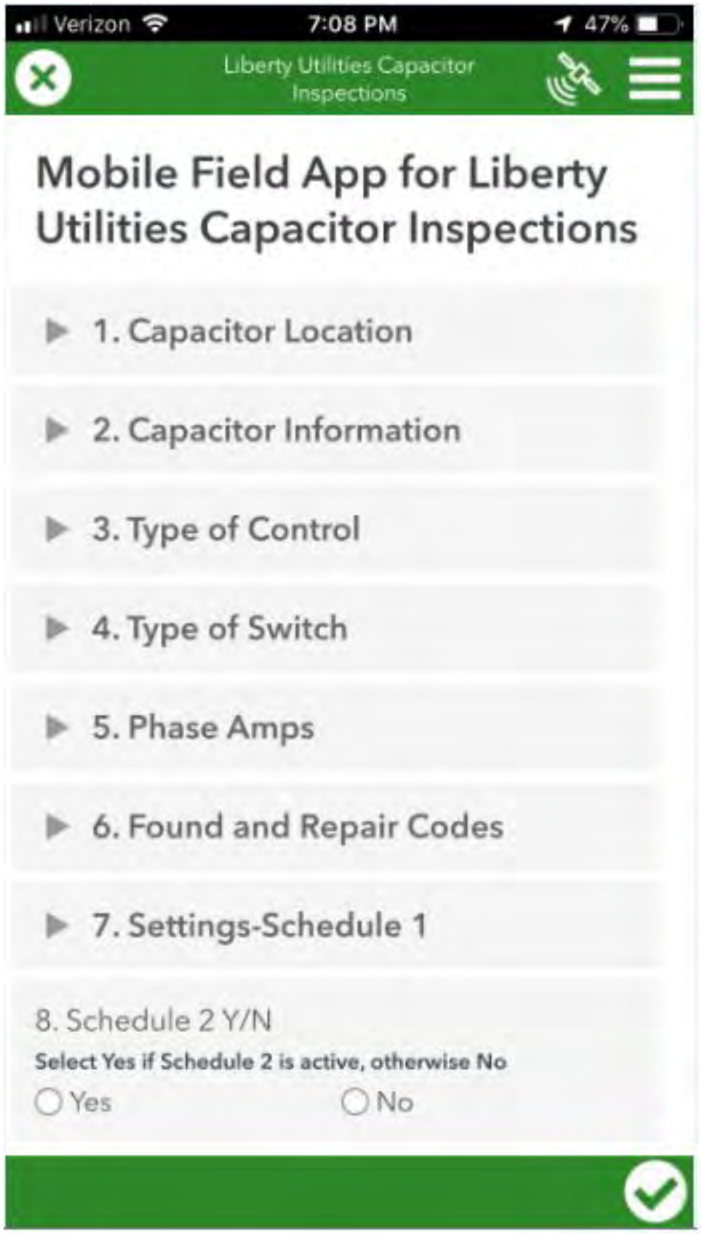
The installed cost (2019 dollars) for a complete distribution line capacitor bank is approximately $15,000. Maintenance costs associated with replacement of controls, vacuum switches, or individual capacitor units range from approximately $1,500 to $5,000 per bank. The following allocations to the transformer/capacitor blankets are estimated and are associated with distribution line capacitor maintenance and installation as well as compensation for additional reactive demand and losses associated with annual system load growth:

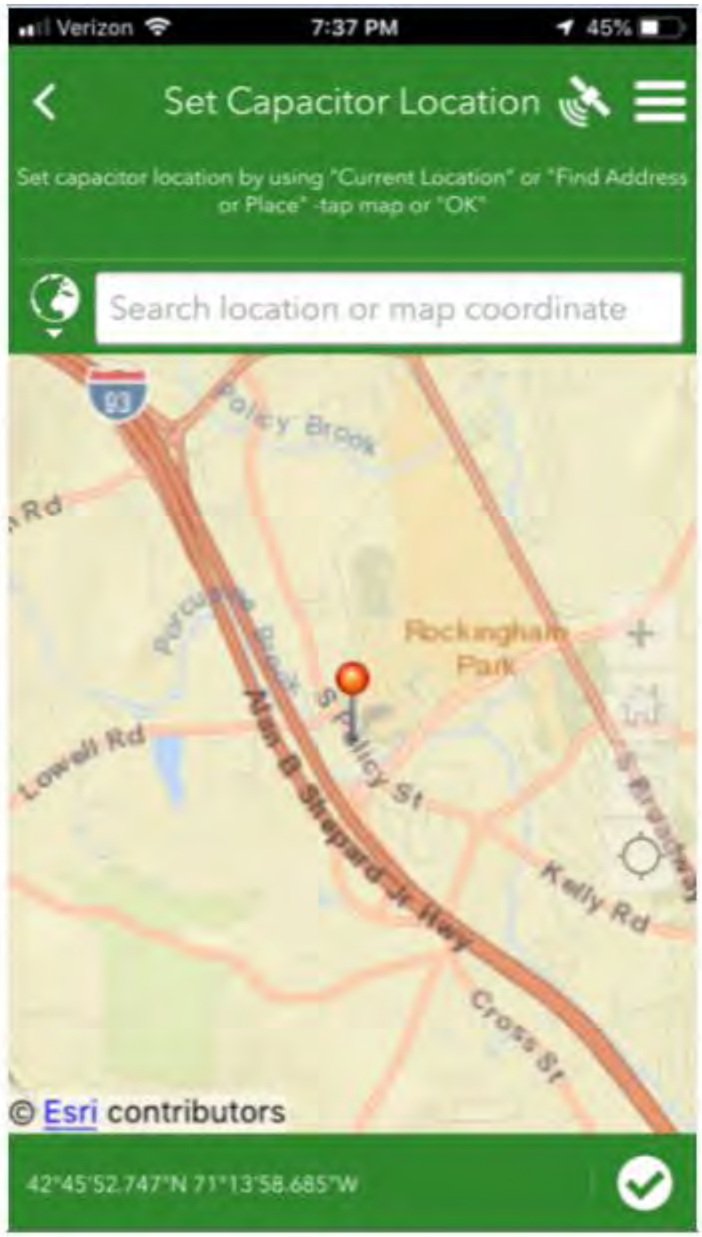
	CAPITAL	O&M	REMOVAL	TOTAL
Existing banks—Inspection & Maintenance	$75,000	$8,000	$8,000	$91,000

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

5.0 Implementation

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





6.0 Risk Assessment

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

7.0 Data Requirements

7.1 Existing:

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

7.2 Proposed:

- Same

8. References

- LU-EOP D004 – Distribution Line Patrol and Maintenance
- LU-EOP G012 - 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
Table of Contents

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	June 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

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

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

5.0 Implementation

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

6.0 Risk Assessment

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

7.0 Data Requirements

7.1 Existing/Interim:

- ArcFM/GIS
- Synergi Electric

7.2 Proposed:

- Same

8.0 References

- LU-EOP D006 – Procedure for Checking Ratio Transformer Installations
- LU- EOP D004 – Distribution Line Patrol and Maintenance

DAS-005
Distribution Line Voltage Regulators
Asset Management Strategy
Table of Contents

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	June 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 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 34 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 14 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 43 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

- LU-EOP D004 – Distribution Line Patrol and Maintenance
- LU-EOP D003 - Single Phase Step Type Pole Mounted Voltage Regulators
- Liberty Substation Maintenance Procedure, SMP 404.01.2 – “Step Voltage Regulator”

DAS-006
Distribution Line Transformer Strategy
Table of Contents

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 9,300 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 9% (1,320) 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 1,340 installations (~ 14% 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	June 2019	Revision of Strategy for Liberty-NH	Joel A Rivera Manager - Electric System Planning	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 9,300 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).

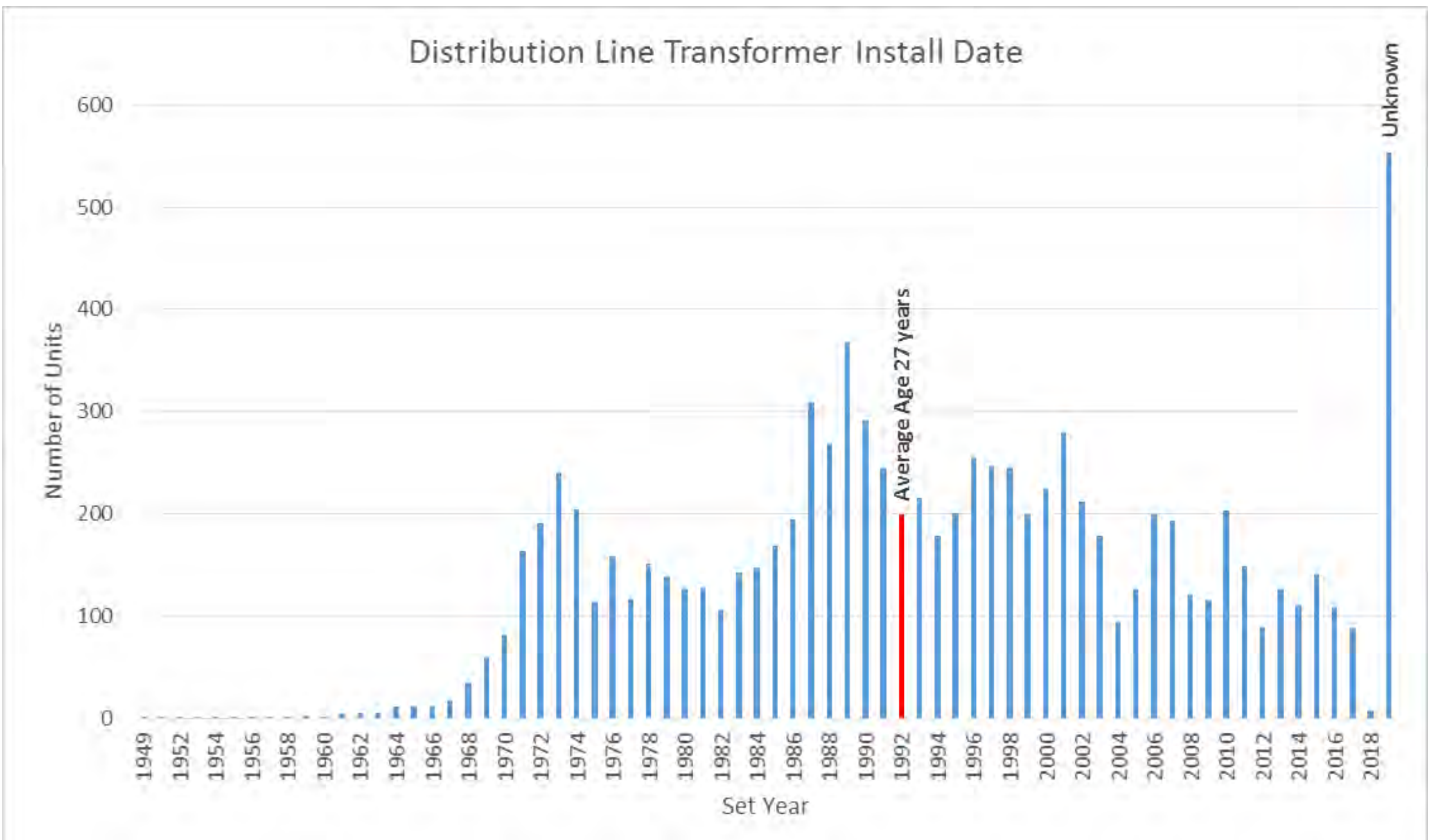


Figure 1

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.

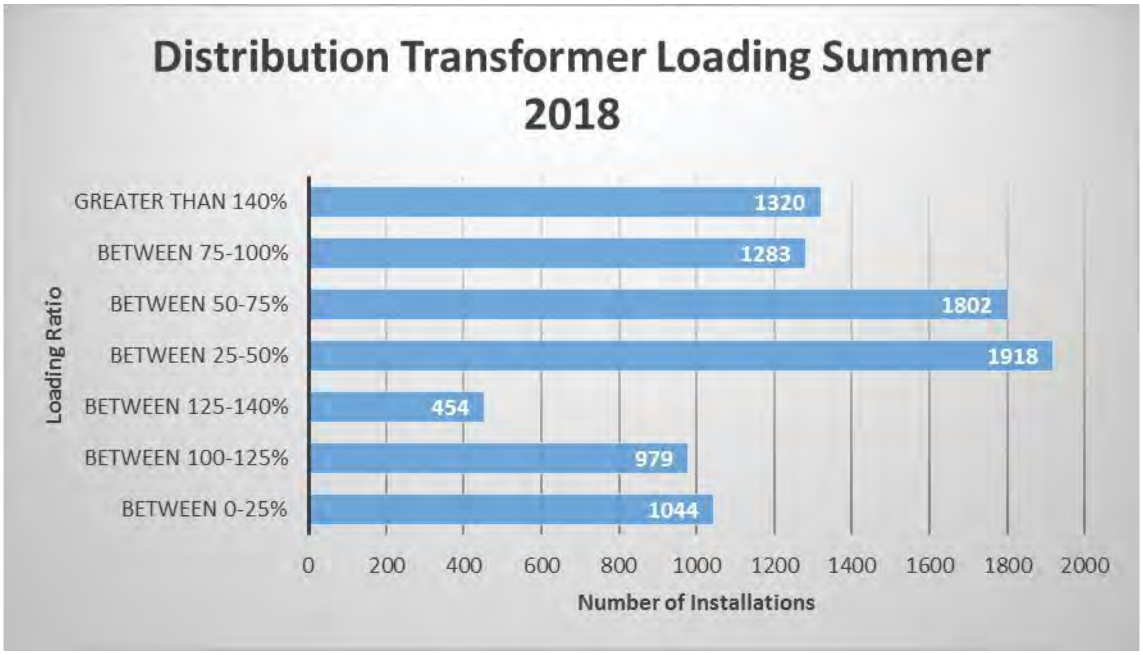


Figure 2

Loading in excess of levels recommended within the ~~National Grid~~ Liberty Utilities Standards accounts for the majority of transformer upgrades. Heavily loaded transformers account for approximately 14% of the total population based on load information contained within the CIS. The expectation is that single phase overhead units have the highest percentage. .

The average age of heavily loaded transformers is 31 years with an average install year of 1988 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 1,340 installations (~ 14% of population) are potentially loaded in excess of the loading guidelines documented in the Construction Standards. The majority of these units are single phase overhead transformers which are typically the least expensive and easiest to address.

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

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

Load Related Replacements	$75,000

Condition Based Replacements	$1,500
Total Annual Program Cost	$76,500

5.0 Implementation

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

5.1 Performance Targets

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

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

6.0 Risk Assessment

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

6.1 Safety and Environmental

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

6.2 Reliability

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

6.3 Customer/Regulatory/Reputation

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

6.4 Efficiency

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

7.0 Data Requirements

7.1 Existing/Interim

- ArcFM/GIS
- CIS/Cogsdale

7.2 Proposed

- same

7.3 Comments

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

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

8.0 References

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

DAS-007
Overhead Switch Strategy
Table of Contents

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	June 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

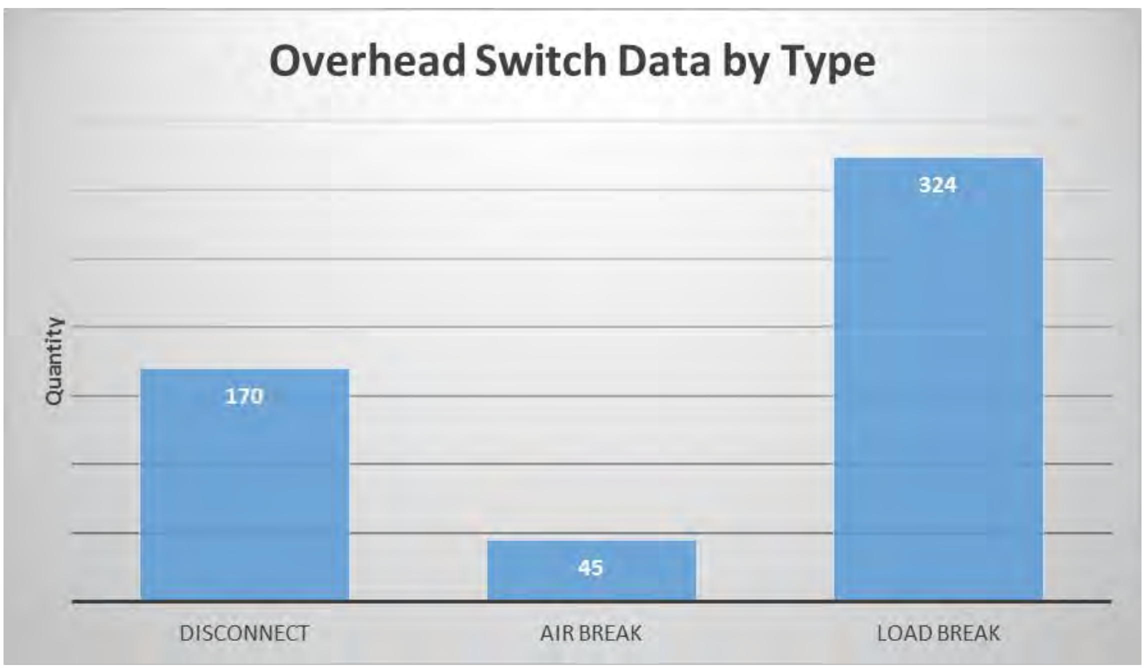
1.0 Purpose and Scope

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

2.0 Strategy Description

2.1 Background

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



2.2 Strategy

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

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

3.0 Benefits

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

3.1 Safety & Environmental

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

3.2 Reliability

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

3.3 Regulatory

The regulatory benefit associated with switch replacement is negligible.

3.4 Customer

The customer benefit associated with pole replacement is negligible.

4.0 Estimated Costs

An estimated cost of $10,000 capital per loadbreak switch is assumed for this strategy. Approximately 45 units are in the target population (airbreak switches). The replacement cost of the total target population is $450,000. Executing this plan over a ten year period would cost approximately $45,000 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)
DAS – 002 Distribution Line Automation Strategy
DAS – 009 Pockets of Poor Performance Strategy

Small Wire Primary Strategy
Table of Contents

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

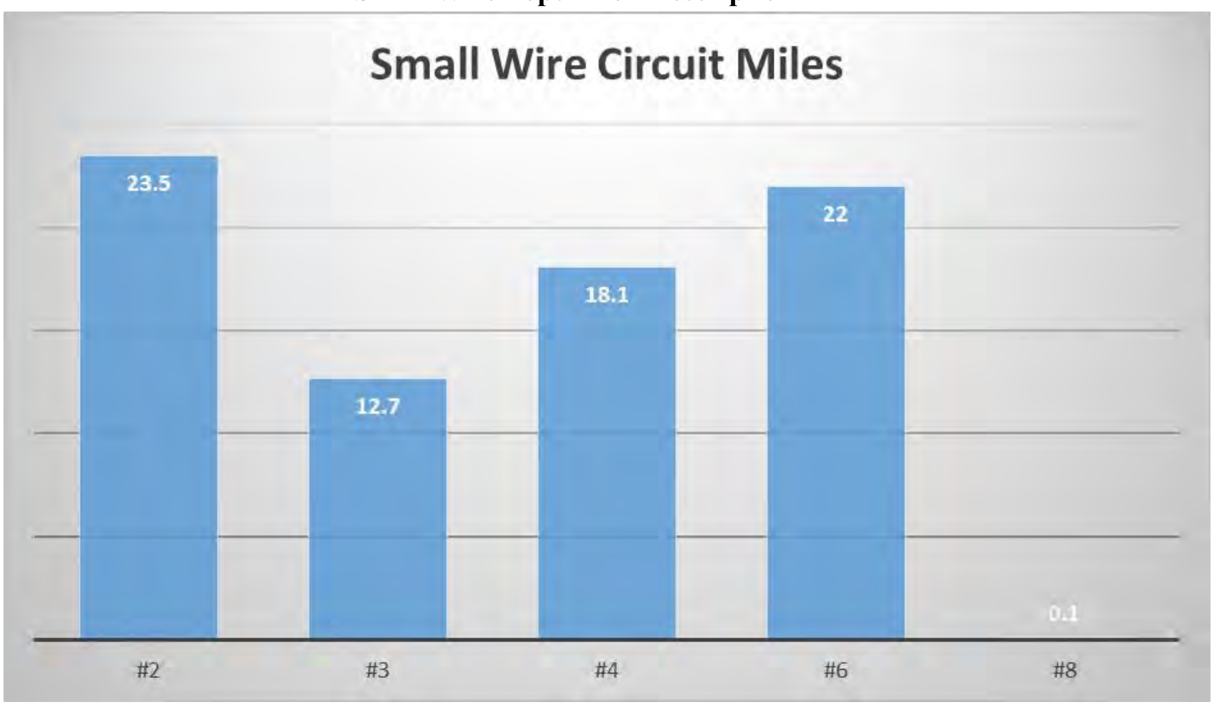
The intent of this strategy is to replace all "small" (< #2 AWG) copper, copperweld, amerductor and aluminum conductor installed across the system in crossarm and armless configurations. This strategy is designed to both provide for a sustainable distribution system and maintain system reliability.

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

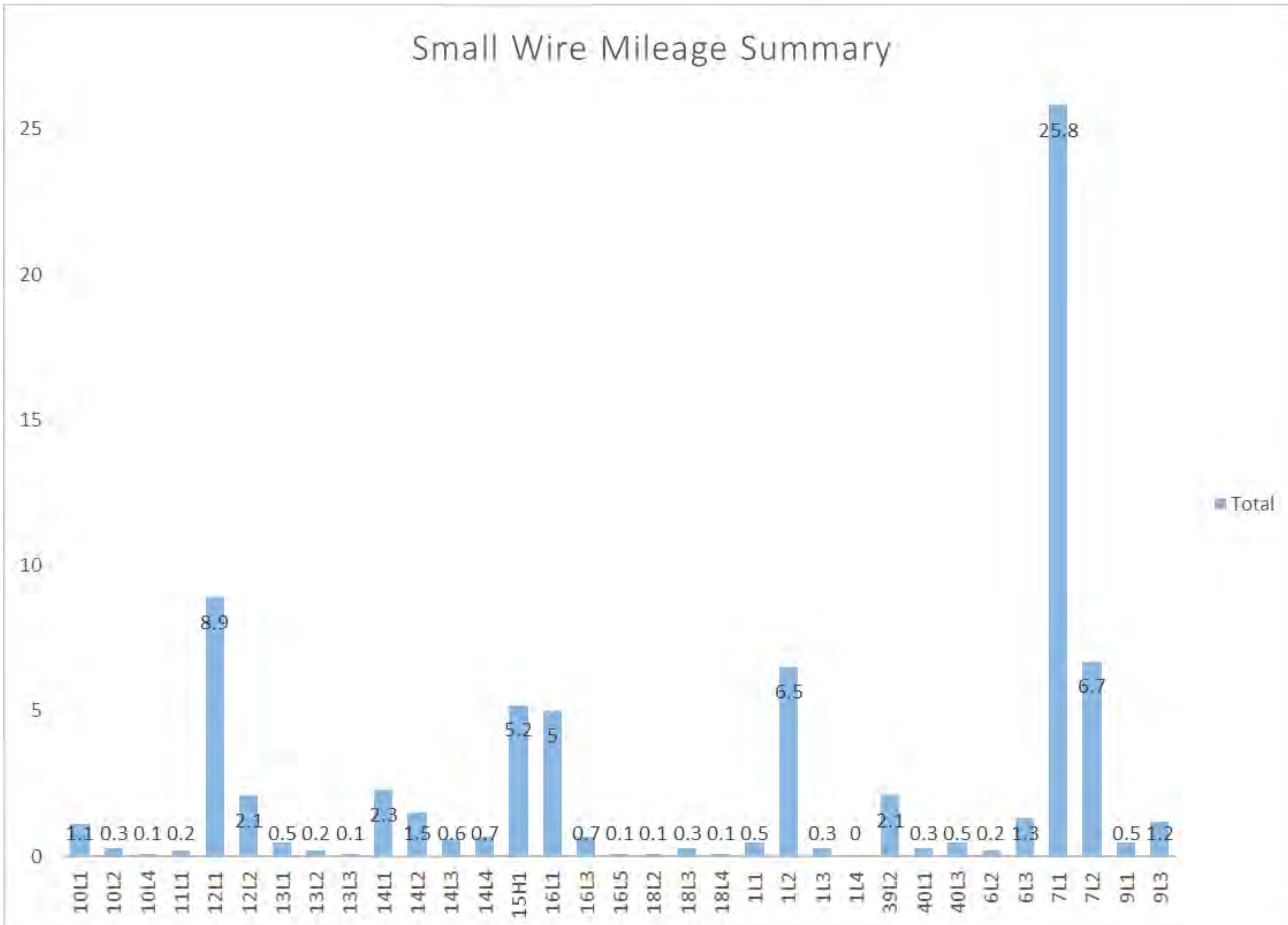
Three strategies are proposed to address the replacement of small wire across the system:

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 in the impacted areas. In addition, replacement will also improve voltage performance on the effected sections. This value would be significantly higher on those nice 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
DAS – 010, 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	June 2019	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

Table of Contents

<u>List of Tables</u>

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 one-year rolling average review timeframe with quarterly updates is also performed. The initial output of the model identified 5 pockets serving approximately 135 customers (557 customers interrupted).

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. Based on the sample data, these interruptions represent approximately 135 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. See sample data below:

Device Type	Location	OID	Outages	Customers
Fuse Bank	Old County Rd Plainfield	694	5	17
Fuse Bank	Ball Rd Acworth	2494	4	15
Fuse Bank	Potato Rd Enfield	1000	4	46
Fuse Bank	Ibey Rd Canaan	50591	4	25
Fuse Bank	South Rd Canaan	40142	4	32

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. Initially, $100,000 will be targeted for pockets of poor performance and could change based on budgetary approval.

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)
DAS – 010 Poor Performing Feeder Strategy

New Hampshire targeted spend

The following division level projects have been established to fund the P3 Program in New Hampshire:

New Hampshire FY11 – FY15 Pockets of Poor Performance Capital Budget					
Fiscal Year	2020	2021	2022	2023	2024
Liberty - NH	$ 100,000	$ 100,000	$ 100,000	$ 100,000	$ 100,000

Table 3 – New Hampshire Pockets of Poor Performance Capital Budget

The initial output identified five pockets serving approximately 135 customers (557 customers interrupted).

DAS-010
Poor Performing Feeder Strategy

Strategy Statement

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

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

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

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

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

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

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
1	June 2019	Initial Release of Liberty-NH Strategy	Joel A. Rivera Manager - Electric System Planning	Charles Rodrigues Director of Engineering

Table 1 - Amendments Record

Table of Contents

List of Tables

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

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

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 previous three year data, the poor performing feeders make up about 33% of the company's SAIFI and about 47% of the company's SAIDI. The specific reliability benefits from this program are undetermined as 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.

YEAR	2016
MONTH	(All)
STATUS	(Multiple Items)

Feeders	cKAIDI	cKAIFI	SAIFI	SAIDI
41-1L1	262.57	3.38	0.03	2.06
41-6L4	228.66	0.94	0.00	0.79
41-7L2	436.23	3.44	0.10	12.96
42-13L2	296.52	3.36	0.15	13.30
42-18L4	102.94	2.53	0.04	1.77
43-12L2	303.82	2.97	0.09	8.77
PPF Total	**1630.74**	**16.63**	**0.41**	**39.64**
% of System Total			**31.4%**	**33.6%**

YEAR	2017
MONTH	(All)
STATUS	(Multiple Items)

Feeders	cKAIDI	cKAIFI	SAIFI	SAIDI
41-1L2	259.87	1.41	0.12	21.79
41-39L2	382.68	2.10	0.03	4.64
41-6L2	271.11	2.17	0.04	4.93
41-6L3	247.30	0.96	0.03	8.91
42-14L3	208.44	3.14	0.15	10.17
43-12L2	384.79	1.85	0.05	11.09
PPF Total	**1754.20**	**11.64**	**0.42**	**61.54**
% of System Total			**46.2%**	**52.3%**

YEAR	2018
MONTH	(All)

STATUS	(Multiple Items)

Feeders	cKAIDI	cKAIFI	SAIFI	SAIDI
41-16L1	451.75	1.02	0.02	9.13
42-9L3	240.55	1.34	0.04	7.01
43-12L1	548.60	1.15	0.06	30.69
43-12L2	639.22	1.60	0.05	18.62
PPF Total	**1880.11**	**5.11**	**0.17**	**65.45**
% of System Total			**23.1%**	**53.7%**

Table 2 – Reliability Statistics Poor Performing Feeders 2016 - 2018

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

The estimated costs to address poor performing feeders 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, budgetary estimates will be developed for the different solution types. The 5 year capital budget is based on an annual targeted spend of $300,000 and may differ based on budgetary constraints or changes.

5.0 Implementation

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

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

Table 3 – 2018 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 33% of total SAIFI and 47% 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:

- Responder Archive – feeder reliability data

8.0 References

DAM – 016, Problem Identification Worksheet (PIW) Process for Distribution Lines

DAS-011
Distribution Line Recloser Application Strategy
Table of Contents

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 96 minutes, based on 120 minute goal less 20%). Additionally any circuit identified as a desirable candidate from the Recloser Model 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 Recloser Model which identifies and ranks feeders with characteristics 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	June 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

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 96 minutes, based on 120 minute goal less 20%). Additionally any circuit identified as a desirable candidate from the Recloser Model 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.

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 $50,000 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, the more economic reclosers will be included.

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:

- ArcFM/GIS – Feeder asset data
- Responder – 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 – 011 Distribution Line Recloser Application Strategy
DAS – 012 Line Recloser Strategy

DAS-012
Line Recloser Strategy
Table of Contents

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.

LU-EOP D011 Inspection and Maintenance of Distribution Reclosers outline the required maintenance procedures for line reclosers. 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).

Amendments Record

Issue	Date	Summary of Changes / Reasons	Author(s)	Approved By (Inc. Job Title)
2	June 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

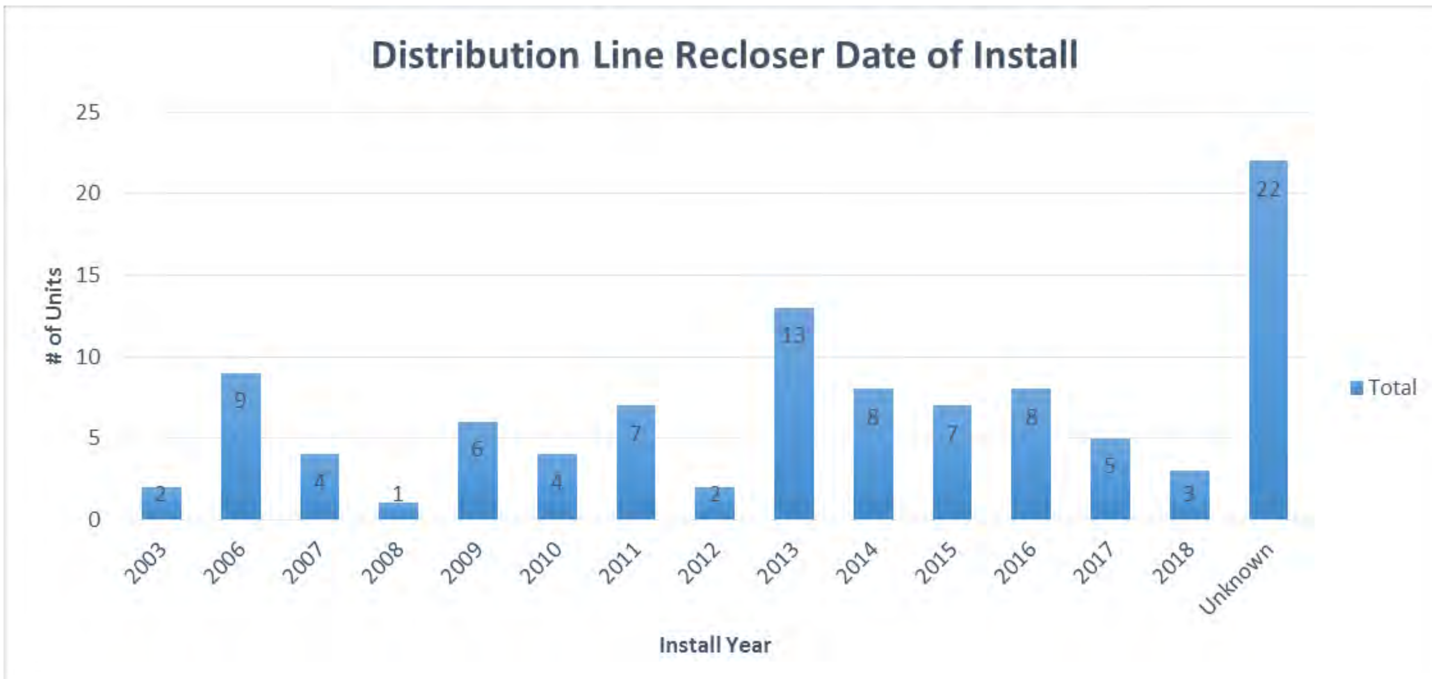
1.0 Purpose and Scope

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 subtransmission 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.

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

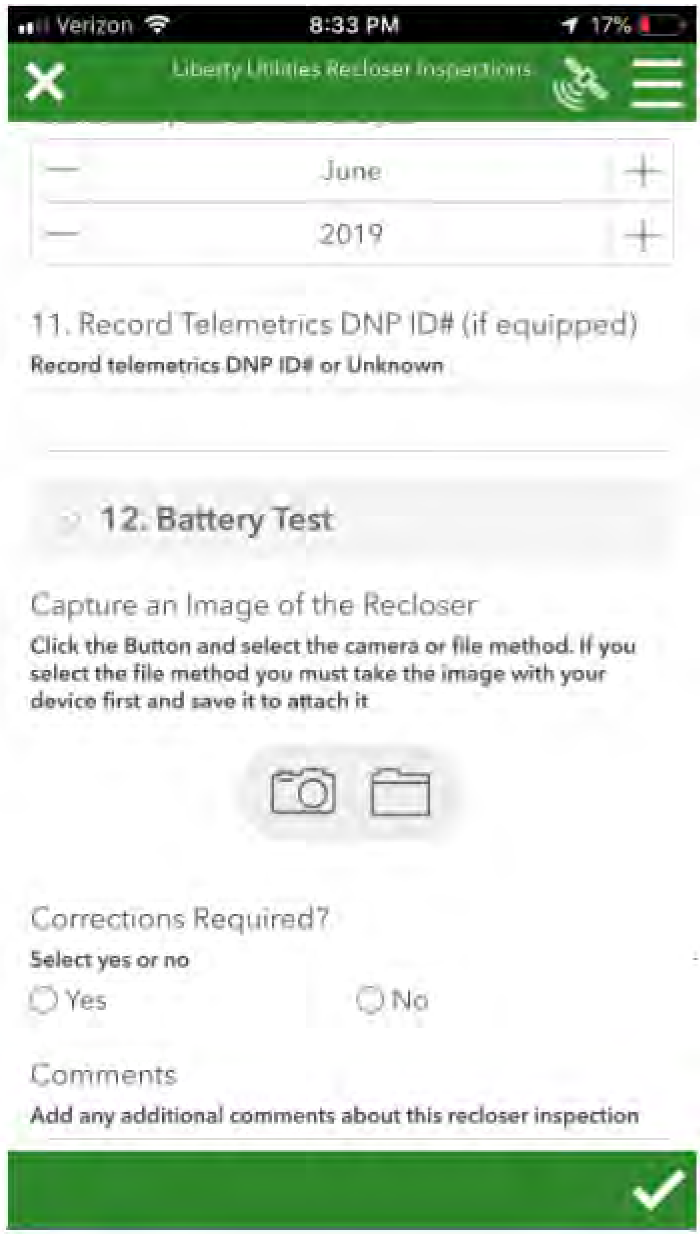
The customer level benefit associated with recloser replacement is negligible. Customers will share in the benefit from the improved reliability expected from the inspection program.

4.0 Estimated Costs

An estimated cost of $50,000 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.

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 misoperation. Not conducting routine inspections represents a greater risk (due to increases misoperations) 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 web application - Inspection data

7.2 Proposed:

- Same

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-EOP D011 Inspection and Maintenance of Distribution Line Reclosers
DAS – 011 Distribution Line Recloser Application Strategy
DAS- 002 Distribution Line Automation Strategy

DAS-013
Underground Getaway Cable
Table of Contents

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. Proactive replacement of get-away cables is not provided for by this strategy.

Direct Buries Cables

Upon the first failure of a direct buried get-away cable, the cable is to be repaired as an emergency, that is, repaired immediately 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 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 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	June 2019	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.

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 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.

	5 Year Totals				**Annual Effect on System**	
	# of Ckts w/Cable Failure	**Events**	**CI**	**CMI**	**SAIFI**	**SAIDI**
NH	5	8	281	39,860	0.006	0.9

Table 1- Get-Away Cable 2014-18 Reliability Data

Over the most recent five years, 5 circuits have experienced a get-away cable failure.

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.

2.2 Direct Buries Cables- Strategy

Upon the first failure of a direct buried get-away cable, the cable is to be repaired as an emergency, that is, repaired immediately 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 scoring model. 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 as an emergency, that is, repaired immediately 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 does not provide for proactive replacement or maintenance of get-away cables that have not experienced a failure. Currently the company does not conduct and condition assessment testing of get-away cables. The company should investigate the cost and viability of a proactive testing program. This strategy may be modified.

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 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

Get-away cable failures currently add approximately 0.006 to system SAIFI and 0.9 minutes to system SAIDI annually. As this strategy is primarily reactive, there is little change expected in system SAIFI or SAIDI.

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

Due to the great variance in get-away length and construction conditions, it is not possible to provide an accurate estimate of the on-going or planned replacement costs.

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:

As get-away cables experience failure, they should be tracked in a defect database. The use underground the existing underground failure database should be used for this purpose.

7.3 Comments:

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

8.0 References

Electric Distribution Planning Criteria

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	June 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

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.

Data obtained in Table 2 is from GIS.

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 history of faults for these URDs:

URD Faults	2010	2011	2012	2013	2014	2015	2016	2017	2018	URD Total Faults	URD 5Yr Average SAIDI
Oak Ridge URD - Lebanon	1	0	0	1	2	0	0	0	2	6	1.9
Lancelot Court - Salem	0	1	0	0	1	0	0	2	1	5	10.1
Lancaster Farm Rd - Salem	0	0	0	1	0	2	0	0	1	4	2.4
Blueberry Cir - Pelham	0	0	2	0	0	0	0	2	1	5	2.4

Hidden Acres - Charlestown	0	0	0	0	1	0	0	1	1	**3**	**5.9**
Hidden Valley - Charlestown	0	0	1	0	1	0	1	0	0	**3**	**41.4**
Total Faults by Yr	**1**	**1**	**3**	**2**	**5**	**2**	**1**	**5**	**6**		

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.

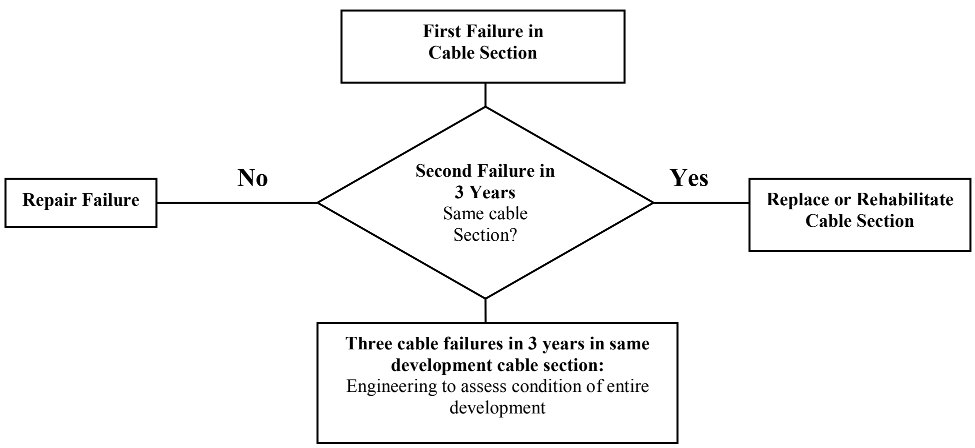


Figure 1 – Response to a URD/UCD Cable Failure (direct buried, loop fed arrangement)

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.

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

	Current planning horizon							
	Prior	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6 +	
$M	**YR'S**	**2019**	**2020**	**2021**	**2022**	**2023**		***Total***
Blueberry Cir - Pelham		$1.200						$1.200
Replace Subsurface Transformers		$0.300		$0.250	$0.350			$0.900
Hidden Valley - Charlestown			$1.500					$1.500
Lancaster Farm Rd				$0.250				$0.250
Hidden Acres - Charlestown				$1.000				$1.000
Lancelot Court - Salem					$0.250			$0.250
Oak Ridge - Lebanon					$0.900			$0.900
Total	$0	$1.500	$1.500	$1.500	$1.500	$1.500	$0.000	$7.500

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 direct buried with new 1ph cable in conduit.
Hidden Valley – Charlestown	Replace direct buried with new 2ph cable 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.

6.0 Risk Assessment

6.1 Safety and Environmental

There is no safety or environmental risk associated with these cable faults.

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.

6.3 Customer/Regulatory/Reputation

This strategy allows for the implementation of a reactive approach when dealing with URD/UCD cable failures. Therefore, these cable faults will not be minimized and it may result in a high number of cable failures affecting a single customer or group of 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.

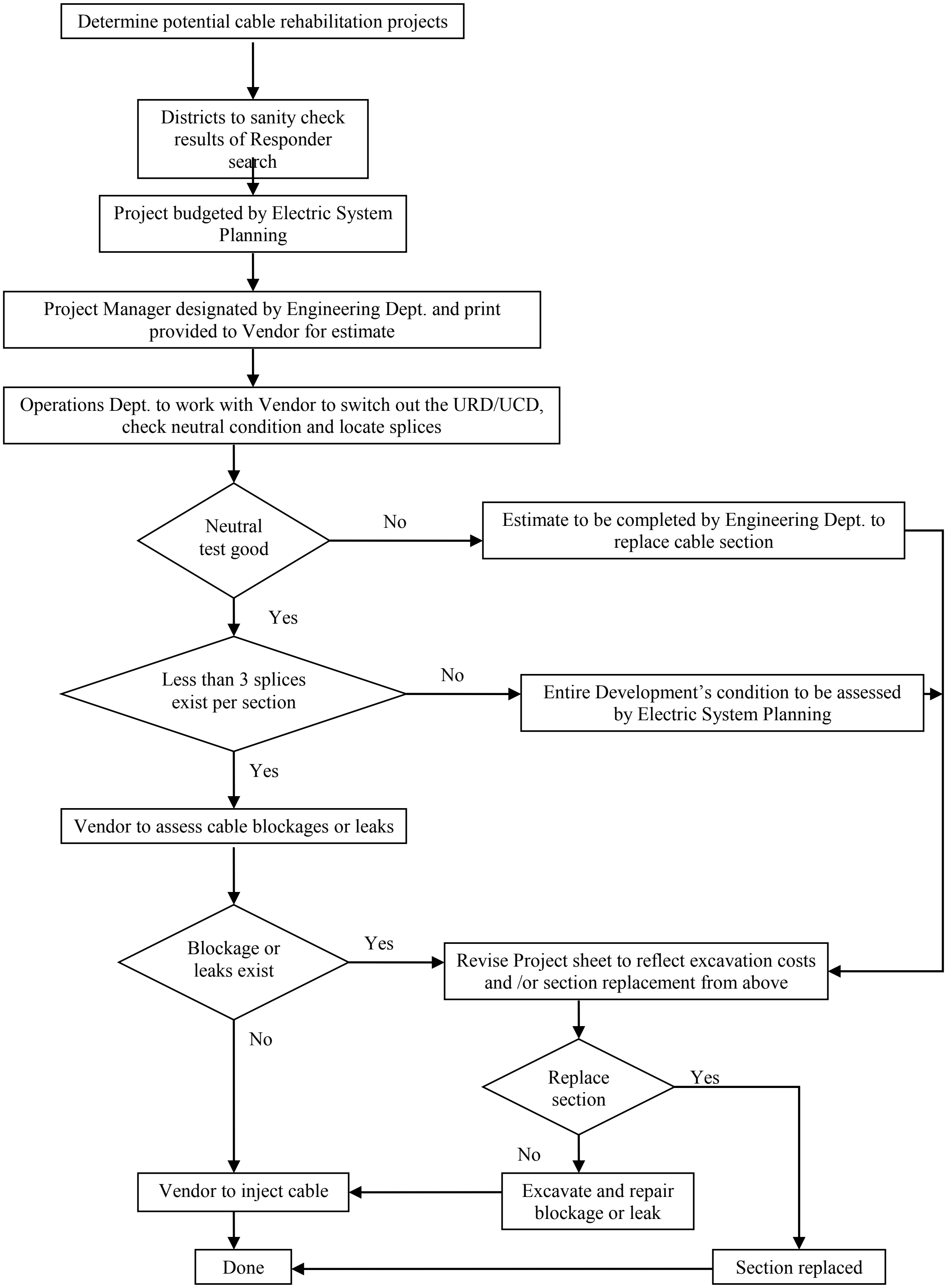
7.2 Data Governance:

URD/UCD GIS designs shall include fault circuit indicators as specified by this strategy by Distribution Design and fault circuit indicator data shall be maintained by the Asset Information group.

8.0 References

LU-EOP UG009 Distribution Underground Failure Log / Responder Archive
Liberty Utilities Construction Standards

9.0 Appendix A – Replace or Rehabilitate Decision Tree



DAS-015
Overhead Distribution Fusing Strategy
Table of Contents

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 (2019 – 2023) for proper fuse installations. Based on approximately 40 overhead feeders in New Hampshire, 8 feeders require review annually from 2019 through 2023.

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.

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 over the next five years (2019 – 2023) for proper fuse installations. Based on approximately 40 overhead feeders in New Hampshire, 8 feeders require review annually from 2019 through 2023.

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
2019	120	$ 60,000
2020	120	$ 60,000
2021	120	$ 60,000
2022	120	$ 60,000
2023	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 the next five years (2019 – 2023) for proper fuse installations. Synergi Distribution modeling software 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/Interim/Proposed

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

Liberty Utilities **Asset Manager's Notebook**	**Doc No.:** DAM-012 **Page:** Page 1 of 9 **Date:** 06/19/2019
SUBJECT: Engineering Reliability Review Process Guideline	**SECTION:**

APPLICABILITY:

Engineers conducting Engineering Reliability Reviews (ERR) as part of Liberty's Reliability Enhancement Initiative.

GENERAL INFORMATION:

This guideline documents the scope of the engineering reliability review for the purpose of establishing a clear understanding of the level of analytical detail required to ensure that reviews are conducted in a consistent manner within the prescribed time period. This is a new guideline to be implemented by the Engineering Department.

PROGRAM ADMINISTRATOR:

Electric System Planning Department

SCOPE:

I. Program Summary
II. Scope of the Engineering Reliability Review
III. Data Sources and Documentation

I. PROGRAM SUMMARY

The Electric System Planning Department will create a list of Poor Performing Feeders (PPF) for the purpose of conducting an ERRs to identify where opportunities exist to improve feeder reliability. This guideline focuses on the scope of the ERR which engineers will perform on the selected feeders. Typically between 4 and 6 feeders are identified annually as poor performing feeders.

II. SCOPE OF THE ENGINEERING RELIABILITY REVIEW

The following activities should be performed when conducting an engineering reliability review:

- Review of historical feeder reliability.
  - Review one and three year historical SAIFI, CAIDI and SAIDI metrics.
  - Review historical outages looking for trends and/or problem areas on the feeder that can be addressed within the scope of this review.

	Drafted By: Joel A Rivera	Reviewed By: Robert Johnson

        - Poor feeder reliability attributed to supply and/or major events should be excluded per PUC criteria.
        - Poor feeder reliability attributed to an excessive number of tree related outages should be investigated. Tree trimming schedules from feeder miles should be reviewed to determine if either the feeder is scheduled for tree trimming in the future or has recently been trimmed. Feeders requiring additional review for tree trimming should be noted as such and a PIW form should be sent to Veg Management.
    - Briefly document any recently completed (within the last three years) and/or future work which is expected to impact the feeder's future reliability performance.
        - Examples of such are: Feeder Hardening, regularly scheduled inspection and maintenance, installation of additional line reclosers, installation of additional fusing, installation of spacer cable, or tree trimming.
- Opportunities for reliability improvements from line recloser installations (add/remove/relocate/loop sectionalizing).
    - A radial or loop sectionalizing (LS) recloser installation is considered justifiable where the calculated annual Customer-Faults Saved (CFS) is 2,000 or greater—see Appendix A for details on calculating CFS.
    - Recommendations for recloser installations will be prioritized based on the CFS improvement.
- Opportunities for reliability improvements from additional circuit sectionalizing including:
    - Installation of additional sectionalizing fuses. Fuses should be installed at all side taps off of the feeder mainline greater than one span in length. Additional sectionalizing fuses should be installed on sub-taps serving more than 50 customers to reduce the number of customers interrupted by a fault. Peak load beyond the fuse(s) should be no more than 75% of the fuse's nominal rating. Coordination between sectionalizing fuses and larger transformers may not always be practical. In certain cases it is acceptable to forego coordination between a sectionalizing fuse and a larger transformer in order to realize the benefit that the sectionalizing fuse provides. See fusing Strategy for more details.
        - NOTE: Fuses tapped off of mainline and sub-taps should be identified separately for the purpose of prioritizing installations. The engineer has the choice of creating tables within the memorandum listing the specific location and fuse size for each fuse installation, or summarizing the install/remove/resize quantities and marking the location and size on a feeder map.
    - Installation of additional sectionalizing switches where practical on 15 kV class feeder mainline where practical to ensure that the maximum amount of load served between switches is 75 amps or less.
- Protective device coordination review; including
    - Station breaker to line recloser and/or largest fuse. (plot using Synergi)
    - Line recloser to line recloser. (plot using Synergi)
    - Line recloser to largest fuse. (plot using Synergi)
    - Fuse to fuse. (visual via feeder map/GIS)
    - End of mainline fault availability.
- Opportunities for reliability improvements from load balancing activities, including:
    - Feeders with excessive neutral current (>=30% of feeder breaker or line recloser ground relay trip setting).
    - The loading between the low and high phase should not exceed 100A.
    - Heavily loaded single phase taps:
        - Loaded in excess of 100 amps on 15 kV and 4 kV circuits based on Synergi modeling; or taps with connected single phase transformation in excess of 1,500 kVA (15 kV class feeder) or 500 kVA (5 kV class feeder).

    - Identification of phase swaps. (Utilize Synergi load balancing analysis, historical measured data or connected transformer kVA)
- Opportunities for reliability improvements from installation of additional feeder ties and/or feeder rearrangements, including:
    - Optimization of feeder configuration to reduce unnecessary exposure.
    - Identification of the CMI resulting from unserved load due to limited or no feeder tie capacity for certain contingencies.
- Opportunities for reliability improvements from system improvement/upgrade, including, but not limited to:
    - Reconductoring of bare open wire with spacer/covered—areas where repeated tree-related outages have occurred (via Responder event data) and sufficient tree trimming cannot be obtained.
    - Replacement of underground cable—such as 1970's XLP cable, varnished cambric cable, or other cases where repeated outages are attributed to cable failures (via Responder event data).
    - Replacement of equipment in poor condition—such as a misoperating/malfunctioning circuit breaker or line recloser (via Responder event data).
    - Replacement of obsolete equipment or functionality which has or may contribute to poor reliability such as:
        - Equipment which creates unnecessary exposure or decreases reliability and can be upgraded—such as an older airbreak switch or recloser.
    - Installation of faulted circuit indicators at locations which will aid in faster fault location and service restoration, such as at:
        - Entrances/exits of overhead lines onto limited access right-of-ways
        - Bifurcation points or switch points in underground circuits
    - Replacement of overloaded equipment—use Synergi model to identify overloaded conductor, step down transformers, fuses, etc. Any load related concerns and/or recommendations will be forwarded to the System Planning department for consideration into the Load Relief budgets.

III. DATA SOURCES AND DOCUMENTATION

Feeders can be modeled on Synergi to facilitate the analysis process.

The following data will be maintained to facility ERRs:
- Engineering Reliability Review response template
- One and three year historic feeder reliability data
- Tree trimming schedules
- Instructions to print GIS feeder maps
- Latest version of estimating spreadsheet.
- Major Event Day Exclusion dates for past three years.

Although field investigation is beneficial, time constraints may require an expedited review. If a field investigation cannot be performed, analysis can be based on the accuracy of company records. All recommended improvements will need to be estimated using the estimating spreadsheet. Improvements exceeding $50,000 will require approval by the Manager of Electric System Planning and then initiation of a business case for prioritization into future budgets.

Upon completion of the engineering reliability review, documentation of findings and recommendations will be made via a memorandum to the Manager of Electric System Planning. A

Microsoft Word template for this memorandum has been created to ensure consistency. The template is attached to this document for reference in Appendix B.

Enter information as indicated in the shaded fields. Delete sections if no problems requiring remediation were found. Otherwise, this template should be filled out completely. If multiple recommendations are developed under a single heading, the engineer should use the copy feature to duplicate the section, thereby providing a separate description and cost estimate for each recommendation. Expected reliability benefit ($/dCi and/or $/dCMI) for specific projects is needed to evaluate value of the recommendation when developing future budgets. Documentation of alternatives and/or other suggestions which could be implemented, but are not actually recommended, should not be included in the memorandum.

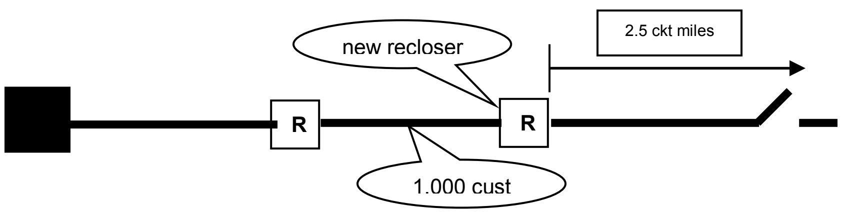
The Engineer performing the review will submit a draft copy for review to the Manager of Electric System Planning. A final copy of the memo containing the proposed recommendations can be released once all outstanding issues have been resolved. Business Cases must be initiated for project-level (work exceeding $50,000) recommendations—with the funding project number provided by the finance department. Prioritization of specific projects will be handled by the Electric System Planning Department for future year budget or walk-in to current year budget. Non project level work (work less than $50,000) will be prioritized and funded pending budget availability in the blanket programs. Recloser recommendations must also be documented fully as described in the Recloser Program Guideline. Work plan documents will be prepared for the approved recommendations and delivered to the operations department once funding has been secured.

Appendix A: Customer Fault Saved (CFS) calculation for reclosers

To justify installation of one or more line reclosers on a particular feeder (either radial or Loop Sectionalizing), expected Customer Fault Saved must by 2,000 or greater.

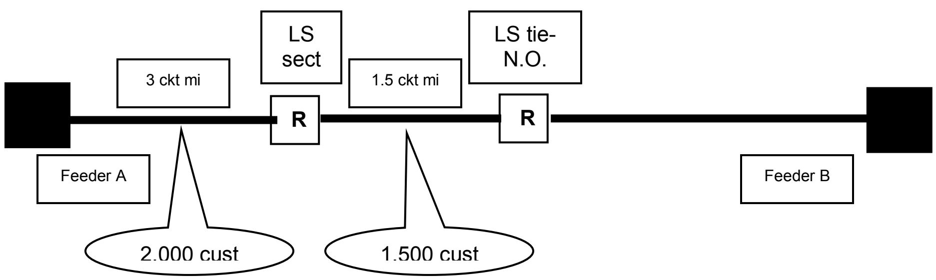
To calculate CFS for a RADIAL installation, simply multiply the number of customers between the potential recloser location and the next upstream protective device[1] by the number of unprotected, downstream circuit-miles of conductor/cable.

Example: 1,000 customers upstream from a new potential recloser location. 2.5 circuit-miles of downstream mainline conductor. Total CFS = 2,500….A GOOD LOCATION FOR A RECLOSER BECAUSE CFS > 2,000.



To calculate CFS for a LOOP SECTIONALIZING (LS) installation, there are two methods which can be used to justify the installation. It may be beneficial to use one over the other depending on the individual CFS values of the LS-sectionalizing and LS-tie reclosers.

1. Justify the LS-sectionalizing and LS-tie reclosers separately:



*LS sectionalizing recloser CFS = 2,000 cust (up) * 1.5 ckt mi (down) = 3,000 CFS…GOOD LOCATION BECAUSE CFS > 2,000*
*LS tie recloser CFS = 1,500 cust (down) * 3 ckt mi (up) = 4,500 CFS…GOOD LOCATION BECAUSE CFS > 2,000*

2. Justify both the LS-sectionalizing and the LS-tie reclosers together:

(using same picture)

*LS-sect and LS-tie recloser CFS = 2,000 cust * 1.5 ckt mi + 1,500 cust * 3 ckt mi = 7,500 CFS…GOOD LOCATIONS BECAUSE CFS > 4,000*

[1] Credit can be given for "large" or "important" customers. To obtain a representative customer count for these customers, divide their peak demand by 5 kW or their connected transformation kVA by 14 kVA.

Appendix B: Engineering Reliability Review response memorandum template.

Memorandum

To: [Click **here** to enter manager's name]

From: [Click **here** to enter your name]

Date: [Click **here** to enter today's date]

Subject: Engineering Reliability Review for the [Click **here** to enter feeder] feeder

---

The following memo documents the recommendations of the Engineering Reliability Review of the [Click **here** to enter feeder] feeder.

HISTORIC RELIABILITY PERFORMANCE / PREVIOUS RECOMMENDATIONS:
DisplayText cannot span more than one line!

LINE RECLOSER INSTALLATIONS:

[Click **here** to enter recommended line recloser installation description and location]
Expected annual CF = [enter estimated CF]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

ADDITIONAL CIRCUIT SECTIONALIZING:

[Click **here** to enter recommendation for additional circuit branching]
Funding Project Required: [enter FUNDING PROJECT NUMBER]
Prioritization Matrix Score: [enter MATRIX SCORE]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

PROTECTIVE DEVICE COORDINATION REVIEW:

[Click **here** to enter recommendation for protection system changes]
Funding Project Required: [enter FUNDING PROJECT NUMBER]
Prioritization Matrix Score: [enter MATRIX SCORE]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

LOAD BALANCING:

[Click **here** to enter recommendation to improve feeder load balance]
Funding Project Required: [enter FUNDING PROJECT NUMBER]
Prioritization Matrix Score: [enter MATRIX SCORE]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

ADDITIONAL FEEDER TIES/RECONFIGURATION:

[Click **here** to enter recommendation for additional feeder ties/reconfiguration]
Funding Project Required: [enter FUNDING PROJECT NUMBER]
Prioritization Matrix Score: [enter MATRIX SCORE]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

SYSTEM IMPROVEMENT / SYSTEM UPGRADE:

[Click **here** to enter recommendation for system improvement / system upgrade]
Funding Project Required: [enter FUNDING PROJECT NUMBER]
Prioritization Matrix Score: [enter MATRIX SCORE]

Capital	O&M	Removal	TOTAL
$[enter est cost]	$[enter est cost]	$[enter est cost]	$[enter est cost]

This memorandum is not intended to initiate the design and construction process. Recommendations will be considered for implementation in the Engineering Reliability Review work plan. Funding projects with estimates have been initiated for all project work identified above for consideration in future budgets. A workplan document will be prepared and delivered to Design Engineering once the budgeting process is complete.

CC: J. Rivera
A. Strabone
H. Green
R. Johnson

Liberty Utilities **Distribution Asset Manager's Notebook**	**Doc No.:** DAM-016 **Page:** Page 1 of 5 **Date:** 06/19/2019
SUBJECT: Problem Identification Worksheet (PIW) Process	**SECTION:**

1.0 Purpose

1.1 To establish and set forth the formal documentation, tracking, and review of the problems identified with the assets maintained by Operations departments.

1.2 Problem Identification Worksheets (PIWs) are intended to identify equipment, or operating conditions that require attention, but cannot wait for the next scheduled inspection process or other review processes.

1.3 PIWs are intended to initiate action to resolve only those issues which will require capital expenditures for remediation of the problem. Routine maintenance issues should be handled by the Operations department.

1.4 The PIW is **not** to be used for an emergency situation or where failure is imminent. However, it may be used as a follow-up to (1) prevent the situation from recurring at the same location or elsewhere and/or (2) request a long-term solution to a temporary fix. Typically, a 1 month or longer response time should be expected.

2.0 Initiation

2.1 The PIW can be initiated by any Liberty employee: union, salaried, or management. (Contractors may fill out a PIW but the formal initiator should be a Liberty employee.) The PIW is intended to bring forth issues not otherwise likely to be captured by the engineering groups.

2.2 The PIW form is to be filled out as completely as possible with as much supporting documentation as is available including technical test results and photos when available.

2.3 The initiator's intent shall be to communicate the problem as specific and detailed as they can with supporting material and all available information. Vague PIWs are not helpful.

3.0 PIW Submission

3.1 All PIWs (Distribution Line, Substation, Vegetation, etc.) are formally submitted to the Electric System Planning Department (ESPD). ESPD continually monitors and tracks the progress of all PIWs through closure. This department is the initial center point of the Distribution PIW process.

3.2 PIWs received by the ESPD shall be forwarded to the appropriate department.

3.3 PIWs can be submitted by hard copy or electronically via e-mail to the ESPD. The ESPD will, within one week of receipt of a PIW, notify the initiator that the PIW has been received and the Review & Decision process has been initiated.

3.4 See Appendix A for a copy of the PIW Form.

4.0 Review Process

4.1 As part of the Review & Decision process, each PIW must be logged and documented so that its status can be followed to a resolution (e.g. blanket, program or a capital project initiated).

4.2 The ESPD will maintain an active list of the PIWs received. This list includes a unique Distribution PIW identification number, date of the PIW, equipment classification, description, status, and assigned individuals or department.

4.3 As part of the initial review process, the ESPD determines the appropriate department that should review the PIW:

4.3.1 If the PIW is determined to be a load or voltage issue, ESPD will evaluate the PIW and determine if the PIW should be the subject of or included in any planning studies.

4.3.2 If, after review of the problem, it is determined that the PIW requires immediate attention, Engineering will initiate corrective action. If the PIW does not require immediate attention, but needs to be resolved within the current fiscal year, Engineering will sponsor the recommended resolution and work within the budget process to assure funding. If the PIW requires attention beyond the current fiscal year, ESPD will prioritize it for inclusion in a future year budget. Upon completion of the PIW review, the appropriate asset owner will inform the ESPD how the problem will be resolved.

4.4 Once a decision has been made to do the work, it must be determined how the project impacts the implementation plan. Whenever any work is added, the impact to the overall schedule must be considered to ensure that adequate resources are made available to address it. Engineering Design and Operations will review and adjust schedules. Specific projects will be prioritized consistent with the normal prioritization process.

4.5 Future year work must be justified using the appropriate business form & budgeted. It must also be included in a future year Work Plan.

4.6 See Appendix B for the PIW process flow diagram.

Liberty Utilities **Distribution Asset Manager's Notebook**	**Doc No.:** DAM-016 **Page:** Page 3 of 5 **Date:** 06/19/2019
SUBJECT: Problem Identification Worksheet (PIW) Process	**SECTION**:

5.0 Notifications and Follow-up Responsibilities

5.1 ESPD will inform the initial submitter of the PIW action taken. This can be in the form of an e-mail, phone call, or personal visit.

5.2 The ESPD will assure that Engineering Project Management has been informed of the resulting PIW action planned if it results in adjustments to the blanket forecasts or requires a walk-in funding project.

5.3 The sponsoring department will be responsible having necessary funding projects initiated and considered for budget approval.

5.4 If work is to be done under a distribution blanket project, the sponsoring department shall submit a request for Engineering Design.

6.0 Closure of PIW

6.1 ESPD will monitor the progress of any initiated efforts in response to a PIW. PIWs will be closed after it has been determined that no action is required, or after required capital work has been completed.

6.2 Closed PIWs should remain accessible for future reference for a minimum period of 3 years following close out.

Liberty Utilities Distribution Asset Manager's Notebook	**Doc No.:** DAM-016 **Page:** Page 4 of 5 **Date:** 06/19/2019
SUBJECT: Problem Identification Worksheet (PIW) Process	**SECTION:**

7.0 Appendix A – PIW Form

Liberty Utilities	PROBLEM IDENTIFICATION WORKSHEET (P.I.W.)		
Originator/Position (please print):	**Date:**	**Phone**	**P.I.W. Submittal No**
Town:	**Station/Line/Feeder**		**Pole #**

DESCRIPTION OF PROBLEM IN DETAIL

IMPACT OF PROBLEM

☐ Reliability Related ☐ Equipment Failure ☐ Operability ☐ Other

IMPACT DESCRIPTION

PROBLEM RESOLUTION TIME FRAME: (FOR INTERNAL USE ONLY)

☐ Immediate ☐ 1 Year ☐ 2 – 4 Years ☐ 5 or More Years

CHECK OFF REQUIRED BACKUP DATA SUBSTANTIATING PROBLEM AND ATTACH TO PIW (Originator to Check appropriate boxes)

☐ Work Request ☐ Reports ☐ Interruption Reports ☐ Outage Information ☐ Inspection Reports ☐ Trouble Reports ☐ Post weather event assessment	☐ Standards Requirement ☐ Product Advisories ☐ Safety	☐ Voltage Charts ☐ Current Charts ☐ Electric Service Request
	☐ Regulatory Complaints ☐ Voltage Complaints ☐ Customer Complaints	☐ Other

PIW DISPOSITION (FOR INTERNAL USE ONLY)

☐ Accepted Assigned to: PIW# Date

☐ Denied Date

☐ Recorded Date

Comments

Liberty Utilities **Distribution Asset Manager's Notebook**	**Doc No.:** DAM-016 **Page:** Page 5 of 5 **Date:** 06/19/2019
SUBJECT: Problem Identification Worksheet (PIW) Process	**SECTION**:

8.0 Appendix B – Process Flow