Supply Issues and Power Outages Review Island Interconnected System

Executive Summary
of
Report on
Island Interconnected System to Interconnection with Muskrat Falls
addressing
Newfoundland Power Inc.

Presented to:

The Board of Commissioners of Public Utilities
Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

December 17, 2014

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Executive Summary

Background to Liberty's Examination

- The Board of Commissioners of Public Utilities ("Board") retained The Liberty Consulting Group ("Liberty") to examine the causes of widespread electricity outages experienced by customers on the Island Interconnected System ("IIS) of Newfoundland and Labrador from January 2 through 8, 2014. This report follows an April 2014 Interim Report from Liberty.
- This report: (a) confirms the outage causes described in the Interim Report, (b) examines the actions Newfoundland Power has taken to address the directions from the Board's May 2014 Interim Report, the recommendations in our Interim Report, and additional initiatives identified by Newfoundland Power and (c) reviewed the adequacy and reliability of Newfoundland Power's system, including its efforts to sustain reliability at appropriate levels. We remain engaged in a review (expected to be completed in the spring of 2015) of the reliability impacts that will follow the interconnection of Muskrat Falls generation through the Labrador-Island Link.
- Liberty has been serving utility regulators for more than 25 years, working on hundreds of projects across the full range of areas involved in ensuring safe, reliable, and cost effective utility service. Liberty's work extends to 55 North American jurisdictions, ranging from some of the continent's most expansive holding companies to small providers that serve largely rural areas. Liberty has examined reliability and outage response in extreme weather, hurricane, flood, and wind conditions.

Overall Conclusions

- Liberty continues to conclude, in full accord with our Interim Report, that the outages of January 2014 stemmed from two differing sets of causes: (a) the insufficiency of Newfoundland & Labrador Hydro ("Hydro") generating resources to meet customer demands, and (b) issues with the operation of key equipment on Hydro's transmission system.
- Newfoundland Power's planning and design of its system, its asset management practices, its system operations, its outage management and emergency practices and its customer communications processes all conform to good utility practices. Liberty has identified additional opportunities to enhance performance in certain areas as described in this report.
- Newfoundland Power's reliability performance has been better than Canadian comparators on standard reliability metrics for the last five years.
- Past conservation efforts have focused on energy savings. Current capacity circumstances, however, dictate a robust consideration of short-term demand-management options. Work in that direction, planned for imminent commencement needs to consider a sufficiently broad range of Muskrat Falls in-service dates, in order to properly assess the pay-back periods of short-term options. Completion of that work needs to be accelerated as much as possible. As our companion report addressing Hydro observes, this work needs to be a fully joint effort between Hydro and Newfoundland Power.

Reliability

- Newfoundland Power's reliability has improved significantly since 1999 and has recently remained stable overall. Its transmission and distribution systems operate effectively in ensuring adequate service reliability. Effective maintenance and capital programs, that appropriately recognize the age of its assets, have contributed materially to improved reliability.
- Liberty does recommend a more formal method for prioritizing capital projects and additional ways to reduce the number of equipment caused failures on the distribution system. Liberty also recommends that Newfoundland Power increase the emphasis on the Rebuild Distribution Lines segment of its annual capital budgeting and evaluate reinstituting a regular annual program for addressing worst-performing feeders.
- The expanded role of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should continue as it will improve planning and coordination between Newfoundland Power and Hydro.

Planning and Design

- The planning and design of Newfoundland Power's system has been effective. It incorporates appropriate levels of redundancy and employs appropriate design standards, criteria, and practices. The Company, however, can extend the use of SCADA and automatic reclosers to minimize interruption frequencies and durations. Completion of in-process developments in the Geographic Information System will increase its effectiveness.
- Newfoundland Power's protective relays schemes conform to industry practice, but require documented guidance. The Company is addressing what has been a temporary delay in testing of electromechanical relays. Liberty recommends that Newfoundland Power address the lack of a program requiring periodic exercising of circuit breakers and that it begin to track centrally actions to address the causes of frequent protective device operations.

Asset Management

- The program, organization, and staffing of Newfoundland Power's asset management functions are sound. The Company uses an effective combination of periodic inspection and maintenance programs and capital rebuild and modernization projects. Vegetation management practices also conform to good utility practices.
- Newfoundland Power's transmission line and pole inspection and corrective maintenance practices conform to good utility practices. Liberty does recommend that Newfoundland Power examine the benefits of chemical treatment of poles and periodic testing of aged poles for internal decay.

System Operations

- System operations structure, staffing, systems, tools, and practices are effective. Liberty does recommend examining the addition of a dedicated training console. The planned replacement of the SCADA system and its Outage Management System should further improve the effectiveness of system operations.
- Newfoundland Power does not employ its own Energy Management System, but links to Hydro's. This arrangement is currently satisfactory.
- The operation and maintenance of Newfoundland Power's generation has been appropriate and the units have maintained a reasonable level of generating availability. The Company has

analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

Outage Management

- Newfoundland Power's approach, organization, staffing and practices associated with outage management are effective. Numbers and locations of field personnel are consistent with outage-related needs and the Company appropriately responds to trouble calls. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.
- Customers have appropriate options for reporting outages and restoration information. Newfoundland Power conducts an effective process for estimating restoration times following outages. Those processes should improve with the replacement of the existing SCADA system.

Emergency Management

- Newfoundland Power's emergency response practices, resources, training, and drilling are effective and consistent with good utility practices. The Company has made effective pre-assignment of management and operational duties for its emergency management organization. Its Emergency Command Center has appropriate capability and functionality.
- Storm tracking practices and capabilities support preparation for major weather events. A range of in-house and contractor resources are available for timely restoration for even severe weather events. The System Restoration Manual is consistent with good utility practice, but a clear description of actions for insufficient generation should be added.

Customer Communications

- Newfoundland Power has made significant progress on the outage improvement recommendations made in Liberty's Interim Report, however, important monitoring work remains. The Company should monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience.

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Table of Contents

List of Charts, Tables, and Figures

I. Introduction

A. Events Leading to The Board's Investigation

The interconnected electrical system serving the vast majority of customers on the island of Newfoundland (the Island Interconnected System, or "IIS") has experienced significant outages in each of the past two winter seasons.

In January, 2013 a series of events on the system of Newfoundland and Labrador Hydro ("Hydro") produced Island-wide, extensive customer outages, primarily on the Avalon Peninsula. The next year, in January 2014 conditions on Hydro's system caused two series of outages across the period from January 2 through 8, 2014. Island customers experienced a series of outages whose immediate origins lie in two separate streams of events. First, a shortage in Hydro generating resources caused the institution of a series of rotating outages. Second, as Hydro and Newfoundland Power, Inc. ("Newfoundland Power") were recovering from the circumstances leading to and the responses to these outages, a series of equipment and operations issues led to additional outages. The consequences of this second series of events included both widespread, uncontrolled outages and another series of rotating outages.

The shortage in Hydro's generating resources was caused by the unavailability, as January approached, of a number of its generation facilities which were out of service. At the same time, Hydro anticipated very high loads, reaching levels sufficient to threaten its ability to provide continuous service. Customers were asked to conserve energy after 2 p.m. on January 2. At about 4 p.m., rotating outages began. They continued until nearly 11 p.m. that day. Rotating outages resumed for a short time during the next morning's peak load period.

The equipment and operations related outages started on January 4th when Hydro experienced a major fire at one of its Sunnyside station transformers. At about 9 a.m., a variety of equipment failures and the operation of protective equipment caused the loss of generation and transmission capacity serving the Avalon Peninsula. Hydro worked through an extended series of equipment problems, variations in available generation, and operations activities, finally completing the bulk of immediate recovery efforts at around 3:30 p.m. on January 8.

Newfoundland Power reported outages to three-quarters of its retail customers during the two series of events that took place between January 2 and 8 of 2014. Some of them were for extended periods of time. Newfoundland Power attributed 15 percent of its customer outages to the capacity-induced rotating outages of January 2nd and 3rd, and 80 percent to the equipment related outages that followed and finally ended on January 8th. Winter storm conditions coinciding with these events independently produced the remaining 5 percent of outages for Newfoundland Power's retail customers.

B. Scope of Liberty's Engagement

The Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") retained The Liberty Consulting Group ("Liberty") to study and report on *Supply Issues and Power Outages on the Island of Newfoundland Interconnected Electrical System*. This engagement followed the Board's determination, under the *Public Utilities Act*, R.S.N.L 1990, c. P-47, to conduct an investigation. The Board's objective in this investigation has been to:

> *complete a full and complete investigation into the issues that are to be identified by the Board on the supply issues and power outages that occurred on the Island Interconnected System in late December 2013 and early January 2014.*

The Board identified issues to be addressed in its investigation following a February 5, 2014 pre-hearing conference and consideration of a wide range of issues proposed by stakeholders, who provided written comments and participated in the pre-hearing conference. Board Order No. P.U. 3(2014) (the "February 19 Order") established the issues to be addressed by Liberty's study and reports thereon.[1]

Liberty was asked to investigate and complete an interim report including an explanation of the IIS events that occurred in December 2013 and January 2014, an evaluation of possible IIS changes to enhance preparedness for the 2014-2016 winter periods, and an examination of each utility's response to the outages. Liberty was also asked to provide a final report including an analysis of the events of December 2013 and January 2014, an evaluation of the adequacy of and reliability of the IIS up to and after the interconnection with the Muskrat Falls generating facility ("Muskrat Falls"), and an examination of customer communications and service enhancements for each utility.

Subsequently, in early October, the Board advised the parties that the remaining scope of the investigation would be dealt with in two phases, with the first addressing the adequacy and reliability of the IIS up to the interconnection with Muskrat Falls and the second dealing with the implications of the interconnection for adequacy and reliability. This report is filed in response to this Board direction.

1. The Interim Report

Liberty filed an interim report on April 24, 2014 (the "Interim Report"), which addressed the issues set out by the Board for that report. The overall scope of the Interim Report included an:

- Explanation of the IIS events that occurred in December 2013 and January 2014
- Evaluation of possible system changes to enhance preparedness in the short term (*i.e.*, 2014 through 2016)
- Examination of the response by the two utilities to the power issues and customer issues.

2. Purpose of this Report

The review leading to the Interim Report focused on outage causes and identification of measures that Hydro and Newfoundland Power could take to mitigate the risk of outages through the time when Muskrat Falls enters service as now scheduled. The Board's May 15, 2014 Interim Report focused on issues and actions that should be addressed to mitigate the potential for significant outages during the coming winter. The Board also asked Liberty to address longer

[1] **IN THE MATTER OF** *the Electrical Power and Control Act, 1994*, SNL 1994, Chapter E-51 (the "*EPCA*") and the *Public Utilities Act*, RSNL 1990, Chapter P-47,(the "*Act*"), as amended; and **IN THE MATTER OF** an Investigation and Hearing into supply issues and power outages on the Island Interconnected System.

term issues affecting reliability on the IIS. This report provides Liberty's assessment of the adequacy and reliability of the IIS up to the interconnection with Muskrat Falls. It discusses both immediate-term actions to address reliability for the coming winter and identifies opportunities for ensuring reliability of service in the longer term. It also provides our assessment of the progress Newfoundland Power has made in responding to the recommendations in the Interim Report and the directions in the Board's Interim Report.

3. Next Steps

Liberty continues to address reliability issues specifically raised by the introduction of Muskrat Falls. Liberty anticipates a spring 2015 report addressing the issues associated with Muskrat Falls and its link to the IIS.

C. Causes of 2014 Outages

Hydro and Newfoundland Power operate the equipment and infrastructure needed to provide service to IIS customers. Hydro provides the vast majority of the generation (supply) needed to produce electricity and the transmission needed to move that electricity to the areas where customers use it. Newfoundland Power operates most of the distribution facilities of the IIS, connecting end-use customers to the sources of electricity provided by Hydro's generation and transmission facilities.

Liberty continues to conclude, as we reported in the Interim Report, that the January 2014 outages stemmed from two differing sets of causes: (a) the insufficiency of supply (generation) resources to meet customer demands, and (b) issues with the operation of key transmission system equipment. Liberty found at the time that a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons.

Liberty did not find then that Newfoundland Power operations or conditions contributed to the outages. That remains our view after completing the work leading to this report. The next paragraphs summarize the Hydro circumstances that we continue to believe lie at the root of the 2014 outages.

A shortage of generating capacity to meet customer demand produced outages that began on January 2, 2014. This shortage caused Hydro to request institution of a series of controlled, but substantial rotating customer outages. Liberty found that addressing the continuing risks of supply/demand imbalances would require adding resources and making sure that existing resources are available during winter peak load conditions. Liberty's Interim Report found, and Liberty continues to believe, that there exists a continuing and high risk of supply-related emergencies until Muskrat Falls and the Labrador-Island Link come into service. That time will be the winter of 2017/2018, at the earliest.

Liberty concluded in the Interim Report, and Liberty continues to believe, that transformer failure, protective relay design, circuit breaker malfunction, and operator knowledge issues all contributed to the January 2014 outages. Multiple equipment failures also underlay the January 2013 outages. Not only did equipment fail, but failures had consequence beyond what one would ordinarily expect to occur. In the second half of the period from January 2 through 8 of 2014, more widespread and uncontrolled outages resulted from Hydro equipment failures. These failures began with a fire at a major transmission system substation. Hydro ultimately experienced a series of major equipment failures at three of its terminal stations.

D. The Interim Report's Findings Regarding Newfoundland Power

The vast majority of the Interim Report's recommendations concerned Hydro. The 2014 outages resulted from Hydro's generation resources being unavailable and the failure of key transmission equipment on Hydro's system. Implementing rotating outages posed Newfoundland Power's major operational challenge during the January 2014 events. Conducting rotating outages in cold weather caused problems early in the process, but, as the outages continued, the Company was able to limit the duration of outages to the one-hour standard it sought to achieve. The Interim Report recommended that Newfoundland Power take advantage of the knowledge it gained in executing rotating outages, in order to facilitate the process of limiting the durations of any required rotating outages in the future.

Newfoundland Power made significant improvements between the 2013 and 2014 outages to increase the availability of representatives and information about outage condition and status. Liberty nevertheless did identify additional opportunities to pursue in continuing to improve performance. Liberty also recommended a formal joint effort by Hydro and Newfoundland Power to identify goals, protocols, programs, and activities that will improve operational and customer research, information, and communications coordination.

Liberty examined Newfoundland Power's progress in addressing the Interim Report's recommendations. Liberty also looked at other, longer term issues that may affect the performance of its transmission and distribution systems.

E. Response to Outage Events

The examinations leading to the Interim Report examined customer service accessibility and response and public and media communications in the context of the January 2014 events.

Liberty concluded in the Interim Report that Hydro and Newfoundland Power needed to work in a closely coordinated fashion during major events. Their goals should be common. The customer knowledge that forms the basis for their decisions should also be common. Particularly, their basis for making notifications to customers should be common, robust, and as objective as possible. The need to do so is strongly exhibited by a late request for customers to initiate conservation measures on January 2, 2014.

The principal recommendations in the Interim Report to address the communications issues at Hydro and Newfoundland Power include:

- Beginning the transition to a system that provides self-service (*i.e.*, without reaching a live representative) for reporting outages and emergencies, and inquiring about restoration status
- Conducting a joint Hydro/Newfoundland Power lessons learned exercise, involving the communications teams of both utilities, and seeking to develop a common set of plans for coordinating communications goals, processes, and interfaces for future major events

- Developing joint and individual outage communications strategies
- Conducting joint customer research designed to improve both Companies' understanding of customer expectations about outage information and conservation requests
- Developing clearer and more comprehensive advance notification procedures for Newfoundland Power customers
- Exploring additional communications channels (*e.g.*, two-way SMS text messaging or broadcasting options) for delivering outage status updates.

During Liberty's investigation in this phase Liberty reviewed the actions taken to address these recommendations.

F. Intercompany Coordination

The Interim Report also identified customer and intercompany communications as areas where greater efforts and more coordination between Hydro and Newfoundland Power would prove beneficial. This report examines efforts made in those areas. The needs Liberty identified include: (a) a number of operational data exchanges and protocols and procedures, (b) joint efforts to address communications with customers in advance of and during outages, and (c) undertaking structured, formal efforts to understand more about customer perceptions, attitudes, and expectations about service reliability and outage response.

G. Other Issues This Report Addresses

Liberty also examined for this report, as requested by the Board, the adequacy and reliability of Newfoundland Power's generation, transmission and distribution assets used to supply customers on the Island Interconnected System. The review included Newfoundland Power's reliability performance in recent years, the planning and design of its system, its asset management practices, its system operations, its management of outages and emergencies, including the plans, resources, and principal activities as intended and as actually implemented during the January 2014 events, and its communications with customers.

H. Study Approach and Methods

In this phase of the investigation, Liberty's study team first looked again at the nature of the events contributing to the outages and their immediate causes. Liberty did so to determine whether any new information or analysis would cause changes, deletions, additions, or emphasis on the causes determined during the review leading to Liberty's Interim Report. Liberty found nothing that would cause a change in our views. Second, we examined Newfoundland Power's progress in implementing the Interim Report recommendations involving it. Third, as requested by the Board, Liberty reviewed Newfoundland Power's system, approaches, resources, and activities associated with planning, design, and operation, in order to identify whether any opportunities for improving reliability exist.

Liberty conducted interviews with executives and managers responsible for the performance of the functions reviewed for the first time in this report, as part of Liberty's review of longer term plans, practices, resources, and actions to sustain service reliability. Liberty issued many formal requests for information, and reviewed the responses to them. Liberty again reviewed the reports that each utility filed in response to the Board's directions and we conducted interviews with Hydro and Newfoundland Power management about matters affecting them both (*e.g.*, customer communications and intercompany coordination issues identified in the Interim Report). After assembling a comprehensive set of factual findings, Liberty reviewed them and the tentative conclusions with both companies in order to give them an opportunity to identify errors or omissions of fact.

I. Liberty's Team

Liberty utilized essentially the same team that was used to conduct the review leading to the Interim Report, with one change. Liberty added a senior electric utility veteran whose management experience includes asset management and emergency planning. Each team member has spent 30 years or more in the industry. Liberty's president and one of the firm's founders, John Antonuk, led Liberty's examination. He received a bachelor's degree from Dickinson College and a juris doctor degree from the Dickinson School of Law (both with honors). He has led some 300 Liberty projects in more than 25 years with the firm. His work extends to virtually every U.S. state and he has performed many engagements for the Nova Scotia Utility and Review Board across a period of about ten years.

Mr. Antonuk has had overall responsibility for nearly all of Liberty's many examinations for public service commissions. His work in just the past several years includes: (a) examinations of overall direction of construction program, project management and execution, and operations and maintenance planning and execution at five major utilities, (b) assessment and monitoring of progress against major infrastructure replacement and repair programs, (c) multiple reviews of generation planning by electric utilities, and (d) use of risk assessment in the formation of electric utility capital and O&M programs, schedules, and budgets. Overall, he has directed more than 20 broad audits of energy utility management and operations, and more than 40 reviews of affiliate relationships (including organization structure and staffing) and transactions at holding companies with utility operations.

Mark Lautenschlager is a widely recognized expert in electricity transmission and distribution equipment and systems. His particular areas of expertise include electrical testing and maintenance, substation design and construction, forensic investigations of failed equipment, and technical training of electrical testing and maintenance technicians.

Mr. Lautenschlager has been conducting T&D reliability evaluations for Liberty for more than ten years. Most recently, he led Liberty's review of electric system operations in a management and operations audit of a utility engaged in a major program to address a series of weather-related, major outages. He focused on maintenance, construction, and root cause analysis. He has performed similar work for Liberty at nine major electric companies, including a number of Maine and Nova Scotia utilities. Before beginning his consulting career, he held substation maintenance and relay engineering positions in the electric utility industry, and ran a business focused on training electrical maintenance technicians and engineers, developing RCM-based substation maintenance programs, and performing forensic investigations of electrical equipment failures.

Mr. Lautenschlager is a registered professional engineer in Indiana, Ohio, and Pennsylvania, and holds a B.S.E.E. degree. He is a past president of the International Electrical Testing Association, and has been active in developing ANSI electrical equipment maintenance specifications.

Christine Kozlosky examined customer service and communications issues for this report. A nationally recognized utility customer service expert, she has worked with Liberty on many projects over 17 years. Her recent work with Liberty includes reviews of customer service and communications on four recent, broad management and operations reviews of major electric utilities, and on one project focusing specifically on customer service and communications. She has conducted many reviews of customer service and communications in the context of outage preparation and response, most recently in New England. She has also conducted base and follow-up reviews of outage communications at Nova Scotia Power as part of Liberty's engagement for the Utility and Review Board. This review examined storm response and communications.

Her earlier work in reviewing customer service and communications for Liberty includes four electric utilities, four natural gas utilities, and two telecommunications utilities. Ms. Kozlosky has been providing customer service performance benchmarking and performance improvement consulting since the early 1990s. She has conducted significant research into customer care best practices, process improvement, and performance benchmarking. She has a B.S. in Information & Computer Science from Georgia Institute of Technology.

Philip Weber was added to the Liberty team for the work for this report. He has over 35 years of professional experience in the electric utility industry specializing in reliability and maintenance of electric distribution systems, planning, and construction and project management. Phil managed the reliability and maintenance of the transmission and distribution system of a major Northeast electricity supplier PPL, where he produced major improvements in SAIFI and SAIDI performance.

Phil served on Liberty's team tasked with Development of Long-Term Electric & Gas Infrastructure Improvement Plan on behalf of NorthWestern Energy. He also served on Liberty's management reviews of East Kentucky Power Cooperative and Southwestern Public Service.

During a long career at PPL, Phil served as Project Manager in the Systems Operations Department, overseeing consolidation of the transmission operations function (69 kV and above) to a single office, while simultaneously managing the separation of the transmission operations function from the distribution operations (12 kV) function, and consolidation of regional offices. He also served as the System Maintenance Engineer, where he managed the reliability and maintenance of the transmission and distribution system, including the inspection and maintenance of 27,600 miles of overhead and 6,000 miles of underground circuits and related devices, managed the vegetation management program, administering an annual budget in excess of $50 million. He also had extensive experience in planning and managing storm response for the utility. Phil holds a B.S. in Industrial Engineering and a M.S. in Management Science from Lehigh University. He is a Registered Professional Engineer in Pennsylvania.

II. Planning and Design

A. Background

Newfoundland Power's[2] transmission system contains 103 lines having a total length of 2,055 kilometers, including eighty-three 66 kV transmission lines, 1,430 kilometers in length, nineteen 138 kV lines, 619 kilometers in length, and one legacy 33 kV line, six kilometers in length. Newfoundland Power's overhead transmission system contains about 27,000 poles, mostly pressure-treated wood poles, and some steel and laminated wood transmission poles. Forty-two percent of the transmission lines (870 km) are supported by single poles, while the remaining 58 percent (1,186 km) are supported by H-Frame structures. Four of Newfoundland Power's 66 kV transmission lines have underground sections, located where aerial construction is impractical, that have a total length of approximately three kilometers.

Newfoundland Power[3] has 306 distribution feeders with a total length of about 9,662 kilometers, including 210 – 12.5 kV feeders, 6,660 kilometers in length; 69 – 25 kV feeders, 2,458 kilometers in length, and 27 - 4.16 kV feeders, 544 kilometers in length. The Company's distribution system contains 294,722 wood poles.

Newfoundland Power's[4] distribution system is mostly (about 97 percent) overhead construction, with about 45 kilometers of mainline underground feeder cables, and about 65 kilometers of fused Underground Residential Distribution (URD) lateral cable loops fed by mainline feeders. Newfoundland Power typically installs underground distribution cable in locations where overhead construction is not practical due to property restrictions or congestion of equipment or buildings, such as the exiting of substations located in urban areas. URD installations are typically requested by a subdivision developer who wishes to provide underground distribution service to a housing development within the subdivision.

Newfoundland Power[5] has 130 substations with 149 transformers, not including voltage step-up substations at generation facilities, with transformers ranging in size from 1.0 MVA to 50 MVA. Some of the substations have multiple transformers and multiple feeders serving large numbers of customers, while others have a single transformer and a single feeder serving few customers.

1. Reliability

Liberty's examination of planning and design emphasized how reliability issues affect identification of needs to meet current and future system needs. Liberty therefore began with a review of recent-year reliability metrics for Newfoundland Power's transmission and distribution systems, in order to determine its base levels of performance and to identify the impacts that major events in recent years have had on that performance. This baseline review also sought to disclose any particular areas of concern or emphasis for Liberty's review of transmission and

[2] Responses to RFIs #PUB-NP-076 and 241.
[3] Responses to RFIs #PUB-NP-076 and 242.
[4] Response to RFI #PUB-NP-241.
[5] Responses to RFIs #PUB-NP-145, 244 and 274.

distribution management and operations. Electric utilities generally measure reliability in several ways, which include:

- The number of customer interruptions (CIs)
- The number of customer minutes of interruptions (CMIs)
- The system average interruption duration index (SAIDI)
- The system average interruption frequency index (SAIFI).

2. Planning

Transmission and Distribution Systems Planning activities identify and plan to fill needs for capital transmission, substation, and distribution projects required to provide the capacity to accommodate load growth and stability and to maintain system condition and reliability at acceptable levels. Planning duties include conducting load flow and other studies, developing energy and peak demand forecasts for business and technical reasons, and assisting system operators in addressing real-time system operations issues. Liberty examined the planning organization, criteria for planning capacity and reliability projects, and provision of support for Energy Control Center activities.

3. Design

Transmission and distribution electric power system designs need to balance cost, reliability, and load growth needs. Newfoundland Power equipment should be designed to withstand expected loads and known fault current levels. Transmission and distribution line conductor load ratings should employ industry accepted standards. Poles and lines should be designed with sufficient strength to withstand physical loads caused by expected high winds and heavy icing. Lightning arresters should be installed on distribution feeders and substation equipment to minimize lightning-caused damage. Animal guards should be installed to minimize animal-caused damage and customer interruptions. Liberty reviewed Newfoundland Power's design standards and criteria, its use of sectionalizing, Supervisory Control and Data Acquisition (SCADA), and overvoltage and animal protection for comprehensiveness and sufficiency in meeting customer needs.

4. Protection and Control

Protective relays quickly trip circuit breakers to clear line, bus, and transformer faults, in order to minimize equipment damage and to maintain system stability. Utility transmission systems typically use sophisticated impedance-type distance measuring relay schemes. They supplement them with backup secondary relay schemes to allow tripping following primary relaying or circuit breaker malfunction. Utility distribution systems typically use overcurrent relays or electronic reclosers to protect distribution-voltage equipment and feeders. Single-function electromechanical impedance and overcurrent relays have been used for about 90 years. They sometimes prove inaccurate and they require periodic testing to verify operation. Replacing electromechanical transmission relays with electronic relays has become increasingly common in recent decades. The use of programmable multifunction relays reflects the most recent trend. These relays offer high accuracy, do not require much testing, and provide relay status and fault current data. They can also provide breaker control via a SCADA system.

Liberty reviewed Newfoundland Power's protective relay scheme design philosophy, maintenance practices for electromechanical relays, the extent of modernization of the relay scheme with programmable relays, and how relay malfunctions are investigated.

B. Chapter Summary

1. Reliability

Newfoundland Power has in recent years made substantial improvements in its transmission and distribution systems. Focused rebuild and modernization projects have supplemented regular maintenance and vegetation management practices to produce steady improvement in the performance of its aged electric systems. After excluding the impacts of major outage events, the amount of interrupted per customer experiences has fallen from 5.7 to 2.2 hours between 1999 and 2013. The number of interruptions per customer fell during this period from 4.72 to 1.71. Recent performance under these metrics has been better than the average of other Canadian utilities over the last few years. Nevertheless, Newfoundland Power has opportunities to improve distribution system performance, which accounted for about 85 percent of outage durations metrics in 2013. Newfoundland Power should consider applying more capital for distribution system rebuilds and in installing more downstream reclosers on feeders.

2. Planning

Newfoundland Power's system planning organization is appropriately staffed and uses capacity planning criteria that are consistent with good utility practice. Planning engineers and technologists assist asset management personnel to identify and prioritize capital projects for rebuilding and modernizing the electric systems. The organization provides system operations personnel with the load flow and other studies needed to operate its systems. Since 2013, system planning senior management has been working with their counterparts at Hydro to examine reliability, system contingency and restoration planning, generation availability, and peak load management preparedness. Newfoundland Power should, however, change its prioritization practices for proposed projects by weighting scores under its selection criteria and by including a comparison of project costs versus anticipated reductions in customer interruption numbers and minutes.

3. Design

Liberty reviewed Newfoundland Power's design standards and criteria, its use of sectionalizing, its Supervisory Control and Data Acquisition (SCADA), and its overvoltage and animal protection practices for comprehensiveness and sufficiency in meeting customer needs. Liberty found them to be appropriate.

4. Protection and Control

Organization and staffing of the relay group matches needs. Newfoundland Power's protective relay scheme designs comport with those of similar utilities. Newfoundland Power has been replacing obsolete transmission system electromechanical with microprocessor relays that improve accuracy, flexibility, and monitoring capability, while reducing maintenance requirements. Newfoundland Power investigates relay malfunctions and coordination issues.

Liberty found, however, that Newfoundland Power does not: (a) formally document standard relay scheme designs and their operation, and (b) periodically test operate (“exercise”) its relay-to-circuit breaker operation. It does verify operation when commissioning equipment, investigating operating issues, and when it operates breakers by the SCADA system.

C. Findings

1. Reliability - T&D System Performance Overview

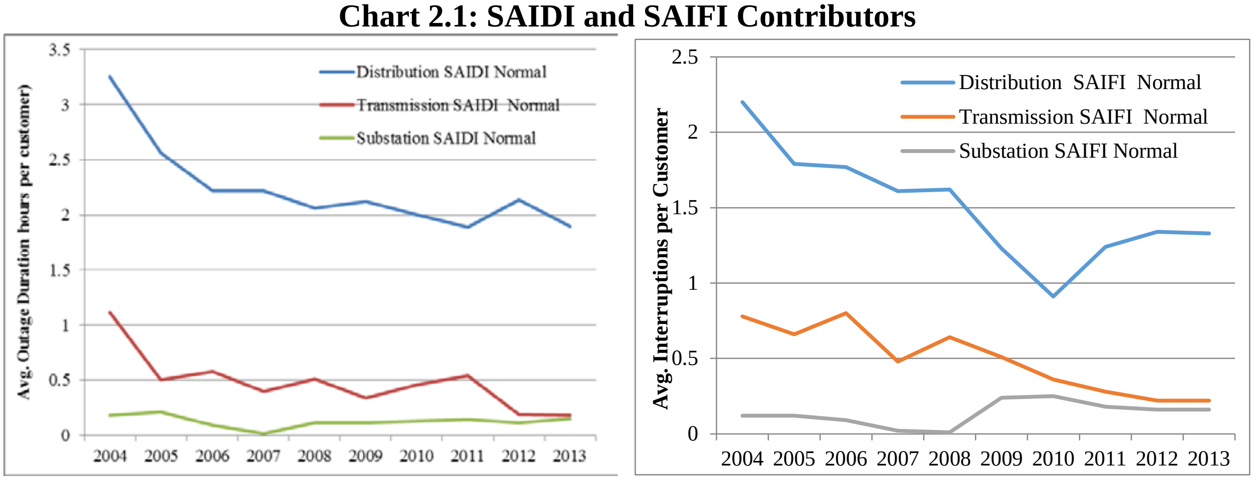
Consistent with usual electric utility practice, Newfoundland Power[6] tracks the performance of its transmission and distribution systems using measures of outage frequency and duration:

- For frequency, System Average Interruption Index (SAIFI)
- For duration, System Average Interruption Duration Index (SAIDI), measured in minutes.

Newfoundland Power also tracks numbers and minutes of customer interruptions (CIs and CMIs). Newfoundland Power also recently began to use the new Canadian Electricity Association (CEA) metrics of customer interruptions per kilometer (CIKM) and customer hours of interruption per kilometer (CHIKM). These metrics highlight performance on shorter feeders that serve denser populations.

Newfoundland Power[7] has experienced significantly improved SAIDI and SAIFI metrics, measured after excluding major events, as the next chart demonstrates. Its performance under these two metrics exceed Canadian Electricity Association composite measures, although direct comparisons of performance are difficult, given differences among participating utilities. The next charts, however, show that Newfoundland Power’s overhead distribution system, compared to its transmission system and it substations, has caused by far the most interruptions, measured by both frequency (SAIFI) and duration (SAIDI).

Chart 2.1: SAIDI and SAIFI Contributors

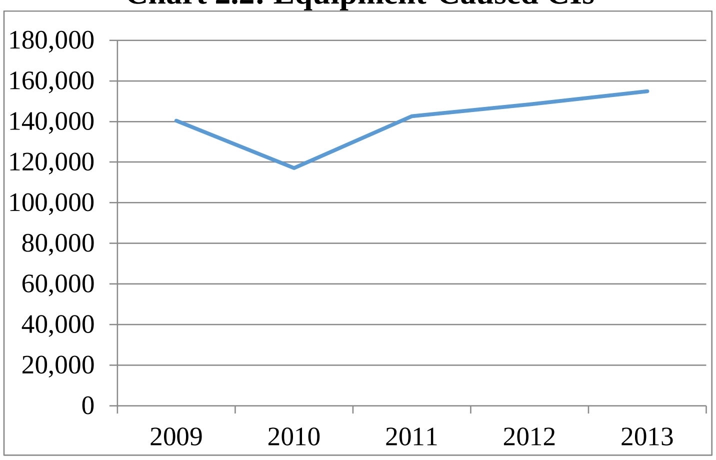


6 Responses to RFIs #PUB-NP-061 and 065, and Newfoundland Power’s 2015 Capital Budget Application.
7 Responses to RFIs #PUB-NP-308.

2. Reliability - Primary Causes of Customer Interruptions

Newfoundland Power's outage cause codes follow Canadian Electricity Association guidelines.[8] "Equipment failures" have been the predominant outage cause, accounting for 0.63[9] of the Company's 1.71 SAIFI[10] in 2013 and 25 percent[11] of customer interruptions. The next chart shows, despite reduction and eventual leveling of SAIFI in recent years, that equipment-caused interruptions have increased, driven principally by primary conductor, insulator, and cutout failure.[12] Primary[13] conductor failures generally result from winds and severe ice. They break older ACSR (aluminum conductor-steel-reinforced) conductors having steel cores weakened by salt corrosion. Insulator and cutout failures generally result from the physical failure adhesive binding insulators to steel parts. Recloser failures generally result from loss of oil or water entry caused by corrosion. A Newfoundland Power initiative replaces old steel-reinforced conductors with aluminum-alloy-conductor concentric-lay-stranded conductors, and replaces insulators and reclosers. Failures of Newfoundland Power[14] equipment contributed only marginally (6 percent of outage time) to outages during the January 2014 events.

Chart 2.2: Equipment-Caused CIs



3. Reliability – Sectionalizing Devices

Installing automatic circuit reclosers on distribution feeders downstream from substations can provide substantial reliability rewards. These reclosers sectionalize a faulted feeder section from other sections. Newfoundland Power[15]currently has twenty-six automatic circuit reclosers downstream from substations on seventeen distribution feeders. Newfoundland Power plans by the end of 2014 to add 14 additional reclosers to the few now remotely controlled via SCADA. These installations primarily seek to address cold load pickup issues occurring during the rotating feeder outages of January 2014.

[8] Response to RFI #PUB-NP-154.
[9] Response to RFI #PUB-NP-286.
[10] Response to RFI #PUB-NP-287.
[11] Response to RFI #PUB-NP-288.
[12] Response to RFI #PUB-NP-288.
[13] Liberty meeting with Newfoundland Power on September 19, 2014.
[14] Response to RFI #PUB-NP-037.
[15] Responses to RFIs #PUB-NP-078, 079, 289, and Order No P.U. 14 (2014).

Newfoundland Power protects lateral feeders which are tapped off of the mainline feeders with fuses, except for very short and heavily loaded feeders and single and two phase lateral feeders. Fusing prevents proper coordination with mainline (trunk) feeder protection. Newfoundland Power monitors these cases, and authorizes capital projects that reduce single-phase loading.

4. Planning - System Planning Organizations

The Transmission and Substation Planning Engineer directs annual forecasts of peak demands and load factors, which Hydro uses as well. The Planning Engineer directs or assists with medium- and long-term transmission planning.[16] The Supervisor of Engineering and Standards, with assistance from Regional Distribution Engineers, directs medium- and long-term distribution planning. This Supervisor also directs real-time distribution system operational analyses necessary for daily System Control Center operations. The Planning Engineer and the Supervisor also assist in performing technical and financial studies of proposed capital projects.

The Vice-President, Customer Operations and Engineering approves capital projects for inclusion in the annual capital budget, in consultation with other executives. The Vice-President works directly with the Manager of Engineering, Manager of Operations, Regional Managers, and senior engineers responsible for the transmission, substation, and distribution asset classes in the development of the annual capital budget.

Planning personnel also conduct the real-time operational analyses of the transmission system necessary for daily System Control Center operations. A Senior Engineer, two Engineering Technologists, and engineering work-term students support planning efforts. The Supervisor, Distribution Engineering Standards and the Manager, Revenue and Supply, support various planning activities.

5. Planning – Transmission Capacity Additions

Transmission and distribution planning criteria[17] must align with those of the Canadian Electricity Association (CEA). Newfoundland Power designs and constructs transmission and distribution systems so as to support forecasted peak flows without: (a) exceeding normal ampacities (thermal limitations), (b) violating voltage criteria, and (c) exceeding equipment fault duty (short circuit) ratings. The Company, however, allows limited equipment operation above planned ampacities under emergency conditions or when the systems are out of normal configuration.

Newfoundland Power[18] prepares annually five-year capital plans and budgets. These capital plans include projects designed to resolve MW and MVAR flow and voltage restraints on transmission lines and substation transformers. Newfoundland Power conducts analytical load-flow analyses, using a computer model that simulates system performance across the planning horizon, considering anticipated winter peaks and Newfoundland Power generation availability. Newfoundland Power develops solutions if future operating conditions are expected to produce

[16] Responses to RFIs #PUB-NP-155, 157, and 191.
[17] Responses to RFIs #PUB-NP-155 and 157.
[18] Responses to RFIs #PUB-NP-147, 148, 155, 269, and 272.

violations of design and equipment rating criteria. Annual load growth of 1.7 percent has required some distribution substation and feeder construction or upgrades, but the most recent transmission line construction occurred some 10 years ago.

The 2012[19] winter peak forecast produced a maximum peak loading level on a transmission line at less than 65 percent of normal winter rating, with most lines loaded at even lower levels. Modeling under the 2014/2015 winter peak forecast shows all transmission system transformers operating within nameplate ratings. Newfoundland Power therefore plans no transmission line or transformer capacity upgrades.

6. Planning – Distribution Capacity Additions

Annual five-year capital project plans address anticipated technical transformer and feeder issues resulting from load growth and other causes. Newfoundland Power conducts annual distribution load growth and voltage analytical studies, based on transformer and feeder ampacities, historical demand levels, and anticipated customer load additions. The Company also considers the results of short-circuit studies and voltage level studies (conducted every two to three years) and protective device coordination studies when the system is changed.

The 2014/2015 winter peak forecast would place eight distribution substation transformers above nameplate ratings. The Company has procedures to monitor these transformers if they are operated in excess of ratings and plans upgrades, added transformers, or load transfers to address the observed capacity insufficiencies. Newfoundland Power will have also completed capacity upgrades at Hardwoods, Bay Roberts, and Marble Mountain Substations in preparation for the 2014/2015 winter peak. Forecasted 2014/2015 winter peaks will not require any distribution feeder to operate in excess of its winter rating. Only a few feeders currently approach 100 percent of ratings.

7. Planning - Reliability Improvement

Newfoundland Power[20] considers reliability, rather than a need to serve new load, the primary driver of capital work, accounting for an estimated fifty percent of each annual capital budget. The Asset Management groups identify the need to improve the condition and reliability of aged T&D equipment and, working with various planning personnel, develop solutions based on merit, least cost alternatives, and priorities. However, the process for assessing reliability projects uses no scoring process. Other companies Liberty has observed use a comparison of project cost versus expected numbers of customer interruptions or customer minutes of interruption. Newfoundland Power relies on engineering judgments that consider reliability metrics, inspection results, and condition and event assessments.

Newfoundland Power implemented in 1998 a Distribution Reliability Initiative to address a number of reliability issues. Identification of potential projects begins with an annual identification of the 15 worst performing feeders. Five-year trends in SAIDI, SAIFI, and customer minutes of interruptions determine these 15 feeders. Other structured programs include:

[19] Responses to RFIs #PUB-NP-274, 275, and 276.
[20] Responses to RFI #PUB-NP-272.

- Rebuild Distribution Lines Projects (introduced in the 2004 capital budget application and updated in 2013)
- Long-term Transmission Line Rebuild Strategy (implemented in 2006 and included in capital budget applications) to identify aging transmission line infrastructure for rebuild, based on physical condition, risk of failure, reliability statistics and potential failure impacts on customers.
- Long-term Substation Strategic Plan (implemented in 2007 and included in capital budget applications) to deal with aging substation infrastructure in a manner that is based on criteria similar to the Transmission Line Rebuild Strategy.

8. Planning - Inter-Utility Communications

Oversight[21] of matters of joint concern related to system reliability falls under the Inter-Utility System Planning and Reliability Committee. This committee is made up of senior operations and engineering management of both Newfoundland Power and Hydro. The Committee meets twice a year to consider matters related to system reliability, system contingency and restoration planning, generation availability, and peak load management preparedness. In 2013 the two companies increased the work of the Joint System Planning Subcommittee. Planning engineers from both utilities review Newfoundland Power's annual energy and winter peak demand forecast.

The utilities keep each other informed of major transmission and transformer capacity additions and, on occasion, conduct joint transmission and terminal station capacity constraint studies. Newfoundland Power, however, has not been able to conduct a formal analysis of the effect of the Labrador-Island Link on its transmission system because it is not privy to Hydro's operations and stability studies related to integration of Muskrat Falls that may have been conducted by Hydro.

9. Design - Transmission Line Standards and Criteria

Newfoundland Power[22] designs, builds, and rebuilds its transmission lines in accordance with the vertical and horizontal clearance requirements specified in Canadian Standards Association Standard C22.3 No. 1 Overhead Systems. Newfoundland Power's transmission and vegetation inspection programs identify any deficiencies with respect to line clearance requirements. The Company employs transmission line conductor ratings designed to allow the availability of full ampacity for each line, under normal and emergency conditions and various ambient temperatures, without causing conductor damage or excessive sag. Newfoundland Power designs conductors on the basis of[23] continuous winter (0° C) and summer (25° C) load current ratings, under specific air temperature and wind conditions, based on limiting conductor temperatures to 75° C. Greater temperatures could cause conductor damage and excessive conductor sag. Newfoundland Power does not employ "emergency" ratings for transmission line conductors, but allows ratings to be exceeded on a case-by-case basis when ambient air temperature and wind speed conditions allow for higher loading.

[21] Responses to RFIs #PUB-NP-002 and 170.
[22] Response to RFI #PUB-NP-282.
[23] Response to RFI #PUB-NP-146.

The ability to transfer loads from one transmission line to another line improves reliability and system stability when transmission equipment is not in service. Newfoundland Power does not have a policy specifically requiring full N-1 contingency redundancy (no customer interruptions for the loss of a line at peak load). Nevertheless, more than half of the transmission system provides such redundancy.[24]

About fifty-four percent[25] of Newfoundland Power's transmission system, mostly serving urban areas, is "looped." Looping serves substations by at least two lines, thus providing redundancy. The Company's four sections of underground transmission lines have full redundancy. About twenty-two percent of its transmission system serves substations radially. Diesel, gas turbine, or hydro backup generators are available to serve some or all loads at a substation during radial line maintenance outages. About twenty-four percent of its transmission system, mostly serving rural areas, serves substations radially without any backup generation capability.

Newfoundland Power[26] directly controls and monitors 94 of its 103 transmission lines from its System Control Center via its SCADA. Eight of the remaining nine are controlled by operating SCADA controlled breakers on lines that feed the substations supplying those lines.

10. Design - Transmission Line Fault, Overvoltage, and Galloping Protection

Newfoundland Power protects transmission lines with relay-controlled circuit breakers and automatic sectionalizing switches. Virtually all[27] transmission lines employ protective relays operating substation circuit breakers to clear faults. The remaining four transmission lines have automatic sectionalizing switches (motor-operated air-break switches) at substations.

Preventing transmission line equipment damage and faults caused by overvoltages is a function of line design, grounding, relaying, and the use of lightning arrestors. Lightning is not now an issue for Newfoundland Power. To minimize transmission line lightning-caused damage the overhead ground wires on 138 kV transmission lines[28] have been extended 800 meters out from substations and lightning arresters have been installed at its 66 kV transmission line underground cable terminations. It protects its 138 kV and 66 kV steel structures with grounded lightning rods. Newfoundland Power also uses instantaneous relay/breaker tripping to minimize damage caused by lightning.

Wind and ice-caused conductor oscillation (so called galloping) can damage transmission line hardware. Newfoundland Power[29] installed interphase insulated spacers on the few transmission line sections that have experienced damaging conductor galloping.

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[24] Responses to RFIs #PUB-NP-145 and 155.
[25] Response to RFIs #PUB-NP-061 and 145.
[26] Response to RFI #PUB-NP-245.
[27] Response to RFI #PUB-NP-149.
[28] Response to RFI #PUB-NP-281.
[29] Response to RFI #PUB-NP-284.

11. Design - Feeder Standards and Criteria

Newfoundland Power[30] designs, builds, and rebuilds its distribution lines in accordance with the vertical and horizontal clearance requirements as specified in CSA Standard C22.3 No. 1 Overhead Systems. Newfoundland Power's transmission, distribution and vegetation inspection programs identify any deficiencies with respect to the clearance requirements.

Newfoundland Power performs distribution feeder conductor planning and determines operating ratings under the same ampacity considerations and temperature conditions that apply to transmission conductors.

Newfoundland Power also considers in winter planning ratings the amount of initial current occurring when a feeder is restored. This "cold load pickup" can be twice the winter peak demand load. However, the cold load pickup current flowing when a feeder breaker is closed can be reduced to about one 1.33 times winter peak demand. A recloser, located downstream from the substation, can be opened so as to pick up no more than about two-thirds of the feeder load during restoration.

Newfoundland Power has normal and emergency ratings for its aerial and underground distribution cables. Underground ratings depend on conditions (direct buried, run in conduits, number of circuits at a location, insulation type, ambient earth temperature, and thermal resistivity). Newfoundland Power allows aerial and underground cables to operate at twice normal ratings for up to one hour (for cold load pick up) and for longer times at "emergency ratings."

Load transfer capability is supported on 249 of Newfoundland Power's[31] 306 distribution feeders. The 249 feeders have line ties outside of substations to other adjacent feeders. Line ties are not practical for the remaining fifty-seven feeders, which lie in rural areas where no adjacent feeders are available. For underground primary feeders, Newfoundland Power generally provides redundant capacity if an underground primary feeder cable fails. Newfoundland Power's underground residential distribution (URD) laterals tapped off of mainlines are open-looped at normally open tie switches. This configuration reduces the time required to restore service to customers on a half loop when a cable section fails.

12. Design - Distribution SCADA

Newfoundland Power[32] operates SCADA control and monitoring in substations serving about 60 percent of its distribution feeders and it has 26 automatic circuit reclosers (downstream from substations) on 17 of its 306 distribution feeders. Its 2015 Capital Budget Application included a two-year project to replace the existing SCADA system because the vendor of the current system no longer supports it. Newfoundland Power will solicit proposals from vendors who supply smaller utilities. The new system will be capable of advanced distribution management functions

[30] Response to RFI #PUB-NP-282.
[31] Response to RFI #PUB-NP-246.
[32] Response to RFIs #PUB-NP-077, 078, 079, and 149.

including eventual interfaces with the Geographic Information System (GIS) and to a new commercial Outage Management System (OMS).

13. Design - Distribution Fault and Overvoltage Protection

Newfoundland Power has fused all of its lateral feeders, except for short taps and heavily loaded taps, where fuses cannot be coordinated with the mainline feeder protection.

Based on the "cold load pick up" issues Newfoundland Power[33] experienced restoring heavy loaded feeders during the January 2014 rotating feeder outages, it identified that installing additional feeder sectionalizing, via fourteen SCADA-controlled downstream automatic circuit reclosers on heavily loaded feeders, would minimize recurrence of that problem. Probably as importantly, these new reclosers should improve both SAIDI and SAIFI metrics for those feeders. The automatic reclosers provide better isolation of faults, more timely restoration of feeders, and more efficient use of line crews. The Company plans to have the fourteen additional downstream feeder reclosers installed by the end of 2014.

Newfoundland Power[34] installs lightning arresters on all new distribution pole-mounted transformers and on downstream voltage regulators and reclosers, and, since 2003, has been installing arresters on existing devices under its distribution rebuild capital projects. It also installs arresters on underground cable terminations supplying pad mount transformers.

14. Design - Line Strength Criteria

The ability of a transmission or a distribution line to withstand expected high winds and icing occurring during storms depends substantially on pole strength or tower design and span length. Newfoundland Power[35] constructs and rebuilds its overhead transmission and distribution lines to exceed the latest Canadian Standards Association (CSA) overhead systems wind and ice load criteria. It uses using larger class poles, shorter line spans, and additional guying. These standards require constructing overhead transmission and distribution lines to withstand at least 92 kilometers per hour wind (a force of 400 Pascals), 12.5 mm of radial ice when wind and ice have been "heavy," and 19 mm for "severe" radial ice.

Since 2001, Newfoundland Power has been constructing and rebuilding its overhead T&D systems in the Avalon and Bonavista Peninsulas consistently with the "severe" criterion. Much of Newfoundland Power's overhead systems were constructed under previous CSA criteria; it cannot report exactly how much. However, the long practice of exceeding the CSA criteria, gives the Company confidence that the number of facilities that do not meet current design criteria is relatively low.

15. Design – Substation Load Transfer

The ability to transfer loads from one substation transformer to another transformer improves reliability when substation equipment is not in service. Some Newfoundland Power transformers

[33] Response to RFI #PUB-NP-289.
[34] Response to RFI #PUB-NP-281.
[35] Responses to RFIs #PUB-NP-242 and 243.

have the capacity to accept loads from other transformers. Twenty-nine substations have more than one power transformer, and contain twenty-four sets of multiple transformers sized to provide N-1 contingency (no customer interruptions for loss of a transformer in a set), except under peak winter loads. Thirteen of the twenty-nine multiple-transformer substations are located in the more densely populated St. John's area. Newfoundland Power also maintains four portable substations to bypass fixed substations as required. The substations contain by-pass switches to limit the length of customer outages occurring when a substation circuit breaker or recloser fails, or when maintenance work is conducted.

16. Design - Substation Transformer Operating Ratings

Under expected conditions, an electric utility should seek as far as practicable to retain the capacity to operate substation equipment within the load versus temperature ratings as indicated by the equipment manufacturers. Newfoundland Power[36] plans and operates its substation equipment within manufacturer's ratings under expected peak load conditions. When the distribution system is out of normal configuration (*e.g.*, following a transformer failure), the Company allows circuit breakers and other transformers to operate temporarily in excess of normal ratings (within IEEE C57.12 temperature limitations). This exception can permit continuity in customer service until deployment of a mobile substation is in place, or there is a return to normal configuration.

Newfoundland Power[37] operates its power transformers according to its *Power Transformer Loading Guidelines.* The Company normally allows its substation transformers to operate up to 105 percent of nameplate rating during the summer. The Company also allows, under short-term emergency conditions, transformers to operate up to 130 percent, and even higher, with on-going scrutiny of load and temperature, and by limiting load, loading time periods, and transformer temperatures based on accepted "Loss of Transformer Life" curves derived from ANSI/IEEE Loading Guide C57.12.30-1981.

17. Design - Animal Protection

Newfoundland Power[38] reports that animals have minimal effect on its system reliability performance. Less than 1 percent of 2013 customer interruptions were caused by animals and birds. Nevertheless, Newfoundland Power reported that large birds and small animals occasionally cause short circuits in distribution reclosers, metering tanks and station service transformers. These instances have often severely damaged equipment. Based on success at other utilities with modern methods of animal protection, Newfoundland Power began installing devices on its substation equipment and distribution transformers in the mid-2000s. The Company found that installing insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages and therefore includes "varmint protection" as one of the refurbishment items completed under its annual Substation Refurbishment and Modernization capital project

[36] Responses to RFIs #PUB-NP-145 and 146.
[37] Response to RFI #PUB-NP-064E, page 1488.
[38] Response to RFI #PUB-NP-283.

18. Design - Substation Overvoltage Protection

Preventing substation transformer and bus damage and faults caused by excessive transient voltages requires the use of lightning arrestors. Newfoundland Power[39] equips its substation power transformers with lightning arrestors on both the high voltage and low voltage sides, it grounds its substation bus structures, and it protects its 138 kV and 66 kV steel structures with grounded lightning rods.

19. Design - Fault Duty Studies

Fault currents at various locations on transmission and distribution systems can increase when system changes are made, such as when additional generation is installed, circuits are paralleled, or transformers are changed. Newfoundland Power[40] conducts short-circuit studies every two or three years and when system changes are made to verify that none of its transmission or distribution circuit breakers or feeder reclosers will be exposed to fault currents in excess of fault-duty ratings. Newfoundland Power has replaced twelve circuit breakers since 2004 because of fault-duty limitations.

20. Design - Geographic Information System (GIS)

A Geographic Information System (GIS) is a digital record of a utility's equipment locations and electrical connectivity, and usually includes other important equipment data critical for operating the system, for conducting engineering studies, and for managing equipment repairs and maintenance. Newfoundland Power[41] implemented a GIS only recently, in 2013. Its GIS displays on computers equipment data and locations of primary distribution feeders, streetlights, and poles, based on data collected from its distribution model in the 1990s, on the Streetlight Management System, and on a pole survey Bell Aliant pole database from the 2011 pole sale to Newfoundland Power. Newfoundland Power has processes in place for reviewing the accuracy of the data and for updating the GIS when new equipment is installed in the field.

21. Protective Relays - Designs

Newfoundland Power[42] has no formal protective relay scheme design criteria document describing its standard design philosophies. Its practice, however, for transmission line and circuit breaker protection includes the use of a single relay protection scheme with backup from remote, back-line protection. It uses three types of protection schemes for its transmission lines: (a) line current differential protection schemes with fiber optic communication, (b) distance or impedance protection, and (c) overcurrent protection with phase and ground fault elements. Current differential protection protects transmission lines less than ten kilometers in length. Distance protection exists for 138 kV looped transmission lines, with distance or overcurrent protection applying on other transmission lines.

Newfoundland Power is in the process of modernizing the technology used in its protection schemes. This process has resulted in increased use of distance protection and a decreased use of

[39] Response to RFI #PUB-NP-281.
[40] Response to RFI #PUB-NP-148.
[41] Response to RFI #PUB-NP-278.
[42] Response to RFI #PUB-NP-279.

overcurrent protection as the primary method. Newfoundland Power is also implementing expanded functionality of programmable relays in new relay schemes to provide multiple protection schemes. As appropriate, it also uses overcurrent protection as a backup to differential and distance relaying schemes. Finally, the Company is modernizing breaker failure schemes to provide backup when breakers fail to operate.

For its substation protection, Newfoundland Power uses relaying with three protection zones, high voltage (66 kV and 138 kV) bus protection, power transformer protection and low voltage bus protection. The protection scheme used varies depending on the number of transmission line terminations and transformers.

Newfoundland Power provides differential protection schemes for high voltage buses which have two or more circuit breaker controlled transmission lines. It protects its other high voltage buses by remote, back-line transmission line protection. High voltage buses with three or more transformers have high voltage bus-tie breakers to improve fault clearing selectivity and to improve service reliability. For power transformers with capacities greater than a 7.5 MVA base rating, Newfoundland Power uses a differential current protection scheme along with phase and ground overcurrent protection. In substations where there is no high voltage breaker, the transformer protection scheme operates a high-speed ground switch which trips back-line transmission line protection. Power transformers rated 7.5 MVA and lower are protected by power fuses.

Newfoundland Power uses phase and ground overcurrent protection to protect distribution feeders. It blocks the instantaneous tripping function after the first trip, in order to allow time for downstream fuses to operate before the feeder trips the second time.

22. Protective Relays – Maintenance, Testing, and Replacement

An Engineering Technologist responsible for substation maintenance work planning schedules relay testing. An Asset Maintenance Coordinator monitors substation inspection and preventative maintenance activity, scheduling and tracking testing. The Superintendent System Control and Electrical Maintenance directs substation inspections and preventative maintenance activity.

Newfoundland Power[43] has since 1998 been systematically replacing electromechanical relays with new micro-processor programmable relays. Protection and Control Engineers and Engineering Technologists review all updated relay schemes to verify conformity with design criteria. The new relays comprise micro-processor controlled, programmable relays. One programmable relay can replace multiple electromechanical ones. Self-diagnostic capability and programmable monitoring capacity combine to improve the reliability of protection, and increase efficiency in the use of field personnel. Newfoundland Power[44] spent $10.1 million replacing old electromechanical relays from 2008 through 2012.

[43] Responses to RFIs #PUB-NP-075, 279 and 280.
[43] Response to RFI #PUB-NP-075.

Newfoundland Power[45]tests, adjusts, or replaces its electromechanical relays on five-year cycles. Newfoundland Power does not formally periodically test operate ("exercise)" relay-to-circuit breaker operation, but verifies operation when commissioning equipment or investigating operating issues. It also operates breakers via the SCADA system. The programmable relays do not require scheduled testing. Their self-diagnostics can generate alarms remotely monitored through the Company's SCADA system. Newfoundland Power targets a completion rate of 70 percent for relay maintenance items. It has maintained that rate, albeit with substantial acceleration, in the past several years. Newfoundland Power[46] investigates relay malfunction and coordination issues. The SCADA system time-tags events in a manner that permits analysis of event sequences. Engineering Technologists and Electrical Engineers who specialize in protection and control systems review SCADA events logs to verify the appropriateness of events sequences associated with protection schemes.

D. Conclusions

Reliability

2.1. T&D reliability has substantially improved since 1999 and has recently remained stable overall.

SAIFI and SAIDI metrics have substantially improved. Performance has been better than Canadian Electricity Association (CEA) composite measures since 2005 for SAIDI and since 2009 for SAIFI. Newfoundland Power employs a suitable range of processes and programs that address equipment conditions. Effective maintenance practices and infrastructure-improvement capital programs have contributed to improved reliability. Newfoundland Power designs overhead lines to weather standards exceeding CSA standards, performs regular inspections, and addresses worst performing feeders.

The Company has engaged in a number of specific initiatives to improve reliability performance, including its Distribution Reliability Initiative, Rebuild Distribution Lines Project, Substation Refurbishment and Modernization Strategy, and Transmission Rebuild Strategy. Newfoundland Power's capital expenditures for its transmission, substation, and distribution rebuild and modernization strategies have steadily increased since 2004. Expenditures in 2014 remain substantial.

2.2. The large contribution that the distribution system makes to outages and the number of equipment-caused failures indicate room for further improvement in reliability. (*Recommendation #2.1*)

The Company's transmission system and substations contributions have contributed only in small measure to SAIFI and SAIDI measures. Excluding major outage events, equipment failures have caused the greatest number (25 percent, and increased marginally since 2010) of customer interruptions related to the distribution system. Primary conductor, insulator, and cutout failures were the greatest causes of equipment-caused CIs. The comparatively large number of distribution system-caused customer outages can be addressed through the use of additional

[45] Responses to RFIs #PUB-NP-075, 200, 233, and 234.
[46] Response to RFI #PUB-NP-200.

downstream feeder reclosers and through increasing the priority on the *Rebuild Distribution Lines Project* when prioritizing capital projects. Improving the condition of older distribution feeders particularly by upgrading conductors, insulators, and cutouts will address conditions that have contributed the most to the Company's equipment-caused failures.

2.3. Newfoundland Power focused on worst performing feeders for some time, but has recently ceased committing resources to them despite the fact that such feeders still exhibit disproportionately high outage metrics. *(Recommendation #2.2)*

Newfoundland Power identifies worst performing feeders, but has not addressed any under its Distribution Reliability Initiative since 2011. Since the 1998 inception of a process for addressing worst performing feeders, the SAIDI on such feeders has improved from 17.42 to 5.15 (by 2013). That improvement is notable. The current gap between worst performing and all feeders is 5.15 versus 1.9. Newfoundland Power does not consider this gap sufficient to continue including worst performing feeders in its Distribution Reliability Initiative. Liberty views the remaining gap as substantial enough to warrant the common utility practice of a targeted funding program to address that 10 to 15 percent of feeders exhibiting worst SAIDI and SAIFI performance during the previous year, absent a showing that other expenditures on reliability improvement are more cost effective.

Planning

2.4. Newfoundland Power's Transmission and distribution systems operate effectively in ensuring adequate service reliability.

Planning resources are appropriately organized and staffed. Newfoundland Power employs appropriate criteria and standards. Capacity planning takes an appropriately conservative view of weather conditions. Transmission lines, transmission voltage transformers, and distribution feeders continue to operate overall with healthy margins under current and forecasted load conditions. Distribution substations forecasted to operate in excess of criteria have been slated for capacity increase. Planners conduct an appropriate range of load flow, voltage, short circuit, and protective device coordination studies, supported by sufficient computer-based tools and models. They verify model accuracy through comparisons with actual conditions.

2.5. The expanded work of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should improve planning coordination between Newfoundland Power and Hydro.

2.6. Capital programs have been effective in improving reliability, but better methods for prioritizing projects under consideration exist. *(Recommendation # 2.3)*

Reliability, the largest contributor, drives about half of transmission and distribution capital budgets. Planners sufficiently focus on reliability issues in forming budgets.

Decisions on which projects to fund consider operating benefits, the costs of alternative solutions, and priorities. Newfoundland Power does not, however, employ a structured objective scoring process for prioritizing projects, relying instead on more subjective consideration of engineering judgment, reliability index measures, inspection results, and condition assessments.

Others employ a similar range of factors, but seek to employ them in a more structured, quantifiable, weighted, analytical process. Best practice in doing so also includes the use of a comparison of the expected costs of potential projects in relation to the benefits they may bring in avoided numbers of customer interruptions or minutes of interruptions.

Design

2.7. Newfoundland Power has incorporated appropriate levels of redundancy in its transmission and distribution systems and in its substations.

Newfoundland Power's approach to design incorporates levels of reliability consistent with the nature of its serving areas. Liberty found its levels of redundancy and its availability of emergency generation very competitive with other utilities having a substantial degree of low-density, rural load. Newfoundland Power has looped a sufficient portion (roughly half) of its transmission system, which avoids outages when one line fails. Diesel, gas turbine, or hydro backup generators are available to serve some or all loads to avoid outages during maintenance on radial lines. Only about a quarter of the transmission system has neither transmission looping nor backup generation capability. Moreover, wherever practicable on distribution feeders (249 of Newfoundland Power's total of 306) allow load transfer from one feeder to another feeder. Line ties are not practical for the remaining fifty-seven feeders located in rural areas where no adjacent feeders are available.

2.8. Newfoundland Power employs appropriate design standards, criteria, and practices for transmission and distribution lines.

Overhead transmission and distribution line design exceeds Canadian Standards Association clearance and ice loading standards. When rebuilding lines on the Avalon and Bonavista Peninsulas, the Company uses conservative wind and radial ice criteria. Appropriate measures have been taken to address transmission line galloping in high winds. The Company uses appropriate operating standards to avoid equipment damage and excessive sag. Criteria that permit substation transformers to operate in excess of manufacturer ratings are consistent with industry practices.

2.9. Current use of SCADA and use of automatic reclosers on feeders downstream from substations currently do not serve to minimize interruption frequency and duration. *(Recommendation #2.4)*

Use of SCADA control is appropriate for its transmission system. It directly controls and monitors 94 of its 103 transmission lines and indirectly controls others. SCADA control, however, exists for only about 60 percent of distribution feeders. The Company will begin SCADA replacement in 2015, under plans to include all distribution feeders in its new system. Executing these plans will bring Newfoundland Power into conformity with good utility practices.

Downstream reclosers can reduce by about one-half the number of customers affected by feeder faults occurring past the downstream recloser. Newfoundland Power currently makes only minimal use of these devices. It will have installed some more by the end of 2014. Continuing to install more of these reclosers over time, beginning with those worst and mediocre performing feeders that have substantial loads would be consistent with good utility practices, and presents a likely more cost effective way of further improving distribution reliability.

2.10. Newfoundland Power employs appropriate lightning and animal protection.

Extending ground wires 800 meters out from substations on 138 kV lines, employing lightning arresters on substation transformers and feeders, and installing lightning arresters on feeder-mounted equipment during rebuilds comprise effective measures. The use of insulated coverings, guards and insulated leads have been effective in preventing animal-caused damage and outages.

2.11. Newfoundland Power makes effective use of short circuit studies.

Short circuit studies have been carried out on an effective time cycle, and employed when system changes occur. Newfoundland Power has used them appropriately to address the prevention of circuit breaker failures resulting when fault currents exceed equipment fault duty ratings.

2.12. Completion of in-process developments in the Geographic Information System will increase its effectiveness.

Newfoundland Power only recently, in 2013, implemented a Geographic Information System. The Company recognizes the need to improve the level of accuracy in the system to take it beyond its current sufficiency for use in determining electrical connectivity of the distribution system and locating equipment in the field. It needs to ensure completion of plans for field surveys to gather equipment data and to install in line trucks the capability to update system data in the field.

Protective Relays

2.13. Newfoundland Power's protective relay schemes conform to industry practice, but they do not operate under documented guidance. *(Recommendation #2.5)*

The Company uses reasonable practices and it has for a number of years been replacing obsolete relays with modern programmable relay schemes. It spent more than $10 million to replace relays from 2008 to 2012. Newfoundland Power has not, however, employed a formal protective relay scheme criteria document explaining its protective relaying objectives, approaches, and methods for each electric systems element.

2.14. A temporary delay in testing of electromechanical relays is being addressed.

Reassignment of testing responsibility produced training requirements that caused some delay in testing electromechanical relays. As the end of 2014 approached, Newfoundland Power had nearly completed the testing on its five-year cycle.

2.15. Newfoundland Power does not formally periodically exercise its circuit breakers. *(Recommendation #2.6)*

Newfoundland Power does, however, verify relay to circuit breaker operation when commissioning equipment, investigating operating issues, and when it operates breakers by the SCADA system it does so via programmable relays, where applicable.

2.16. Newfoundland Power does not centrally track actions to address the causes of frequent protective device operations. *(Recommendation #2.7)*

Area operating personnel identify and address multiple protective device operations (such as feeder tap fuses) occurring within a year. Some such operations may not have a material impact on overall SAIFI and SAID metrics, but nevertheless produce dramatic outage effects for a small number of customers. Many utilities, but not Newfoundland Power, formally track "multiple protective device operations" (usually three or more operations of the same device during a rolling 12 months) to ensure that even very small numbers of customers are not experiencing multiple service interruptions. Best practice requires resolving the causes of multiple operations promptly. Personnel in the field may now be addressing multiple device operations effectively, but central tracking comprises a material element in verifying that effectiveness.

E. Recommendations

Reliability

2.1. Increase the emphasis on the Rebuild Distribution Lines initiative in annual capital budgets, with the goal of reducing distribution equipment failures. *(Conclusion #2.2)*

2.2. Perform a structured evaluation of the costs and benefits of reinstituting a regular annual program for addressing worst performing feeders. *(Conclusion #2.3)*

The program employed in the past has produced very substantial reliability improvements. While the gap between worst performing and all feeders is now much narrower, it is not clear that the gap has become small enough to make continuation uneconomical. The Company should assess in a structured, analytical way the cost/benefit ratio for this program, in comparison with other programs that its resumption might displace.

Planning

2.3. Develop a weighted analytical scoring of criteria process to support capital planning; include in this a scoring criterion that relates expected project costs to avoided numbers of customer interruptions or minutes. *(Conclusion #2.6)*

Using a process for scoring project selection criteria is good utility practice. Newfoundland Power should also consider including cost versus anticipated avoided customer interruption (CI) and/or avoided customer minutes of interruption (CMI) as part of the scoring process. Using a weighted scoring process would also help justify proposed capital projects to stakeholders, including the Board, and will demonstrate whether a proposed project is needed to primarily improve equipment condition or to primarily improve future reliability (such as improving SCADA). This approach also works to eliminate any subjective bias to the prioritization process.

Design

2.4. Investigate the installation of downstream feeder reclosers for the purpose of improving distribution SAIFI and SAIDI indices, in addition for reducing cold load

pick up difficulties, with priorities given to feeders based on installation costs versus anticipated avoided customer interruptions. *(Conclusion #2.9)*

<u>Protective Relays</u>

2.5. Document protective relay scheme objectives, criteria, and methods for protecting transmission lines, buses, and distribution feeders. *(Conclusion #2.13)*

2.6. Conduct circuit breaker operation tests from relays (so called trip checking) on a periodic basis to assure that all relay trip circuits and circuit breakers operate as intended. *(Conclusion #2.15)*

2.7. Centrally report multiple device operations. *(Conclusion #2.16)*

Newfoundland Power should install a method for ensuring that regional personnel promptly address such operations. The goal is to ensure timely resolution of issues that may produce dramatic effects on customer groups too small to have a material bearing on overall reliability metrics.

III. Asset Management

A. Background

Effective utility asset management seeks to prevent equipment-caused customer interruptions by using cost-effective inspection, maintenance, and rehabilitation practices. Programs and practices should be designed and funded to provide sufficient skilled resources and equipment to accomplish the goals of asset management strategies. Liberty reviewed Newfoundland Power's transmission and distribution asset management strategies, including equipment inspection, repair, replacement, upgrading, maintenance and rehabilitation policies, programs and actual practices, and the adequacy of and its compliance with its strategies. The examination included the practices for maintaining and enhancing the condition and reliability of transmission lines, substation equipment, and distribution feeder poles and other line equipment, and the adequacy of vegetation management practices. Liberty also examined asset management operational organizations, work completion accountability, staffing levels, training, and succession planning and the maintenance management tracking methods used to accomplish its asset management strategy. Chapter V addresses how Newfoundland Power manages and maintains generating facilities, and Chapter II addresses how it manages and maintains its protective relays.

B. Chapter Summary

One of Newfoundland Power's asset management objectives is to detect and correct equipment condition issues before equipment failure occurs. Newfoundland Power performs effectively in minimizing equipment-caused outages. It supplements regular equipment maintenance practices on aged equipment with annual targeted capital equipment rebuild and modernization projects. This approach has contributed to improved reliability metrics since 1999, as described in Chapter II.

Newfoundland Power's asset management team operates under an effective structure with appropriate staffing for planning, scheduling, and tracking asset planning work. It has appropriate numbers of skilled resources, good apprenticeship programs, and conducts succession planning for retiring skilled workers. Vegetation management meets good utility practice. Maintenance work conforms reasonably well to schedules. Inspection and maintenance practices generally conform to good utility practices, however the Company should review its distribution system wood pole inspections practices.

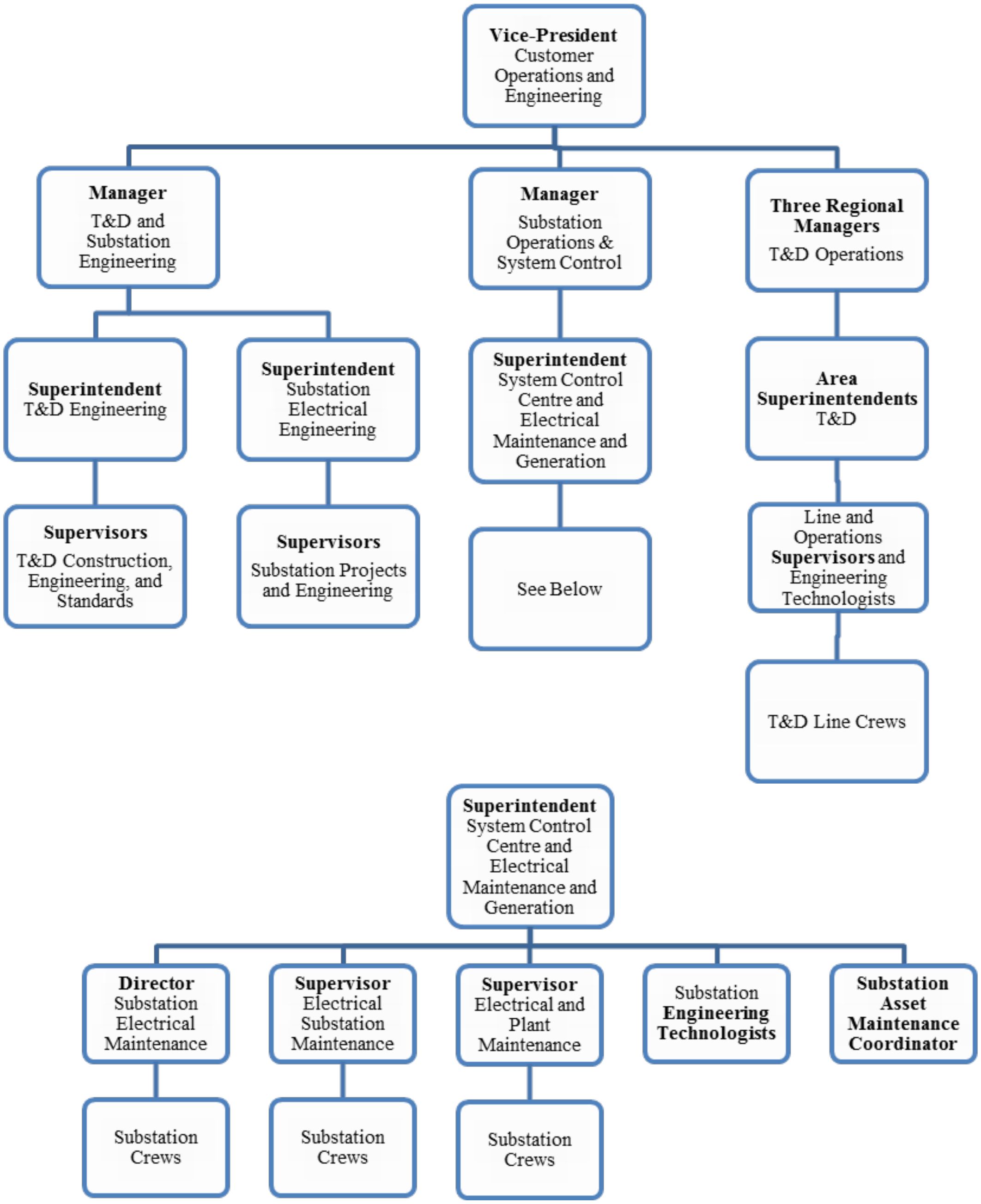
C. Findings

1. The Transmission & Distribution Asset Management Organization

Newfoundland Power's[47]Vice-President of Customer Operations and Engineering has responsibility for overall management of transmission, distribution, and substation electric systems. The Manager of Engineering, the Manager of Operations, and the three Regional Managers (Western Region, Eastern Region, and St. John's Region) all report to the Vice-President. The next table shows the organization.

[47] Responses to RFIs #PUB-NP-135 and 191.

Chart 3.1: Newfoundland Power Asset Management Organization



The Manager of Engineering (T&D and Substation Engineering), referred to in this report as the Manager of Engineering is responsible for policies, standards, practices, and planning for medium- to long-term substation, transmission, and distribution asset management and load growth related initiatives. Superintendents and supervisors carry out medium- and long-term projects.

The Manager of Operations (Substation, Operations & System Control) referred to in this report as the Manager of Operations is responsible for the inspection and maintenance of all substations, including monthly inspections, routine maintenance work, and high priority repairs which cannot be included in larger planned substation projects.

The Superintendent of the System Control Center, Electrical Maintenance, and Generation is accountable to the Manager of Operations for the scheduling and completion of substation inspection and maintenance activities, using the electrical maintenance team. The Manager of Operations and the Manager of Engineering work together to assure that Substation Refurbishment and Modernization Projects and load growth and routine maintenance projects are clustered together to minimize substation outages.

The three Regional Managers (Transmission and Distribution Operations) are responsible for the operations and maintenance of the transmission and distribution systems within their respective regions. The St. John's Regional Manager position was implemented in January 2011 to better address the increasing residential and commercial load growth on the northeast area of the Avalon Peninsula.

The Manager of Operations, the appropriate Regional Manager, and the Vice President of Customer Operations and Engineering are all notified of planned substation and transmission outages. The President/CEO is notified when transmission line or substation outages might be of long duration.

The Superintendents of Operations (one of three in Western Region and one of two each in the Eastern Region and in the St. John's Region) review, assess, and if necessary, prioritize distribution and transmission lines inspections and maintenance jobs on a monthly basis, and routinely report work status to the Regional Managers.

2. Skilled Worker Staffing

Many of the 329[48] full time employees have duties that concern multiple parts of the electrical system. All 153 Power Line Technicians (PLTs) receive training and experience on transmission line, distribution line, and substation construction and maintenance work. Only tenured Technicians with specialized experience qualify for assignment to energized high-voltage circuits on transmission lines and in substations using hot-line methods.[49]

Newfoundland Power's[50] Engineering Technologists also typically work on multiple parts of the system. They provide support in developing and maintaining design, material, and construction standards, provide supervision to construction crews and contractors, implement programs and procedures for the development and operation of power systems, prepare engineering reports to identify, evaluate and make recommendations for system upgrades to the power system, and undertake feeder monitoring and modeling associated with delivery of power and electrical

[48] Response to RFI #PUB-NP-081.
[49] Response to RFI #PUB-NP-193.
[50] Response to RFI #PUB-NP-194.

system loading. Engineering Technologists also interact with developers and contractors, obtain approvals from regulatory bodies, and prepare estimates and material lists.

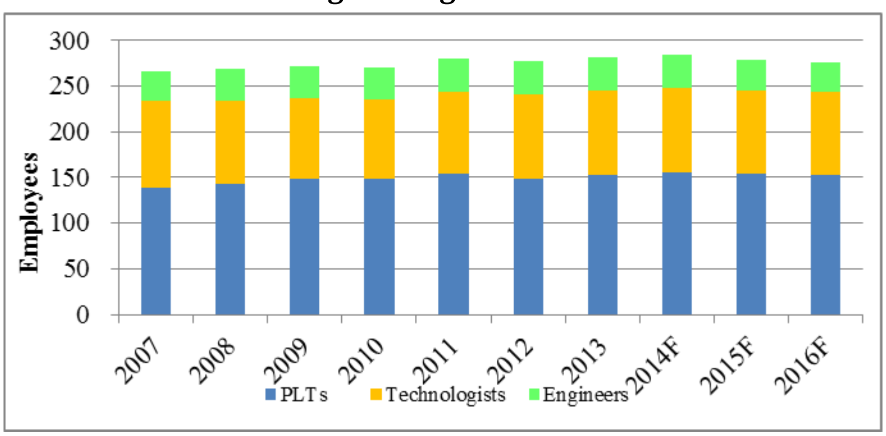
Newfoundland Power's Industrial Electricians work with substation and generation electrical components. They have responsibility for the installation, assessment, and maintenance of electrical equipment.

Newfoundland Power's Industrial Millwrights normally work with generation assets. They perform installation, inspection, and maintenance of generation mechanical equipment. Millwrights also operate generating units and maintain dams and waterways.

The primary functions of Newfoundland Power's[51] Transmission and Distribution Planners include inspection, work planning, and contractor supervision. Work Planners perform transmission line, distribution line, pad mount transformer, and vegetation inspections. Planners also review completed work orders for follow-up and close-out. Planners also work with supervisors to ensure priority work is communicated and completed in a timely manner. Planners implement vegetation management programs including reviewing customer requests for vegetation removal, determining tree trimming and brush clearing requirements during inspections, planning work orders and supervising vegetation contractors.

The next chart and table break down engineering and skilled workers by overall category.

Chart 3.2: Engineering and Skilled Workers



[51] Responses to RFIs #PUB-NP-196 and 197.

Table 3.3: Skilled Workers by Occupation

	2009	2010	2011	2012	2013
Power Line Technicians	148	148	154	149	153
Technologists	88	87	88	91	92
Industrial Electricians	25	27	25	26	25
Industrial Millwrights	14	14	14	14	13
Engineers	36	35	37	37	36
"Work" Planners	15	15	14	11	10
Totals	326	326	332	328	329

The number of Power Line Technicians and Technologists increased, beginning in 2009. The number of Planners (typically Power Line Technicians by training) decreased as the deployment of mobile computing in line trucks, a computerized operations dispatch system, and expanded use of geographic information systems have increased efficiency in planning functions. These changes have made line crew dispatch by the Central Dispatch Team often more effective than using General Forepersons. The latter are also typically Power Line Technicians or Technologists, by training.

Newfoundland Power[52] primarily uses its own Power Line Technicians and Apprentices for new distribution construction, but supplements its workforce with power line contractors. It uses only power line contractors for new transmission line construction. It uses a mix of its own workforce and contractors for its substation refurbishment and modernization capital projects.

3. Newfoundland Power Relay and Control Engineers and Technicians

Newfoundland Power's Protection and Control resources include 8 relay engineers and 6 engineering technologists[53]. Electrical maintenance personnel or electrical contractors install protective relays and control circuit wiring. Newfoundland Power's Protection and Control engineers and engineering technologists are responsible for its protective relay and control designs. Newfoundland Power's engineering technologists (working as relay technicians) are responsible for ensuring that electronic relay and control schemes operate properly. In 2009, the Company began using Electrical Maintenance persons to perform maintenance tests on the older electromechanical relays. Newfoundland Power's power line technicians sometimes record and reset relay targets.

4. Inspection and Maintenance Work Completion Performance

Newfoundland Power[54] targets completion of all required inspections and maintenance work in the year scheduled.[55] Responsibility for distribution, transmission and substation inspections, corrective maintenance and preventative maintenance rests with the Superintendent of Operations and the Superintendent, System Control and Electrical Maintenance. Newfoundland

52 Response to RFI #PUB-NP-198.
53 Responses to RFIs #PUB-NP-082, 199, and 201.
54 Response to RFI #PUB-NP-202.
55 Response to RFI #PUB-NP-141.

Power holds its Regional Managers and its Manager of Operations accountable for ensuring the timely completion of transmission, distribution and substation inspections and maintenance.

a. Transmission Line Inspections

The next table[56] shows the numbers of transmission inspections scheduled and completed since 2011.

Table 3.4: Transmission Line Inspections

Item	2011	2012	2013
Scheduled	103	103	103
Completed	103	95	96
Number Backlogged	0	8	7
Percent Backlogged	0	8	7

Newfoundland Power indicated that four retirements in 2012 and 2013 caused a need for training new resources, which in turn adversely affected productivity. Tropical Storm Leslie also adversely affected inspection work. When it becomes apparent that some transmission line ground inspections cannot be completed in a year, the Company uses prioritization designations to ensure critical work completion, or may employ aerial (helicopter) to expand coverage. For example, recently rebuilt and looped (providing redundancy) lines typically impose lower outage risk and therefore get lower priority. Completing a current year's program early in the following year presents a last option.

Newfoundland Power reported that all transmission lines not given a full ground inspection in 2012 and 2013 received partial or complete helicopter inspection during the year, underwent ground inspection early in the succeeding year, or presented relatively low risk of customer impact.

b. Transmission Line Repair/Replacement Performance

The next table shows recent year[57] transmission lines corrective work performed and backlogged.

Table 3.5: Transmission Repairs and Replacements

Item	2011	2012	2013
Total	127	353	144
Completed	91	309	139
Number Backlogged	36	44	5
Percent Backlogged	28	13	4

Repairs can encompass small items (*e.g.*, cross arm, insulator string) or a complete structure. Management monitors backlogged repairs to assure that the backlogged do not affect reliability. The higher number of repair items in 2012 resulted in major part from a large transmission line

56 Response to RFI # PUB-NP-062 (1st Revision).
57 Response to RFI #PUB-NP-062.

rehabilitation project that involved the correction of 184 deficiencies. Newfoundland Power[58] reported that the backlogged work shown in the tables represented lower priority tasks completed subsequently. The next table summarizes completion data for backlogged items.

Table 3.6: Backlogged Transmission Order Completions

Year	Backlog	Completed	
		Following Year	Later
2011	36	19	17
2012	44	40	4
2013	5	5	0

c. Transmission and Distribution Pole Replacements

The next table shows recent transmission and distribution pole replacement numbers.[59]

Table 3.7: Wood Pole Replacements

Type	Number	2009	2010	2011	2012	2013
Transmission	24,283	219	441	578	320	261
NP-Owned Distribution	210, 002	1,268	1,620	730	976	869
Joint-Owned Distribution	84,720	0	0	487	471	428
Total Distribution	294,722	1,268	1,620	1,217	1,447	1,297

Newfoundland Power replaced about 7.5 percent of its transmission poles and about 2.3 percent of its distribution poles from 2009 through 2013 under its maintenance programs and its transmission line and distribution feeder rebuild strategies. On average the Company has been replacing transmission poles at about 1.5 percent per year, and distribution poles at about 0.5 percent per year. At these replacement rates, Newfoundland Power is replacing its transmission poles every 67 years and its distribution poles about every 200 years. Newfoundland Power replaces poles under its Rebuild Distribution Lines initiative.

d. Distribution Line Inspections

The next table shows[60] distribution line inspection work in recent years. Backlogs have been nominal.

[58] Response to RFI #PUB-NP-204.
[59] Responses to RFIs #PUB-NP-063 and 070.
[60] Responses to RFIs #PUB-NP-069 (1st Revision) and 208.

Table 3.8: Distribution Feeder Inspections

Inspections	2011	2012	2013
Total	46	44	47
Completed	45	43	44
Number Backlogged	1	1	3
Percent Backlogged	2	2	6

e. Pad Mount Transformer Inspections

The next table shows[61] pad mount transformer inspection work performed in recent years. Backlogs here have also been nominal.

Table 3.9: Pad Mount Transformer Inspections

Inspections	2011	2012	2013
Total	1,228	1,215	1,246
Completed	1,220	1,193	1,216
Number Backlogged	8	22	30
Percent Backlogged	<1	2	2

f. Distribution Repair Work

The next table shows[62] the numbers of distribution line repair jobs conducted and backlogged in recent years. Backlogs have been much more substantial here.

Table 3.10: Distribution Repair Work

Jobs	2011	2012	2013
Total	845	1,143	1,021
Completed	554	824	753
Number Backlogged	292	321	267
Percent Backlogged	35	28	26

Newfoundland Power[63] prioritizes distribution corrective maintenance jobs, in order to address first those equipment issues most likely to cause an outage. It regularly reviews the status of backlogged work orders. The Company sometimes schedules them in clusters as part of capital projects, depending on priority, outage scheduling, and similar work. The next table shows progress in completing backlogged items in years following initial order creation. To illustrate, the Company completed 65.5 percent of 2011 orders in 2011, had completed 83.2 percent of them by the end of 2012, and has completed 99.6 percent of them as of mid-August 2014.

[61] Responses to RFIs #PUB-NP-069 and 067.
[62] Response to RFI #PUB-NP-069 (1st Revision).
[63] Response to RFI #PUB-NP-209.

Table 3.11: Cumulative Distribution Work Orders Completed

Created	2011	2012	2013	2014
2011	65.5%	83.2%	94.6%	99.6%
2012		72.0%	94.1%	99.4%
2013			73.8%	97.3%

g. Substation and Protective Relay Inspections and Maintenance

Newfoundland Power[64] employs the following annual preventive maintenance completion targets:

- Substation inspections: 11 per year, only once during July/August, 100 percent completion target
- Oil sampling from power transformers, tap changers, and bulk oil circuit breakers: annual, more frequently if necessary, 100 percent completion target
- Vibration analyses on transformer load tap changers: annual, 100 percent completion target
- Battery bank tests: every six months, 100 percent completion target
- Substation thermographic inspections: annual, 100 percent completion target
- Portable substations maintenance: annual, 100 percent completion target
- Substation transformer maintenance: 12-year cycle, less if condition indicates the need for maintenance, target of 8 percent of transformers each year
- Relay Maintenance: 5-year cycles, 100 percent completion target
- Circuit breaker maintenance: 10-year cycle, less if condition indicates the need for maintenance, target of 10 percent of breakers each year.

The next table summarizes substation equipment maintenance numbers targeted and the percentages of those numbers completed in recent years.[65]

Table 3.12: Substation MaintenanceTarget Numbers and % Completed

Year	2011	2012	2013	Average Completion
Preventive Maintenance	**Number (%)**	**Number (%)**	**Number (%)**	**%**
Substation Inspections	1,624 (95)	1,625 (89)	1,290 (96)	93
Equipment Oil Samples	452 (97)	474 (98)	459 (98)	98
Tap 4 Vibration Analysis	- (-)	66 (86)	70 (93)	90
Battery Maintenance	396 (97)	382 (85)	427 (83)	88
Thermography Inspections	131 (98)	131 (99)	187 (98)	98
Portable Substation Maintenance	3 (100)	3 (100)	3 (100)	100
Power Transformer Maintenance	16 (50)	16 (63)	16 (106)	73
Breaker/Recloser Maintenance or Replace	36 (69	36 (94)	36 (89)	84
Relay Maintenance`	176 (63)	128 (45)	120 (106)	70

The Company reported that reduced transformer work completion in 2011 and 2012 and reduced circuit breaker completions in 2011 resulted from reduced resources caused by a 2010 ice storm

[64] Responses to RFIs #PUB-NP-066, 210, and 233.
[65] Response to RFI #PUB-NP-212.

and hurricane, among other things. The Company experienced Tropical Storm Leslie in 2012. This storm required resource redirection, which affected completion of lower priority jobs. Substation investment also increased materially from 2011 through 2013. The approximately $13 million per year exceeds by 60 percent the approximately $8 million spent per year from 2008 through 2010. This increase also stressed resource availability for other work.

Newfoundland Power's[66] completion rate for relay maintenance testing and calibration in 2013 was 106 percent, in contrast to the 2011 through 2013 rate of 70 percent. The Company changed its relay maintenance program in 2009. It began using electrical maintenance personnel rather its electrical engineering technologists for testing electro-mechanical relays. The large backlog of relay maintenance in 2011 and 2012 was largely due to Tropical Storm Leslie and to training and test set availability issues, which have been resolved. As of August 15, 2014, out of the 762 electromechanical relays scheduled for maintenance since 2009, only 42 relays were backlogged, with the remainder scheduled for completion within the current 5-year maintenance cycle.

5. T&D Inspection and Maintenance Monitoring

Power[67] schedules and tracks transmission line inspections and resulting maintenance activities via its computerized Transmission Asset Management System (TAMS) software application. The Company schedules and tracks seven-year distribution line inspections and its three and a half-year Vegetation Management inspections and maintenance activities via its computerized Avantis maintenance tracking software application. Transmission line and distribution feeder inspectors use handheld devices to record inspection data and typically download the results of their inspections daily into the applicable program. Regional Planers prioritize discovered deficiencies, in consultation with Supervisors who schedule the corrective maintenance items. Supervisors, Superintendents, and Regional Managers access the systems to monitor the performance of inspections and required actions.

The highest priority repairs (emergency) are scheduled for completion within a month via the Outage Management System (OMS). The System Control Center, working with regional personnel, control the corrective maintenance work. Corrective maintenance jobs having lower priorities are clustered, based on priorities, with other work and completed under the following year's *Transmission Line Rebuild Projects* or *Rebuild Distribution Lines Projects*. Regional supervision manages this work.

Superintendents of Operation monitor inspections and corrective maintenance monthly. They reprioritize activities as necessary.[68]

Newfoundland Power's[69] Vice-President of Customer Operations and Engineering reviews the performance of the Company's maintenance activities with Regional Managers on a regular basis. This review includes a status update for maintenance activities, along with to-date progress

[66] Response to RFI #PUB-NP-211.
[67] Responses to RFIs #PUB-NP-060, 067, and 213.
[68] Response to RFI #PUB-NP-136.
[69] Response to RFI #PUB-NP-214.

on the capital maintenance program. Typically quarterly, this review sometimes occurs more frequently, as circumstances dictate.

In 2013, Newfoundland Power installed a computerized operations dispatch system[70]. It expanded the use of its graphic information systems for its vehicles and for its electrical system assets to improve inspection and maintenance work performances, improve responses to outages, and improve the efficiencies of managing field operations including inspections, maintenance, and capital projects.

6. Substation Inspection and Maintenance Monitoring Methods

Newfoundland Power[71] also uses its Avantis maintenance management system database for managing substation equipment and maintenance data. Each regionally based substation Asset Maintenance Coordinator has responsibility for compliance with activities required by the Substation Maintenance Standards Manual. The Company also uses its maintenance software program to schedule and to track routine substation preventive maintenance work, monthly substation inspections, and resulting corrective maintenance. The Asset Maintenance Coordinator, monitors substation inspections, corrective maintenance jobs, and routine maintenance status. The coordinator conducts weekly scheduling meetings with regional substation maintenance supervisors and superintendents to discuss and adjust job scheduling and status.[72]

7. Transmission and Distribution Line Programs

a. Transmission Line and Feeder Inspection and Maintenance Practices

Regional Managers ensure that transmission and distribution line inspection and maintenance activities are completed in accordance with Newfoundland Power's policy. Responsibility for maintaining and revising this policy rests with the Superintendent, responsible for Transmission. Newfoundland Power conducts transmission line and distribution feeder equipment and ground (walking and using ATVs) inspections, and it repairs deficiencies identified by the inspections. The Company conducts transmission line and vegetation inspections at least on an annual basis. It conducts distribution feeder and feeder equipment inspections at least on seven-year cycles. Newfoundland Power[73] conducts annual infrared inspections of all major distribution equipment, including voltage regulators, reclosers, sectionalizers, capacitors, and associated switches. It also conducts infrared inspection on primary connects and cutouts on mainline feeders once every seven years with the regular distribution feeder inspections.

Newfoundland Power conducts at least one detailed ground inspection for each transmission line on an annual basis and at least one inspection in a four year period is conducted when snow is not covering the ground. Additional unscheduled ground inspections, and sometimes specific

[70] Response to RFI #PUB-NP-278.
[71] Response to RFI #PUB-NP-064.
[72] Response to RFI #PUB-NP-136.
[73] Response to RFI #PUB-NP-230.

detailed climbing inspections and helicopter inspections are conducted to investigate storm damage or operating issues.

Newfoundland Power[74] conducts at least one detailed inspection from the ground on each distribution feeder on at least a seven-year cycle. Special inspections are conducted to investigate specific feeder condition and performance issues. The seven-year inspections include feeder-mounted capacitor banks. Feeder-mounted automatic reclosers and voltage regulators are inspected quarterly under the substation inspection program.

Newfoundland Power's line inspectors (Regional Planners) identify poor transmission and distribution pole and tower conditions, and inspect all conductors, cross arms and braces, insulators, switches, anchors, dead ends, jumpers, sleeves, capacitor banks, guy wires, and other hardware and devices. They inspect the transmission rights of ways for encroachments, vegetation, and other unacceptable conditions. The inspectors enter all deficiencies, and deficiency priority levels, and each pole's or tower's GPS coordinates (transmission lines only)[75] into digital inspection forms on the handheld recording devices. The inspectors also take digital photographs of deficiencies, if necessary. Newfoundland Power does not use handheld computers for recording distribution inspections.

T&D line inspectors[76] verify the condition of all wood poles by examining each from top to ground line for pole top rot, ground line rot, external decay, deterioration, splits, checks, cracks, breaks, fire damage, woodpecker damage, insect infestation, and out of plumb condition. Inspectors conduct "sounding" tests on transmission poles over 35 years old to identify internal voids, caused by decay or insects, for example. The inspectors randomly sound transmission poles less than 35 years old and any that appear to be decayed. Newfoundland Power does not apply fungal or insect treatment to poles because it feels that the cool Newfoundland weather precludes the need to do so. Inspectors sound distribution poles only when a pole appears to be decayed.

The inspectors correct minor transmission or distribution deficiencies while on site as part of routine operating maintenance work. The inspectors prioritize deficiencies based on the Company's General Guidelines for Classification of Priority[77] for transmission line inspections and on the Company's Deficiency Tables[78] for distribution feeder inspections. Work Planners assign repair priorities to the non-emergency deficiencies, and report high priority deficiencies to supervisors and to the Central Dispatch Team for scheduling in the Outage Management System.[79] TD1 (serious) priority deficiencies are corrected within seven days. TD2 (less serious) priority deficiencies are corrected within one month. TD 3 (minor hazard) priority deficiencies are corrected within six months. TD 4 (no safety hazard) priority deficiencies are corrected during following years under capital budgets.

[74] Response to RFI #PUB-NP-219.
[75] Response to RFI #PUB-NP-221.
[76] Responses to RFIs #PUB-NP-060 and 223.
[77] Response to RFI #PUB-NP-060.
[78] Response to RFI #PUB-NP-067.
[79] Response to RFI #PUB-NP-215.

Planners are responsible for organizing the resources necessary to timely complete priority TD1 and priority TD2 repairs. Priority TD3 repairs are included in monthly maintenance schedules, as appropriate. Regional Superintendents and/or Supervisors are ultimately accountable for completion of repairs within time frames. Corrective maintenance jobs more than six months overdue are reported to the *Regional Managers* for action.

High priority capital work that cannot wait until the next budget year is completed under the Reconstruction capital project. For example, deteriorated or damaged distribution structures and electrical equipment deemed to present a risk to safety or reliability are addressed through the Reconstruction project within the year identified.

Newfoundland Power[80] has 96 underground residential distribution (URD) cable loops, which employ more than 700 cable sections. When a cable fault occurs, an outage ticket is created in the Outage Management System and a line crew is immediately dispatched to isolate the fault and restore service. Following service restoration, the line crew routes the outage ticket to the appropriate supervisor for follow-up replacement of the faulted section. Rather than repairing old deteriorated cables, Newfoundland Power installs new ones, located in conduits.[81]

Newfoundland Power indicated that it normally restores its URD loops immediately and most loops are restored within two weeks. As of August 21, 2014, no URD cables are out of service due to failure.

b. Transmission and Distribution Line Expenditures

The next tables summarize[82] capital and O&M expenditures for transmission line and distribution line inspections, corrective maintenance and preventive maintenance work.

Table 3.13: Transmission Line Maintenance Costs ($ thousands)

Category	2010	2011	2012	2013
Inspections	212	211	197	163
Corrective Maintenance	246	259	150	69
Preventive Maintenance	2,110	1,186	2,071	2,303

Table 3.14: Distribution Line Maintenance Costs ($ thousands)

Category	2010	2011	2012	2013
Inspections	174	191	246	285
Corrective Maintenance	2,419	1,000	654	859
Preventive Maintenance	1,613	3,504	3,981	3,664

[80] Responses to RFIs #PUB-NP-216 and 217.
[81] Liberty meeting with Newfoundland Power on September 19, 2014.
[82] Responses to RFIs #PUB-NP-224 and 225.

c. *Vegetation Management*

Newfoundland Power[83] inspects transmission lines for vegetation (trees, limbs, and brush) clearance issues on annual cycles and it inspects its distribution lines for vegetation clearance issues on 3.5 year cycles. It inspects each transmission line annually and inspects each distribution feeder for vegetation issues twice every seven years; once every seven years as part of walking distribution feeder inspections and, in between, by drive-by inspections. Newfoundland Power also reinspects lines after the inspection year when the actual tree trimming and other vegetation management work is conducted. Line inspectors record the vegetation management data in handheld devices which they upload into the Company's tracking programs. Newfoundland Power reports that less than three percent of power interruptions are attributable to tree contact. It believes that reducing tree-caused customer interruptions during normal conditions by even another fifty percent, would produce only a one percent improvement in overall reliability.

Based on the results of each year's inspections, Newfoundland Power solicits contractor proposals to perform brush cutting, tree trimming, and tree removal work for the following year, specifying that work follow its detailed specifications. The next table lists the width to which contractors must trim limbs from ground to sky.

Table 3.15: Vegetation Clearance Distances

Line Type	ROW Width
138 kV H-frame	26 meters
66 kV H-frame	20 meters
66 kV single pole	15 meters
Three-phase distribution	7.4 meters
Two-phase distribution	7.4 meters
Single-phase distribution	5.4 meters
Secondary distribution	5.4 meters
Communications	1.0 meter

Newfoundland Power's contractor also cuts brush from right of ways, and removes "Danger Trees" outside of right of ways which could fall into the power lines, including dead, mostly dead, and diseased trees, unsound and leaning live trees, and shallow rooted trees. Newfoundland Power's full time arborist works with vegetation management personnel.[84] Newfoundland Power's[85] operating expenditures for vegetation management (shown in the next table) have increased from $997,000 in 2003, primarily because of the effects of increasing numbers of tropical storms and hurricanes.[86]

[83] Responses to RFIs #PUB-NP-067, 080, 222, 226, and 228.
[84] Liberty meeting with Newfoundland Power on June 19, 2014.
[85] Responses to RFIs #PUB-NP--227 and 309.
[86] Response to RFI #PUB-NP-227.

Table 3.16: Vegetation Management Expenses

Year	Capital	O&M
2010	$1,002,512	$1,671,780
2011	$536,269	$1,611,501
2012	$796,571	$1,745,661
2013	$819,646	$1,993,000

d. Substation Inspection and Corrective Maintenance Practices

Newfoundland Power's[87] substation technicians (Industrial Electricians) conduct substation inspections on a near monthly basis, including four quarterly *long inspections* each year and seven (only one in July/August period) *short monthly inspections* between the long inspections each year. Newfoundland Power also conducts infrared inspections of substation equipment during the first quarter of each year.[88] The Company may sometimes postpone short inspections if the technicians are needed for more important maintenance activities. Long inspections are detailed substation and equipment-specific formal inspections of all equipment in each substation. The inspectors use handheld devices and have the ability to update forms for each substation. The Company implemented the use of handheld devices in 2007.[89] Short inspections are walk-around inspections intended to identify more obvious equipment safety and operating issues.

Inspectors report emergency repairs when a substation deficiency is hazardous or might cause an outage. They classify these repairs as Emergency (address immediately) or Urgent (repair within one week). The inspector prioritizes other deficiencies whether as P1 (repair within one month) or P2 (repair within three month). Minor deficiencies are clustered with other work and included in capitalized substation projects.

Newfoundland Power does not segregate substation operating costs by inspections, preventative maintenance and corrective maintenance, but provided its total annual substation operating and maintenance costs. The next table shows total expenses for recent years.

Table 3.17: Substation Operating Costs ($ thousands)

	2010	**2011**	**2012**	**2013**
Total	2,340	2,242	2,555	2,672

The next table shows capital expenditures for substation work.

[87] Responses to RFIs #PUB-NP-064, 065, 066, and 143.
[88] Response to RFI #PUB-NP-230.
[89] Liberty meeting with Newfoundland Power on September 19, 2014.

Table 3.18: Substation Capital Costs ($ thousands)

	2010	2011	2012	2013
Corrective	2,388	2,689	3,267	3,485
Preventive	3,202	3,661	2,279	3,495

e. Substation Preventive Maintenance Practices

Newfoundland Power's[90] substation equipment proactive preventive program and its reactive corrective maintenance program consist of five maintenance categories. The Company's Standard Procedures describe the tasks required for each type of maintenance, which consist of:

- ***Maintenance I:*** Tasks for commissioning new or relocated equipment
- ***Maintenance II***: Tasks required for routine monthly substation inspections
- ***Maintenance III***: Detailed periodic maintenance activities of substation equipment, including diagnostic tests and conducting minor repairs; intrusive maintenance requiring disassembling equipment is conducted based on need, as determined by inspections and test results[91]
- ***Maintenance IV***: Major substation equipment maintenance tasks (overhauls) usually triggered by time (maximum of 10-year cycles),[92] or by deficiencies identified by Maintenance I, III, or V activities (inspections and tests)
- ***Maintenance V***: Unscheduled reactive corrective maintenance (major urgent repairs) tasks carried out following malfunctions or modifications.

Liberty reviewed Newfoundland Power's substation equipment maintenance guideline document, which indicates the tasks to do for each type of maintenance indicated under Type I, II, III, IV, and V Maintenance, and its electronic test sheets. Liberty found that the Company's maintenance guidelines and equipment test sheets were appropriate.

Newfoundland Power[93] uses senior engineers and engineering technologists for investigating substation equipment operating and condition issues and for leading failure investigations. These senior engineers and engineering technologists have specialized knowledge and expertise developed during their long experience working with the Company's electrical equipment, and by regularly taking part in specialized training provided by equipment manufacturers.

8. T&D Critical Spares

Newfoundland Power[94] maintains an inventory of transmission and distribution lines materials in its Central Stores facility in St. John's and in eight area offices located throughout the service territory. It stores spare equipment and parts for substations (such as circuit breakers, voltage regulators, and instrument transformers) at its Mount Pearl Electrical Maintenance Center. An outside supplier provides and installs new wood poles under a consignment contract. Wood pole inventories are maintained at the pole supplier's facility and at the contractor's eight storage

[90] Responses to RFIs #PUB-NP-064 and 065.
[91] Liberty meeting with Newfoundland Power on September 19, 2014.
[92] Responses to RFI #PUB-NP-064.
[93] Response to RFI #PUB-NP-232.
[94] Responses to RFIs #PUB-NP-033 and 235.

yards located throughout the territory. In August 2014, about 3,000 spare poles were available in Newfoundland.

For some equipment, Newfoundland Power also requires, via contractual agreements, some of its electrical system equipment vendors to maintain dedicated release quantities in local warehouses to help ensure adequate equipment and parts are available outside of Newfoundland Power's internal inventory.

Newfoundland Power reported that it regularly reviews its numbers of spare transmission and distribution equipment, parts, and materials and that it has not had any issues having sufficient line materials during past ice storms. The Company maintains an inventory sufficient for rebuilding five kilometers of transmission lines and it can share materials with Hydro.

9. Transmission Rebuild Strategy

In 2005, a detailed evaluation of transmission lines led to the conclusion that lines constructed since the late 1960s and 1970s (built to near modern Canadian Standards Association and current Company standards) could be rebuilt appropriately by applying the Company's normal inspection and maintenance practices. The study also concluded that transmission lines constructed prior to that time were more aged and not necessarily designed to more modern standards. At that time, thirty-nine percent (about 800 km) of the transmission system consisted of lines constructed from the 1940s through the 1960s.

Newfoundland Power developed a 10-year Transmission Line Rebuild Strategy to supplement its transmission inspection and maintenance program. The Company began in 2006 to include the new strategy in annual capital budgets. Newfoundland Power has steadily replaced aged transmission system sections and troublesome components. The Company has updated the strategy to employ line rebuild priorities that reflect updated reliability data, inspection information, condition assessments, and potential failure impact on customers. Newfoundland Power rebuilds line sections to exceed strength standards, in order to better withstand ice and wind conditions. Between 2007 and 2013, the Company rebuilt 17 kilometers of 138 kV transmission lines, 17 kilometers of 66 kV transmission lines, and will have rebuilt another 16 kilometers of 66 kV transmission lines during 2014 for a cost of about $3.17 million. It plans to rebuild sections of another ten transmission lines by the end of 2018, and another eight transmission lines by the end of 2015.

10. Distribution Rebuild Strategy

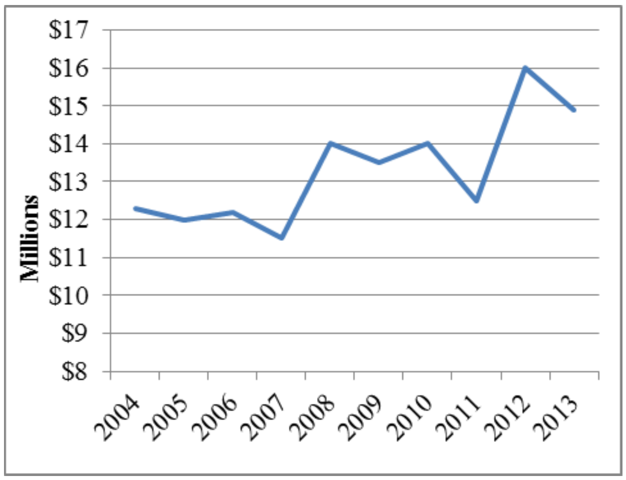
Newfoundland Power's[95]annual Reconstruction Project and its Rebuild Distribution Lines Project involve the replacement of deteriorated distribution structures and electrical equipment previously identified through the Company's ongoing inspection program, or as a result of engineering reviews. The items typically replaced include poles, cross arms, conductor, cutouts, surge/lightning arrestors, insulators, and transformers. Individual distribution feeder projects are identified through Newfoundland Power's seven-year distribution inspection cycle, which inspects approximately forty-three feeders each year.

[95] Response to RFI #PUB-NP-270.

Newfoundland Power's[96] Distribution Reliability Initiative project involves the replacement of deteriorated poles, conductor and hardware to reduce the frequency and duration of power interruptions to customers served by specific distribution lines. The Company identifies the fifteen worst performing feeders each year, based on reliability metrics, and carries out engineering reviews of all identified feeders. Where necessary, the Company carries out detailed engineering inspections to determine what reliability-focused work is required.

Newfoundland Power[97] does not track the amounts of distribution feeders rebuilt each year by project type. It reported that in total it rebuilds about fifty kilometers of distribution feeders every year. The next chart shows recent-year capital expenditures for distribution plant replacements

Table 3.19: Distribution Plant Replacement



11. Substation Refurbishment and Modernization Strategy

Nearly one-half of Newfoundland Power's 130 substations were over 40 years old in 2006 and about one-third were over 50 years old. Much of its substation transformers, oil-circuit breakers, structures, and other equipment had been in service since the substations were built. The Company determined that its maintenance practices would not remain sufficient to maintain the very old and obsolete equipment in reliable condition. In 2007, Newfoundland Power determined that capital substation refurbishment and modernization projects were justified for about 80 percent of its substations over the following 10 years. The Company enhanced its substation equipment maintenance programs, which had been in effect at least since 1986, with an annual capitalized Substation Refurbishment and Modernization program. Since 2007, Newfoundland Power has been replacing aged and troublesome components of its substations.

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[96] SAIDI is the system average interruption duration index, calculated by dividing aggregate customer hours of outages by the number of customers served. SAIFI is the system average interruption frequency index, calculated by dividing aggregate number of customer interruptions by the number of customers served. CHIKM is the customer hours of interruption per kilometer and is calculated by dividing aggregate customer hours of outages by the kilometers of distribution plant. CIKM is the customers interrupted per kilometer, calculated by dividing aggregate number of customer interruptions by the kilometers of distribution plant. Customer-minutes is calculated by multiplying the number of outage minutes by the number of affected customers.
[97] Response to RFI #PUB-NP-237.

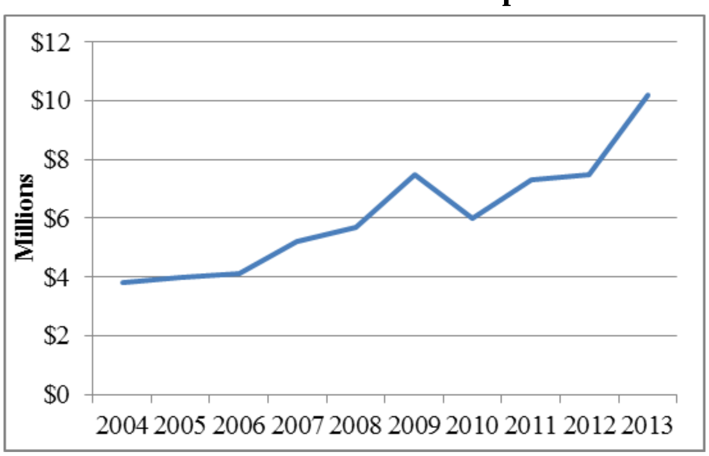
Newfoundland Power's strategy prioritizes for replacement deteriorated and obsolete substation facilities in a stable fashion, under its annual Substation Refurbishment and Modernization program. Newfoundland Power reviews its substation refurbishment and modernization plan annually. When updating the plan, the Company makes assessments based upon the condition of the infrastructure and equipment, the need to upgrade and modernize protection and control systems, and other relevant work. Newfoundland Power has replaced substantial amounts of substation equipment under its asset management programs since 2004. The next table shows substation equipment replaced since 2004.

Table 3.20: Replaced Substation Equipment

Equipment	Replaced	In Service
Circuit Breakers	111	410
Reclosers	56	200
Voltage Regulators	157	360
Power Transformers	9	190
Potential Transformers (PTs)	224	360
Current Transformers (CTs)	44	90
CT/PT Metering Units	51	51

The next chart shows capital expenditures for substation refurbishment and modernization projects.

Chart 3.21: Substation Plant Replacement



Newfoundland Power is upgrading six more substations in 2014 for a cost of about $6 million. It plans to upgrade another twenty substations by the end of 2018.

12. Worst Performing Feeders

As indicated above,[98] distribution reliability improvement strategies include a Worst Performing Feeders Program that addresses feeders, as identified by analysis of performance over the previous rolling five-year period. The next table[99] shows the "worst performing feeders" addressed in Newfoundland Power's Distribution Reliability Initiative capital project since 2004. Newfoundland Power commenced formally addressing its worst performing feeders in 1998. Although Newfoundland Power still identifies its worst performing feeders and corrects some issues, the reliability indices have not been sufficiently high since 2011 to include new worse performing feeders in its Distribution Reliability Initiative.

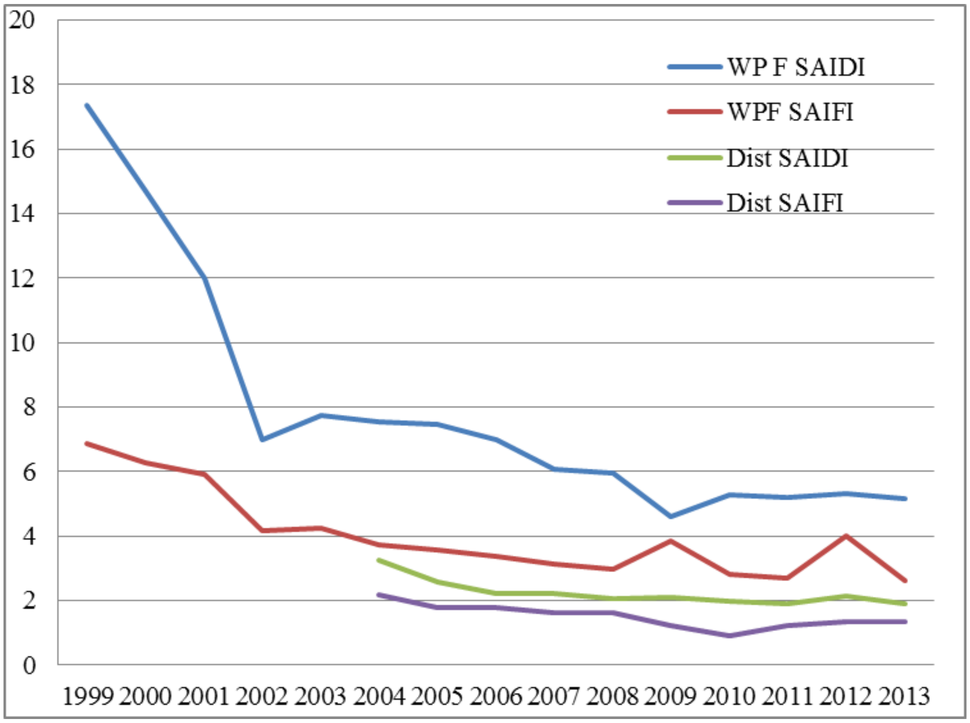
Table 3.22: Worst Performing Feeders Addressed

2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
WES-02	WES-02	BCV-02	None	BOT-01	NWB-02	NWB-02	None	None	None
BRB-04	GBY-02	BOT-01		LEW-02	LEW-02				
PUL-01		LEW-02		GLV-02	GLV-02				
PUL02		GBY-02							
		GPD-01							
		GLV-02							
		SMV-01							

Newfoundland Power has reduced the average SAIDI of its worst performing feeders from about 17.42 to 5.15 in 2013, as the next chart demonstrates.[100] This chart illustrates the improvement of Power's worst performing feeders (WPF) since 1999. However, in 2013, the average SAIDI for Power's Worst Performing Feeders was still 5.15 compared to a SAIDI of 1.9 for the Company's Distribution System.

[98] Response to RFIs #PUB-NP-068 and 285.
[99] Response to RFI #PUB-NP-290.
[100] Response to RFI #PUB-NP-310.

Chart 3.23: Average Worst Performing Feeder SAIDI and SAIFI Compared to Distribution System



D. Conclusions

3.1. Asset management at Newfoundland Power operates: (a) under a program, (b) with an organization, and (c) with the support of sufficient numbers and skills to meet system reliability needs effectively.

Liberty has found at some utilities that the asset management organizations do not have sufficient authority, control, or overview for ensuring that all areas of field operations complies with the corporate asset management organization agendas. Liberty found that Newfoundland Power's organization has appropriate authority, control, and overview to ensure that all asset management work is conducted consistently with sufficiently scoped, designed, and executed objectives, strategies, programs, initiatives, planning, scheduling, monitoring, and measurement.

Newfoundland Power's Manager of Engineering is responsible for policies, standards, practices, and planning for medium to long term substation, transmission, and distribution asset management and load growth related initiatives which require capital expenditures to install new equipment or maintain or replace existing equipment. Newfoundland Power's Vice-President of Customer Operations and Engineering has the ultimate responsibility for the overall management and integrity of the Company's electric systems. The Manager of Engineering, the Manager of Operations, and the three Regional Managers (Western Region, Eastern Region, and St. John's Region) all are accountable to the Vice-President for completing asset management maintenance and project work under their authority. The trail of responsibility appropriately flows down to superintendents, to supervisors, and to crews.

Newfoundland Power's number of skilled workers, engineers and technologists, and contractors appear to be sufficient for the Company to comply with its asset management agenda. The Company monitors the numbers of workers in each category about to retire and bases hiring and training new employees on its succession studies. Newfoundland Power has an intensive apprenticeship program and provides other training as necessary.

3.2. Newfoundland Power uses an effective combination of periodic O&M inspection and maintenance programs and capital transmission, distribution, and annual capital substation capital rebuild and modernization projects to address condition, reliability, and operating issues with its transmission, distribution, and substation assets.

About one-third, more or less, of Newfoundland Power's T&D equipment is over 40 years old indicating that some equipment is at an age or level of obsolescence where standard inspection, repair, and preventive maintenance activities, by themselves, are not sufficient for maintaining the condition and operating reliability of the aged equipment. To supplement its inspection and maintenance practices, Newfoundland Power's Asset Management Organization has been appropriately applying, on an annual basis, various capital transmission, distribution, substation, and protective relay rebuild and modernization projects, addressing condition, reliability, obsolescence, and operating issues.

3.3. Newfoundland Power completes its transmission, substation, and distribution inspection and maintenance work in a reasonably timely fashion.

Newfoundland Power schedules corrective maintenance repairs based on priorities related to safety and failure risk in a manner that conforms to good utility practices. It repairs defects with safety or imminent failure risk immediately and it plans other repairs under its various capital projects during the same year or during the following year or years based on priorities.

Newfoundland Power normally completes its inspections, corrective maintenance work, and preventive maintenance work consistent with its schedules, although it defers completion of some lower priority repair work a year or more so that the work can be efficiently clustered with annual capital projects. The Company, however, had to defer some substation transformer, circuit breaker, and relay preventive maintenance work in 2011 and 2012 because of the resources required to address system damage caused by the severe storms occurring during the 2010 through 2012 time period.

Newfoundland Power appropriately uses effective software packages to schedule and track its transmission, substation, and distribution inspection and maintenance work. Newfoundland Power schedules and tracks its transmission, distribution, and substation equipment inspection and maintenance activities, and its T&D vegetation management inspections, using its Avantis work management software application, or subsets of this application.

Transmission line and distribution feeder inspectors, who are also regional planners, use handheld devices to record inspection data and typically download the results of their inspections daily, or when the inspection of a line is complete, into the maintenance management application. Inspectors prioritize deficiencies in consultation with their supervisors. Supervisors, Superintendents, and Regional Managers access the maintenance management data bases to monitor the performance of inspections and the resulting data, and make sure required actions are taken.

Newfoundland Power uses its maintenance software application to schedule and to track its routine substation preventive maintenance work, its monthly substation inspections, and resulting corrective maintenance work to completion. The Asset Maintenance Coordinator, who works in the Substation Operations group, and reports to the Superintendent of System Control and Electrical Maintenance, monitors the substation inspections, corrective maintenance jobs, and routine maintenance status. The coordinator conducts weekly scheduling meetings with regional substation maintenance supervisors and superintendents to discuss and adjust job scheduling and status.

3.4. Newfoundland Power's transmission line and pole inspection and corrective maintenance practices are consistent with good utility practices, except that the Company does not have a program to chemically treat its aged poles. *(Recommendation #3.1)*

Treating poles is a typical utility practice. It can reduce future replacement costs. Newfoundland Power inspects its 2,000 kilometers of transmission line and its more than 24,000 transmission poles on at least an annual basis. Additional unscheduled ground inspections, and sometimes specific detailed climbing inspections and helicopter inspections are conducted to investigate storm damage or operating issues. The Company prioritizes defects identified and schedules corrective maintenance work based on criticality and ability to cluster repairs with budgeted transmission capital projects. Newfoundland Power spends about $2 million per year, more or less, on transmission line inspection and maintenance work, not including equipment replacement and upgrade work conducted under the Company's Transmission Rebuild Initiative.

Inspectors appropriately prioritize deficiencies, and assign repairs in accordance with them. They verify the condition of wood transmission poles through sound and reasonably complete examination practices. Newfoundland Power does not chemically treat its transmission poles to extend pole life because it considers that pole rot and insect infestation is not an issue in the cool Newfoundland climate.

Newfoundland Power's transmission pole replacement rate of about 1.5 percent per year produces replacement of a pole, on average, every 67 years is consistent with good utility practice. Nevertheless, Newfoundland Power would likely reduce future transmission pole replacement costs by implementing a program to chemically treat its aged transmission poles.

3.5. Newfoundland Power's distribution feeder and pole inspections and corrective maintenance practices are generally consistent with good utility practices, except for: (a) lack of periodic sounding (testing for internal decay) of all aged poles, and (b) a slow replacement rate for aged distribution poles. *(Recommendation #3.2)*

Newfoundland Power inspects its each of its 306 distribution feeders (9,000 kilometers) at least on seven-year cycles. Special inspections investigate specific feeder condition and performance issues. Feeder–mounted automatic reclosers and voltage regulators are inspected quarterly.

Newfoundland Power conducts annual infrared inspections of all major distribution equipment. Inspectors sound distribution poles only when a pole appears to be decayed. Newfoundland Power inspects the condition of its distribution poles, but only conducts "sounding" tests (testing for internal decay) when visual observations show the appearance of decay.

Newfoundland Power replaces its distribution poles on average at about 0.5 percent per year. At this rate, Newfoundland Power is replacing each distribution pole, on average, about every 200 years, well in excess of wood pole life expectancy of 40-80 years. Its distribution pole replacement rate should be more in line with its transmission pole replacement rate of 67 years.

3.6. Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices.

Newfoundland Power's substation maintenance activities are an appropriate mix of time-based inspections and predictive and preventive maintenance activities, and of condition-based major preventive equipment maintenance/overhaul activities, based on inspections, oil tests and other non-intrusive tests, and operating issues, and by the Company's experience with the equipment. Substation technicians conduct substation inspections on a near-monthly basis, including four quarterly *long inspections*. Newfoundland Power also conducts infrared inspections each year. Liberty reviewed the Company's substation electronic substation inspection data sheets and found them appropriate.

Substation inspectors report emergency repairs when a deficiency exists in a substation which is hazardous or might cause an outage. Newfoundland Power spent about $9.7 million in 2013 on substation inspections, corrective maintenance, and preventive maintenance work.

3.7. Newfoundland Power's vegetation management practices are consistent with good utility practices.

Liberty found that Newfoundland Power's vegetation management has been effective. Trees caused only a marginal amount of customer interruptions. Newfoundland Power conducts transmission right of way vegetation and distribution inspections on proper cycles and under an appropriate regimen.

Newfoundland Power spends about $2 million per year on vegetation management (brush clearing, tree trimming, and danger tree removal).

3.8. Newfoundland Power's T&D System Rebuild and Modernizations Strategies are generally consistent with system needs.

Newfoundland Power recognizes that much of the equipment in its T&D system is aged and that its preventive and corrective maintenance activities alone, as good as they are, are not sufficient to assure that its systems approaching end of service life will operate reliably. To supplement its maintenance programs, Newfoundland Power annually budgets various rebuild and modernization capital projects to address transmission, distribution, and substation reliability issues and to proactively address aged equipment condition and obsolescence issues. Annual capital strategies include measures (Transmission Rebuild Strategy, Rebuild Distribution Lines Projects, Distribution Reliability Initiative, and Substation Refurbishment and Modernization

Strategy) well targeted to the needs of its equipment. Asset management strategies have promoted improved system reliability since 1998, while keeping annual capital T&D expenditures under control.

3.9 As indicated in Chapter II, despite notable reliability improvement since 1999 and stable SAIFI and SAIDI metrics exhibited recently, it appears that room remains for improving distribution equipment-caused customer interruptions by applying more weight to the Rebuild Distribution Lines Project. *(Recommendation #2.1)*

Newfoundland Power's system maintenance and capital project practices have resulted in significantly improved SAIDI and SAIFI metrics, excluding major events, since 1998. Newfoundland Power's performance has been even better than Canadian Electricity Association (CEA) composite measures since 2005 for SAIDI and since 2009 for SAIFI.

However, Liberty feels that there is some room for further reducing the distribution system's contributions to Newfoundland Power's SAIFI and SAIDI by installing additional downstream feeder reclosers and applying more weight to its *Rebuild Distribution Lines Project* when prioritizing its annual capital projects. The Company's transmission system and substations contributions have contributed only to small degrees to the overall SAIFI and SAIDI; the majority of the SAIFI and SAIDI have been caused by distribution system-caused customer outages, where additional reclosers can reduce SAIFI and SAIDI.

E. Recommendations

3.1. Unless it can show that fungus and insect infestation does not occur on its wood poles, Newfoundland Power should reconsider the need to treat its transmission poles for fungus and insect infestation, as does Hydro. *(Conclusion #3.4)*

Much of Newfoundland Power's pole plant is aged and applying fungicide and insecticide could extend pole life, reducing the need for capital projects to replace aged poles. Newfoundland Power, however, indicated that the treatments were not necessary because of the cool short Newfoundland summers. Newfoundland Power should review the transmission pole testing and treatment studies which have been conducted by Hydro indicating the need to treat its transmission poles. Treating older poles is good utility practice. Treatment extends pole life, thus reducing replacement costs.

3.2. Consider conducting "sounding" tests on all older distribution poles (not just those obviously rotted) when inspecting feeders; reconsider chemically treating distribution poles to extend their lives. *(Conclusion #3.5)*

The Company does not conduct sounding tests on its older distribution poles, as it does on its older transmission poles. Newfoundland Power should not only consider periodically conducting sounding tests on its older distribution poles to identify which poles have internal rot and may be physically weak, but it should also consider treating older poles to reduce future pole replacement costs.

Many utilities use specialized contractors for inspecting and testing poles and for applying chemical treatments to extend pole life. Utilities use these contractors because they free up resources and conduct the pole inspection work effectively for generally less cost than using in-house line personnel. These specialized contractors not only inspect the poles above ground, but also excavate to examine, bore, and treat a pole below ground line, where fungi damage often occurs. Some utilities also find that installing reinforcing devices on some weak poles save the cost of replacing the poles.

IV. Power Systems Operations

A. Background

An electric utility's power system operation functions include monitoring, managing, and controlling the electric systems under normal and abnormal weather and operating conditions, dispatching trouble call responders, and assisting with keeping customers informed of service outage situations. Power system operators use supervisory control and data acquisition ("SCADA") and other software applications to identify operating constraints on the systems, manage customer outages, and direct safe switching operations. Liberty reviewed Newfoundland Power's system operations facilities, staffing, and training. This chapter discusses the functionality of SCADA and other software applications for predicting loading or voltage constraints, managing customer outages, directing switching operations, and communicating outage information to customers. Liberty also reviewed interaction between Newfoundland Power and Newfoundland and Labrador Hydro.

B. Chapter Summary

Newfoundland Power's System Control Center operates soundly, and with an appropriate number of qualified staff. Adequate measures have been taken to support continued operations should the Control Center not be in service. Using a Central Dispatch Team for dispatch, allows system operators to focus on operations, switching, and other normal and emergency responsibilities. System Operators directly monitor and control the transmission system and most of the distribution system via SCADA.

Liberty did determine that Newfoundland Power needs to: (a) provide for operator training on a console programmed to simulate various system events, and (b) enhance its ability to forecast next 1-to-3 day demands.

C. Findings

1. System Control and Central Dispatch Center Operations

The System Control Center comprises Newfoundland Power's[101] electric system operating facility. It operates from a dedicated, physically secure office. Power System Operators control and monitor Company generation, transmission and distribution systems including equipment loads, bus voltages, and device status via SCADA system. Linkages between Newfoundland Power's and Hydro's SCADA systems allow Newfoundland Power[102] to monitor, but not control the status of Hydro's generating and key interconnection facilities. Four operator consoles are located on the floor, with two staffed at all hours. During storm or emergency situations, the other two positions can be staffed as needed. A fifth console located on an upper floor can support training, but the Company has no dedicated training console. Three other facilities can serve temporarily, should the System Control Center become inoperable or inaccessible. Newfoundland Power has a dedicated fiber-optic loop, redundant servers and power back-up.

[101] Liberty on site visit, 19 September 2014.
[102] Response to RFI #PUB-NP-247.

The SCADA system monitors demand in real time. Telemetry data from the Hydro infeed points comes via the Inter-Control Center Communications Protocol ("ICCP") link between Hydro's Energy Management System and the SCADA system. Adding the total system infeed value from Hydro to the Company's total generation value calculates the instantaneous total system demand. Newfoundland Power[103] and Hydro worked together to bring more real-time operating data into the Control Center. Newfoundland Power now has full information on the status of Hydro's generating stations, total Island Interconnected System ("IIS") load, and major terminal stations that supply Newfoundland Power load.

The System Control Center[104] also directs switching of energized equipment by field forces, which allows workers to de-energize facilities required safely to maintain or repair equipment. Newfoundland Power uses a worker protection permit system (based on the tagging of devices) that must undergo a status change after initiating worker protection. Field workers place tags on any device opened for providing safety clearances. SCC operators simultaneously apply corresponding electronic tags on the switching devices shown on the Company's SCADA system. Devices tagged on the SCADA system cannot be operated remotely from SCADA or have their status manually updated on SCADA while the SCADA tag remains in place.

Newfoundland Power's[105] Central Dispatch Team manages the scheduling and dispatch of field crews during regular working hours, except when safety issues and other high priority issues require dispatch from the Control Center. The Central Dispatch Team ensures efficient work scheduling. This Team forms part of the Company's recently adopted method for dispatching transmission and distribution line work. Newfoundland Power has deployed mobile computing in all of its line trucks, implemented a computerized operations dispatch system, and expanded the use of its geographic information system.

Newfoundland Power's Customer Contact Center receives customer trouble calls during normal working hours (8:00 am to 5:00 pm, Monday through Friday). The Central Dispatch Team dispatches work arising from customer trouble calls received between 8:00 am and 4:00 pm. Off-hour trouble calls route to the System Control Center, which the Company staffs 24 hours every day of the year.

During large storms or major electrical system events, the Contact Center and Central Dispatch Team typically operate on extended hours, receiving and dispatching work associated with customer trouble calls. This function permits System Operators to focus on power system restoration.

2. Control Center and Central Dispatch Team Staffing

The four[106] Lead Power System Operators have an average of 25 years of experience, and the six Power System Operators average 11. Efforts to secure replacements begin within a year of expected retirements. As do most utilities, Newfoundland Power seeks applicants with 10 to 12

[103] On site meeting, 19 September 2014.
[104] Response to RFI #PUB-NP-261.
[105] Response to RFI #PUB-NP-254 and 260.
[106] On site meeting 19 September 2014.

years of field experience to promote into the Power System Operator positions. The smaller Central Dispatch Team[107] includes 5 Operations Coordinators.

Control Center staff operates on a dual 12-hour shift basis to provide continuous staffing.[108] Each shift includes an experienced Lead Power System Operator and one or two Power System Operators. The Supervisor of System Control, the Superintendent of System Control and Electrical Maintenance, and the SCADA Team provide technical support and guidance to the system operations teams.

3. Power System Operations' Management Tools

SCADA serves as the primary tool for Power System Operators. There is no dedicated SCADA training console. A fully functional SCADA outside the control room, however, is available for training use.[109] The primary software tools used by the Central Dispatch Team include ClickSoftware. This application permits the Central Dispatch Team automatically to schedule work for power line technician crews. A schedule optimizer reduces driving time, and increases overall efficiency by automatic work schedule creation that considers skill, location, and priority factors. The software tracks work progress as field crews update job status from laptops in the field.

Operators use SCADA to monitor and control remotely 71 substations, 25 hydro generators, 2 gas turbines, 187 distribution feeders and 78 power transformers. Engineering and operations employees also use real-time and historical data from the SCADA system for system assessment, analysis and planning purposes. The SCADA system monitors and controls a total of 40,000 individual data points. Ninety percent of transmission lines and 60 percent of distribution feeders (61%) have SCADA-controlled circuit breakers or reclosers.[110] Operators monitor system power frequency via a SCADA under-frequency load-shedding application. Such monitoring permits operators to feeders following an under-frequency event. Newfoundland Power[111] plans to upgrade its SCADA system, and place all feeders under SCADA control by 2016.

Energy Management Systems operate on top of a SCADA platform to monitor, control and optimize the performance of generators and transmission networks. Typical applications include automatic generation control, unit commitment, state estimator, online three-phase load flow, load forecasting and a dispatcher training simulator. Newfoundland Power[112]does not have its own Energy Management System. It does not foresee the need for such applications, given its planned SCADA replacement. Newfoundland Power has included custom applications within its SCADA system to support operation of the small hydro plants and the distribution system.

Newfoundland Power, however, links its SCADA system to Hydro's energy management system. This link provides each utility with near real-time information concerning each other's

[107] Response to RFI #PUB-NP-254.
[108] On site meeting 19 September 2014.
[109] Response to RFI #PUB-NP-253.
[110] Response to RFI #PUB-NP-149 and 245.
[111] Response to RFI #PUB-NP-265.
[112] Response to RFI #PUB-NP-257.

electrical operations on the IIS. Communication and coordination between Newfoundland Power's SCC and Hydro's ECC is continuous and is the central feature of daily operational coordination on the IIS. This link ensures that routine daily electrical system operations such as generation dispatch and switching procedures are performed on a safe and reliable basis.

The ARC-FM GIS application displays information about the geographic location and electrical connectivity of the distribution network. The System currently stores information about primary distribution lines, streetlights, and poles. This information includes equipment specifications and geographic location. Newfoundland Power installed the System in 2013 as part of a project to streamline the manual processes used to maintain and distribute distribution asset information.

4. Short-Term Forecasting

Power System Operating departments generally develop short-term load forecasts that cover the next day and up to three days. These forecasts help operators to schedule generation, identify facilities that can be taken out of service under low load periods or returned to service (or denied an outage) for higher than expected loads. Sophisticated tools exist to perform this function, but many smaller utilities use manual methods. A manual process might proceed, for example, by examining the typical daily load curve for the next day, based on the day of the week and season, and then applying local knowledge of weather effects. Newfoundland Power[113] does not have an operations tool to produce its own daily load forecasts. It does not see the need for one, because it believes it can gauge short-term needs based on experience and engineering judgment, or as provided to them by Hydro. These circumstances have led Newfoundland Power to conclude that it cannot justify the expense of an EMS application to provide short-term forecasts.

5. Load Management Tools

a. Conservation and Curtailment

Newfoundland Power[114] has some means to control its daily peak demands when generation supply is insufficient. It undertook in December 2013 and January 2014, and other times, customer energy conservation initiatives to minimize activating automatic underfrequency load shedding and the need to conduct rotating feeder outages. Newfoundland Power's[115] approach is to: (a) reduce energy usage at its own facilities, (b) issue energy conservation advisories and energy reduction instructions to residential, commercial, industrial, and other customers via all media forms and its website, and (c) if necessary, shed commercial customer loads after one-hour notice for those customers who have opted for the Curtailable Service Option ("CSO") billing rate.

Newfoundland Power[116] is not able to estimate the effectiveness its customer energy conservation measures for reducing demand, but does know that curtailments have reduced demand between 7.0 and 8.5 MW. During 2013, Newfoundland Power[117] requested customer curtailments a total

[113] On site interview 19 September 2014.
[114] Response to RFI #PUB-NP-014.
[115] Response to RFI #PUB-NP-014.
[116] Response to RFI #PUB-NP-014.
[117] Response to RFI #PUB-NP-085.

of 13 times. Eight of these times were to manage demand related costs and the other five times were on the behalf of Hydro to support the IIS. The durations of these curtailments were from one to three and one-half hours.

b. Voltage Reduction

Newfoundland Power[118] has the ability to temporarily reduce load by reducing voltage to about 186,000 (73 percent) of its customers. Newfoundland Power[119] can exercise voltage reduction by requesting Hydro to adjust voltage at the interconnection terminal stations, via the SCADA control of voltage regulating equipment in fourteen substations, or by manually readjusting voltage regulating equipment in its substations where the transformers have on-load tap changers and where generation or feeder length do not preclude reducing voltage. When Hydro reduces system voltage, it does so in two steps -- a three percent reduction followed by a two percent reduction. If Newfoundland Power reduces voltages at various substations, it is initially at two or three percent then up to seven percent, depending on feeder characteristics.

Newfoundland Power reported that it can reduce peak demand on about 1,005 MW of its 2013 peak demand of 1,378 MW. [120] The Company estimates that a five percent voltage reduction causes an immediate load reduction of about 66 MW and a sustained load reduction of about 26 MW. Newfoundland Power[121] exercised voltage reduction on eleven occasions during 2013. Eight of these occasions were to manage demand costs and three were occasions at the request of Hydro to support the IIS.

c. Automatic Underfrequency Load Shedding

Newfoundland Power's[122] distribution protective relay system is programmed so that whenever system demand or the availability of generation causes reduced system frequency (which could cause system collapse) some customer load will be shed (by tripping distribution feeder reclosers at the substations) to protect the integrity of the IIS. Following such an event, Hydro's Energy Control Center cooperates with Newfoundland Power's SCC to ensure that customers disconnected from the system are reconnected to the system quickly, while maintaining system integrity.

Newfoundland Power has underfrequency relays controlling 168 out of its 306 feeders. A feeder must have remote control capability and a minimum of 2 MW of estimated peak load to be considered for underfrequency tripping. Feeders with critical customers such as hospitals are not included. Following an underfrequency event, the feeders that were impacted by the trip are rotated with others that have not been recently impacted. This helps to share the burden of these outages among all customers. Newfoundland Power's underfrequency trip groups have a total of 482 MW of estimated peak load. Table 4.1, below, shows the power frequency at which each of the trip groups operate and the estimated peak load of each group. The "Group 1" frequency trigger at 59 Hz includes a 15-second delay.

[118] Response to RFI #PUB-NP-087.
[119] Responses to RFIs #PUB-NP-091 and 092.
[120] Response to RFI #PUB-NP-088.
[121] Response to RFI #PUB-NP-090.
[122] Response to RFI #PUB-NP-002.

Table 4.1: Underfrequency Trip Groups

Group	Frequency (Hz)	Estimated Peak Load (MW)
1	59.0[1]	40
2	58.8	34
3	58.6	43
4	58.4	56
5	58.2	60
6	58.1	90
7	58.0	159

6. Rotating Outages During the January 2014 Generation Insufficiency Event

The purpose of conducting rotating feeder outages is to prevent uncontrolled collapse of the system and to minimize the effect on customers during generation deficiencies. These outages proactively reduce small blocks of load for one-hour periods before automatic underfrequency load shedding occurs and before total system collapse. During the period from January 2 to January 8, 2014, [123]as customer demand approached the limit of available generation, small blocks of customer load were rotated off the system to match load with available generation. While monitoring system frequency and voltage levels, Newfoundland Power rotated additional small blocks of load on and off. Newfoundland Power's goal was to limit rotating power outages for each feeder to one hour. Operational difficulties, such as cold load pick up issues, however prevented restoring some feeders within one hour. Newfoundland Power could not provide its customers with specific advance notice of the precise timing and location of rotating power outages because of the quickly changing needs to reduce demand occurring during the January 2 through 8, 2014 time period.

Newfoundland Power[124] indicated that the impact on customers of any future need for conducting rotating outages would be reduced if: (a) it had real-time IIS generation and demand data from Hydro prior to a generation shortfall event, and (b) more feeder automation (downstream reclosers) was installed to provide remote controlled feeder sectionalizing. Newfoundland Power[125] plans to install more downstream reclosers in 2015 to provide better sectionalizing of some highly loaded feeders.

[123] Response to RFI #PUB-NP-022.
[124] Response to RFI #PUB-NP-049.
[125] Response to RPI #PUB-NP-024.

7. Coordination between Newfoundland Power and Hydro

Among other things, Newfoundland Power[126] and Hydro communicate with respect to load forecasting and planning of major electrical system modifications. They also communicate on an ongoing basis in relation to the coordination of activities related to capital work and maintenance of major system components and to operational coordination of response to storms and other events affecting the system. Communication with respect to the various matters takes place on an ongoing basis as required between personnel at various levels of the two utilities.

Oversight of matters of joint concern related to system reliability is the responsibility of the Inter-Utility System Planning and Reliability Committee. The Committee includes senior operations and engineering management from Newfoundland Power and Hydro, and meets regularly to consider matters related to system reliability, including reliability targets, system contingency and restoration planning, generation availability and peak load management preparedness.

Newfoundland Power and Hydro coordinate scheduling of work on their respective systems. This is done for two basic reasons. One is to ensure that one utility's actions will not unnecessarily affect the other utility's provision of service to its customers. The other is to ensure that the joint actions of the two utilities are undertaken in a way which is least disruptive to the reliable delivery of electricity to customers. Coordination of planned outages on the IIS requires a high degree of communication and cooperation. The Inter-Utility System Planning and Reliability Committee provide oversight of how the utilities communicate and cooperate.

8. Energy Management

Newfoundland Power[127] monitors its own demand, which comprises about 85 percent of the total demand on the IIS. Newfoundland Power's[128] System Control Center operates SCADA that allows it to monitor and control Newfoundland Power's generation, transmission and distribution systems. For daily operational coordination, Hydro's Energy Control Center monitors and controls its generation and bulk transmission system. The Center's primary functions comprise economic dispatch of generation and ensuring the balance of electrical system supply and demand for the IIS. Newfoundland Power and Hydro both staff their control centers [129] all the time.

Newfoundland Power's[130] SCADA system links with Hydro's Energy Management System. Newfoundland Power's SCADA monitors 754 unique data points exchanged through the Inter-Control Center Communications Protocol link to Hydro's Energy Management System. This total includes approximately 400 data points that first became available in June 2014. There are no outstanding requests for data points to be added to the exchange.

[126] Responses to RFIs #PUB-NP-002 and 042.
[127] Response to RFI #PUB-NP-042.
[128] Response to RFI #PUB-NP-264.
[129] Response to RFI #PUB-NP-002.
[130] Response to RFI #PUB-NP-247.

Communication[131] and coordination between Newfoundland Power's SCC and Hydro's ECC is intended to be continuous. It comprises a central feature of daily operational coordination, with the purpose to ensure that routine daily electrical system operations such as generation dispatch and line and equipment switching are performed on a safe and reliable basis.

Hydro[132] had not provided Newfoundland Power with real-time demand and generation reserve information on the IIS until the end of September 2014. A new joint utility protocol now calls for informing Newfoundland Power of real-time IIS demand and generation reserve information (and for providing additional EMS data points). The fact that Newfoundland Power did not have direct access to real time IIS operating status was typically of little consequence during normal conditions when Hydro's generation reserve is sufficient. However, on the occasions when Hydro's generation reserves were not likely to meet the demand such as during the January 2014 events, Hydro had not contemporaneously provided Newfoundland Power with demand and generation reserve information. Also, Hydro did not work closely with Newfoundland Power in a timely fashion prior to the January 2 event to address demand relief solutions, and to agree on joint actions for requesting conservation measures and for informing both utilities' customers of where and when outages might occur and when outages are expected to end.

D. Conclusions

4.1. The System Control Center is appropriately equipped and backed up by two other locations.

4.2. Although the SCC has a control console used for one-on-one training, it does not have software for simulating the electric systems under normal and emergency conditions. (*Recommendation #4.1*)

Newfoundland Power uses a spare, but active monitor where a trainee can view application screens. Newfoundland Power does not have a software application that allows a trainee to practice dealing with programed simulated system event scenarios. For some utilities, the energy management systems can be programmed to provide training simulations. However, Newfoundland Power does not have such a system.

4.3. Newfoundland Power's use of its Central Dispatch Team to relieve the System Control Center of duties for managing and dispatching planned work and trouble call crews during regular hours and emergencies is a sound practice.

The separation of duties allows System Operators to focus on operating Newfoundland Power's electric systems and on supervising switching procedures, while the Central Dispatch Team's focus is on customer service and on scheduling work efficiently. Also, Newfoundland Power has provided its crews with laptop computers containing geographic information system data for trouble call locations and with work management applications for trouble call action reporting. It also can track crew locations, via Global Positioning System, to more quickly dispatch the nearest crews to trouble calls.

131 Response to RFI #PUB-NP-002.
132 Hydro's November 21, 2014 Updated Integrated Action Plan as of the end of October 2014.

4.4. The System Control Center and the Central Dispatch Team are appropriately staffed.

Newfoundland Power's four lead system operators and six power system operators have substantial experience. Shift teams are appropriate.

4.5. Newfoundland Power appropriately monitors its transmission system, its infeed points from Hydro, and Hydro's generation via a link between Hydro's Energy Management System and Newfoundland Power's SCADA system.

4.6. The planned replacement of Newfoundland Power's SCADA system and its Outage Management System should improve the effectiveness of its system operations.

The new system will be designed to be capable of advanced distribution management functions including interfaces with the Geographic Information System and to a new commercial Outage Management System. Its current Outage Management System will be replaced with an advanced commercial system.

4.7. The System Control Center and the Central Dispatch Team appropriately use software tools for managing system operations.

Newfoundland Power's System Control Center controls and monitors its transmission system and much of its generation and distribution system with its SCADA system. The Outage Management System provides support to staff who create, process, dispatch, and close out outage reports. Other systems adequately support the variety of functions required to be performed.

4.8. Newfoundland Power's SCC does not have an Energy Management System because it links its SCADA system to Hydro's EMS.

This link provides each utility with near real-time information concerning each other's electrical operations on the IIS. Communication and coordination between Newfoundland Power's SCC and Hydro's ECC is continuous and is the central feature of daily operational coordination on the IIS. This link ensures that routine daily electrical system operations such as generation dispatch and switching procedures are performed on a safe and reliable basis.

4.9. The System Control Center does not have an operations software tool for producing daily forecasts. (*Recommendation #4.2*)

The Center depends on 1-3 day forecasts based on operations/engineering judgment and on short-term forecast provided by Hydro. Liberty found Newfoundland Power's current software and other applications used for the daily operation of the Company's system to be appropriate. The Company's recognition of the need to integrate the various operations applications into more holistic SCADA and OMS packages is also sound. The Company is going in the right direction with the exception of ceding the short-term forecasting function to Hydro's Nostradamus system.

4.10. If Hydro had timely consulted with Newfoundland Power about solutions for mitigating Hydro's generation shortfalls, Newfoundland Power would possibly have been better able to mitigate the issue with voltage reductions and load curtailments.

Hydro did not work closely with Newfoundland Power in a timely fashion prior to the January 2, 2014 event, to jointly discuss IIS demand relief solutions, and to agree on joint actions for requesting conservation measures and for informing both utilities' customers of where and when outages might occur and when outages are expected to end.

Although the communications and coordination between Newfoundland Power and Hydro appear to be adequate for normal operations, during the January 2014 outages Hydro did not confer with or provide Newfoundland Power with timely communications related to joint mitigating actions, and it did not provide accurate real-time information about short-term load demand and generation capacity shortfalls when these issues arise, such as prior to the January 2, 2014 generation shortfall.

E. Recommendations

4.1. Include in the specification for the new SCADA system the ability to turn an operator console into a formal training system simulation console for instruction and evaluation. (*Conclusion #4.2*)

4.2. Consider including a short-term forecasting application, if possible, when it replaces its current SCADA system. (*Conclusion #4.9*)

V. Generation

A. Background

Newfoundland Power purchases most of its energy from Newfoundland and Labrador Hydro (Hydro), but its hydroelectric and thermal generating units have the capability to produce a small portion of its energy and peak demand requirements. Liberty reviewed how Newfoundland Power operates and maintains its generating units and whether its practices are consistent with the needs of the electric system and with good utility practices.

Newfoundland Power[133] can generate about 139 MW from its own generating units. These resources include[134] 23 small hydroelectric plants, ranging from less than 1 to slightly more than 10 MW. The total output of Newfoundland Power's hydroelectric generators is 97.516 MW. Another 41.5 MW comes from two 2.5 MW diesel-fueled generators (one portable) and three gas turbines (20 MW, 10 MW, and 6.5 MW).[135] The hydroelectric facilities range in age from 15 to 114 years. Its gas turbine generators range in age from 39 years to 45 years.

B. Chapter Summary

Newfoundland Power has been appropriately operating and maintaining a fleet of aged generation units. Its generation maintenance strategy seeks to employ inspection and maintenance practices and refurbishment projects that will maintain, on average, a minimum availability of at least 95 percent. It has studied and is taking actions to address issues that affected the availability of hydroelectric and thermal units during the January 2014 system events. Except for a few small units, Newfoundland Power's generation units are either automatically controlled, or controlled by the System Control Center.

C. Findings

1. Generation Availability during the January 2014 Outage Events

Several Newfoundland Power[136] thermal generators were out of service for more than one day during the January 2 – 8, 2014 time period. One 2.5 MW diesel generator was out of service during the entire period because bearings were being replaced. The other 2.5 MW diesel generator was taken out of service on January 6, because of bearing damage. The Wesleyville 10 MW gas turbine was out of service from January 5 through January 22, because of a lube cooler oil leak. The Greenville 20 MW gas turbine ran out of fuel for most of January 3 and 4. Weather conditions prevented Newfoundland Power from supplying fuel to the gas turbine.

About 10.48 MW of hydroelectric generation was out of service during this same period. The Tors Cove G3 2.4 MW generator was out of service because of an AC drive failure beginning on January 6. The Westbrook 0.68 MW generator was out of service for a bearing failure and the

[133] Responses to RFIs #PUB-NP-033, 036, 038, and 171.
[134] Responses to RFIs #PUB-NP-001 and 056.
[135] Response to RFI #PUB-NP-001 and Newfoundland Power 2015 Budget Application.
[136] Responses to RFIs #PUB-NP-001, 039, and 180.

Rattling Brook G1 7.4 MW generator was out of service because of a damaged rotor pole. The last two were out of service for the entire January 2 through 8, 2014 time period.[137]

Experience from the 2013 and 2014 outage events led Newfoundland Power[138] to consider changes in the operation of its hydroelectric and gas turbine generating facilities. Hydro requested operation of Newfoundland Power hydro units for periods much longer than usual. Extended usage reduced water resources for some of the facilities. Hydro also requested continuous operation of the 20 MW gas turbine generator. The unit ran out of fuel after 39.5 hours of operation. Winter storm conditions prevented timely replenishment of fuel supply.

Following the January 2014 events, Newfoundland Power[139] decided to enhance winter-season generation availability by increasing water storage for hydro units and fuel storage for thermal ones. It also decided to conduct reliability assessments of its thermal generating plants.[140] Inflows[141] to Newfoundland Power's hydroelectric storage and river systems fall during winter months. Increasing water storage at existing facilities prior to winter season will require an examination of water management practices to address increased risk of spilling. A solution may lie in increasing the number of dams or increasing the height of existing dams.

2. Generation Availability

Newfoundland Power's[142] 32 hydroelectric generating units were available, on average, for 96.6 percent of the time during the 2009 to 2013 five-year time period and 95.5 percent of the time during the winter of 2013. Newfoundland Power's hydroelectric units had an average capacity factor (percentage of running at full capacity all year) of 51.1 percent during the 2009 to 2013 five-year time period and 62 percent capacity factor during the 2013 winter season.

3. Generation Operations

Generating units with remote control capability can be operated remotely, when necessary, by Newfoundland Power's System Control Center (SCC) Power System Operators via the Company's SCADA system. Generating units that are not remotely controlled are manually controlled by local operating staff under the direction of SCC Power System Operators.

Of the 32 hydroelectric units, 24 have remote control capability. The remaining hydro units possess generator breaker indication and limited telemetry. Of the eight hydroelectric units where full remote control is not available, two are third units at a three-unit plant. The other two units, given available water supply, are sufficient for most of the year. The remaining six units range from 255 kW to 680 kW, which makes them too small to justify full automation. The gas turbine generators at Greenhill and Wesleyville possess remote control capability. The mobile gas turbine and the mobile diesel generator units can provide indication of a limited set of points

[137] Response to RFI #PUB-NP-001.
[138] Response to RFI #PUB-NP-036.
[139] Response to RFI #PUB-NP-036.
[140] Liberty meeting with Newfoundland Power on September 19, 2014.
[141] Response to RFI #PUB-NP-056.
[142] Response to RFI #PUB-NP-177.

(for example generator breaker and unit lockout) when installed at substations and plants where SCADA monitoring and control is available.

Sixteen of the hydro plants use local programmable logic controllers (PLCs) to run water management algorithms that automatically determine optimal unit operation. Power System Operators can adjust water management systems to control how the logic controllers operate the hydro plants.

4. Generator Maintenance

Newfoundland Power's[143] generating plant preventative maintenance activities fall under the responsibilities of plant operators, maintenance staff, engineering staff, and consultants. Planners schedule, track, and monitor completion of maintenance activities using maintenance management software. The Company conducts regular inspections of dam, plant, and generator equipment on predetermined cycles. It uses predetermined cycles for preventive maintenance and testing work as well.

Corrective maintenance needs identification comes from inspections and observations of operating anomalies. Priorities govern the order of repairs:

- Priority 1 – Very High Priority – one month or sooner
- Priority 2 – High Priority – three months
- Priority 3 – Medium Priority – six months
- Priority 4 – Low Priority – one year.

Newfoundland Power's Superintendent of Generation and Substation Operations and the maintenance supervisors have the responsibility to ensure completion of all corrective maintenance on schedule and as defined.

The rate of completion of maintenance work has declined, as the following tables demonstrate.[144] Newfoundland Power indicated that all backlogged preventive maintenance tasks were either completed or rescheduled in the following year. It expects to timely complete the remaining preventive and corrective maintenance orders scheduled for 2014.

Table 5.1: Preventive Maintenance Performance

Work Orders	2010	2011	2012	2013	2014 (YTD)
Completed	11,945	1,995	1,922	1,880	975
Backlogged	157	229	280	312	282
Completed	92.50%	89.70%	87.30%	85.80%	77.60%

Table 5.2: Corrective Maintenance Performance

Work Orders	2010	2011	2012	2013	2014 (YTD)
Completed	120	90	83	73	55
Backlogged	5	3	4	7	26
Completed	96.00%	96.80%	95.40%	91.30%	67.90%

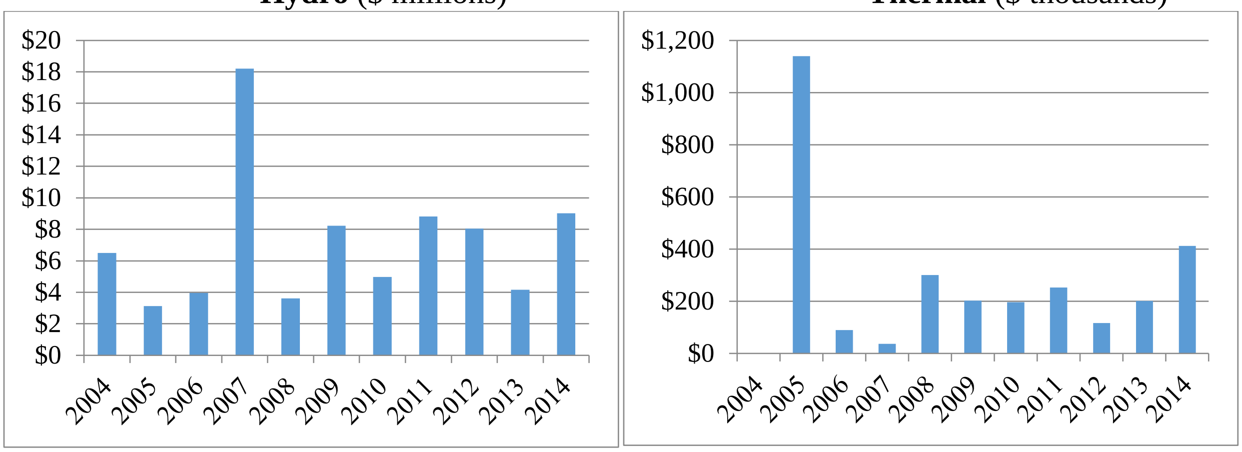
[143] Response to RFI #PUB-NP-175.
[144] Response to RFI #PUB-NP-176.

5. Capital Refurbishment

The average age of Newfoundland Power's 23 small hydro plants is 71 years and its five thermal plants, including the mobile unit, have an average age of 36 years. Refurbishment of aging assets thus drives much of the capital budget for generation. Generation capital refurbishment programs involve considerable capital expenditures on an annual basis as in-service assets deteriorate with age and service. The next chart shows[145] hydro and thermal generation plant capital expenditures over time. The amounts reflect annual authorizations; 2014 amounts are forecasts. Large 2007 hydro expenditures were influenced by the ($18,242,000) Rattling Brook Hydro Plant Refurbishment Project. The large expenditures in 2005 for thermal plants reflect refurbishment of the Mobile Gas Turbine and the purchase of the Portable Diesel unit.

Chart 5.3: Generation Capital Expenditures

Hydro ($ millions) **Thermal** ($ thousands)



6. Spare Parts

Newfoundland Power[146] maintains a substantial quantity of spare parts on hand (about 900) for its generating equipment. Some of the replacement parts for the old facilities are not available. At times, Newfoundland Power must make modifications to the facilities to make use of modern replacement systems and parts. The maintenance personnel responsible for generator maintenance are responsible for routinely replenishing the Company's spare generator facility parts inventory.

D. Conclusions

5.1. Newfoundland Power has appropriately operated and maintained its generating units.

Newfoundland Power conducts inspections at its generating stations on daily, weekly, monthly, bi-monthly, and semi-annual bases. Although Newfoundland Power backlogs some corrective maintenance work, it completes the work during the following year. Newfoundland Power undertakes generation repair, rehabilitation, and production improvement work on an

[145] Response to RFI #PUB-NP-174.
[146] Response to RFI #PUB-NP-033.

appropriately planned basis. The ages of Newfoundland Power's generating units appear likely to require increasing maintenance costs as time passes.

5.2. Newfoundland Power has maintained a reasonable level of generating availability.

Hydro units averaged 96.6 percent availability from 2009 through 2013, and 95.5 percent during the winter of 2013.

5.3. Newfoundland Power has analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

5.4. Newfoundland Power can control its larger units through SCADA or other automatic means.

E. Recommendations

Liberty has no recommendations related to Newfoundland Power generation.

VI. Outage Management

A. Background

Liberty examined Newfoundland Power's outage management approach, organization, resources, practices, and activities. The review included field personnel available to respond to trouble calls, and the receipt, location, and tracking of trouble calls. Liberty examined Newfoundland Power's Outage Management System (OMS), training to use the system, and the use of outage cause codes to improve system performance. The examination also addressed the basis for estimating and communicating estimated restoration times following outages.

Outage Management Systems play a critical role in response to storm-related outages. Many utilities struggle with Outage Management System performance, reliability, and usage during large events and storms. Systems that perform with great effectiveness during small events can degrade and even collapse under the stresses of major outages. When they do, distribution field personnel must revert to manual processes that further burden and delay outage response.

B. Chapter Summary

Newfoundland Power has stationed throughout its serving area sufficient numbers of outage responders trained to report outages for analysis for reliability reasons. The Company provides customers with options for reporting outages and it provides estimated restoration times to customers. Newfoundland Power, however, does not know the accuracy of the estimates it provides. While the Outage Management System serves the system adequately, the Company plans to replace the in-house system with a more effective, commercially available one, within five years. The new system will better integrate with a new SCADA system (due for installation in the next two years or so) and with other applications used to operate the electric systems.

C. Findings

1. Outage Response Staffing

Newfoundland Power operates under a[147] goal to respond to customer outages within two hours. During normal work hours, the Company assigns 12 Supervisors and 27 Power Line Technicians (PLTs) operating out of the three regional offices, plus 19 technicians operating out of its ten remote districts, to respond to trouble tickets. The Company also assigns shift crews, to respond to trouble calls from 8:00 am to midnight, seven days a week in the St. John's region. A total of 7 Supervisors, 12 regional and 7 district Technicians remain on standby to support outage response after-hours.

2. Outage Reporting

Newfoundland Power[148] provides customers several options for reporting outages and obtaining outage restoration information. Customers can call the Customer Contact Centre (CCC) using the Company's toll free number or they can use the *Report Power Outage* function available on the

[147] Responses to RFI #sPUB-NP-152 and 154.
[148] Response to RFI #PUB-NP-095.

Company's website. When the customer reports an outage on the phone, the Customer Account Representative (CAR) uses call screening guidelines to determine whether the customer is calling about an outage the Company may already be aware of, or whether the customer is calling about an outage which has not yet been logged. If the customer identifies a new outage, the CAR will create an outage ticket to record the details of the outage in the Company's Outage Management System. The CCC operates from 8:00 am to 5:00 m, Monday to Friday. After normal business hours customer calls are answered by the System Control Centre except in major outage events where the CCC is staffed outside normal business hours.

Newfoundland Power's[149]inbound call system has the capability of providing customized messages to one of eight districts within the Island Interconnected System, based on the telephone exchange of the incoming call. Tailored messages regarding acknowledgement of an outage, status of the response, and estimated restoration times can precede the transfer of the call to the CAR.

When a customer uses the *Report Power Outage* function on the Company website, the customer is presented with a series of questions to determine whether the customer's situation warrants that a new outage ticket needs to be created, or whether the outage is already known by the Company.

Customers can obtain outage restoration information via the Company's High Volume Call Answering (HVCA) system, the Company's website, or through a CAR. The outage restoration information customers receive via these channels originates with the Company's Outage Management System. Customers can also report outages and obtain outage restoration information on Newfoundland Power's Twitter feed and Facebook page. These are used to share outage event information with customers, and include links back to the Company's website.

3. Response to Outages

Customer account representatives or Power System Operators generate outage tickets[150] using the Outage Management System. The system transmits outage tickets electronically to trouble response crews consisting of two Power Line Technicians. The crews receive the tickets via computers in the line trucks. Geographic Information system transponders in the trucks expedite response. The Central Dispatch Team or the System Control Center monitors trouble crew locations, and dispatches the available line crew closet to the outage. Senior engineers and technologists review the outage causes and numbers of customers interrupted to identify possible responsive actions.

4. Outage Management System

The Outage Management System creates, processes, dispatches, and closes outage reports from customers. The system also maintains records of outage calls and response times and records interruption reports for managing reliability statistics. A series of 2012 enhancements to the internally developed system: (a) allow customers to report outages via the website or mobile

[149] Site visit 19 September 2014.
[150] Response to RFI #PUB-NP-154.

devices, (b) improved functionality for grouping and assignment of related outage tickets, and (c) integrated with the scheduling and dispatch software to provide for electronic dispatch and completion of outage tickets in the field via a mobile computing application.

Unavailability of the[151] Outage Management System has been nominal since 2009. The System was unavailable for approximately two hours due to unplanned issues that required support and maintenance. The Information Services department supports and maintains the Outage Management System.

Newfoundland Power expects to replace its existing Outage Management System with a commercial alternative within five years. Modern outage management systems provide more advanced functionality through integrations with SCADA systems and geographic information systems. This functionality includes predictive analysis and automatic grouping of related outage calls, as well as automatic customer outage notifications.

5. Outage Management System Training

Newfoundland Power's experienced senior employees provide Outage Management System training to new employees in the Customer Contact Center (CCC) and System Control Center (SCC), as part of new employee orientation[152]. Newfoundland Power's line staff received training on the ClickMobile application when it was initially installed on the laptops in their vehicles and again when software upgrades are implemented.

Newfoundland Power also conducts periodic Outage Management System refresher training. When enhancements are made to the Outage Management System, training is included as part of the project plan. This training is led by employees who have been involved in the design and testing of the enhancements. In preparation for severe weather events occasional Outage Management System users that assume a customer service role as part of the storm response will typically receive one-on-one training from employees experienced with the system. These employees also have access to an on-line training document that can be referenced from within the application.

6. Outage Cause Codes

Newfoundland Power codes outages under 28 Canadian Electricity Association (CEA)-defined categories for entry[153] into the Outage Management System by the Power Line Technicians who identify outage causes. When applying outage cause codes through mobile computers, technicians can provide additional outage cause details, and indicate follow up work required. On a daily basis, Newfoundland Power's System Control Center personnel review the accuracy of closed trouble call orders and edit the outage cause code reports and restoration time data. The review also ensures entry of any follow-up work into the appropriate system. All interruption data is also reviewed by Area Superintendents on a monthly basis. Area Superintendents and

[151] Responses to RFIs #PUB-NP-300 & 301.
[152] Response to RFI #PUB-NP-302.
[153] Response to RFI #PUB-NP-154.

Line Supervisors also review outage response times on a monthly basis to identify reasons for delayed response and for determining opportunities for improvement.

A key function[154] of an Outage Management System is to collect outage data and cause codes to develop reliability indices. These data are used to evaluate and report on reliability performance, and to help asset management and system planners allocate assets appropriately.

Newfoundland Power's Outage Management System contains a database with a user interface to allow customer interruptions to be entered, saved, and edited. Reporting functionality within the Outage Management System provides the ability to directly report standard customer based reliability data corporately, by region or by feeder. Current and historical data can be reported for SAIDI, SAIFI, CAIDI, CAIFI, customer minutes of interruption and customer interruptions.

7. Estimated Restoration Times

Newfoundland Power uses its Outage Management System to log customer reported power and street light outages, via telephone or the Company's website, and to electronically dispatch outage tickets to crews located in the field.[155] The outage tickets dispatched by the Outage Management System are then completed electronically by the crews. Outage tickets might be for individual outages or for grouped outages as occurs during storms.

The Company uses its *Informer Application* to communicate outage information to customers. Outages recorded in the Informer system include details such as the locations affected, estimated restoration time, reason for the outage, and other relevant information. Customers can view this information on the Company's website in a list or map format. Customers can also listen to a recorded message with the same outage information by calling the Company's Customer Contact Centre. During normal system operations, the Informer system is typically updated by staff at the System Control Center. This responsibility is transferred to the Communications Hub during large storms or system events, such as those on January 2-8, 2014.

The typical process for updating Informer with outage information is as follows:

- When the Company becomes aware of an outage, either through indication at the Control Center, reports from operational staff, or though customer calls, the outage will be added to the Informer system.
- If the cause and estimated restoration time are unknown, the outage will initially be listed as "Under Investigation" until the required information is provided by field staff responding to the outage. For the rotating outages during January 2-8, 2014, restoration times were typically listed as one hour.
- Field personnel provide updates to the System Control Center and regional operations regarding estimated restoration times or changes to the locations affected. This information is updated in the Informer system as information becomes available.
- The Control Center or the Communications Hub also monitors the outages listed on Informer, and proactively seek updates from field staff regarding ETR status.

[154] Response to RFI #PUB-NP-306.
[155] Response to RFI #PUB-NP-103.

- When an outage ends, the Control Center or Communications Hub removes the outage data from the Informer system.

D. Conclusions

6.1. The numbers and locations of field personnel assigned to outage response duties are appropriate in meeting outage-related needs.

Trouble call responders are available and appropriately located to timely respond to outage calls. The Company makes assignments with the goal of responding to trouble calls within two hours, designating more than 40 Power Line Technicians in its regions and districts to respond.

6.2. Newfoundland Power provides customers with appropriate options for reporting outages and restoration information.

Customers have call-in options during and after business hours and access to a Report Power Outage function through the website. Phone and website options also give customers access to restoration information. Customers can also report outages and obtain outage restoration using popular social media options.

6.3. Newfoundland Power appropriately responds to trouble calls.

Outage tickets are generated within the Outage Management System, which dispatches the outage tickets electronically to response crews. To facilitate faster response to trouble calls, trucks are equipped with transponders.

6.4. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.

6.5. Outage cause coding supports Company needs.

6.6. The estimated restoration time process appears to have been reasonably effective, and should improve with the replacement of the existing SCADA system.

Newfoundland Power's communicates restoration times via its Informer application to its customers. Liberty cannot evaluate the accuracy of the estimated restoration times because Newfoundland Power does not document estimated restoration time accuracy data. It would appear likely, however, that the accuracy of estimated restoration times will improve substantially after Newfoundland Power has completed the replacement of its SCADA system with full distribution system coverage and with the replacement of its Outage Management System, both within five years.

E. Recommendations

Liberty has no recommendations in the area of outage management.

VII. Emergency Management

A. Background

Electric utilities should be well prepared to take actions necessary to minimize the effect on its customers for the occasional events that impact large numbers of customers and cause considerable system equipment damage. The elements required for effective customer restoration following the impact of a severe storm or other major event include being vigilant for approaching severe weather or power supply issues, having a formal emergency restoration organization with distinct duties and responsibilities, having a formal emergency response plan that defines all actions required to prepare for an event and all actions and communications required in response to the event, ensuring that sufficient employees and contractors are available on short notice, and providing all employees involved with an emergency event training in their duties through formal classes and "mock" drills. Liberty reviewed Newfoundland Power's Emergency Command Center, emergency management organization, staff emergency restoration training, tracking of approaching severe storms, emergency response plan and preparation checklist, and restoration performance following severe storms in the past.

B. Chapter Summary

Newfoundland Power's reasonable restoration times following past severe storm events indicate that its emergency management practices for severe storms are appropriate. The Company has a well-organized emergency management organization, it appropriately monitors the progress of approaching severe storms, it has a formal and appropriate storm restoration manual and a storm preparation checklist, it has sufficient resources to address large severe storms, and it conducts storm drills. The only concern Liberty observed is the need for the System Restoration Manual to address loss of supply issues and severe storm events.

C. Findings

1. Emergency Command Center

The System Control Center functions as the Emergency Command Center during major system events. [156] Newfoundland Power also has a fully functional backup control Center at a separate location. The System Control Center and backup link connect through a private fiber optic network that includes headquarters and substations in the St. John's area. This network provides redundant paths to ensure high availability of digital communications to field devices and voice communications with employees and customers.

System Operator workstations at the backup Center connect to the main or backup SCADA servers. Backup SCADA servers use data replicated on a real-time basis from the main SCADA servers. Operators also have access to all voice communications channels at the backup control Center.

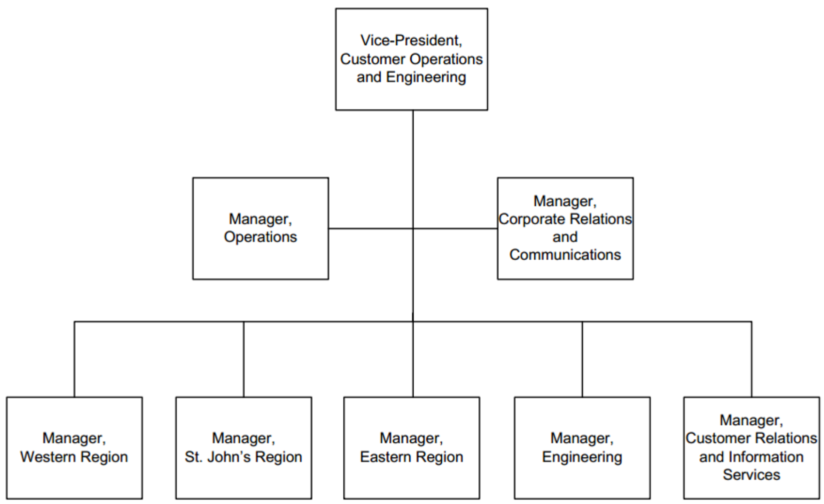
[156] Response to RFI #PUB-NP-028 and 186.

Newfoundland Power also uses its regional field operating Centers as emergency command Centers during more localized system events. During these events, the System Control Center transfers local control authority to regional staff. Newfoundland Power's technical and support staff gather in a central location in each regional Center that has the necessary computer and communications infrastructure to enable coordination of restoration efforts.

2. Emergency Management Staffing

Newfoundland Power[157] has a structured management control organization in place for emergency situations. The next chart illustrates this organization.

Chart 7.1: Newfoundland Power's Major Electrical System Event Organization Chart



The Vice-President of Customer Operations and Engineering has responsibility for preparing for and responding to major events. Managers responsible for electrical system operations, customer relations, and communications take lead roles in preparing and responding to major electrical system events. The Manager of Operations directs the System Control Center, Substation Operations, Generation Operations, Health and Safety, and Environment activities. This Manager also serves as Newfoundland Power's designate for communicating and coordinating electrical system issues with Hydro. When preparing for and responding to a major electrical system event, the Manager of Operations assumes a coordination role among managers responsible for the electrical system.

The three Regional Managers have responsibility for their region's transmission and distribution system field operations. These Regional Managers organize efforts to make repairs and restore service. When some regions suffer greater impact, Regional Managers may reassign personnel to assist with restoration efforts.

The Manager of Customer Relations and Information Services directs customer service efforts, and ensures effective operation of customer service telecommunications and internet based

[157] Response to RFI #PUB-NP-184.

systems. The Manager of Corporate Relations and Communications takes responsibility for communicating information to customers and stakeholders. This role includes issuing public advisories, posting messages on the Company's social media platforms, conducting media interviews, and interacting directly with stakeholders. These stakeholders include the Provincial Government, Fire and Emergency Services, and Hydro. During a major electrical system event, the Manager of Corporate Relations and Communications directs the Communications Hub.

Prior to a forecasted and during a major electrical system event,[158] senior management, led by the Vice-President of Customer Operations and Engineering, meets regularly to:

- Gauge the severity of the event
- Identify locations that require additional resources
- Determine need for deployment of mobile substations and generators
- Review restoration progress if major outages have occurred
- Determine communications requirements
- Discuss other matters that need immediate attention.

3. Personnel for Severe Storm Restoration

For a severe weather outage event, up to 432 of Newfoundland Power's[159] approximately 650 employees can be made available to assist emergency command management, and to conduct the restoration process. The Company can also call on local contractors[160] used for routine work as follows:

- Five who provide distribution construction services
- Three who provide transmission construction services
- Five who provide substation construction services
- Three who provide vegetation management services
- Three who provide poles and anchor installation services
- One who provides live line maintenance service (Avalon Peninsula only)
- One who provides streetlight installation and repair service
- Thirteen who provide civil works services.

Newfoundland Power[161] does not maintain any formal mutual aid agreements with other Canadian utilities because of the island's location and geographic features. The Company, however, has been working with other Canadian utilities via the Canadian Electricity Association to develop a nationwide standard agreement. Newfoundland Power and Hydro have access to each other's assistance. Newfoundland Power[162] also has access to resources from other Fortis-owned utilities, which travel time and logistics limit.

Staffing, especially skilled workers, comprises the most essential element in responding to widespread emergencies. On-island or neighboring contractors provide a source for

[158] Response to RFI #PUB-NP-184.
[159] Response to RFI #PUB-NP-152.
[160] Response to RFI #PUB-NP-195.
[161] Response to RFI #PUB-NP-183.
[162] Electric utilities across Canada, in New York State, and Grand Cayman Island.

supplementing skilled employees. During devastating events, such as Hurricane Igor, Newfoundland Power[163] had arranged for supplemental equipment from other utilities to be flown to the Island.

4. Emergency Restoration Training

Employee training includes training on the Company's service restoration, business continuity and disaster recovery plans.[164] Training includes major event drills on various events that may affect the system. Typically, such training includes a review of the applicable emergency response procedure or system restoration plan, involves a desktop review, and incorporates a partial or full drill exercise. Over the last five years, Newfoundland Power has conducted the following mock emergency drills, using specific system restoration plans:

- Loss of SCADA System
- Loss of System Control Center Building
- Loss of Switch and Outage Management Systems
- Loss of Generation Facilities
- Service Restoration Plan - Eastern Region
- Loss of Hydro Supply - Eastern Newfoundland
- Loss of Submarine Cables - Bell Island.

Actual events have provided a substantial source of experience since 2007:

- December 2007 winter storm in central Newfoundland
- March 2010 eastern Newfoundland sleet storm
- September 2010 Hurricane Igor
- December 2011 wind storm in western Newfoundland
- September 2012 Tropical Storm Leslie
- November 2013 snow storm in Central Newfoundland
- January 2013 loss of Hydro's transmission equipment
- January 2014 insufficient generation and loss of Hydro transmission equipment.

5. Emergency Response Enhancements

Newfoundland Power[165] has recently deployed mobile computing in all line trucks, implemented a computerized operations dispatch system, and expanded its use of geographic information systems in vehicles and for system assets. These changes enhance response capabilities for localized and widespread system distress. The Company also issued a System Restoration Manual in June, 2014. This manual updated action items required before, during, and after system emergencies, including equipment failures. The System Restoration Manual[166] supplements a Storm and Other Significant Event Preparation Checklist.

The System Restoration Manual does not include actions to address insufficient Hydro generation or loss of Hydro or Newfoundland Power transmission equipment. The manual does,

[163] On-site interviews, 19 September 2014.
[164] Response to RFI #PUB-NP-185.
[165] Response to RFI #PUB-NP-028.
[166] Response to RFI #PUB-NP-187.

however, included detailed procedures to prepare for severe storms and to conduct service restoration following storms. The manual's instructions address:

- Proactive monitoring approaching weather conditions
- Event preparations from the Storm and Other Significant Event Preparation Checklist
- Initial responses to system faults and restoration plans specific to the territory's five areas
- Air-patrol assessments to identify numbers and types of equipment damaged
- Actions to protect the public
- Actions to mitigate further damage (*e.g.*, potential cascading structure failures)
- Event categorization for use in determining restoration team requirements
- Restoration effects based on damage estimates including:
  - Detailed description of the damage
  - Time required to complete repairs
  - Materials required
  - Salvageable materials
  - The number of crews required
  - Specialized equipment requirements
  - Other resources required such as engineering, substations, and generation
- Restoration priorities
  - Importance of each line in the overall restoration process
  - Priority customers
  - Crew and material availability
  - Access to sites
- Establishing the Restoration Operations Center
- Communication with customers
- Determining workforce based on the level of the event
- Identifying and obtaining equipment and materials in excess of inventory
- Securing and dismantling damaged equipment
- Assignment of duties
- Rotating power outage and cold load pick up procedures
- Post-event and management reviews.

6. Severe Storm Tracking

Severe weather events generally affect only one particular area on the Island, but can affect the entire territory. Severe fall storms (when trees remain in leaf) typically involve tree contact. Winter and spring storms bring ice on lines and structures. Usually severe storms develop some distance from Newfoundland. The Company tracks them, and monitors their impact as they approach the Island. The Supervisor of System Control monitors weather alerts. Monitoring determines whether a forecasted storm has sufficient strength to cause likely damage. If so, the Manager of Operations begins preparation discussions with other operations management personnel, the Vice-President, and with Hydro to identify any shortfalls of generation and bulk power transmission anticipated.

Newfoundland Power[167]relies primarily on weather forecasts from Environment Canada. Newfoundland Power believes that the weather information from Environment Canada proves sufficient to plan adequately for weather events. Nevertheless, the Company has recently obtained forecasts from Provincial Aerospace,[168] which provides more detailed information. The Company may also seek information from the U.S. National Hurricane Center, where applicable.

Hydro subscribes to the LTRAX system, which monitors lightning strikes across North America; Newfoundland Power does not. Hydro alerts Newfoundland Power if it detects significant lightning approaching or already present. Newfoundland Power has also arranged for weather forecasts from Gander Airport. The Gander forecasts provide more detailed information than civilian sources. They are tailored for emergency responders.[169]

7. Storm Preparation Checklist

a. Prior to Severe Storm Arrival

Newfoundland Power typically[170] initiates severe storm response preparations for expected severe weather events two days prior to the event. For event threats posed by reduced bulk power generation or equipment issues, Newfoundland Power takes actions as soon as Hydro communicates the problem. The Company typically begins preparations for weather events under its Storm Preparation Checklist. This Checklist addresses:

- Preparing trucks, tools, materials, and generators (2.5 MW diesel and 6.5 MW gas turbine mobile generators and three portable substations, with a fourth imminently available)
- Verifying availability of off-road equipment and heavy equipment permits and escorts
- Coordinating response with Hydro and determining resources available from other utilities
- Holding pre-storm safety meetings
- Arranging accommodations
- Preparing generators at Company buildings
- Verifying Central Stores full staffing and sufficient stocks
- Deploying fueled mobile generators and portable substations
- Correcting any abnormal system configurations, changing protection settings, allowing equipment to operate under overloaded conditions
- Reviewing priority feeder and critical load lists
- Putting electrical, vegetation, flagging, snow clearing, and helicopter contractors on notice
- Preparing customer service and customer hub personnel
- Preparing Operations Center personnel and equipment
- Confirming accuracy with Department of Transportation and municipality contacts.

[167] Response to RFI #PUB-NP-028.
[168] Provincial Aerospace is a St. John’s based defense contractor, specializing in airborne maritime surveillance.
[169] On site interviews, 19 September 2014.
[170] Response to RFI #PUB-NP-028.

Regional Operations staffs are place on alert two days prior to anticipated severe weather events. Where practical, equipment subject to work in progress and temporary system conditions is returned to service and to normal configuration. Staffing numbers and optimum location undergo review. If necessary, employees are recalled from vacation and other employees, trained in duties to support the regular workforce, are put on notice. Contractors are put on notice and contact is made with other utilities to determine if those resources are available, if needed.

On the day before the severe storm, Newfoundland Power continues preparations started on the day before, and deploys resources to locations where severe storm damage is most likely. Employees are briefed on anticipated work conditions and when and where they are expected to report for work. The Company contacts key customers -- government, municipalities, schools and hospitals, to ensure that they are making necessary preparations for the upcoming event.

b. The Day of Arrival

On the day of the event, the System Control Center monitors the system, and notifies the regional field operations and the customer service staff of equipment failures as they occur. The Customer Contact Center also keeps operations staff up to date on outages reported by customer calls.

Experienced, line crews or technical staff are dispatched to assess damage failures. Based on priority, the appropriate work crews are dispatched to facilitate repairs. The highest priority repairs involve removing hazards to the public, and repairing transmission lines, substations, and mainline feeders. Repair work orders go into a dispatch queue, for the next available crew. As needed, the Company deploys engineering and information services staff, and other personnel with operations experience to the System Control Center, Customer Contact Center, and Regional Operations facilities to provide on-site support for critical technology and to supplement the regular complement of employees.

8. Coordination with Hydro

Newfoundland Power's[171] System Control Center and Hydro's Energy Control Center coordinate restoration efforts following major system events. When responding to major electrical system events, Newfoundland Power's System Control Center and Hydro's Energy Control Center work together to reestablish normal operations on the electrical system in a controlled and orderly fashion. Newfoundland Power's Control Center relies upon Hydro's Energy Control Center to keep it updated on system demand. Similarly, Newfoundland Power's Control Center relies upon its Hydro counterpart for information concerning availability of Hydro's generation resources.

9. Service Restoration Times

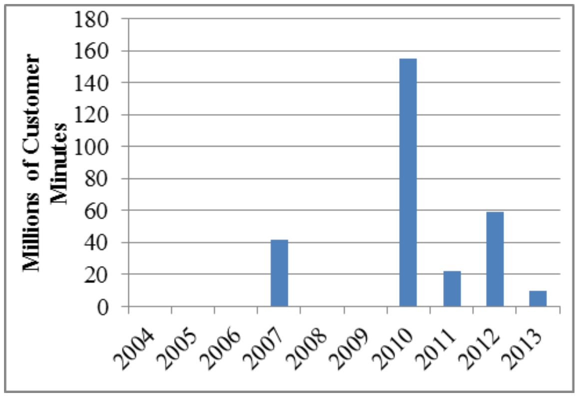
The amount of time to restore customers following a severe impact storm depends on a number of variables. These variables include storm type (heavy snow, wind, ice, or flooding), the type and amount of equipment damaged, the amount of the system affected, and travel restrictions caused by factors such as downed trees and snow coverings on roads. A review of restoration times following severe storms provides one indication of effectiveness in storm restoration activities.

[171] Response to RFI #PUB-NP-002.

a. December 2007 Wet Snow and Ice Storm

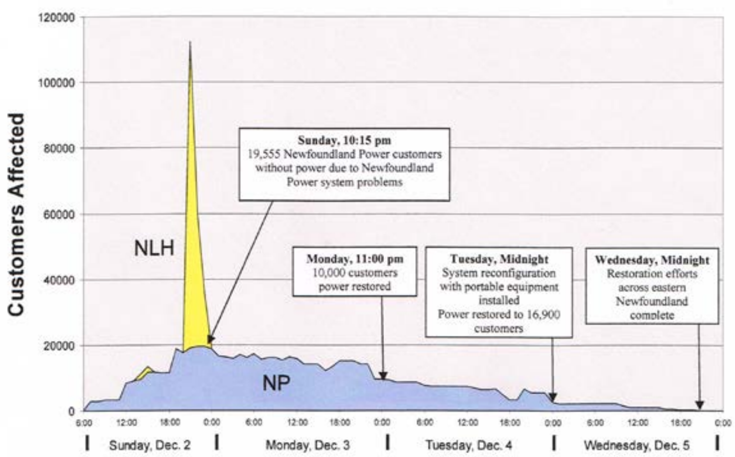
Prior to the 2013 and 2014 events, Newfoundland Power[172] had experienced several severe storms and other events that affected substantial numbers of its customers. The next chart shows the minutes of customer interruptions (in millions) for the severe storm-caused events affecting Newfoundland customers during since 2004.

Chart 7.2: Significant Storm-Caused Outages



In December of 2007 Newfoundland Power[173] faced a wet snow and ice storm with winds gusts of up to 160 kilometers per hour and ice loads of as much as 1.5 inches. During the storm, a problem on Hydro's electrical system resulted in a power interruption of up to 2.5 hours for 93,000 customers in the greater St. John's area. Damage to the Newfoundland Power system affected over 19,500 customers (about 8 percent), many for several days. Newfoundland Power spent about $1.7 million restoring customers and replacing damaged equipment. About 200 Newfoundland Power employees were involved in the restoration process, as well as Hydro and contractor personnel. The next chart shows the restoration time plot for the December 2007 storm.

Chart 7.3: 2007 Storm Restoration Time Plot



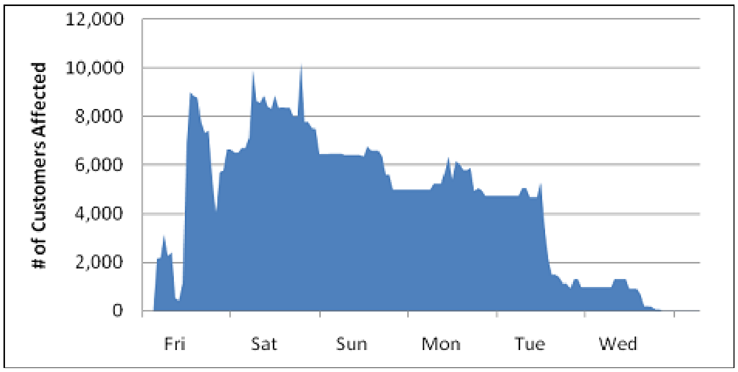
172 Newfoundland Power graphic presentation on February 12, 2014.
173 Response to RFI #PUB-NP-189.

b. March 2010 Ice Storm

Newfoundland Power suffered[174] two major storms in 2010. A March 2010 ice storm affected portions of the Avalon Peninsula, with actual ice loads in excess of 1.5 inches of radial ice. The resulting line and structure damage affected about 12,500 customers. Average time to restore customers, due to the extent of the damage, was about 58 hours. The storm caused over 43 million minutes of customer interruption time. This was the exception to the average customer minutes of interruption experienced during the other major events. Although the number of customers impacted by the storm was relatively small (about 5 percent of all customers) Newfoundland Power spent about $4.2 million for restoring customers and replacing damaged equipment.

The next chart shows the restoration time plot for the March 2010 ice storm.

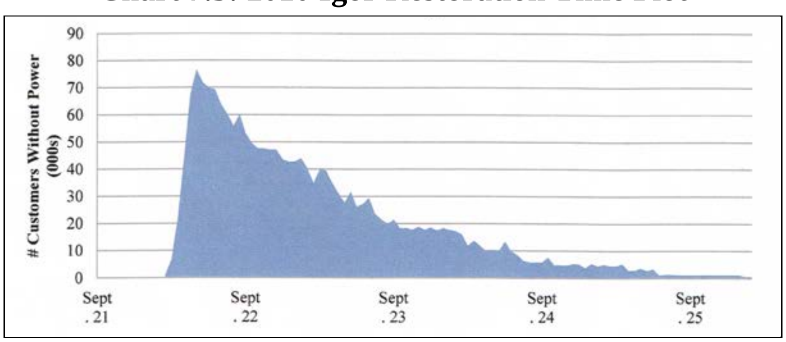
Chart 7.4: 2010 Ice Storm Restoration Time Plot



c. September 2010 Hurricane Igor

Hurricane Igor caused extensive flooding and high winds on September 22, 2010. Customers experienced, on average, about 17.5 hours of interruptions. About 106,000 customers (about 40 percent of total customers) were impacted by the storm. Newfoundland Power restored the bulk of its affected customers within three days. The storm caused 111 million minutes of customer interruption time. The Company spent about $1.9 million restoring customers and replacing damaged equipment. The next chart shows the restoration time plot for Hurricane Igor.

Chart 7.5: 2010 Igor Restoration Time Plot



[174] Response to RFI #PUB-NP-189.

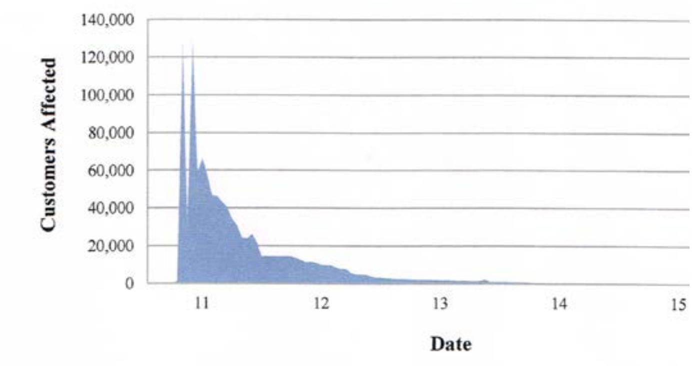
d. December 2011 Wind Storm

A wind storm struck in December 2011,[175] bringing high winds and affecting about 16,000 customers (about 6 percent of total customers) in remote areas. Average interruptions lasted about nine hours. Newfoundland Power restored all customers impacted within two days.

e. September 2012 Tropical Storm Leslie

Tropical Storm Leslie[176] in September of 2012, caused the loss of about 128,700 customers (about 49 percent), with an average duration of about 7½ hours. Newfoundland Power deployed 255 personnel to restore services. The bulk of customers were restored within two days. Newfoundland Power spent about $635,000 to replace damaged equipment. Chart 7.6, below, indicates the Newfoundland Power's restoration time plot for Tropical Storm Leslie in September 2012.

Chart 7.6: 2012 Storm Leslie Restoration Time Plot



f. The Hydro Terminal Station/Transmission Event in January 2013

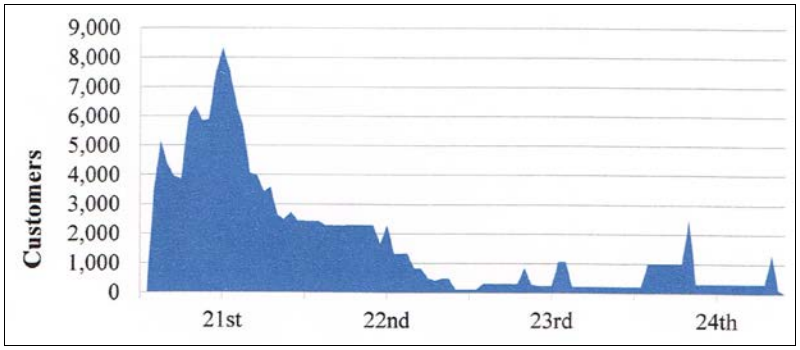
In January 2013, Hydro equipment problems, both generation and terminal stations, caused the loss of load for 173,000 Newfoundland Power customers with an average duration of over 11 hours.

g. The November 2013 Winter Storm

In November, 2013[177] a Winter Storm caused the loss of about 12,000 customers for an average duration of 9 hours. The bulk of the customers were restored within two days. The next chart shows the restoration time plot for November 2013 storm.

[175] Response to RFI #PUB-NP-166.
[176] Response to RFI #PUB-NP-166.
[177] Response to RFI #PUB-NP-166.

Chart 7.7: 2013 Storm Restoration Time Plot



h. The January 2014 Events

Insufficient generation capacity and terminal station equipment failures on Hydro's system in January 2014 caused the loss of load to about 188,000 customers, with an average duration of about 12½ hours. This event affected more Newfoundland Power customers than any of the severe storms affecting Newfoundland Power's customers since 2007.

D. Conclusions

7.1. Newfoundland Power's emergency response practices are effective and consistent with good utility practices.

Newfoundland Power was able to restore the bulk of the customers affected by its two largest recent storm events (Hurricane Igor and Tropical Storm Leslie) within two or three days. The only storm resulting in lengthy restoration time was the 2010 ice storm, which produced extensive damage to some transmission lines and distribution feeders. That storm, however, only affected about 5 percent of Newfoundland Power's customers.

Newfoundland Power's response times to severe storms should improve via increased restoration efficiencies, following installation of its new Outage Management and SCADA systems. The additional downstream feeder reclosers being installed by Newfoundland Power on some of its distribution feeders will also assist in storm restorations by helping to isolate faults and by mitigating the cold load pick up effects.

7.2. Newfoundland Power has made effective pre-assignment of management and operational duties for its emergency management organization.

Newfoundland Power's emergency management organization has well-defined control and command duties and responsibilities. Newfoundland Power has a large number of employees available and trained for addressing or assisting with the preparation of a forecasted severe storm event and for assigning specific storm duties. It also has local contractors available to assist.

7.3. Newfoundland Power's Emergency Command Center has appropriate capability and functionality.

The Company has dedicated a room located in its System Control Center as its Emergency Command Center, and equipped it with SCADA monitoring capability. The[178] System Control Center functions as its Emergency Command Center during major system events across its service territory.

7.4. Newfoundland Power has a well-defined process for tracking severe storms.

Newfoundland Power is vigilant in monitoring approaching weather that might produce severe storms for the island and it triggers its storm preparation checklist two days before a severe storm is anticipated to affect the Island. Newfoundland Power appropriately tracks approaching storms, and uses weather data from an appropriate number and range of services.

7.5. Newfoundland Power has a range of in-house and contractor resources for timely restoration of even large severe weather events.

For a severe weather outage event, up to 432 of Newfoundland Power's approximately 650 employees can be made available to assist emergency command management and to conduct the restoration process. Newfoundland Power also has access to numerous contractors and Hydro personnel, if needed.

7.6. Newfoundland Power conducts training exercises for its emergency management personnel.

Newfoundland Power has conducted mock emergency drills seven times over the last five years.

7.7. Newfoundland Power's formal System Restoration Manual is consistent with good utility practice, except that it does not describe actions for insufficient generation. (*Recommendation #7.1*)

With only one exception, Liberty found the considerations and procedures described in the restoration manual thorough and appropriate, and consistent with good utility practices. Newfoundland Power has separate procedures for conducting rotating power outages and for mitigating cold load pick up issues when restoring distribution feeders. The System Restoration Manual, however, does not formally describe communications and operating considerations and actions, including reducing system voltage, providing additional generation, and conducting rotating feeder outages if and when Hydro is unable to supply peak demand.

7.8. Newfoundland Power and Hydro cooperate in severe storm restoration efforts.

Newfoundland Power's System Control Center and Hydro's Energy Control Center coordinate restoration efforts following major system events caused by severe storm-caused equipment damage, and by the failure of major system components or the loss of supply. When responding to major electrical system events, Newfoundland Power's System Control Center and Hydro's Energy Control Center work together to reestablish normal operations on the electrical system in a controlled and orderly fashion.

[178] Responses to RFIs #PUB-NP-028 and 186.

E. Recommendations

7.1. **Include in the System Restoration Manual a section delineating actions for the loss of supply to its system, such as occurred in January 2014.** (*Conclusion #7.7*)

VIII. Customer Service and Outage Communications

A. Background

Liberty performed a review of Newfoundland Power's progress addressing outage communications recommendations arising from Liberty's April 24, 2014 Interim Report. Liberty's Interim Report contained eight recommendations that jointly concern Newfoundland Power and Hydro, one specific to Newfoundland Power, and one specific to Hydro. Newfoundland Power has undertaken initiatives to improve outage communications and inter-utility coordination in response to the nine recommendations that concern it. Newfoundland Power reports that actions to address seven of the nine recommendations initiatives have been completed. It plans to complete the remaining two initiatives by the end of 2014.

#	Recommendation	Status
37	Develop Joint Outage Communications Technology Strategy	Complete
38	Conduct Joint Customer Outage Expectations Research	Complete
39	Stress Test Enhancements to Customer-Facing Technologies	Complete
41	Pursue Multi-Channel Communications	In Progress
42	Develop Advance Notification Communications Protocols	Complete
43	Improve Conservation Request Communications	In Progress
44	Develop Storm/Outage Communications Plan	Complete
45	Conduct a Joint Lessons-Learned Exercise	Complete
46	Create Executive-Level Committee to Guide Initiatives	Complete

B. Chapter Summary

This chapter reviews Newfoundland Power's reported progress in addressing recommendations to improve outage communications. In the days since the January outage event, Newfoundland Power and Hydro have worked individually and jointly to tackle outage communications issues and improve inter-utility coordination.

A joint executive-level committee directed efforts and facilitated joint cooperation in resolving issues, including the creation of an advance notification protocol to guide decisions and communications during times of reduced generation reserves. Newfoundland Power and Hydro also conducted a joint lessons learned session to discuss opportunities to improve inter-utility coordination and communications. A Joint Communications Plan was created to encourage coordinated and consistent communications during anticipated or actual outage events and both utilities tested the new plan through a joint supply shortage tabletop exercise. Newfoundland Power's website and call handling technologies were expanded and stress-tested to confirm proper operation and responsiveness.

Newfoundland Power has made significant progress on the outage improvement recommendations, completing seven of nine recommendations, but two important recommendations remain. While Newfoundland Power has targeted a year-end date to complete the implementation of the two remaining issues, work will likely continue through the winter to support these initiatives.

Jointly-conducted customer research identified a need for customer education to highlight ways to conserve electricity and to help customers and the public understand the impact of conservation on the IIS. As a result, Newfoundland Power has created a customer education and awareness plan and scheduled customer outreach to raise conservation awareness. This effort will continue throughout the winter.

Newfoundland Power is also in the middle of a technology implementation that will introduce a "texting" option for customers who prefer to receive notifications by text message. Newfoundland Power reports that this feature will be rolled out to customers by December 31, 2014. However, more work will be required over the coming months to promote the option to customers. Newfoundland Power should take steps to measure and monitor the customer experience of this new customer-facing technology and communications tool to ensure a good customer experience.

The next sections address the status of actions responding to each recommendation.

C. Findings

1. Join Outage Communications Technology Strategy

Liberty's recommendation stated:

> *As a first step, Newfoundland Power and Hydro should develop an Outage Communications Strategy to prioritize opportunities and guide near- and longer-term improvements to customer contact technologies and telephony, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

In June, Newfoundland Power developed an outage communications strategy to guide near- and long-term improvements to outage technologies. Near-term initiatives remain underway to address recommendations described in this section (SMS, stress testing, website capacity). Longer-term plans include full deployment of GIS, replacement of SCADA, enhancing website to enable responsive design (all devices), replacement of the Outage Management System, and high-volume third-party overflow IVR services.

Hydro finalized a Customer Service Strategic Roadmap[179] in September. This document describes plans to enhance and improve customer service related technologies over the next three years. Near-term initiatives include revising outage protocols and formalizing after-hours telephone support. In addition, Newfoundland Power and Hydro have discussed possible synergies for shared customer contact and outage communications technologies, especially as Hydro faces replacement of its customer information system, revisions to its customer service pages on its website, and upgrades to its call center telephony over the next few years.

Work to address this recommendation has been reported as completed.

[179] Response to RFI #PUB-NLH-202.

2. Joint Customer Outage Expectations Research

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should conduct customer research (primarily on a joint basis), in order better to understand customer outage-related informational needs and expectations, including requests for conservation, and incorporate results into the Outage Communications Strategies, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Hydro and Newfoundland Power jointly conducted customer research over the summer to understand customer expectations regarding outage-related communications. They conducted a number of surveys:

- Telephone survey of 800 residential customers
- Focus groups to explore preferences in St John's, Carbonear/Sunnyside, Central Newfoundland, and Rocky Harbor
- Online survey of 100+ business customers

Results from this customer research highlighted the need to provide increased education on the ways customers can conserve, including businesses. Additionally, customers shared expectations on how soon ETRs should be provided, how often they should be updated, and how much time is needed to prepare for a potential outage event. This information has been used to revise outage communications and storm preparation protocols.

Work to address this recommendation has been reported as completed.

3. Stress Testing Technology Enhancements

Liberty's recommendation stated:

> *As Newfoundland Power and Hydro move forward with enhancements to any customer-facing outage support systems, each should stress test the technologies well prior to the winter season; this element should comprise a key component of their implementation processes.*

Newfoundland Power conducted extensive stress testing of its website and contact center telephony over the summer. As a result of these efforts, Newfoundland Power's website has been fortified and stress tested, and its contact center telephony has been expanded and stress tested.

Newfoundland Power conducted a series of stress tests of the responsiveness and reliability of the website outage pages. The stress tests replicated the volume of website activity experienced during the January outage event. The testing confirmed capacity requirements and identified slower performing applications. At the same time, the testing vendor provided recommendations to optimize website coding and integration to improve the speed and reliability of the website. Newfoundland Power has secured a means to dynamically boost the capacity of its webservers should demand increase in the future. Additionally, Newfoundland Power continues to contract with a vendor to monitor website performance on an ongoing basis.

Newfoundland Power contracted with another vendor to conduct stress testing of its current telephony configuration. A series of tests were conducted over the summer to simulate the volume of calls received during the January event. The initial test identified an issue with the configuration that has subsequently been resolved and retested. Additionally, Newfoundland Power stress tested the T1 trunk that was added following the January outage. Newfoundland Power will test additions or changes to the telephony going forward.

Work to address this recommendation has been reported as completed. Future monitoring and testing will continue as required.

4. Multi-Channel Communications

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should pursue (primarily on a joint basis) other multi-channel communication options, such as two-way SMS Text messaging or Broadcasting options, for delivering Outage Status Updates, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power has selected a vendor to proceed with an enhancement that will provide multi-channel communications options for customers. This enhancement will enable Newfoundland Power to communicate with customers in the manner they select, whether by phone, email, or SMS texting. Customers will be able to indicate communications preferences through Newfoundland Power's website, including specifying the best available contact phone number or email address. The solution will work in conjunction with Newfoundland Power's existing "Communications HUB" process to enable multi-channel communication of outage and storm information to customers.

The project is currently on on-track. Newfoundland Power introduced the service to its employees on December 1, 2014. Employees will be testing the product to ensure proper operation. Following a successful employee-test, Newfoundland Power will roll out this service option to customers.

5. Advance Notification Communications Protocols

Liberty's recommendation stated:

> *Newfoundland Power and Hydro should aggressively pursue a joint process for delivering advance notification for planned rotating outages, in order to facilitate good initial communications with customers during an outage event, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power and Hydro have jointly developed an advance notification protocol to guide customer communications when generation reserve margins are expected to dip below predetermined thresholds. Hydro modified its T001 protocol to project a shortfall in generation reserves in stages of severity:

- 0-Normal (5-day forecast greater than largest generating unit plus minimum spinning reserves)

- 1-Power Advisory (5-day forecast less than largest generating unit plus minimum spinning)
- 2-Power Watch (24-hour forecast indicates reserves less than largest generating unit)
- 3-Power Warning (Current day reserve margin is less than half of the largest generating unit)
- 4-Power Emergency (Generation shortfall imminent, no reserve margin).

Stakeholders will be notified based on the forecasted severity. Customer notifications guidelines have been established to guide the release of public information for each stage and determines the point at which customers will be asked to conserve electricity and when advisories should be issued to prepare customers for rotating power outages, should they be required.

Work to address this recommendation has been reported as completed.

6. Conservation Request Communications

Liberty's recommendation stated:

> *Newfoundland Power should implement goals to communicate better with stakeholders in the aftermath of outages. If conservation requests have been made of the public, Newfoundland Power should provide feedback following the event to indicate the amount of conservation achieved, and encourage future conservation, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Customer research conducted this summer highlighted the need to provide additional customer education around conservation requests, such as the one issued during the January 2014 event. Residential and business customers indicated that they needed more advance warning to prepare for conservation requests. Focus group research revealed that customers might be using more power after the request to conserve, in order to prepare for the impending outage (*e.g.*, turning up the heat, doing laundry, cooking meals). In addition, customer education is needed to help customers prioritize their efforts to conserve.

To address these issues, Newfoundland Power and Hydro have developed a coordinated customer education and awareness plan. Company website and social media pages have been updated to explain the new advance notification protocol, to demonstrate ways to conserve, and to explain why conservation is important for the IIS. This same message is being shared with media outlets and in public speaking engagements to encourage winter preparedness and emphasize the importance of conservation. December customer bills will also contain an insert communicating this information.

Newfoundland Power and Hydro are not technically able to measure the actual amount of electricity that customers conserve after a conservation request. Instead, following a conservation request, the utilities will provide general feedback such that customers can understand the impact of conservation efforts in terms of reduced or avoided rotating outages. This feedback will provide another opportunity for the utilities to reiterate the importance of conservation and the best ways to conserve, to continue the dialogue.

Additionally, Newfoundland Power is actively partnering with local business organizations to discuss conservation options with businesses and to encourage future cooperation.

Both utilities have updated their critical infrastructure and customer lists. Newfoundland Power is actively meeting with large commercial customers to discuss conservation requests, outage communications, and when possible, to participate in regional emergency response drills.

Newfoundland Power and Hydro have also developed a Joint Communications Plan to guide customer communications during large outages or events. This plan is described in the following recommendation.

Actions to address this recommendation are still underway. Customer outreach will continue throughout the winter as needed. Feedback will be provided, as required, following any future conservation requests.

7. Storm/Outage Communications Plan

Liberty's recommendation stated:

> *Hydro and Newfoundland Power should jointly develop a coordinated, robust, well-tested and up-to-date Storm/Outage Communications Plan documenting protocols, plans, and templates to guide communications during major events, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.*

Newfoundland Power and Hydro have developed a Joint Communications Plan[180] to guide customer communications during large outages or events. The Joint Outage Communications Plan provides clear guidelines and templates for major events that result in damage to or interruption of power supply to the island interconnected electricity system. The Plan is intended to ensure that the Utilities are the primary authoritative voice during a critical incident that affects either Company's operations. It enables both Corporate Communications Teams to quickly activate, and provides strategies, tools and templates to effectively communicate to customers, employees, media and key stakeholders during outage situations.

The plan was successfully tested through a tabletop scenario drill in September 2014. Individuals representing operations, management, and communications from both utilities were involved in the testing exercise. The test of the Plan was successful—both utilities were prepared to handle the scenario and the Plan guided communications at all levels[181]. The Joint Communications Plan will be updated as needed to capture any changes to the process, including any lessons learned from future outages or storms. Additionally, Hydro and Newfoundland Power have committed to testing the plan annually.

Work to address this recommendation has been reported as completed.

[180] PUB-NLH-304 Attachment 1
[181] PUB-NLH-460 Attachment 1

8. Joint Lessons-Learned Exercise

Liberty's recommendation stated:

Newfoundland Power and Hydro should conduct a joint "lessons learned" exercise including both their Communications Teams, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

The Communications Teams from Hydro and Newfoundland Power conducted a joint "lessons learned" session on May 20, 2014 to review the January outage event. The joint session was broadened to include individuals from customer service, operations, and energy efficiency. Discussions covered the January events as well as initiatives underway following the event. Discussion focused on ways to work jointly to address issues, ways to share information, planned improvement initiatives, and customer research.

Both utilities plan to conduct similar joint lessons-learned sessions following any future events.

Work to address this recommendation has been reported as completed.

9. Executive-Level Committee to Guide Initiatives

Liberty's recommendation stated:

Hydro and Newfoundland Power should commit to a formal effort, sponsored at their most senior executive levels, to work together in formulating joint efforts to identify goals, protocols, programs, and activities that will improve operational and customer information and communications coordination, leading to the development, by June 15, 2014, of identified membership on joint teams, operating under senior executive direction and according to clear objectives, plans, and schedules.

An executive-level committee of senior managers from both utilities was given an enhanced focus following Liberty's 2014 Interim Report. Since April, this committee has been meeting monthly to oversee joint recommendations, discuss action items, and coordinate activities.

A key accomplishment of the executive committee was the joint development of the Customer and Stakeholder Advance Notification Protocol (refer to recommendation #42 in Liberty's Interim Report). These meetings were used to further the discussions around stakeholder information needs as well as the thresholds guiding the release of information. These discussions established the foundation for the Joint Communications Plan (refer to recommendation #44 in Liberty's Interim Report).

This committee was also key in expanding the level of real-time status information available between Hydro and Newfoundland Power concerning the status of lines, equipment, and generation. Additionally, short-term load and generation information is being made accessible to Newfoundland Power, which will determine the timing of customer communications during a projected shortfall.

Subsequent meetings defined the need to jointly test the advance communications protocols and the Joint Communications Plan. A successful tabletop drill was ultimately conducted in late October.

This committee also served as a forum to discuss ways to improve operational coordination as well as discuss progress on other joint recommendations, including the customer research, multi-channel outage communications, and technology stress testing. While many of the action items subsequently have been completed, these meetings continue on a monthly basis to address any issues requiring inter-utility cooperation.

Work to address this recommendation has been reported as completed.

D. Conclusions

8.1. Newfoundland Power has made significant progress on the outage improvement recommendations, but important monitoring work remains. (*Recommendation #8.1*)

One of Liberty's recommendations in its Interim Report (*Item #41*) involved the implementation of new customer-facing technologies to enable multi-channel communications with customers. The implementation for this recommendation is still underway. As with the introduction of any new customer-facing technology, it is important to monitor the customer experience to ensure the service is working as intended and to provide feedback to improve the service if necessary.

E. Recommendations

8.1 Monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience. *(Conclusion #8.1)*

Newfoundland Power's effort to introduce multi-channel communications is just beginning with the implementation of the SMS iFactor solution on Newfoundland Power's website. More work will be required over the coming months to introduce and promote the technology to customers and to gather customer feedback. Implementation progress should be monitored. Additionally, Newfoundland Power should take steps to measure the customer experience of this new customer-facing technology and communications tool.

Appendix A: Conclusions and Recommendations Summary

Chapter II: Planning and Design

Conclusions

2.1. T&D reliability has substantially improved since 1999 and has recently remained stable overall.

2.2. The large contribution that the distribution system makes to outages and the number of equipment-caused failures indicate room for further improvement in reliability. (*Recommendation #2.1*)

2.3. Newfoundland Power focused on worst performing feeders for some time, but has recently ceased committing resources to them despite the fact that such feeders still exhibit disproportionately high outage metrics. *(Recommendation #2.2)*

2.4. Newfoundland Power's Transmission and distribution systems operate effectively in ensuring adequate service reliability.

2.5. The expanded work of the Inter-Utility System Planning and Reliability Committee commenced in 2014 should improve planning coordination between Newfoundland Power and Hydro.

2.6. Capital programs have been effective in improving reliability, but better methods for prioritizing projects under consideration exist. *(Recommendation # 2.3)*

2.7. Newfoundland Power has incorporated appropriate levels of redundancy in its transmission and distribution systems and in its substations.

2.8. Newfoundland Power employs appropriate design standards, criteria, and practices for transmission and distribution lines.

2.9. Current use of SCADA and use of automatic reclosers on feeders downstream from substations currently do not serve to minimize interruption frequency and duration. *(Recommendation # 2.4)*

2.10. Newfoundland Power employs appropriate lightning and animal protection.

2.11. Newfoundland Power makes effective use of short circuit studies.

2.12. Completion of in-process developments in the Geographic Information System will increase its effectiveness.

2.13. Newfoundland Power's protective relay schemes conform to industry practice, but they do not operate under documented guidance. *(Recommendation #2.5)*

2.14. A temporary delay in testing of electromechanical relays is being addressed.

2.15. Newfoundland Power does not formally periodically exercise its circuit breakers. *(Recommendation #2.6)*

2.16. Newfoundland Power does not centrally track actions to address the causes of frequent protective device operations. *(Recommendation #2.7)*

Recommendations

2.1. Increase the emphasis on the Rebuild Distribution Lines initiative in annual capital budgets, with the goal of reducing distribution equipment failures. *(Conclusion #2.2)*

2.2. Perform a structured evaluation of the costs and benefits of reinstituting a regular annual program for addressing worst performing feeders. *(Conclusion #2.3)*

2.3. Develop a weighted analytical scoring of criteria process to support capital planning; include in this a scoring criterion that relates expected project costs to avoided numbers of customer interruptions or minutes. *(Conclusion #2.6)*

2.4. Investigate the installation of downstream feeder reclosers for the purpose of improving distribution SAIFI and SAIDI indices, in addition for reducing cold load pick up difficulties, with priorities given to feeders based on installation costs versus anticipated avoided customer interruptions. *(Conclusion # 2.9)*

2.5. Document protective relay scheme objectives, criteria, and methods for protecting transmission lines, buses, and distribution feeders. *(Conclusion #2.13)*

2.6. Conduct circuit breaker operation tests from relays (so called trip checking) on a periodic basis to assure that all relay trip circuits and circuit breakers operate as intended. *(Conclusion #2.15)*

2.7. Centrally report multiple device operations. *(Conclusion #2.16)*

Chapter III: Asset Management

Conclusions

3.1. Asset management at Newfoundland Power operates: (a) under a program, (b) with an organization, and (c) with the support of sufficient numbers and skills to meet system reliability needs effectively.

3.2. Newfoundland Power uses an effective combination of periodic O&M inspection and maintenance programs and capital transmission, distribution, and annual capital substation capital rebuild and modernization projects to address condition, reliability, and operating issues with its transmission, distribution, and substation assets.

3.3. Newfoundland Power completes its transmission, substation, and distribution inspection and maintenance work in a reasonably timely fashion.

3.4. Newfoundland Power's transmission line and pole inspection and corrective maintenance practices are consistent with good utility practices, except that the Company does not have a program to chemically treat its aged poles. *(Recommendation #3.1)*

3.5. Newfoundland Power's distribution feeder and pole inspections and corrective maintenance practices are generally consistent with good utility practices, except for: (a) lack of periodic sounding (testing for internal decay) of all aged poles, and (b) a slow replacement rate for aged distribution poles. *(Recommendation #3.2)*

3.6. Newfoundland Power's substation inspection, corrective maintenance, and preventive maintenance practices are consistent with good utility practices.

3.7. Newfoundland Power's vegetation management practices are consistent with good utility practices.

3.8. Newfoundland Power's T&D System Rebuild and Modernizations Strategies are generally consistent with system needs.

3.9 As indicated in Chapter II, despite notable reliability improvement since 1999 and stable SAIFI and SAIDI metrics exhibited recently, it appears that room remains for improving distribution equipment-caused customer interruptions by applying more weight to the Rebuild Distribution Lines Project. *(Recommendation #2.1)*

Recommendations

3.1. Unless it can show that fungus and insect infestation does not occur on its wood poles, Newfoundland Power should reconsider the need to treat its transmission poles for fungus and insect infestation, as does Hydro. *(Conclusion #3.4)*

3.2. Consider conducting "sounding" tests on all older distribution poles (not just those obviously rotted) when inspecting feeders; reconsider chemically treating distribution poles to extend their lives. *(Conclusion #3.5)*

Chapter IV: Power Systems Operations

Conclusions

4.1. The System Control Center is appropriately equipped and backed up by two other locations.

4.2. Although the SCC has a control console used for one-on-one training, it does not have software for simulating the electric systems under normal and emergency conditions. (*Recommendation #4.1*)

4.3. Newfoundland Power's use of its Central Dispatch Team to relieve the System Control Center of duties for managing and dispatching planned work and trouble call crews during regular hours and emergencies is a sound practice.

4.4. The System Control Center and the Central Dispatch Team are appropriately staffed.

4.5. Newfoundland Power appropriately monitors its transmission system, its infeed points from Hydro, and Hydro's generation via a link between Hydro's Energy Management System and Newfoundland Power's SCADA system.

4.6. The planned replacement of Newfoundland Power's SCADA system and its Outage Management System should improve the effectiveness of its system operations.

4.7. The System Control Center and the Central Dispatch Team appropriately use software tools for managing system operations.

4.8. Newfoundland Power's SCC does not have an Energy Management System because it links its SCADA system to Hydro's EMS.

4.9. The System Control Center does not have an operations software tool for producing daily forecasts. (*Recommendation #4.2*)

4.10. If Hydro had timely consulted with Newfoundland Power about solutions for mitigating Hydro's generation shortfalls, Newfoundland Power would possibly have been better able to mitigate the issue with voltage reductions and load curtailments.

Recommendations

4.1. Include in the specification for the new SCADA system the ability to turn an operator console into a formal training system simulation console for instruction and evaluation. (*Conclusion #4.2*)

4.2. Consider including a short-term forecasting application, if possible, when it replaces its current SCADA system. (*Conclusion #4.9*)

Chapter V: Generation

Conclusions

5.1. Newfoundland Power has appropriately operated and maintained its generating units.

5.2. Newfoundland Power has maintained a reasonable level of generating availability.

5.3. Newfoundland Power has analyzed and is addressing issues, such as water and fuel supply, that may enhance the capacity it can make available to the Island Interconnected System during periods of generation shortage.

5.4. Newfoundland Power can control its larger units through SCADA or other automatic means.

Recommendations

Liberty has no recommendations related to Newfoundland Power generation.

Chapter VI: Outage Management

Conclusions

6.1. The numbers and locations of field personnel assigned to outage response duties are appropriate in meeting outage-related needs.

6.2. Newfoundland Power provides customers with appropriate options for reporting outages and restoration information.

6.3. Newfoundland Power appropriately responds to trouble calls.

6.4. The Outage Management System has served adequately, but the Company is appropriately moving to a commercially provided replacement.

6.5. Outage cause coding supports Company needs.

6.6. The estimated restoration time process appears to have been reasonably effective, and should improve with the replacement of the existing SCADA system.

Recommendations

Liberty has no recommendations in the area of outage management.

Chapter VII: Emergency Management

Conclusions

7.1. Newfoundland Power's emergency response practices are effective and consistent with good utility practices.

7.2. Newfoundland Power has made effective pre-assignment of management and operational duties for its emergency management organization.

7.3. Newfoundland Power's Emergency Command Center has appropriate capability and functionality.

7.4. Newfoundland Power has a well-defined process for tracking severe storms.

7.5. Newfoundland Power has a range of in-house and contractor resources for timely restoration of even large severe weather events.

7.6. Newfoundland Power conducts training exercises for its emergency management personnel.

7.7. Newfoundland Power's formal System Restoration Manual is consistent with good utility practice, except that it does not describe actions for insufficient generation. (*Recommendation #7.1*)

7.8. Newfoundland Power and Hydro cooperate in severe storm restoration efforts.

Recommendations

7.1. Include in the System Restoration Manual a section delineating actions for the loss of supply to its system, such as occurred in January 2014. (*Conclusion #7.7*)

Chapter VIII: Customer Service and Outage Communications

Conclusions

8.1. Newfoundland Power has made significant progress on the outage improvement recommendations, but important monitoring work remains. (*Recommendation #8.1*)

Recommendations

8.1 Monitor the "customer experience" of the new multi-channel communications services, and adjust the service offering as necessary to ensure a good customer experience. *(Conclusion #8.1)*