Supply Issues and Power Outages Review Island Interconnected System

Executive Summary of Interim Report

Presented to:

The Board of Commissioners of Public Utilities Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

April 24, 2014

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EXECUTIVE SUMMARY

Background to Liberty's Examination

- The Board of Commissioners of Public Utilities retained The Liberty Consulting Group ("Liberty") to examine the causes of widespread electricity outages experienced by customers on the Integrated Island System ("IIS) of Newfoundland and Labrador from January 2 through 8, 2014.
- Newfoundland Power Inc. ("Newfoundland Power") and Newfoundland and Labrador Hydro ("Hydro") play generally different roles with respect to the IIS. Newfoundland Power's predominant role is to deliver to end-use customers the energy that Hydro generates and transmits. Hydro does have a small number of end users, and Newfoundland Power a small amount of generating resources. The causes of the outages arose on Hydro's system, making responses to, rather than causes of, outages the focus of Liberty's examination of Newfoundland Power.
- This report identifies priority actions that Hydro and Newfoundland Power should take prior to the in-service date of the Muskrat Falls project to reduce risks of future outages and improve response to any that may occur.
- Liberty's examination will continue through this coming fall, as we review plans and execution of efforts to effectuate improvements, and examine longer-term risks to maintaining reliable, continuous service to customers on the Island portion of the Province.
- Liberty has been serving utility regulators for more than 25 years, working in 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 Conclusion

- The outages of this past January stemmed from two differing sets of causes: (a) the insufficiency of generating resources to meet customer demands, and (b) issues with the operation of key transmission system equipment.
- Liberty found that a continuing and unacceptably high risk of outages from such causes remains for the 2015-2017 winter seasons.
- Liberty identified a number of actions that will improve the ability to avoid outages and to prepare for and respond to those that cannot be avoided.

Generation Resource Sufficiency

- The outages that began on January 2, 2014 resulted from a shortage of generating capacity to meet customer demand. Hydro responded by asking Newfoundland Power to institute a series of controlled, but substantial rotating customer outages. Hydro did the same for some of its end-use customers, but the location and nature of Newfoundland Power's loads made rotating outages on its system more effective in responding to supply/demand balancing needs.

- Addressing the continuing risks of supply/demand imbalances requires either or both of adding resources and making sure that existing resources are available at peak times (during winters in the case of Newfoundland and Labrador).
- First, Liberty found that Hydro's shortage of generation capacity was exacerbated by a failure to complete planned outage work needed to ensure the availability of its full range of generating facilities as the winter season began. Hydro should increase its emphasis on scheduling and completing required outage work prior to the winter season, in order to increase assurances of unit availability when most needed.
- Second, Liberty found that Hydro needs to plan its resources to meet more severe weather than it has assumed to date. Weather, and wind chill in particular, comprises a critical component in analyzing the resources required to ensure reliability. This approach will have the effect of identifying a higher level of required generation sources. Hydro should no longer use an assumption that produces in each year a 50 percent chance that weather will prove worse than what Hydro has assumed for planning purposes.
- Third, Liberty has identified the need to review the planning criteria Hydro has long used for adding new generation capacity. This review will require the engagement of all stakeholders. Hydro has planned its system to the same overall standard for many decades. This standard provides for lower reliability than what Liberty has observed in other regions of North America. Liberty found that reliance on this standard in the current circumstances has resulted in generation capacity reserves which are too low. Liberty believes it is time to reassess the service reliability and cost balances that underlie the decisions on what level of supply resources to make available.

Equipment –Related Outages

- In the second half of the period from January 2 through 8 of 2014, more widespread and uncontrolled outages resulted from Hydro equipment failures, starting with a fire at a major transmission system substation. Hydro ultimately experienced a series of major equipment failures at three of its terminal stations.
- The number and nature of the failures that occurred within this compressed time frame is very unusual, and raises questions about Hydro's operation and maintenance of equipment.
- Liberty found that Hydro did not complete recommended maintenance activities on the equipment that failed, and that protective relay design issues and insufficient operator knowledge of the protective relay schemes existed. These circumstances contributed to the outages caused by the equipment failures.
- Liberty found that Hydro should make improvements in its maintenance practices to mitigate the risks of equipment-related outages. Hydro has moved toward the industry best practice of adopting an "asset management" program, which is the industry's common term for optimizing infrastructure performance and costs, including structured, comprehensive maintenance. Hydro's execution of its program, however, has not fully recognized some aspects of inspection, testing, maintenance, and operation that have become appropriate, considering the advanced age of some of its transmission system asset types.
- Aging infrastructure is a continent-wide phenomenon. Replacing it immediately is not economically feasible for utilities generally, including Hydro. The company needs to: (a) recognize the special needs of aged equipment, (b) identify required inspection, testing, and maintenance activities appropriate to them, (c) establish sufficiently short maintenance cycles,

(d) provide the resources needed to rigorously perform planned actions, (e) complement internal resources with outside expertise and resource levels where required, and (f) ensure that operators understand equipment limitations and weaknesses.

Rotating Outages

- Implementing rotating outages (however much one believes they should and may remain a principal tool for managing supply/customer demand imbalances) formed Newfoundland Power's major operational challenge this past January. Conducting rotating outages in cold weather caused problems early in the process, but, as the outages continued, the company became able to limit the duration of outages to the one-hour standard it sought to achieve.
- Newfoundland Power should reflect the knowledge it gained in executing rotating outages to clearly document procedures, practices, and guidance, in order to facilitate the process of limiting the durations of any required rotating outages in the future.
- While Newfoundland Power made improvements between the 2013 and 2014 outages to increase the availability of representatives and information about outage condition and status, Liberty recommends the pursuit of additional options in continuing to improve performance.

Intercompany Communication

- Liberty believes that Hydro and Newfoundland Power should commit to a formal effort to work together in formulating joint efforts to identify goals, protocols, programs, and activities that will improve operational and customer research, information, and communications coordination.
- The companies should form teams operating under senior executive sponsorship and direction and according to clear objectives, plans, and schedules.

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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. Equipment and operations issues raised by these two major series of events led to the current investigation.

1. January 2013

The very early morning hours of January 11, 2013 brought heavy and blowing snow to the Island portion of Newfoundland and Labrador. During these conditions, the inception of a series of events on the system of Newfoundland and Labrador Hydro ("Hydro") produced Island-wide, extensive customer outages, primarily, on the Avalon Peninsula. Faults and disturbances took all three of Hydro's Holyrood generating units out of service, and caused trips of the buses connecting them to the transmission system. The first Holyrood Unit that went out of service (Unit 3) tripped at about 4 a.m. The other two Holyrood units tripped off line at about 6:45 a.m. Hydro also lost key transmission-line capacity in this immediate time period. A major transmission line of Newfoundland Power, Inc. ("Newfoundland Power"), the island's principal retail supplier, went out of service at the same time.

Newfoundland Power lost load to a significant number of its retail customers, primarily on the Avalon Peninsula. An hour later, with these facilities still out of service, Hydro's remaining high capacity transmission line into Western Avalon and serving the St. John's area went out of service as well. Equipment failures caused widespread outages to spread to the Island's central and western areas. During restoration efforts, continuing problems (*e.g.*, communications and equipment) produced additional switching and equipment issues that led to more equipment trips.

Restoration efforts continued, with trips and other equipment issues continuing through about 9 a.m. Service levels returned to normal in the western region by about noon on January 11th. The transmission facilities serving the Avalon Peninsula returned to service at about 3 p.m. Hydro continued to bring generation and transmission facilities back into service as the day progressed. Two of Holyrood's three generating units returned to service in the early morning hours of January 12, 2013, with service restored across the Island by approximately 5 a.m. Significant damage to Holyrood Unit 1 suffered in its initial trip resulted in an extended outage.

2. 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 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.

<u>Generation-Related Outages:</u> As January approached, a number of Hydro's generation facilities 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.

<u>Equipment- and Operations-Related Outages:</u> Hydro experienced a major fire on January 4th at a Sunnyside station transformer. 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 This Report

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] Schedule "A" of the February 19 Order designated an extensive set of issues for examination in the first of two reports by Liberty. The overall scope of this first of those reports (the "Interim Report") includes an:

- Explanation of the IIS events that occurred in December 2013 and January 2014

[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.

- 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.

Hydro and Newfoundland Power have been examining the causes of the January 2014 outages, and identifying and implementing changes to address those causes. Continuation of those efforts will undoubtedly have caused some new information to develop after the time established for completion of this report. The first steps of our coming work will address information and plans that have continued to emerge and develop in what has been an understandably dynamic environment.

C. Summary of Major Conclusions and Recommendations

1. Background

Liberty's review so far has focused on outage causes and identification of measures that Hydro and Newfoundland Power can take to mitigate the risk of outages through the time when Muskrat Falls enters service as now scheduled. We will continue to study longer term issues associated with ensuring reliability for the customers of the two utilities. Our plan is for the Fall 2014 Report to address those issues, which include consideration of changes that the new source of supply from Muskrat Falls will bring.

Hydro and Newfoundland Power together 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. These distinctions between the two companies are not total. Hydro does provide some electricity directly to end users and Newfoundland Power does have some small generating units. Nevertheless, understanding this basic distinction between the two companies best frames the discussion of the 2013 and 2014 outage events.

In both cases, the origins of the outages, while affected by external conditions (snow and cold weather), lie with Hydro's generation and transmission systems. Both outages had significant consequence for Newfoundland Power customers, making its role in these particular events best understood in terms of preparation for and response to consequences on its system arising from causes outside that system.

Our review of these outages raised the following principal concerns:

- The base level of generation that Hydro has to serve customers during winter peak seasons and the ability to ensure full availability of its resources as those seasons commence
- The maintenance and operation of key equipment on Hydro's transmission system
- Hydro and Newfoundland Power programs for addressing outage communications and for formally examining customer expectations and attitudes regarding reliability and outages

- Coordination between Hydro and Newfoundland Power regarding customer communications and operations in anticipation of and during outages.

We will develop a more detailed understanding of the management and operation of the facilities and infrastructure of Hydro and Newfoundland Power after completion of the study leading to the Fall 2014 Report. Only that study will support general conclusions about the overall effectiveness of management and operations of systems, equipment, and activities necessary for ensuring safe, reliable, and continuous service. The focus of the study leading to this report concentrated on near-term changes that can reduce risks that threaten service continuity during the next several winter peak seasons. The Fall 2014 Report will discuss how the companies have identified and acted upon risk factors that have longer term consequences. It will also have the breadth required to determine whether potentially existing risks not contributing directly to the events of the last two winters (but material to future service levels nevertheless) have been fully addressed.

Consequently, this report focuses more on "exceptions," as opposed to overall assessments of management and operations effectiveness. That focus is appropriate, given the Board's paramount immediate concern; *i.e.*, to identify actions that the Companies should be taking now, as matters of first priority, to reduce service-continuity risks. Such a focus means, however, that it will take our Fall 2014 Report to support overall conclusions about management and operations effectiveness.

2. Hydro Generation

We found that there exists a continuing and unacceptably 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. A significant source of this continuing risk results from Hydro's modeling of required generation capacity and reserves. Hydro has used its current approach for decades, but its modeling, as currently constructed and used, does not produce acceptable levels of reserves.

First, Hydro's planning in effect averages winter conditions. Given the very large percentage of customers using electric heat, this approach does not give sufficient emphasis to the extreme loads that colder winter conditions can produce. Planning for generation, which uses worst-day winter conditions having a 50/50 chance of being exceeded every year, is not sufficient to ensure continuous service in Hydro's circumstances. Second, Hydro correctly seeks to make its generation available by December 1 of each year. The goal is to complete required maintenance and repairs by the time that each winter season begins. This goal recognizes the significant probability that Hydro will experience its winter peak loads sometime in December. Hydro has not, however, met that goal. Hydro needs to place a higher priority on finishing the work required to support unit availability by December 1. Reserve planning should not assume such availability to the degree that Hydro remains unable to support it.

Beyond these two specific conclusions, we observed that Hydro's planning basis, as reflected in its historical design and operation of its electric system, makes greater allowance for the use of interruptions than do other North American locations and utilities we have examined. We believe that the time has come for a robust, structured examination of how the standards Hydro uses conform to current customer expectations in what we would expect is a changing regional environment. It has generally been the case that North American utility customer expectations have risen.

It has also been the case that meeting rising expectations often takes significant expenditures. To some degree, interconnection among utilities in most of North America has a tempering effect on the total amount of resources required to ensure supply adequacy across wide, multi-utility regions. Interconnection provides opportunities to support enhanced reliability at comparatively lower cost than non-interconnected utilities can generally achieve. The IIS differs materially when it comes to regional interconnection. Nevertheless, the variance we have seen in reliability standards and in acceptance, for example, of rotating outages as an acceptable demand management device, does indicate that it has become important for the Board and stakeholders to review the balance between customer expectations (as they exist today and as one can expect them to change in the future) and the costs it takes to meet them.

Beyond this broader recommendation, which engages stakeholders broadly, some of our key recommendations for Hydro to implement in the near term in the supply area include:

- Making the securing of new generating capacity a first priority, seeking, if possible, an in-service date of December 1, 2014
- Modeling system supply needs on the basis of weather assumptions that assume worst-day weather more extreme than the use of long-term averages would produce
- Improving the accuracy of tools that consider the effects of extreme weather
- Evaluating the causes of deviations between forecasted and actual winter loads
- Accelerating implementation of a program to better ensure unit availability (*e.g.*, through more aggressive completion of maintenance outages) as winter peak seasons approach
- Continuing discussions with large customers about interruptible service arrangements.

3. Hydro Transmission Equipment

We found that a number of equipment maintenance and operation issues on Hydro's transmission system merit substantial attention in the near term. 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.

The industry has moved increasingly in recent years to adopt "asset management" programs to address key infrastructure components, such as those that caused problems for Hydro in the outages of the past two winters. The term "asset management" refers to a systematic process for the cost-effective operation, maintenance, upgrading, and retirement of such components.

Hydro has placed an industry-competitive emphasis on creating and committing to the use of an asset management program. The results observed (*i.e.*, the quality of asset performance) during the outages of the past two years, however, call into question the effectiveness of the application of the process. Our review to date leads us to observe that Hydro's execution of the program gives more visibility to cost effectiveness than to preventing the kinds of equipment failures that have caused widespread outages.

Effective asset management requires well designed and implemented inspection and maintenance cycles. Hydro generally uses defined cycles in areas associated with the recent outages, but it has deferred some maintenance, including equipment that failed, required by its established cycles. Backlogs are significant, and have grown since 2011 for both corrective and preventive maintenance activities. Hydro has redirected personnel to more critical repairs, indicating that it has not maintained resources needed to get both proactive and reactive maintenance accomplished in a timely way. Despite increasing levels of work, the applicable resources have remained flat since 2011. In one example, we found, as Hydro has recognized, the need for examining and revising its protective relay schemes. Such schemes serve to isolate faulted portions of an electrical system from affecting others. They can prove essential in limiting the effects of equipment failures on service continuity. Hydro has, however, lost some its most experienced people qualified to do the work. Its engineering personnel in the area have dropped by 20 percent and its technologist complement has remained flat.

Effective asset management also requires recognition of and accounting for equipment age. Older equipment can continue to be effective, but making it so necessitates care appropriate to the needs that advancing age imposes. We found Hydro's maintenance standards more appropriate for a system comprising equipment of "younger" vintage than characterizes Hydro's infrastructure.

For example, Hydro makes use of the now-dated technology of air-blast circuit breakers. Recent outage events on the IIS involved three of these devices. They should be, as has been recommended to Hydro in the past, operated (on a test basis) periodically to ensure that they will operate under extreme (but nevertheless predictable) environmental conditions. Our discussions with Hydro indicated that the company is now committed to doing so, but Hydro did not test them earlier. We also found that changes to Hydro's transformer examination and testing cycles and practices would better reflect the age and nature of its equipment.

The aftermath of the January 2014 outages also leaves open two important questions that require analysis. First, there exists the possibility that a harmonics resonance issue contributed to a key transformer failure. Hydro has employed a contractor to examine this question, whose answer may have important consequences for addressing future threats to the system. Second, Hydro plans to take an existing transformer from one location (at the Western Avalon terminal station) to serve at another (the Sunnyside terminal station) until replacement of the destroyed transformer at the second location. Hydro needs to complete an already-commenced examination of the vulnerabilities created by this relocation.

Our key recommendations for addressing Hydro transmission system issues include:

- Emphasizing prevention of equipment-related failures as a key component of asset management
- Intensifying equipment testing by assessing and complying with maintenance cycles for aging equipment, including dissolved gas analysis for critical transformers and regular operation of air-blast circuit breakers

- Addressing needed relay protection changes, including examination of protection schemes, consideration of the installation of breaker failure relay protection where it does not now exist, and completion of high-priority relay replacement
- Adding the resources necessary to reduce maintenance backlogs and to address relay protection and control issues
- Bringing in a qualified substation contractor to add needed maintenance and repair resources
- Assessing the consequences of transformer relocation and field repairs.

4. Use of Rotating Outages

The acceptance of rotating outages as a measure for balancing supply resources with demand merits (as described above) a broader re-examination for its applicability to the future. Nevertheless, the recent outages required the availability of this tool to avoid widespread, uncontrolled outages at times during the events of this past January. Hydro and Newfoundland Power worked together to identify the need for and timing of required rotating outages. These outages affected retail customers on both systems, but Newfoundland Power far more. The disparate impact reflects the fact that the concentration of loads on Newfoundland Power's system and operational factors (such as the ability to control feeder operation remotely) made them generally better candidates for producing the required amounts and locations of demand reduction. The reductions followed an organized plan that prioritized circuits on the basis of load and presence of critical customers.

Hydro and Newfoundland Power executed the rotations in an organized fashion. Newfoundland Power had compiled in advance of the January 2013 events a candidate list of feeders for rotating outages, but did not have to use such outages at that time. Newfoundland Power was again prepared to commence rotating feeder outages in January 2014. It had not anticipated, however, the severity of the cold load pickup issues it would face when it began restoring its most heavily loaded feeders. Cold load pickup causes loads to be much higher when a circuit is re-energized (and large amounts of customer equipment restart) than is the case when it is operating on a steady-state basis. Therefore, the Companies must account for such surges in load when seeking to keep the system from suffering the consequences. Newfoundland Power realized that it needed to sectionalize some feeders and to change its feeder restoration procedures to address cold load pickup. As Newfoundland Power proceeded through the cycling of circuits involved in the rotating outages, it gained knowledge of cold load pickup constraints. Its outage durations by the second day fell to within its one-hour duration guideline.

Newfoundland Power reported that virtually all of its breakers and reclosers performed as intended, with issues caused by temperature affecting a few. The key Newfoundland Power issue for the coming winter seasons is to document the lessons learned from the cold load pickup and the few equipment performance issues it experienced, in order to inform its personnel in a comprehensive form for use in planning and executing any required rotating outages. It may well be that consideration of longer term reliability standards will remove the use of such outages as an accepted response tool. If so, it will bring the IIS more into conformity with general North American experience.

5. Customer Service and Communications

We examined customer service accessibility and response and public and media communications in the context of the recent outages. The scope of Newfoundland Power's (versus Hydro's) retail customer base makes the challenges of keeping customers informed during emergency events different. The flood of calls that accompany large-scale outages makes the adoption of a robust system for handling the surge necessary. We found that Newfoundland Power has incorporated a number of lessons learned from its experience in January 2013. For example, Newfoundland Power has contracted with a third party to provide a high-volume call answering service to supplement its automated phone capabilities. It provides an automated outage-status message, tailored to one of eight regions, based on the calling customer phone exchange.

Newfoundland Power also expanded its number of phone trunks for handling customer calls, provided enhanced call menu options, trained personnel for assignment to phone duty during emergencies, and conducted a storm scenario test of these improvements. During the January 2014 events, Newfoundland Power extended call center hours. The company found the resources needed to increase its call center staffing materially during the 2014 outages.

Newfoundland Power also upgraded its website capabilities, incorporated the ability to modify the site to accommodate event-specific messaging, provided an interactive outage map with outage status information, and created the ability for on-line outage reporting by customers. Another important Newfoundland Power change enabled inbound callers reporting emergencies to reach the operations center, thereby permitting the expediting of emergency reporting. The power of using the web as a communications tool was shown by the almost 1 million site visits during the January 2014 events, as compared with the less than 200,000 during the outage events of January 2013. The use of Twitter, Facebook, and YouTube also benefitted communications with customers in January 2014. We also found that media contacts during the events robust and comprehensive.

Despite the improvements during the January 2014 events, a high number (20 percent) of callers to Newfoundland Power still underwent what the industry would define as a "poor customer experience;" *i.e.*, a "call back later" message, a busy signal, or a decision to abandon a call while waiting for a live representative. We also observed that Newfoundland Power's automated call menu (Interactive Voice Response, or "IVR") does not permit customers to report outages. It takes live contact or the web site to do so.

Hydro lost access to key customer information and contact systems due to a loss of power at its headquarters building. The failure of backup systems to operate as designed caused a number of systems (important to system operations) to be lost for 45 minutes. Systems important to maintaining communications with customers regarding the outage were lost for approximately four hours.

We believe that Hydro and Newfoundland Power should 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 what we consider to be a late request for customers to initiate conservation measures on January 2, 2014. Despite a growing recognition that the imbalance between available supply and demand would come to require rotating outages, a conservation advisory did not come until 2:30 p.m.; *i.e.*, shortly before those outages began (after 4 p.m.). This timing left little time for customers at home to initiate measures, and essentially none for those at work during normal business hours.

The principal recommendations 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.

6. Intercompany Coordination

The events of this January 2014 have shown the need for improved coordination and communication between Newfoundland Power and Hydro. The needs 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. The two companies acknowledged to Liberty the need for such coordination and joint efforts. Both, however, need to commence an organized effort, sponsored by top executive management of both, to identify common goals, emergency coordination teams, procedures and protocols, and customer research efforts.

7. List of Recommendations

Appendix A to this report sets forth a list of all the recommendations detailed in this report.

D. Study Approach and Methods

Liberty's study team undertook a review of:

- The nature of the events contributing to the outages
- Their immediate causes
- The management and operations issues underlying those events and contributing to those immediate causes.

In particular for this Interim Report, we focused on management and operations issues having the potential for correction or improvement in the short term; *i.e.*, in time to reduce risk in an effective manner over the winter seasons prior to the availability of Muskrat Falls. We thus concentrated particularly on the circumstances and causes underlying the recent outages. In doing so, we recognize that three other sources of risk remain to be addressed in our Fall 2014 Report:

- An exploration of outage-risk mitigation efforts likely to require an implementation period extending past the next several winter seasons
- A more detailed exploration of potential areas of risk that, while they may (or may not) be material, lie beyond those contributing more directly to the outages of the past two winters
- The overall reliability risks that will exist following the introduction of the major new supply source from Muskrat Falls and related transmission issues.

We began our review with an examination of the substantial efforts being undertaken by Hydro to study the direct and root causes of the outages. We accompanied that review with access to Hydro management and to the teams it had assembled to conduct its examinations. We met with Board Staff to identify other documents that would be helpful in conducting our study. We identified the issues we would address in this Interim Report through these sources of information, and through presentations from and initial interviews with Hydro and Newfoundland Power management. We then asked a number of formal requests for information, and reviewed the responses to them. We also reviewed the March 24, 2014 reports that each utility filed in response to the Board's schedule for the conduct of this proceeding. We continued as well to conduct interviews with Hydro and Newfoundland Power management. We made a number of site visits to examine facilities and equipment and to interview personnel directly responsible for their operation.

E. Issues Raised by Stakeholders

The Board's February 19 Order served as the foundation for setting the scope of our work. That order came following a great deal of information provided by stakeholders. The February 19 Order generally encompassed stakeholder issues and concerns. We reviewed the contributions that stakeholders have made, in order to assure that our work took cognizance of them. Some will form a focus in the coming work that will lead to the Fall 2014 Report; *e.g.*, post-Muskrat Falls reliability and risk. We will also examine closely the responses of the Board and stakeholders in planning that coming work

F. Liberty's Team

Liberty assembled a team with outstanding levels of experience and capabilities. Each of them 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.

Richard Mazzini reviewed planning and generation issues in the study leading to this Interim Report. Mr. Mazzini holds a B.E.E. (Electrical Engineering) degree from Villanova University and an M.S. degree in Nuclear Engineering from Columbia University. He is a Registered Professional Engineer in Pennsylvania, and is a member of the American Nuclear Society and the Institute of Electrical and Electronic Engineers. He has managed broadly scoped management audits of a number of large electric utilities for Liberty. His broad experience in the electric industry includes very senior positions with a number of global consulting firms. He has assisted many utilities and other energy-related firms in the U.S., Canada, Europe, and the Caribbean. Prior to entering the consulting business in 1995, he had a long career in key management positions at a major Northeast electric utility.

Mr. Mazzini has consulted extensively in the areas of bulk power planning and operations, power procurement (including energy marketing, trading, and risk management), cost management, system reliability, emergency management, strategic business planning, and utility operations. He has considerable experience with electric system reliability, emergency planning and management, and major outage restoration programs and actions. He was responsible for the emergency management elements of a major audit of New York's largest utility in the wake of a number of large-scale outages. His recent work for Liberty includes: (a) leading a project designed to enhance aging electricity system infrastructure to improve reliability, (b) examining generation planning involving both new units and extending the lives of existing lines, (c) evaluating the emergency management functions of a major electric utility operating as part of a holding company, (d) evaluating the appropriateness of major storm costs and their recovery in rates, and (e) reviewing the use of risk management in planning of capital and O&M initiatives and programs for electricity generating units.

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 in the study leading to this Interim 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 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.

Dr. Robert Parente examined transmission planning issues as part of the study leading to this Interim Report. He has examined electric utility management and operations performance at more than five dozen electric utilities in the United States, Belize, Guam, India, London, and Moscow. He holds a number of degrees from the Massachusetts Institute of Technology (MIT): (a) a PhD with a major in systems theory, (b) a professional engineer degree (EE), (c) a master of science degree (M.S.E.E.), and (d) a bachelor of science degree (B.S.E.E.). He was awarded a Professional Designation in Business Management (PDBM) by the University of California Los Angeles (UCLA). He is a registered Professional Engineer in the State of California. He has served as an electrical engineer for General Electric Company, as an MIT instructor of Electrical Engineering, as an assistant engineering professor at UCLA, as corporate planning director for System Development Corporation, and as an electric industry consultant.

Dr. Parente's primary area of focus is electric power supply, in which he has expertise in load research, demand and energy forecasting, integrated resource planning, generation planning, demand-side planning, conservation, load management, and transmission system planning. He holds a patent for a device to study transmission system stability by simulating transmission system transients. He has examined economic dispatch and unit commitment, Supervisory Control and Data Acquisition systems that monitor and remotely control utility transmission equipment, and has reviewed power plant operations and maintenance.

G. Next Steps

We will study and consider the proceedings before the Board involving the issues this report addresses. We will factor them into the plans for conducting the work leading to the Fall 2014 Report. This coming work will address matters with longer-term reliability implications. In particular, the reliability implications of Hydro's system after Muskrat Falls enters service will form a major focus of our coming review. Hydro's structure and organization will as well. Other major focuses will include more in-depth reviews of the Hydro and Newfoundland Power asset management programs, particularly as they concern areas that, while outside those that contributed to the 2013 and 2014 outages, might nevertheless present reliability risks for the longer term.

II. Planning and Supply Issues

A. Introduction

A lack of available generation created the initiating circumstances leading to the rotating outages that started on January 2, 2014. A supply emergency exists when the System Operator ("SO")[2] is, or expects to, become unable to maintain the required balance between the supply of generation and the loads on the system that customer demands impose. When load begins to exceed supply, system frequency declines. A SO may not permit frequency to vary beyond a very narrow range above or below 60 cycles per second ("cps"). As frequency problems arise or become expected, an SO proceeds through a defined check list of actions that seek to maintain the required balance.

Hydro terms the checklist it uses the "generation shortage protocol." When all preceding actions on the checklist fail to restore the required balance, the last alternative calls for lessening the load on the generators by cutting off some customers. Load continues to be reduced until frequency returns to 60 cps, with affected customers restored as soon as possible, while ensuring system stability.

North American electric systems very rarely face this unfortunate scenario. Newfoundland encountered it beginning on January 2, 2014 and extending through January 8th. Other equipment-related events intervening on January 4th produced massive outages across the system. Those other events did not arise from the preceding generation shortages, but they aggravated the situation when they caused the unavailability of a large generating unit (Holyrood Unit 1) for several days.

In analyzing the supply emergency, we examined the events in the following manner:

- Defining the sufficiency of generating reserves
- Reviewing Hydro's supply planning targets
- Determining the status of Hydro generation assets as January 2, 2014 approached
- Assessing the supply-related events of January 2nd and the following days
- Analyzing causes and contributing factors.

B. Generating Reserve Sufficiency

Providing sufficient generation begins with the ability to forecast the amount of load, which involves uncertainty. After determining a forecast, one must also allow for contingencies in the form of unavailable generation. Finally, one must consider the dependability of resources that can exhibit considerable variability. For example, hydro and wind plant outputs will vary according to uncertain factors such as water flow and wind speed.

We discuss the supply planning challenge below, and we address factors such as load forecasting, planning criteria, outage risk, and the broader question of the reliability standards that may be appropriate for today's Newfoundland and Labrador. We do so against a backdrop of

[2] Hydro is the Bulk Power System Operator for the IIS. It has responsibility for maintaining adequate generation and the control of the bulk power system, including supply to Newfoundland Power. In this context, the Newfoundland Power SO is then responsible for the operation of its system from the Hydro delivery points.

increasing customer expectations about service reliability. Such increases comprise a phenomenon we have observed across the industry. There exists no single, universal set of reliability standards, but one clearly needs to avoid the tendency to over-rely on historical notions about customer expectations in changing environments. We also recognize that utilities like Hydro must make difficult decisions and that, when reserves prove insufficient, regardless of whether through dated supply practices or simply misfortune, serious consequences can arise, as witnessed in recent winters in this region. Considering consequences relative to customer expectations plays a central role in examining the sufficiency of supply resources.

C. Hydro's Planning Criteria

Planners generally perform sophisticated probabilistic assessments to guide the determination of reserve requirements. Such assessments seek to calculate the probability of supply-related outages as a function of the amount of reserves. Increasing reserve capacity reduces the probability of supply-related interruptions; lowering reserves produces the opposite effect. Looking at reserve levels in this risk-based manner shows their similarity to purchasing an insurance policy; *i.e.*, increasing reserves reduces outage risk, but at a price.

The amount of supply-related risk that utilities take results from many factors, and can vary. A common North American standard that has emerged seeks to achieve a level of reserves that would place the risk of a supply-related interruption at a 1-in-10 year level. For many decades, Hydro has applied a lower standard, given the significant costs of achieving the higher standard. The standard applied establishes a risk of supply-related interruptions at roughly twice the level common in much of the rest of North America[3].

A second supply-planning criterion that Hydro has used also falls beneath what we have generally seen in our work. We observe, however, that it is less universally applied than the 1-in-10 criterion we have just discussed. This second criterion addresses the weather conditions assumed in estimating future peak loads. Those loads highly correlate to weather. IIS loads peak in the winter, which makes the wind-chill factor the defining variable. The comparatively high penetration of electric heating among IIS electricity customers heightens the impact of this variable.

Hydro establishes this factor by: (a) defining the worst day, in terms of wind-chill, in each year of the 30-year historical period, and then (b) averaging those 30 data points. This average becomes the estimate of future weather used for planning purpose and the peak load associated with that wind-chill becomes the peak forecast. Using an average produces a probability that the estimated peak load will be exceeded 50 percent of the time. Most utilities employ a lower (colder) wind-chill value, in order to reduce the probability that the forecasted peak will be exceeded as a result of colder than "average" worst-day weather.

The result of Hydro's use of these two criteria produces (when compared with most others) a higher probability of supply-related interruptions. This result happens by design. Many past evaluations, including several in the last few years, have deemed this approach to be consistent with industry practice and therefore prudent. We did not evaluate the appropriateness of the

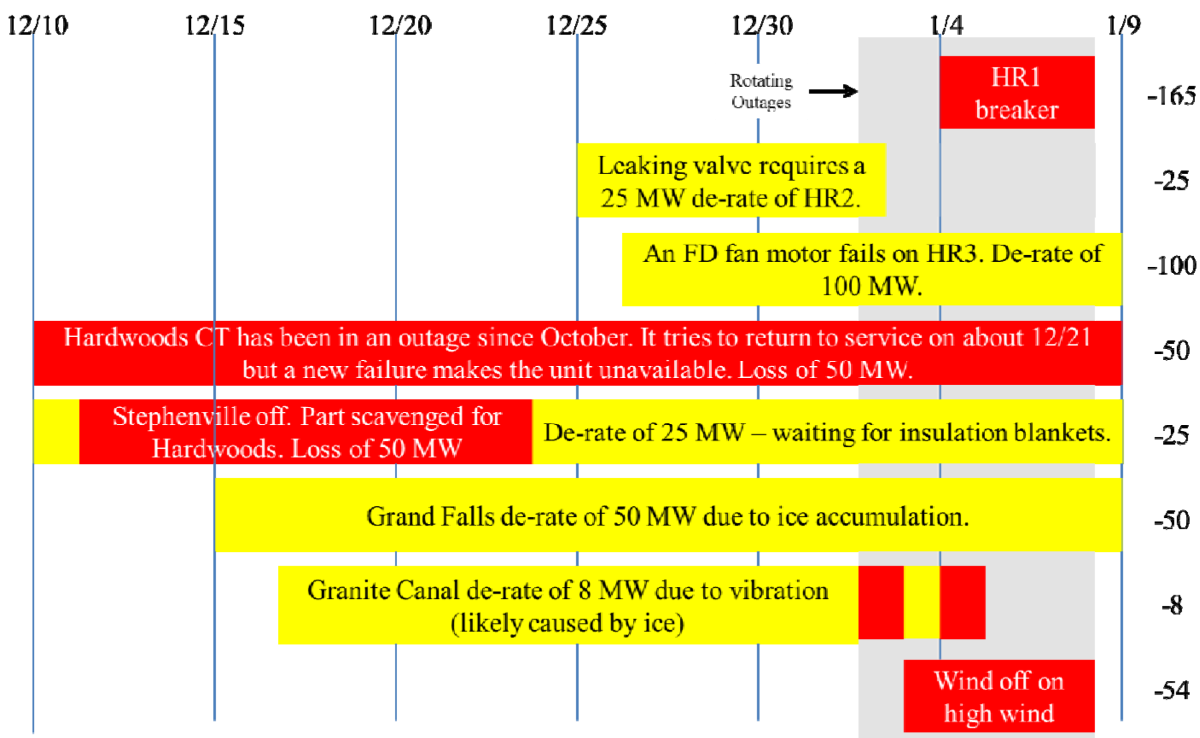
[3] Hydro's March 24, 2014 report, Volume II, Schedule 4, Page 8, Line 5.

standards used in the past, but nonetheless believe that consideration of a change is in order. As discussed below, the supply-planning criteria were indeed a contributing factor to the events of 2014.

D. Status of Hydro's Supply Assets as 2014 Began

Hydro's policy is to have all its supply resources available for the winter by December 1st of each year. Should that goal not be met, the system enters the winter facing a higher degree of vulnerability. Some generating units were unavailable in December 2013. The diagram below shows that both 50 MW combustion turbines ("CTs") at Hardwoods and Stephenville were unavailable (red blocks) in the early part of the month. The Stephenville CT recovered only partially (yellow blocks) just before Christmas. In addition, unusual ice conditions made 58 MW[4] of hydro resources unavailable for the last half of the month. These conditions left Hydro without access to about 133 MW going into Christmas. At about that time, two problems materialized at the Holyrood thermal generating station. A control valve failure (1 of 6) on the Unit 2 turbine led to a 25 MW de-rate,[5] and the failure of a forced draft fan motor (1 of 2) on Holyrood Unit 3 led to a 100 MW de-rate.

Table 2.1: Generation Unavailability Timeline



Note 1: 60 MW interruptible contributed by Corner Brook P&P starting 12/31
Note 2: Grand Falls was operating 25 MW above expectations before the 50 MW reduction

[4] At the time of its interruption, Grand Falls was operating about 25 MW higher than its firm expectation. Hydro thus considers this a net loss of 25 MW, as opposed to the 50 MW loss we have shown.
[5] We will discuss later that a prolonged de-rate is not necessary when one valve fails.

The cumulative effect of these six losses created a highly vulnerable situation. The unavailability of supply resources left Hydro with a very thin margin above expected loads. In such situations, utilities make every effort to get generation back, particularly recognizing vulnerability to adverse weather conditions. Those conditions came to the Island of Newfoundland on January 2.

E. The Events of January 2, 2014

Early on the morning of January 2, 2014, the Hydro SO concluded that it faced a likelihood that rotating outages of customers would prove necessary later in the day. Key people, including Hydro management and the Newfoundland Power SO, were notified. As load moved higher later in the morning, these alerts were repeated. Later in the afternoon, after exhausting all other steps in the generation shortage protocol, the Hydro SO directed the Newfoundland Power SO to begin shedding load, thus disrupting service to Newfoundland Power customers. The interruption of Hydro circuits caused some of its retail customers to lose service as well. Newfoundland Power dropped load until the frequency stabilized at 60 cps. Thereafter, Hydro and Newfoundland Power continued a process of rotating outages. They interrupted some customers, while restoring some previously removed ones, in order to keep loads on Hydro's system at sustainable levels.

The weather deteriorated further across the next few days. Excessively high winds forced the wind units off line. The unavailability of these units cost Hydro a further loss of 54 MW[6]. On January 4th, the equipment-related events discussed elsewhere in this report began. Over the next two days, multiple trips of many units occurred. Hydro generally succeeded in restarting most of them quickly, but Holyrood Unit 1 proved a notable exception. A breaker in the switchyard serving the unit prevented it from starting. Both Holyrood Unit 1 and the wind units returned to service on January 8th. With the weather abating, the immediate capacity problems ameliorated, and the associated rotating outages ended.

F. Analysis of Causes and Contributing Effects

Studies of anomalous conditions that overly focus on the particular event or the equipment, can fail to identify factors that occur over months or even years and that set the stage for the occurrence of those conditions. We therefore examined the conditions of January 2014 broadly. We considered four major areas:

- The underlying priority given to reliability
- Supply planning policies
- Unit unavailability
- Other considerations.

G. Electric System Reliability

The geography of Newfoundland and Labrador poses significant challenges to providing and operating a reliable electric system. The region is blessed with hydro resources, but weather, concentration of load in one area, isolation of the system from the rest of North America, and relatively higher costs to provide high reliability challenge the utilities serving the region in ways that few others face.

[6] Wind turbines become unavailable upon either too low or too high winds.

The planning standard that Hydro applies for supply reliability has existed for more than three decades. We do not question decisions across this long period. We do believe, however, as explained later in this report, that the suitability of continuing to apply this standard merits re-examination. The combination of: (a) rising customer expectations, (b) growing customer needs, (c) the level of supply reserves produced under the old standard, and (d) the lessons of the 2014 supply emergency, indicates that new criteria for reliability may have become appropriate.

While a solution tailored for this particular region should be sought, general experience says that standards for electric reliability throughout North America are rising. The role electricity plays in modern communities has become more critical, and "interconnectedness" continues to be a growing priority. Regulators and utilities have responded with major new programs to minimize storm effects and to maximize service quality. Infrastructure reinforcement and enhancement have become common goals of utilities and those who regulate them, recognizing that achieving those goals will come at a significant cost. Aging infrastructure has diminished as an excuse for declining performance, as it has increased as an impetus for bringing about improvements in service continuity and event response. Network "hardening" and "resiliency" and "storm response" comprise new watchwords for companies, regulators, customers, and other stakeholders examining how to turn talk about infrastructure from "aging" to "effective" and "forward looking."

Recurring bouts of harsh weather on the Island portion of the Province and its strong and increasing dependence on electricity for heat make prolonged electric outages potentially a matter of life and death, as opposed to an inconvenience.

Reliability is easy to understand at a general level, but needs greater definition when it comes to balancing what gains customers can get for what producing them will cost. There are at least three areas to which one might look for improvement:

- Conformance to North American standards, specifically those of the North American Electric Reliability Corporation ("NERC")
- Specific goals for enhanced transmission and distribution reliability performance
- Stricter criteria for defining the amount of generation reserve required.

The wisdom of pursuing a system that can offer higher reliability presents longer-term considerations that make the subject more proper for our Fall 2014 Report. In the meantime, however, we can consider what effect current reliability standards and policies had on the circumstances of January 2014. The tolerance of lower margins in terms of reserves produces a system that will be, by design, more vulnerable to supply shortages similar to those seen in 2014.

We did not find a careless utility attitude about reliability. The personnel with whom we spent time in producing this report fully share the North American industry's healthy priority on "keeping the lights on." That priority shows in the extraordinary efforts of those charged with responding to emergencies, when service must be restored under the worst conditions. We observed no difference between electric utility service workers in this region, as compared with what we have seen elsewhere, when it comes to a sense of urgency, dedication, and personal responsibility.

Nevertheless, it was clear to Liberty that the Hydro system differs at the "front end" when it comes to emergencies; *i.e.*, in designing into the system an enhanced ability to withstand adverse conditions. We understand the notion that particularly extreme weather is the enemy of reliability. We also take cognizance of the limitations of the IIS, where multiple under-frequency interruptions are not considered unusual, although that is a phenomenon we have not typically seen elsewhere.[7] We also recognize that reliability comes at a cost, whose balance with affordability requires an answer unique to the IIS. We also recognize that repetition of off-normal events can be seen as tending to produce matching (*i.e.*, reduced) expectations to which some have become accustomed. Whatever the underlying causes, Hydro plans its system with a higher expectation for interruptions than we have seen elsewhere.

H. Supply Planning Policies

Our second "standards" observation relates to the adequacy of reserves. In this regard, we found at Hydro:

- A design frequency of supply-related interruptions of roughly twice that of other locations
- The calculation of reserve adequacy to meet an "average" worst winter day
- Past planning practices that have tended to allow decisions at the margin to favor more versus less reliability risk.

An example of this third finding is that Hydro has forecasted supply deficiencies in the recent past (for example in 2012). Nevertheless, favorable variances between forecasted and actual circumstances enabled Hydro to avoid taking action on them, without suffering adverse consequences. Forecasted new load failed to materialize, thus eliminating the previously predicted 2012 deficiency. Not spending money to increase reserves has saved money. The favorable gaps between forecasts and actual conditions may still be influencing decisions. One must not forget, however, (just as in purchasing insurance) that the failure of an insured event to materialize does not make paying the premium unreasonable.

The key concept that needs to remain in focus is "risk." Not just the third of the above factors, but all three, increase risk. One could argue that the events of 2014 were abnormal, exceptional, and maybe even unfortunate. Whether so or not, those attributes do not necessarily place such events outside of the range of outcomes for which a utility should plan. In this sense, one cannot term them "unexpected." In fact, a 2015 supply deficit has been forecast by Hydro since 2012, and the 2014 forecast barely missed being classified as a deficit.[8] Hydro has elected to operate rather close to the edge, which raises the risk of adverse outcomes.

In summary, we found that Hydro's practices vis-à-vis reliability standards did influence the supply conditions that contributed to the January 2014 interruptions, indirectly through a culture

[7] Because of system limitations, the IIS cannot ride through a significant perturbation, such as the loss of a large (50 MW) unit. Larger systems generally recover immediately from such events but on the IIS, frequency drops to the extent that automatic load shedding occurs. This happens perhaps six times per year, but that number has already been exceeded in 2014.

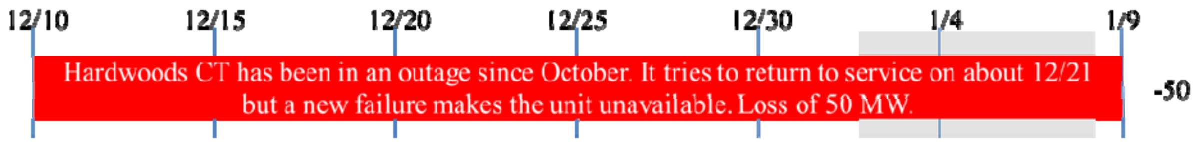
[8] Hydro's criterion for loss of load hours (LOLH) is 2.80. The forecast for 2014 was lower but not by much at 2.59. The forecast for 2015 is 3.98, which exceeds the planning basis. More importantly, the resulting 2014 and 2015 capacity reserves were only 12% and 10% respectively.

more tolerant of rotating outages and directly through the long-established reserve criteria and how the company has implemented them.

I. Analysis of Unit Unavailability

This report section discusses the circumstances of each unit as they contributed to the lack of reserve capacity. We treat them in the chronological order in which their availability became an issue.

1. The Hardwoods Combustion Turbine



Hydro learned in early 2013 that the Hardwoods 50 MW CT required major work. Hydro concluded that an outage at Holyrood generating station made it inappropriate to take the Hardwoods CT outage in the summer. Hydro therefore decided to schedule the Hardwoods CT outage in the fourth quarter, with an expected return to service by December 19, 2013.

Hydro recognized that this scheduling was not in conformance with its policy requiring that all generation be available by December 1 to serve winter loads. Hydro determined that it could not take the outage sooner. The dangerous condition of the machine and the desire to have it available for the heart of the 2013/2014 winter peak season caused Hydro to reject a deferral of the outage into the spring of 2014.

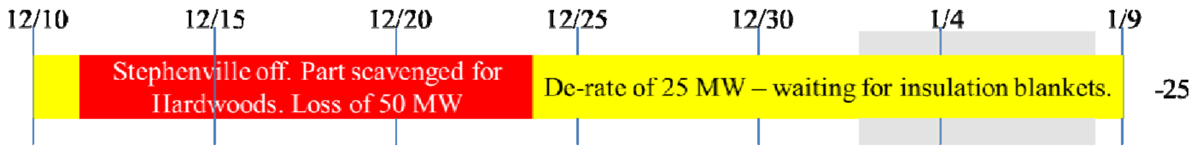
The Hardwoods outage proceeded according to schedule, and the unit entered startup on December 19th, as planned. The fuel control valve failed during testing on December 21st. Hydro had no spare valve. Moreover, a key vendor representative had left for the holidays, given the presumed completion of the work. The Hardwoods CT outage consequently continued into January, making its full 50 MW unavailable for the duration of the early January customer disruptions.

We formed two key observations from these circumstances. First, real and substantial needs drive the December 1 deadline. Every third winter or so, Hydro's winter peak occurs in December. Entering the month with a unit in a planned outage thus adds risk. Hydro's characterization of the scheduled completion date of December 19 as "well before the winter" [9] does not comport with the frequency of winter peaks in December. It also calls into question the degree to which Hydro is committed to December 1 as a meaningful deadline.

The second issue is a resource one. Work on the Hardwoods CT outage was not fully closed out and Hydro was already operating with a thin reserve margin. Failing to require the presence of personnel critical to getting the unit back on line, even recognizing the holiday season, created avoidable risk. The resulting unavailability of Hardwoods' 50 MW in early January contributed to the inability to maintain service in the first days of that month.

[9] Hydro's March 24, 2014 report, Schedule 5, Page 31.

2. The Stephenville Combustion Turbine

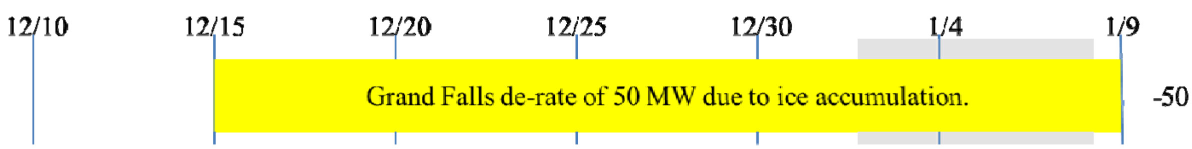


The Stephenville CT is a sister unit to the Hardwoods CT. This unit experienced a 20-month forced outage that ended in the summer of 2013. The unit returned to service in a debilitated state; *i.e.*, the insulating blankets on one end were worn to a degree that would not support acceptable temperature levels. It is not clear why Hydro did not address blanket condition during the 20-month outage.

Work on procuring new blankets began on the unit's return to service in the summer of 2013. Hydro did not, however, solicit bids for them until October 2013. Hydro learned through the solicitation process that the supplier offering the best evaluated proposal could not meet the schedule. Another supplier then offered a more supportive schedule, but it still could not meet the December 1 deadline associated with winter season availability. As a consequence of the delay in procurement associated with the blankets, a de-rate at the Stephenville CT made half of its 50 MW capacity unavailable into early January 2014. The unit then suffered an engine failure afterwards. Hydro placed a borrowed engine in the machine, where it still remains. Hydro has yet to provide for the installation of the blankets. The unit remains de-rated at this writing.

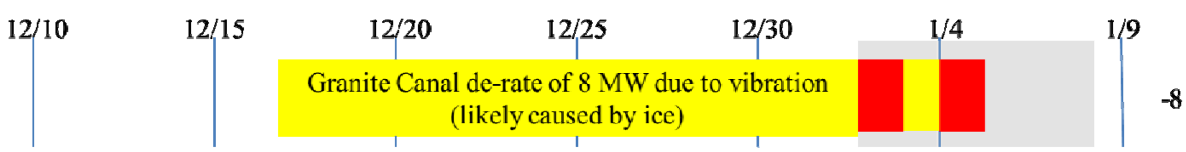
The failure to deal with the blankets, first during the 20-month outage and second with a delayed procurement process, did not demonstrate sufficient concern with respect to the December 1 deadline, and became a contributor to the outage events of 2014.

3. The Grand Falls Hydro Unit



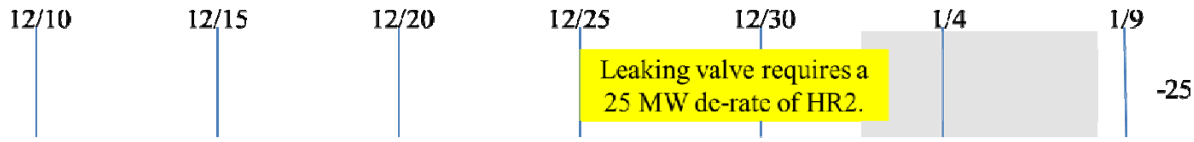
The Grand Falls hydro unit was de-rated from its normal 63 MW capacity by a nominal 25 MW, due to the accumulation of ice in mid-December. This de-rate remained throughout the early January outages. The unit had been running 25 MW above its expected output, however, thus making the loss 50 MW from the unit's then-operating level.

4. The Granite Canal Hydro Unit



The Granite Canal unit is a 40 MW hydro facility that was de-rated in mid-December 2013. This 8 MW de-rate resulted from vibration issues, probably stemming from ice. Over a three day period at the start of rotating outages, the unit tripped, returned to a de-rated state, and then tripped again. When restarted again on January 5th, the unit was able to run at full output.

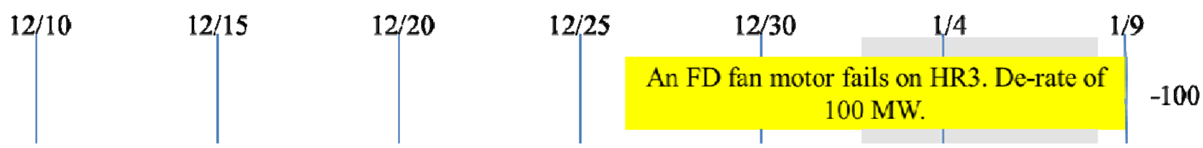
5. Holyrood Unit 2



Holyrood Unit 2 is a 170 MW oil-fired unit. A control valve on the Unit 2 turbine failed on December 25, 2013. The valve's failure caused a de-rate of 25 MW. All three Holyrood units have experienced similar failures in recent years, at which times Hydro has replaced the failed valves with a superior material. Each turbine employs six such valves. Each unit can produce full steam flow with one of the six valves unavailable. Maintaining full flow, however, requires certain steps. They include: (a) determination that it is appropriate to run the other valves further open, followed by (b) implementation of a software instruction to allow this valve operating condition. Hydro has successfully used this five-valve approach in the past, but was slow in implementing it in December 2013. An inability to obtain vendor support over the holidays for the software fix further complicated efforts.

Hydro succeeded in effectuating the process on January 3rd, at which time Unit 2 returned to full output. The de-rate thus lasted for eight days.

6. Holyrood Unit 3



Holyrood Unit 3 is a 150 MW oil-fired unit. The largest capacity loss (100 MW) during the supply emergency occurred on Holyrood Unit 3 when one of the two motors that drive forced draft ("FD") fans failed. There was no spare for the subject motor. Hydro expedited repair of the failed motor, but could not complete it during the early January rotating outages.

7. Wind Turbines

On January 3rd, high winds forced the tripping of the wind turbines, which caused a loss of 54 MW. Hydro explains that the bad weather contributed to access problems. The units could not be restored until January 8th.

8. Holyrood Unit 1

A breaker malfunction on January 4th tripped Holyrood Unit 1, and precluded getting it back on line. The other Holyrood units tripped and re-started multiple times, but Unit 1 remained unavailable until January 8th, because of that same breaker.

J. Common Themes

We examined the events surrounding generation unavailability to identify any possible common causes. We observed the following common elements:

- Some CT units (Hardwoods and Stephenville) were in a degraded state, or offline altogether, entering the winter season. This status contravenes Hydro's objectives. There exists a sound basis for the December 1 planning deadline and it deserves respect. Competing priorities will at times require compromise, but circumstances indicate that Hydro should give more weight to the deadline in balancing priorities.
- Support from vendors was not optimum and key people were unavailable during the holidays. Support personnel should not be released unless it is certain they will no longer be needed, especially when getting them back expeditiously is prone to problems. In addition, Hydro's priorities need to be communicated effectively to vendors, who need to fully understand and remain responsive to needs for timely support.

K. Other Considerations

Several other considerations deserve mention in this Interim Report, even though we will address most of them further in the work leading to our Fall 2014 Report:

- Maintenance practices
- Short-term load forecast
- Staffing
- Black start capability
- Fuel quality.

1. Generation Asset Maintenance Practices

Hydro has been aggressive in recent years in reviewing its maintenance practices. These reviews have not produced large-scale changes. Hydro's effort nevertheless has been substantial and of value, at least in terms of program scope and design. The commitment to new and extensive approaches to asset management triggered many studies, including structured condition assessments, definition of critical components, evaluation of critical spares, and well-defined preventative maintenance (PM) processes. The degree to which Hydro's efforts have been translated into effective field implementation activities and resulting improved equipment reliability will be evaluated in our Fall 2014 Report.

In the meantime, we have concerns with the timeliness of maintenance. For example, each of the two CTs had significant work remaining at December 1. Moreover, both were either de-rated or off-line altogether for the duration of the January 2014 events. With the exception of the timeliness question, there was no direct tie apparent between generation maintenance practices and the supply shortages associated with the 2014 outages.

Holyrood Unit 2 preventive maintenance activities (“PMs”) were restricted by the inability to schedule the unit for its full planned outage in 2013. The restrictions resulted from: (a) the prolonged Unit 1 outage associated with the damage to the unit during the January 2013 events, and (b) the scheduling of the Hardwoods CT outage, with a planned completion around December 19. It is not apparent that the missed PMs contributed to the events. Nevertheless, given the criticality of the Holyrood units in coming years, it is essential to limit the risks that deferred PMs create.

2. Short-term Load Forecast

Hydro uses a predictive tool known as Nostradamus (supplied by Ventyx) to predict hourly load for the next seven days. These forecasts play an important role in scheduling generation to serve anticipated loads. Hydro updates the Nostradamus forecast five times per day. Nostradamus operates as a neural network, which enables it to refine its predictive capabilities based on actual experience. In discussions with Liberty, Hydro voiced satisfaction with Nostradamus. However, Hydro’s March 2014 report on Load Forecasting offered a different assessment: [10]

> *System Operations is evaluating an upgrade to the version of the Nostradamus software that it uses for load forecasting, but there have been ongoing difficulties, especially with intraday forecasts. If these issues cannot be resolved with the existing software, new software should be considered.*

Hydro indicated in the same report that a more accurate forecast would not have prevented the supply disruptions, but may have been beneficial in managing the rolling outages. We agree with both conclusions, but consider the second portion to be understated. During normal operations, variations in the short-term forecast have little impact, but at times of system stress, it is critical for the system operator to have the best information possible, in order to guide operating decisions and to inform others, including the public and other stakeholders, of the nature, magnitude, and likely duration of an emergency. One can reasonably conclude that inaccuracies in the short-term load forecast made management of the emergency more difficult.

Hydro identified a second short-term load forecasting issue. Because of the configuration of generation resources, especially the loss of Hardwoods CT, system losses were 30-40 MW higher than anticipated. This differential affected the magnitude of the event, although it was more an effect of the supply shortage rather than a cause.

3. Staffing

Staffing clearly presents challenges for Hydro. Retention of top people is difficult across eastern Canada, with competition for resources from central and western Canada. The plan to shut down Holyrood generating station in the intermediate term increases the challenges at this plant.

[10] Hydro’s March 2014 report on Load Forecasting, Page 17, Line 3.

Management has dealt with the challenge through a number of initiatives, which include assurance of long-term positions for grandfathered employees and retaining any new employees only on a term basis.

There are indications that capital program staffing availability constrained 2013 construction efforts. The heavy capital workload may also have influenced the availability of people for maintenance projects. As a result, staffing will comprise a high priority in our analysis leading to the Fall 2014 Report.

4. Black Start Capability

The capability to re-start the Holyrood units after the plant becomes totally separated from the system has been a matter of concern. Black start capability, which provides auxiliary power when the station is isolated from the grid, allows the Holyrood generating station to help re-establish the system after a blackout. Black start capability also allows the Holyrood station to remain in a ready condition that avoids further time loss until the system is again ready to receive output. This latter objective has proven especially important at Holyrood generating station in recent years. Black start capability was originally provided for but neither the original capability, nor subsequent substitutes, were able to respond when needed.

It is appropriate to question how the lack of black start capability at the Holyrood generating station may have affected the events of January 2013 and January 2014, when all three Holyrood units tripped. If Unit 2 or 3[11] was unable to be maintained in a warm condition due to the lack of auxiliary power, then subsequent restart of the units would be delayed. The reason is that the units would have to go through a warming cycle. Such a delay did occur during the January 2013 events. It happened again in January 2014, but did not contribute significantly to events at this time.

After receiving approval in late 2013, Hydro leased eight trailer-mounted diesel generators, each supplying two MW. These units cannot be connected until the next Unit 1 outage. In the longer term, a new CT proposed for Holyrood generating station remains the preferred black start solution.

5. Fuel Quality

The question of the contribution that fuel quality may have made to the January 2014 events as they involve Holyrood has been raised. Holyrood generating station did experience fuel problems in 2013. Delivered fuel contained relatively high levels of alumina and silicate. Hydro observed these conditions following the first shipment from a new supplier, when equipment began to plug. Hydro observed plugging problems all along the fuel path, from tanks to the burner tip.

The significant work required to correct the plugging caused considerable cleanup costs. Hydro developed a new fuel specification to address alumina and silicate content. The vendor has since

[11] Recall that Unit 1 was unable to restart in 2013 due to turbine damage and in 2014 due to the malfunctioning breaker.

followed it. It therefore appears that this problem was largely resolved by the start of the winter season in December 2013, and did not contribute to loss of capacity at that time.

Liberty has not identified a nexus between these fuel issues and the capacity circumstances in early January of 2014. Moreover, the causes of Holyrood generating station unavailability described above (Unit 1 breaker, Unit 2 turbine valve, and Unit 3 FD fan motor) are not related to fuel. Accordingly, in the absence of any further evidence, we conclude that the fuel problems of 2013 did not bear on the events of January 2014.

L. Conclusions and Near-Term Actions

1. Summary

Our analysis of the supply situation indicates the need for important initiatives to mitigate the chances of a repeat of the supply-related events of 2014. We discuss that analysis below and offer specific recommendations for mitigation.

First, Hydro's current supply situation creates too high an exposure to supply-related interruptions in the years prior to the completion of Muskrat Falls. The opportunities for significant mitigation of this risk are limited. Nevertheless, an aggressive three-pronged approach of: (a) new supply, (b) reduced load (*e.g.*, via interruptibles), and (c) initiatives to assure greater generator availability should be implemented over the next six months.

Second, it is time to revisit the long-established criterion of 2.8 LOLH, as it is currently constructed, in order to determine whether a more typical standard has become appropriate for the IIS, and should be implemented in a manner that will mitigate present supply problems.

Third, planning for supply on the basis of the average worst annual weather in a 30-year period is not appropriate for determining future supply needs. The failure to consider more extreme weather underestimates the risk of near-term supply-related reliability issues.

Fourth, the forecasted 2014 winter peak was exceeded in all four months of the winter season. This result represented an unprecedented development for Hydro's load forecasting process, especially given the near-average weather.

In ensuring the adequacy of supply over the next several years, two fundamental goals predominate:

- Having a suitable reserve capacity in terms of generation and load reduction
- Assuring that such capacity will be available when called upon to operate.

This Interim Report addresses both goals across the pre-Muskrat Falls time window, which will encompass at least the winters of 2015-2017, and later if the project is delayed.

We discussed earlier how supply decisions have been made in the past and how they influenced the events of 2014. This section examines the various elements of supply planning and the degree to which they might be modified to ensure adequate supply in the years ahead.

2. Load Forecasting

Three load forecasts have importance in planning and managing the electric system. First, the ***Short-term Forecast*** looks at the next seven days. It predicts hourly load, and gets updated five times per day. This forecast has significance in the January 2014 events for two reasons:

- Errors in the model (Nostradamus) during periods of cold weather
- An unexpected 30-40 MW additional load that materialized due to higher system losses resulting from the configuration of supply resources.

Both circumstances hamper Hydro's ability to manage during an emergency, and to communicate with others, including Newfoundland Power and customers. Accordingly, both should be repaired before the coming winter.

We recommend that:

1. **Hydro should complete the modifications or replacement of Nostradamus by December 1, 2014 in order to enable improvements in the accuracy of short-term forecasts under extreme weather conditions.**
2. **By December 1, 2014, Hydro should incorporate into its short-term forecasting process any significant load changes, from losses or otherwise, resulting from varying system configurations.**

The ***Medium-term Forecast***, also termed the operating forecast or OPLF, covers five years and consists of monthly data. Hydro prepares the medium-term forecast, but much of the data comes from Newfoundland Power. Hydro adds its industrial and rural customer loads to the Newfoundland Power forecast to arrive at a Hydro system forecast. Hydro then makes adjustments to produce a coincident peak.

Newfoundland Power uses an econometric model to forecast energy, and then calculates the peak by applying the normalized load factor, as averaged over the last 15 years. Annual normalized load factors are adjusted for any prior curtailments. Planning assumes this peak to occur in January. The actual peak, however, can occur any time after December 1. Hydro adjusts the other months according to their historical relationship to January.

The peak forecast uses the expected coldest wind-chill day. That value is calculated as the average worst annual day from the past 30 years, suggesting that this wind-chill will be exceeded in half of the years addressed by the forecast. Current industry practice is to use a colder day than the average, and this is especially critical where, as is the case for Hydro, supply is expected to be tight. Hydro reports that the use of a P90 forecast, which would be exceeded only one year in ten, would increase the peak forecast by 57 MW[12].

Hydro's "current planning practice relies on system reserve capacity to meet these extreme weather conditions."[13] This practice finds more support where utilities use a more conservative criterion that produces higher reserve levels. That is not the case on the IIS. Thus, we consider it

[12] Hydro's application to "Supply and Install 100 MW (Nominal) of Combustion Turbine Generation," page 24.
[13] March 2014 Load Forecasting report, Page 9, Line 10.

necessary to consider temperature risk explicitly in establishing reserves. Hydro, as its consultant Ventyx has recommended, has accepted this requirement. Hydro plans to implement it, at least in the near-term, via sensitivity analysis (which is the derivation of the 57 MW increase cited immediately above).

We concur that sensitivity analysis comprises an appropriate interim measure for assuring robust consideration of the impact of a worse than average "bad" winter day. We believe, however, that the long-term solution should assume a more conservative value for the temperature variable, such as P80 or P90. Sensitivity analysis will remain appropriate, but it should take place around the new forecast standard. Hydro would continue to use the P50 estimate for this purpose.

We recommend that:

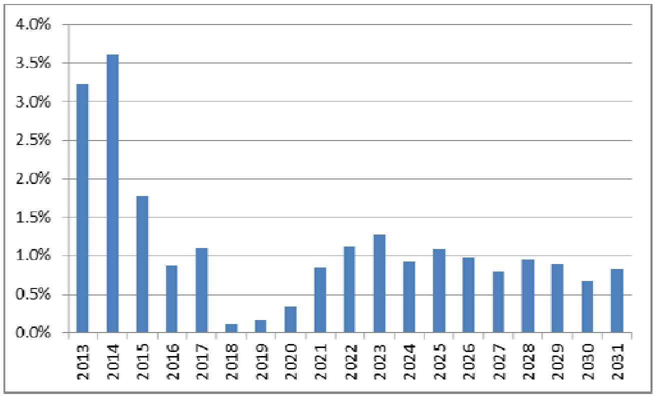
3. **In the interim, Hydro should implement the Ventyx recommendation to consider weather extremes via sensitivity analysis in all forecasting and supply planning evaluations and decisions.**
4. **By September 1, 2014, Hydro should: (a) evaluate and reach resolution on a formal change to the planning process to use a greater than 50 percent probability weather variable, (b) propose that criterion to the Board for use in future capacity decisions, and (c) continue to conduct sensitivity analysis for extreme weather, but around the new weather variable.**

The ***Long-term Forecast***, also known as the planning forecast, or PLF, covers the next 20 years. Hydro prepares it annually. The forecast considers Hydro's assessment of customer growth and industrial customer expectations for their future load. Its primary use is to assure adequate investment to meet long-term customer needs.

The PLF has a long-term nature. We will address it further in our Fall 2014 Report. Its significance for this Interim Report lies in its use by Hydro for the current near-term capacity planning and reserve assessments. The latest PLF dates to November 2012, which seems unusual given the pending deficit condition. Hydro indicates, however, that the 2012 forecast remains valid today.

Table 2.2 below shows the annual growth in the forecast for peak demand on the IIS. The less than one percent per year growth predicted after 2015 appears low, but is consistent with most forecasts in North America, including those of Canada's National Energy Board ("NEB") and the US Energy Information Administration ("EIA"). The rapid growth of electric heating by customers on the IIS might suggest higher growth, but that is apparently offset by other factors in the forecast model. The higher values in the early years represent anticipated industrial growth, particularly the Vale facility.

Table 2.2: IIS Peak Demand Forecasts

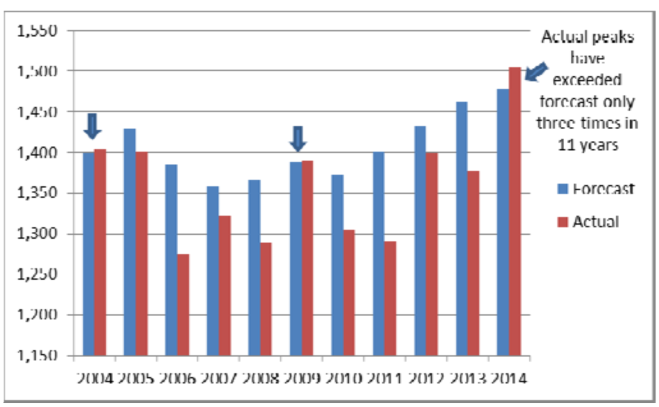


This Interim Report primarily focuses only on the next few years. Table 2.3 below shows forecasted peaks for these years. The actual peak for 2014 exceeded the forecast by 31 MW, or 2.1 percent (see Table 2.4). This variance is relatively small. Any overage at all, however, runs contrary to the long pattern of not exceeding forecasts. This result occurred three times in the last 11 years, and by a very narrow margin (less than a half of a percent) as illustrated in Table 2.4 below.

Table 2.3: Forecasted Peak Loads

	Hydro	IIS
2014	*1,509A*	*1,713A*
2014	1,478	1,691
2015	1,523	1,721
2016	1,543	1,736
2017	1,567	1,755

Table 2.4: Forecasted versus Actual Peak Loads



Given that experience, the overage in 2014 becomes more interesting. A similar analysis for Hydro by Ventyx notes that actual load exceeded the applicable forecast in only seven winter months out of 40 (or six in 39 if December 2013 is excluded).[14] A monthly analysis can prove

[14] Ventyx report based on data in PUB-NLH-011.

misleading. Monthly forecasts have far less significance than the annual peak. Hydro assumes the peak to occur in January, with the other months reduced by their historical proportions. It thus becomes more meaningful to examine the months in which the winter forecast, as opposed to the monthly forecast, was exceeded. That result occurred only twice in 39 months before the winter of 2014. One of those rare occurrences was by two MW.

We therefore observe that, given Hydro's forecasting process and its historical record, it is unusual to exceed the annual forecasted peak in any month. Against that backdrop, data from the winter of 2014 (shown in Table 2.5 below) becomes interesting.

Table 2.5: Winter 2014 Dates of Interest

Date	Peak MW	Notes
Forecast	1,478	
Dec. 4	1,501	A new peak very early in the season
Jan. 2	1,492	Rotating outages
Jan. 3	1,535	Rotating outages – adjusted to about 1,510
Feb. 10	1,509	Official 2014 peak
Mar. 4-7	1,482	Requests for conservation

Actual load exceeded the forecast in all four months, which is out of character with historical experience. This result makes it proper to examine whether factor(s) common to all four months may have driven the atypical experience. For example, one might question whether the unexpected higher system losses discussed above have persisted all winter and produced peaks 30-40 MW higher than expected.

Hydro seems to have ruled out weather as a common cause, because historically extreme conditions did not accompany any of the peaks. To the extent that the theorized common factor will influence future forecasts and necessitate changes in Hydro's modelling and forecasting processes, it needs to be understood. Coincidence, rather than a new common factor requiring analysis, may well be the cause. That conclusion, however, should only result after ruling out the common cause scenario. Accordingly, Hydro needs to conduct additional work to analyze why actual peaks in all four months managed to exceed the forecast, particularly given near-normal weather.

Table 2.5 above includes days that experienced rotating outages and conservation requests. We find the January 3 peak especially notable, although Hydro believes it is artificial and attributable to cold load pickup (as interrupted customers were returned to service). Hydro does not use defined methods for normalizing such events, but indicates that a rough estimate would place the equivalent peak at about 1,510 MW. This load is about the same as the "official" peak reached on February 10. The actual peak in March 2014 was likely artificially depressed due to several days of conservation requests. Hydro does not have a sound estimate of what peak might have occurred then, on a basis that would adjust for the effects of such requests.

We would ordinarily view this as a comparatively minor issue; *i.e.*, one not likely to have a significant effect on future forecasts. However, the fact that unusual events may currently play a role in Hydro's circumstances makes analysis of what may have happened more important. We recognize the complexity in reconstructing load under such circumstances, but nonetheless consider it appropriate to make a greater effort to devise reliable methods.

We have not yet seen the 2014 peaks on a weather-normalized basis. Hydro has pointed out, however, that the peak day weather was not extreme on an historical basis. Therefore, the peak could have been considerably higher had it occurred, for example, on a P90 day. This possibility has special significance in considering the likelihood that the forecasted peaks in 2015-17 might be achieved or exceeded.

Finally, we observed that most data reported by Hydro, including all of the Request For Information responses as well as the March 24, 2014 filing, were given on a "Hydro system" only basis. For practical purposes, the load and supply of the Hydro system alone does not provide a useful basis for assessing reliability. Capacity and load on the IIS would have more significance. The difference (about 200 MW) between the two arises from customer-owned generation, including Newfoundland Power and Corner Brook Pulp & Paper Ltd. Hydro advises that it will assure consistency by focusing on IIS capacity and load in future analyses. We view this change as appropriate.

We are encouraged that, on an absolute basis, the actual peak deviations reached in the troublesome winter of 2014 were not extreme with respect to the forecast. Relative to history, however, something proved very different. The reason for that difference is not yet apparent, which creates new uncertainties going forward.

We recommend that:

5. **Before December 1, 2014, Hydro should: (a) re-evaluate the deviations between its forecasted winter peak and the multiple times it was exceeded during the winter of 2014, and (b) determine what, if any, common factors were responsible and what changes, if any, they suggest for the forecasting process.**
6. **Before September 1, 2014, Hydro should: (a) strengthen its ability to reconstruct the peak load when peaks have been significantly affected by artificial means such as those employed by the generation shortage protocol, and (b) use those improved techniques in the recommended evaluation of 2014 forecast deviations.**
7. **Hydro should follow through on its plans to assure consistency in future reliability analyses by focusing on the IIS, as opposed to the Hydro system alone.**

3. Reliability Standards

Utilities use probabilistic models to estimate the amount of generating reserves required. Such models start with the peak load forecast, and determine the chances that suitable generation will be available to serve that load. The model, using assumed forced outage rates for all of the equipment, calculates a "loss of load probability" ("LOLP"). North American utilities commonly target a one chance in ten years probability[15]. Other models, such as that used by Hydro,

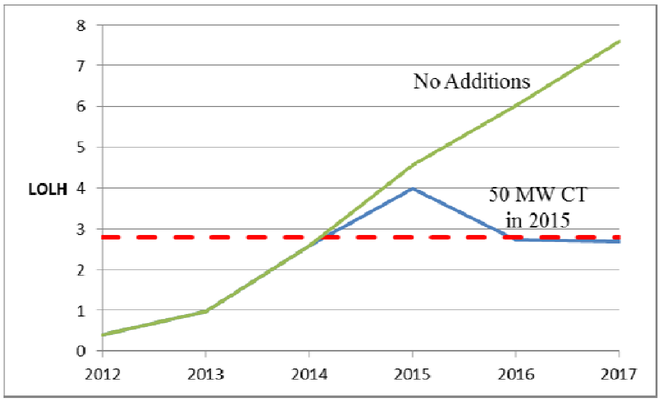
[15] Hydro correctly observes that the North American utilities we cite as "typical" are interconnected, and that "stand alone" utilities like it face higher costs to achieve similar supply-reliability goals. Simply stated, utilities that can depend on their neighbors for the sharing of reserves will require fewer of their own reserves.

calculate a loss of load hours (LOLH). The target LOLH used by Hydro is 2.8, which equates approximately to a one chance in five years of a supply-related interruption.

Hydro has offered several reviews by consulting firms in support of its belief that its criterion conforms to industry standards. There are several reasons today why we consider this no longer to be true. First is the backdrop of rising customer expectations in the industry, which calls into question whether reliability here should differ significantly from other North American communities. Second, the events of 2014, and the conditions likely for 2015-17, demonstrate the risks involved in borderline adherence to a 2.8 LOLH. Third, the resulting reserve margins, as will be discussed below, are low.

Table 2.6 below shows where Hydro stands versus the 2.8 criterion. The estimate for 2014 showed a marginal situation – – one that did not turn out well. Capacity deficits escalate sharply from now, producing an over-the-target and growing LOLH pending arrival of Muskrat Falls.

Table 2.6: LOLH versus 2.8 Criterion



Hydro complied with its standard, but the risks that produced the supply shortage of January 2014 remain, and they will grow in the next few years. Nevertheless, we observe that current circumstances make the standard, whether it continues to be appropriate or not, a secondary issue for the next several years. The options available to meet a more typical North American standard are not practical from a timing perspective. This does not mean that improving reliability in the 2015-2017 windows should not be a first priority. It simply means that only a limited amount of actions are available. Even in the longer term, the standard may not become a central question for some time, should the arrival of Muskrat Falls, planned for 2017 cause the LOLH to drop precipitously,[16] and remain low for a number of years.

Ventyx has recommended that Hydro revisit its reliability criterion after Muskrat Falls. Hydro agrees. This recommendation makes sense, but fails to address the importance of aggressive actions to improve supply reliability now, to the extent possible and practical. All of the mitigating actions that are practical need to be implemented as soon as possible.

We recommend that:

[16] This conclusion applies to supply-related reliability. The effect of the associated transmission on overall system reliability is another topic for later study.

8. **For the near-term, Hydro should abandon the LOLH of 2.8 criterion, and the associated low reserve requirements, in favor of an "as low as practical" objective.**
9. **For the long-term, Hydro should evaluate, taking account of stakeholder input a new supply reliability criterion with a logically associated level of reserves, and seek Board concurrence to use that criterion as a basis for long-term supply planning.**

4. Generation Availability

Generation availability was the cause of the rotating outages that began on January 4, 2014. Within the context of the reliability criterion, this factor raises the question of whether availability will be greater or lesser in the years ahead.

First we considered how generation availability relates to applying Hydro's current reliability criterion (an LOLH of 2.8 hours per year). Hydro's modeling tests the availability of generation as it calculates results. A unit's forced-outage rate sets the probability that it will be unavailable. The larger units have primary importance in this calculation, with smaller units making a much smaller contribution. Accordingly, the key focus turns to Holyrood generating station's three units and the two CTs at the Hardwoods and Stephenville terminal stations. The larger hydro units also have importance, but their forced outage rates fall far lower than those of the thermal units. Therefore, their outages make only limited contribution to the results.[17]

A lower reliability for the thermal units in the future would cause the LOLH calculation to rise. For example, increasing the Holyrood generating station forced outage rates to 12 percent (from the roughly 10 percent Hydro now uses) and those of the CTs to 20 percent (from 10 percent currently) would nearly double the LOLH. This sensitivity shows the criticality of the assumed availability of certain units in Hydro's reliability calculation. In particular, the forced outage rate when the units are needed (during the winter peak season) should be the focus. An all-in rate for the whole year is not material.

In considering the viability of the 2.8 estimate, testing the validity of assumed forced outage rates of the thermal units has first importance. Holyrood generating station has not performed strongly in the last two years. We consider using a 10 percent forced outage rate for its units too low for use under the circumstances. Similar units (100 – 200 MW oil-fired) in North America have experienced a major decline in reliability in recent years, sliding steadily from a 6 to 14 percent forced outage rate over the 2007-2011 timeframe.[18] We recognize that utilities use and maintain this group of units differently. It would not be appropriate to impose simple industry "averages" for the Holyrood generating station without considering the circumstances here.

CT forced outage rates raise different concerns. The CTs tend to run infrequently and failure to start in the first place comprises one of their principal availability concerns. Over a five-year period, Hydro has found its CTs unavailable when needed more than a quarter of the time. Also, the Stephenville CT has been unavailable or in a reduced output condition for more than two

[17] For example, the assumed forced outage rate for Bay d'Espoir is less than 1 percent, compared to about 10 percent for the thermal units.
[18] NERC's Generator Availability Data System (GADS).

years. These factors make it insufficiently conservative to place a high degree of trust in the availability of these units. We consider the assumed 10 percent forced outage rate in Hydro's modeling to be problematic.

The Ventyx analysis of forced outage rates focused on Holyrood generating station and Bay d'Espoir, because of their size. That analysis did not consider the CTs, because they have less impact on reliability.[19] With the exception of Unit 7, the Bay d'Espoir units are not much bigger than the CTs. Moreover, CTs are 10-20 times less reliable than those hydro units. Accordingly, we believe that Hydro needs to test the validity of excluding the CTs from the analysis.

It remains critical for Hydro to adopt an aggressive set of initiatives to maximize unit availability over the next few winters, in order to ameliorate the risk of generation unavailability during peak load conditions.

Liberty recommends that:

10. **By June 15, 2014, Hydro should formalize its established plan to implement an aggressive availability improvement program focused on all generating assets, especially focusing on the Holyrood units and the two CTs.**
11. **Hydro should formalize its maintenance program for Holyrood generating station and the CTs in a submittal to the Board by June 15, 2014, covering the period through November 30, 2014, with the submittal to include, at least: (a) a listing of all key maintenance activities planned for each unit, (b) a critical path schedule for each planned outage of a unit including major work items, (c) a sequencing plan for planned outages showing the relationships among planned outages and how, if at all, an outage at one unit restrains an outage at another, and (d) bulk production curves for maintenance activities at each unit by number of work orders or whatever measure Hydro finds preferable.**
12. **Hydro should formalize by June 15, 2014, a generation master plan for winter preparation, including the above availability improvement activities and tasks addressing emergency preparedness.**
13. **Hydro should, on a monthly basis, and starting no later than June 30, 2014, formally provide updates of the plans under the three preceding recommendations, and meet with the Board Staff to review and observe progress.**
14. **No later than June 15, 2014, Hydro should provide to the Board a detailed report on decisions and pending actions regarding spare parts for Holyrood generating station and the CTs, including: (a) a listing of all critical plant components, (b) the results of risk analyses of such critical components, (c) the decisions on which parts should have spares, either on site or at a vendor, and (d) the action plan to procure any unsecured such parts before November 30, 2014.**

[19] Hydro's March 24, 2014 report, Volume II, Schedule 4, Appendix 1, Page 25.

5. Reserve Requirements and Supply Options

After abstract probabilistic conclusions produce a finite reserve requirement in terms of MW, the analysis becomes tangible, and easier to put in a proper perspective. A reserve of 200 MW, for example, has meaning in terms of physical assets and recognition of what happens when some of those assets become unavailable. Table 2.7 below begins to relate LOLH, reserve percentages, and megawatts of capacity.

Table 2.7: Reserve Levels

		Reserves		
	LOLH	%	Hydro MW	IIS MW
2013	0.97	16.32%	234	266
2014	2.59	12.28%	183	208
2015	3.98	10.32%	157	178
2016	2.73	12.21%	188	212
2017	2.68	11.00%	171	193

- LOLH and % reserves from Hydro's March 24, 2014 filing, Volume II, Schedule 5, Table 3.
- Reserve MW for IIS calculated from load in "Generation Planning Issues", November 2012, Table 5-1, PLB-NLH-047, Attachment 1
- Reserve MW for Hydro based on load 200 MW less than IIS above

In order to clarify the subject in terms of capacity, we can start by translating the LOLH into a reserve requirement, as shown on Table 2.7 above. The data reflect recent model results from Hydro and they assume the addition of a 50 MW CT in late 2015. The resulting impact on reserve margin, whether calculated on the Hydro or IIS load, is not particularly substantial. It is comparable to or less than the reserves in place in 2014.

A Quetta Inc. and Associates study comprised one of many that support the 2.8 LOLH criterion. Interestingly, however, it included the following comment:

> *The Island Interconnected System should have sufficient generating capacity to satisfy a Loss of Load Expectation (LOLE) of not more than 2.8 hours per year. This is equivalent to 0.2 days/year or 1 day in five years. <u>It results in a capacity reserve requirement of 18%.</u>* [20][Emphasis added]

The more recent analyses, however, illustrated in the table above indicate much lower reserve requirements (in the 10-12 percent range); yet they also equate to a LOLH of 2.8. The primary reason for this difference seems to be Quetta's use of total installed capacity in the calculation, rather than a capacity that reflects expected variations in generation capability. Quetta, however, also assumed a higher forced outage rate for the Holyrood generating units than Hydro uses today. This factor illustrates the problem of simply quoting an LOLH. The Quetta case requires a higher reserve margin to produce that LOLH of 2.8. This observation underlies our concern about relying upon the 2.8 measurement as adequate. It produces in today's model a reserve requirement that is simply too low.

With reserves of 10-12 percent, one can observe that an outage of one of the three Holyrood units, combined with an outage of one of the three CTs in place at the time eliminates all of the reserve. Nevertheless, the calculated LOLH, at less than 2.8, would indicate that this result remains acceptable. The solution, as presented in Recommendations 8 and 9 above, is to move to a more appropriate LOLH, and to focus more on the level of reserve required. Focusing on

[20] Hydro's March 24, 2014 report, Volume II, Schedule 3, Page 42, Line 8.

reserves improves understanding, simplifies quantification, and increases the transparency of the associated risk.

Considering sensitivities, which we deem central to effective planning, heightens reliability risk. For example, the weather during the 2014 emergency was not extreme in the 30-year context. Any deviations from “average” weather were a fraction of the 57 MW that might be expected from a P90 day. This sensitivity simply tells us that 2015 might prove worse than January 2014, and perhaps considerably so.

Hydro is seeking economically reasonable opportunities to achieve interruptible load, which the above reserve analysis does not include. Hydro had access to some 60 MW during the emergency of 2014. Also on the positive side lies 133 MW of non-dispatchable generation, including 54 MW of wind and 90 MW of run-of-river hydro. To the extent that some of this generation may be available, it would contribute to reserves.

Generator availability in the future might be better or worse. The lost MW entering January 2nd was the equivalent of less than half of the Holyrood station, which illustrates a degree of vulnerability to potential similar capacity losses in the future. In addition, the 233 MW unavailable in 2014 and the 307 MW unavailable in 2006[21] both exceed the reserves available today.

We discuss other potential mitigating measures for 2015 below. We consider their pursuit a major priority, because the low reserves planned for the pre-Muskrat Falls years create significant risk of further supply-related problems.

The predicted supply deficit, from a planning perspective, was originally forecast for 2012. It failed to materialize, primarily from the deferral of forecasted new industrial load.

New generation is the most direct and substantive solution for reducing reliability risk. A small temporary addition is already on site at Holyrood generating station in the form of the new black start diesels. The eight units of two MW each await connection to the station. Connection will occur at the first opportunity that Unit 1 is off line. This configuration can supply 10 MW for station auxiliaries (and hence the grid), but requires additional modifications to allow use of the full output. The small increment of added capacity, the time (nearly a year) to get it in service, and the cost of the required modifications, and the temporary nature of the facilities will likely diminish the likelihood of this option; however, Hydro is evaluating its potential.

The other option under active consideration by Hydro is one or more CTs. A new CT could potentially be in service by late 2015, which will miss the coming 2015 winter (2014-2015). It could even miss the 2016 winter peak. An existing CT, if a suitable model can be found, could potentially meet the coming winter’s needs. Even if it were delayed into 2015, it (unlike a “start-from-scratch” acquisition of a new CT) would represent a near-certainty for the 2015/2016 winter. Hydro is pursuing an application for its approval, submitted to the Board on April 10, 2014.

[21] Hydro’s March 24, 2014 report, Volume II, Schedule 6, Table 4.

Liberty recommends that:

15. Hydro should treat the securing of new generation as a first priority; reach a prompt decision on a preferred option and proceed expeditiously towards an in-service date of December 1, 2014 or, if not possible, by December 1, 2015 at the latest.

6. Demand Resources

Hydro had access to 60 MW of interruptible load at Corner Brook Pulp & Paper, Ltd., which assisted during the January 2014 events. The Company is addressing with its industrial customers the potential for securing longer-term arrangements, at least through the Muskrat Falls in-service date.

Other demand resources can have real value, but it is important to understand that their maximum contribution has significant limits. Additional interruptible load, further load reductions via curtailment arrangements, and added conservation efforts are all avenues that should be pursued. We would not expect, however, that any of these individual measures will make a very large contribution, although collectively the effects will be welcome. When a borderline situation exists, every saved MW can be of real value; hence, such efforts should be encouraged. We observe that the effects may prove small compared to those of new generation.

We recommend that:

16. Hydro should continue discussions with appropriate industrial customers who might make a material contribution to interruptible load with a goal of securing economically available interruptible loads.

III. Equipment-Related Outages

This chapter reviews the major equipment-related outages that occurred beginning on January 4, 2014, their causes, and Hydro's practices related to those causes. We examined Hydro's maintenance practices in related areas, and addressed near-term recommendations to mitigate outage risks over the period preceding the scheduled in-service date of Muskrat Falls. The Fall 2014 Report will examine Hydro and Newfoundland Power transmission and distribution asset management maintenance programs, practices, and staffing in more depth. The analysis leading to that report will include the adequacy of resources for appropriately maintaining transmission and distribution equipment in the long term.

A. Hydro's Terminal Station Equipment

Hydro's terminal stations formed the focus of the events leading to the equipment-related outages that began on January 4, 2014. The following paragraphs provide a brief summary of the overall configuration of that equipment. Hydro calls its high-voltage transmission substations "terminal stations," because its twenty-four 230kV, sixteen 138kV, and sixteen 66/69kV transmission lines end or "terminate" at these substations.[22] Hydro has 52 high-voltage terminal stations. These stations contain several classes of equipment relevant to a discussion of the outage events.

1. Circuit Breakers

Circuit breakers control normal current flows and abnormal fault currents. These breakers must have the capability to open (trip) very quickly, in order to interrupt fault current. Prompt opening permits the transmission system to remain stable, avoiding abnormal power flow and swings around a 60 Hertz frequency level. Hydro employs 63 air-blast circuit breakers. They range between 35 and 47 years in age.[23] The air-blast circuit breakers use high pressure air to operate breaker mechanisms. A blast of air blows out the electrical arcing occurring across the breaker contacts when fault current is being interrupted. These breakers are susceptible to air leaks at seals, to lubrication issues, and to corrosion. Conditions like these can prevent the breakers from tripping when they should. Water entry into the breaker mechanisms can produce ice, which can also prevent tripping in very cold weather. Occasional operation of these breakers helps to prevent corrosion, thus providing greater assurance that the breakers will trip when required.

2. Relays

Protective relay schemes automatically detect abnormal conditions. They send trip signals to the circuit breakers or to lock out relays, which then trip multiple breakers. When a breaker fails to trip, the initiation of a "breaker failure" relay scheme trips other breakers, in order to clear faults quickly. Generally, a utility can improve relay performance by replacing obsolete electrical mechanical and early electronic relays with modern programmable relays.

[22] Response to RFI #PUB-NLH-101.
[23] Response to RFI #PUB-NLH-096 and 098.

3. Transformers

Power transformers transfer electrical energy from one voltage to another. Hydro transmits energy at 230,000 volts (230kV) and over long distances to the various terminal stations. This high voltage allows large amounts of energy (megawatts) to flow long distances with less transmission line loading (current). The 138kV and 66kV lines (typically shorter and less expensive than 230kV lines) serve Hydro and Newfoundland Power low voltage (4kV, 14.4kV, and 25kV) distribution substations.

4. Terminal Station Buses

Buses generally comprise aluminum tubes designed to carry large amounts of current from generating units from several lines to several other terminal stations or to multiple distribution substations. "Straight" buses use only one circuit breaker for each line or transformer. "Ring" buses use two or more. An advantage of a ring bus lies in its ability to remove one breaker at a time from service for maintenance. A disadvantage of a ring bus arises from the fact that proper isolation of a faulted line or transformer requires that all circuit breakers operate as intended. Protective relay protection design therefore becomes more complicated for ring bus configurations. Hydro upgraded some of its terminal stations from straight buses to ring buses in the 1970s.

5. Air-Break Switches

Motor-operated air-break switches isolate a transformer, circuit breaker, or other equipment from an energized bus or lines. One can operate such switches manually, or by remote control from the control building, or by operators at the system control center, or by automatic control via the protective relay system. These switches are usually not designed to interrupt load current.

6. Capacitor Banks

Capacitor banks improve the efficiency of the transmission system by supplying reactive energy to loads (*e.g.*, from large induction motors) that require such energy. Capacitor banks reduce transmission system current, and help maintain voltage levels. Capacitor banks, however, display sensitivity to harmonics, which are multiples of 60 Hertz current and voltage. Large motor drives and rectifiers generate harmonics on the system. Hydro employs two large capacitor banks in its Come by Chance terminal station.

7. SCADA

Supervisory Control and Data Acquisition ("SCADA") allows system operators to exercise remote monitoring and control of circuit breakers, transformers, and other equipment in terminal stations. Thirty-seven of Hydro's 52 high-voltage terminal stations have full SCADA control and monitoring. One has only monitoring capability. Fourteen terminal stations have no SCADA. Ten of Hydro's thirty-four 14.4kV distribution substations have some level of SCADA control and monitoring. About 91 percent of Newfoundland Power's transmission lines and about 60 percent of its distribution feeders have some level of SCADA control and monitoring.

8. Digital Fault Recorders

Digital Fault Recorders ("DFRs") provide data and graphic presentations of voltages and current prior to and during fault events. This data has value in analyzing the causes and conditions associated with equipment fault events. DFRs can operate as stand-alone units or as components integrated into modern programmable relays.

9. Event Data Recorders

Event Data Recorders provide a record of alarms and breaker operations and event times. The data that these recorders capture helped Hydro's root-cause team identify alarms that occurred prior to the equipment failures.

B. Nature of the Equipment-Related Outage Events

1. Summary

a. <u>January 11, 2013 Outage Events</u>

A January 11, 2013 winter storm with high winds blew wet, salt-contaminated snow onto transmission lines and on equipment in Hydro's Holyrood transmission station. Hydro experienced multiple equipment faults and outage events, which resulted in the loss of all generation at the Holyrood generating station. This sudden loss resulted in numerous misoperations of protective relays, causing the separation of transmission lines and other generating units from the system. More than 700MW of customer load across the IIS was affected. Hydro determined that the effects of the faults on customers were exacerbated by a breaker failure relay scheme design flaw, and by a malfunction of the B12L17 air-blast circuit breaker (failure to open on one phase) at the Holyrood terminal station. Inadequate protective relay settings and scheme designs at various locations also contributed.[24]

Hydro's analyses of the issues generated 56 recommendations for responsive actions. Twenty of these June 2013 recommendations addressed circuit breaker issues and relay operation issues, 20 addressed protective relay setting and relay scheme design issues, and 2 addressed substation and circuit breaker design issues. The remaining recommendations addressed system operations, planning, engineering, and generating station relay protection issues.[25] The June 2013 recommendations included: (a) application of a protective coating on the Holyrood terminal station generating unit air-blast circuit breakers, and (b) review of air-blast circuit breaker maintenance procedures, including exercising the breakers to assure that they will operate properly when needed.

Hydro prioritized the recommendations in August 2013, setting schedules under four classes:[26]

- Priority A – To be completed before the 2013/2014 winter season
- Priority B – Engineering work, if required, to be completed in the winter of 2014
- Priority C – Engineering work or study to be completed in 2014
- Priority D – To be scheduled in 2014 or beyond.

[24] January 11, 2013 Power System Outage Report, December 2013.
[25] January 11, 2013 Winter Storm Events – Power System Performance Review, June 2013.
[26] Response to RFI #PUB-NLH-160.

Hydro reported that it completed the 30 actions required for December 31, 2013 and the 1 action required for January 31, 2014. Hydro indicated that it updated its circuit breaker preventive maintenance practices. Nevertheless, it has not yet implemented the exercising of its air-blast circuit breakers.[27]

b. *January 4 and 5, 2014 Equipment Outage Events*

i. *Newfoundland Power Equipment Outages*

On January 4th, 2014, Newfoundland Power interrupted service to 2,600 customers because a broken guy wire caused an outage of its transmission line 65L between New Chelsea and Old Pelican substations. A downed conductor also caused an outage of transmission line 18L between Goulds and Glendale substations. No customers were affected. These events were caused by wind-caused damage. Newfoundland Power substation equipment functioned as intended.

On January 8th a 30 minute interruption of power occurred to about 29,000 Newfoundland Power customers on the Avalon Peninsula, west of Holyrood. This interruption resulted from Newfoundland Power's application of load to a particular line, which in turn caused the tripping of transformer overload relays at Western Avalon terminal station. Newfoundland Power applied load to this line after another line had been taken out of service because of a circuit breaker issue. The Western Avalon transformers tripped, because Hydro did not make Newfoundland Power aware of reduced transformer capacity resulting from the failure of the T5 transformer at Western Avalon. This event is discussed in more detail later in this report.[28]

ii. *Hydro Equipment Outages*

Two of the three major power outage events of January 4, 2014 resulted from causes consisting of a transformer failure, a circuit breaker malfunction, a protective relay design issue, and an issue related to operator knowledge of the protective relay scheme at Hydro's Sunnyside terminal station. The third major outage, which occurred on January 5th, resulted from a circuit breaker malfunction at the Holyrood plant's terminal station. In addition to those events, a January 4th transformer failure and a circuit breaker malfunction at Western Avalon terminal station delayed restoration for several hours, but did not cause a major outage event.

The initiating cause of the series of three major power outage events on January 4 and 5, 2014 was a fault in one of two 230kV large power transformers at the Sunnyside terminal station. The transformer failure, however, should have had only a minimal and limited effect on customer numbers interrupted and the length of those interruptions. The three major outage events resulted from:

- A malfunctioning (failure to open) 230kV air-blast circuit breaker in Hydro's Sunnyside terminal station
- Insufficiency of a protective relay scheme design in the Sunnyside terminal station

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[27] Liberty will review all Hydro actions addressing the 2013 recommendations for the Fall 2014 Report.
[28] See this chapter's subsection titled, "Western Avalon Tap Changer Failure and Breaker Malfunction."

- Failure of personnel to understand fully the operation of that protective relay scheme at Sunnyside terminal station
- A malfunctioning 230kV air-blast circuit breaker in Hydro's Holyrood plant's terminal station.

These events caused a collapse of most of Hydro's transmission system and the separation of major generating units from the transmission system. The combination of these events and the length of time required to restart generator units at Holyrood generating station caused extended power interruptions for up to 187,500 customers, mostly on the Avalon Peninsula.

A second transformer failure and air-blast circuit breaker malfunction also occurred at Hydro's Western Avalon terminal station. The Western Avalon event did not cause a major power outage event when it occurred. It did lead to delay of customer service restoration on January 4th and the interruption of Newfoundland Power customers on January 8th 2014.

The following sections detail the events surrounding four critical series of events.

2. Sunnyside Transformer Failure and Circuit Breaker Malfunction

At 9:05 a.m. on January 4th, Hydro experienced at its Sunnyside Terminal Station the first major event; *i.e.*, failure of the station's 125MVA T1 Transformer and a malfunction in an air-blast circuit breaker. A major power outage resulted from failure of one of five 230kV air-blast circuit breakers to open to interrupt the fault current produced by the T1 transformer fault, and because 230kV breaker failure protection had not been installed for a transformer fault.[29]

Illustration 3.1 Failed Sunnyside 125MVA T1 Transformer

The T1 transformer failure did not itself cause the major outage event. The Sunnyside terminal station has two 230/138kV 125MVA transformers (identified as T1 and T4). A fault in one of the transformers causes protective relays to sense the fault, and send "trip" signals to either the T1 or T4 "lockout relay." In order to clear (de-energize) a fault in either transformer, a fault detection

[29] Page 13, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

relay sends a trip signal to a lockout relay. This relay then sends trip signals to the two 230kV air-blast circuit breakers and to the three 138kV air-blast circuit breakers. These signals permit the rapid tripping (in less than 200 milliseconds) of all five circuit breakers, in order to isolate both transformers from the 230kV and the 138kV transmission systems. Correct operation of the equipment should have limited the consequences of transformer failure. Loads on each transformer at the time ran at less than 50 percent of capacity. Thus, the failure of one transformer should have permitted switching the 138kV load from that transformer to the other transformer within a short time.

Illustration 3.2: Malfunctioning B1L03 Breaker

The T1 transformer experienced an internal fault at 9:05 a.m. Breaker B1L03 malfunctioned. This breaker serves as one of the two 230kV air-blast circuit breakers connecting the transformers to the 230kV bus and to the four 230kV transmission lines. Breaker B1L03 "stuck," and did not open. The line protection relays at the remote ends of the transmission lines exist primarily to protect the lines from faults. These relays therefore only provide time-delayed "back up" protection for a transformer/bus fault at Sunnyside. The last line to trip was the TL203 from the Western Avalon terminal station (where a transformer failed later in the day). The T1 transformer fault lasted a comparatively lengthy 2.0 seconds, because of the stuck breaker. The fault should have been cleared within the 200 millisecond standard.[30]

The long time required to clear the transformer fault resulted in the explosion and destruction of the T1 transformer. The oil expelled by the explosion ignited. The fire, the collateral damage caused, and ensuing system collapse most likely resulted from the two-second delay in clearing the transformer fault. The tripping of the transmission lines and long delay in clearing the transformer fault caused loss of supply, voltage depressions, and power frequency swings on the transmission system. A collapse of the transmission system and disconnection of the three Holyrood generating units (within three seconds of the transformer fault) ensued. The event caused power interruptions to about 187,500 customers on the Avalon Peninsula.

[30] Page 13, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

Even had the 230kV breaker stuck, Hydro would have had the ability to clear the fault more quickly, had it provided a "breaker failure" protective relay scheme. A breaker failure scheme sends a slightly delayed trip to the breakers on either side of a stuck breaker. Such a scheme would have addressed the effects of experiencing a stuck 230kV breaker upon transformer failure. Interestingly, Hydro has provided breaker failure protection for instances when a 138kV breaker becomes stuck when a transformer fails. It has not done the same for 230kV breakers. Hydro has also provided breaker failure protection for situations where a breaker becomes stuck when a transmission line is faulted.

The use of such a scheme here would have initiated the transmission of a breaker failure trip signal to the 230kV L03L06 breaker and to the TL203 breakers at Western Avalon. Hydro had determined, sometime in the past that the risk of a 230kV breaker malfunction's occurring at the same time as a transformer fault presented too low a risk to justify the expense of installing a 230kV breaker failure schemes to mitigate such risk.

a. <u>Transformer Fault Causes</u>

The exact cause of the transformer failure remains under investigation by Hydro. We believe that the Sunnyside terminal station T1 transformer most likely failed because of an incipient defect in the transformer windings or in a bushing. [31, 32] The transformer had recently experienced an increase in acetylene gas dissolved in the transformer oil. Such increases sometimes indicate an approaching transformer failure, thus requiring action to rule out this possibility. This transformer had a history of elevated acetylene gas for many years prior to the events of early January 2014. Hydro's dissolved gas analysis (DGA) reports show that the level of acetylene gas increased from 7 parts per million ("ppm") in March of 2012 to 11 ppm, in September of 2013. Acetylene should comprise no more than 2 ppm in the oil of a transformer. Internal arcing generates acetylene gas. The September 2013 laboratory analysis report stated: "significant increase in C2H2 (acetylene), consider investigative (more often) DGA sampling."[33]

Hydro did not pursue this recommendation, concluding instead that the acetylene in the transformer resulted from the leakage of tap changer compartment oil (which normally contains some acetylene) into the transformer oil. Hydro neither intensified DGA testing on this transformer, nor conducted internal examination of the transformer or tap changer to determine whether oil from the tap changer compartment was contaminating the transformer oil. Hydro also deferred scheduled preventive maintenance and testing on this transformer. Such testing might have identified abnormal internal conditions.[34, 35]

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[31] The leads from transformer windings to exterior connections are carried through porcelain devices, called "bushings," which are filled with oil and paper insulation.
[32] Page 18, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[33] Appendix 3, p.11, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[34] Transformer tests identify deteriorated insulation in bushings and windings and poor internal connections. The last time the T1 transformer was tested was in September 2007. It should have been tested, according to Hydro's program schedule, by September 2013.
[35] Appendix 3, p.3, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

Hydro currently tests its transformer oil for dissolved combustible gases on an annual basis. We do not consider this cycle sufficient for monitoring quickly developing dissolved gas levels (which raise the possibility of incipient defects) for transformers that contain questionable levels of combustible gases, such as acetylene. Hydro should take action to investigate conditions causing elevated dissolved gases. Hydro indicated that it plans to install gas-in-oil monitors on its critical transformers. This change will alert operators to increasing dissolved combustible gases, such as acetylene gas, in these transformers. It is unlikely however that Hydro will be able to install these monitors in the near term. Hydro should therefore conduct DGA tests on its critical transformers with questionable levels of dissolved combustible gases at least every three months, until the company completes DGA monitor installations.

The loss of the destroyed 125MVA T1 transformer reduces the ability of Hydro to reliably transfer energy from its 230kV system to the 138kV system. Hydro has lost the transformer redundancy (N-1 contingency) designed into the Sunnyside terminal station. The 125MVA T4 transformer has sufficient capacity to carry all normal 138kV loads at Sunnyside. Should the T4 transformer fail before the T1 transformer is replaced, it may prove difficult for Hydro and Newfoundland Power to maintain reliable operation of 138kV systems under a range of other conditions. Hydro plans to replace the destroyed Sunnyside terminal station T1 transformer with the 125MVA T5 transformer, currently located at the Western Avalon terminal station, after it is repaired.

Liberty recommends that:

17. **Hydro should intensify DGA testing of its critical transformers exhibiting questionable levels of combustible gases, and take actions necessary to minimize failures, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**
18. **Hydro should catch up on overdue testing and maintenance on its critical transformers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**
19. **Hydro should complete system studies to verify that its plan to relocate the repaired T5 transformer from Western Avalon terminal station to replace the failed Sunnyside T1 transformer will not unduly reduce the reliability of the Western Avalon terminal station and of the transmission system as a whole, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**[36]

b. <u>Air-Blast Circuit Breaker Malfunction Causes</u>

Hydro has not identified the cause of the B1L03 air-blast circuit breaker malfunction (becoming stuck and not opening), because it began to operate properly (*i.e.*, without corrective action) before the cause could be investigated.[37] These circumstances indicate that, had this breaker been exercised earlier, it likely would have functioned properly. This temporary malfunction led Hydro to hypothesize that issues of the following type may have occurred:

[36] Liberty will review Hydro and Newfoundland Power transformer maintenance programs and practices in depth for inclusion in the Fall 2014 Report.
[37] Page 20, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

- Poor connections in the control circuits
- Low DC voltage
- Component corrosion
- Cold weather
- Dirty linkages.

Hydro returned the breaker to service following an overhaul and functional testing.

Liberty found that Hydro would likely have prevented the malfunction by: (a) having operated (exercising) its air-blast circuit breakers on an annual basis, and (b) servicing and testing the breakers more regularly. We consider such actions appropriate for this type and age of circuit breaker. When these breakers are not periodically operated (either by normal switching or by intentional exercising), conditions can arise that prevent them from opening. Examples of these conditions include air leaks at seals and fittings, water or ice contamination, solidified or poor lubrication, corroded breaker parts, corroded auxiliary trip circuit contacts, dirty linkages, and DC supply problems. Exercising helps to ensure that the breakers will operate as intended. Exercising also wipes the lubricated internal surfaces, and wipes corrosion from auxiliary control contacts in the breakers. More intense servicing and testing (perhaps on a four- year basis rather than a six-year basis) would better assure that:

- Control and trip coil circuit connections are tight and their contacts free of corrosion
- Trip coil resistance is proper
- Moving linkages and interrupters are properly lubricated
- Breakers will trip under conditions that cause DC voltage to be reduced
- Resistances and the opening times of the interrupters are within acceptable limits.

The B1L03 breaker was overdue for its scheduled six-year maintenance. Hydro last serviced and tested it in June 2007.[38]

Had Hydro exercised the Sunnyside breaker and the breakers at Western Avalon and Holyrood generating station (discussed in following sections) before this last winter, the three breaker malfunction events likely would not have occurred. In addition, had Hydro serviced and tested the B1L03 breaker within the six-year time limit (June of 2013), that breaker likely would have functioned properly.

Hydro failed to act upon one of its recommendations following the January 2013 outage event. Hydro recognized that, by June of 2013, its 230kV air-blast circuit breakers needed exercising and more intense maintenance. The company's June 2013 review of the January 11, 2013 winter storm events identified 230kV air-blast circuit breaker malfunctions as causal factors. Hydro developed 56 recommendations from this review. The first recommendation stated that:

> *There were many issues with breakers, particularly the 230kV class, during these events. A review of the <u>preventative maintenance schedules and procedures</u> for these breakers should be carried out to ascertain whether they are being carried out adequately. In addition, this review should address whether or not they are adequate for the age of the breakers. <u>One issue is the failure to trip which is related to the auxiliary contact in the trip circuits and may be mitigated by the exercising of the breakers</u>. A schedule for this*

[38] Appendix 3, p. 33, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

> *"exercising" should be developed and monitored, possibly with the assistance of EMS data which reports the opening and closing of breakers, to identify "dormant" breakers.* (Emphasis added)

Exercising helps assure that breakers will trip from its controls, but the procedure does not verify that the breakers will actually trip from each protective relay. "Trip checking" consists of: (a) periodic tripping of all lockout relays from every protective relay (an interposing relay with many contracts rated to carry breaker trip currents), and (b) tripping all breakers from every lockout relay. When Hydro becomes connected to USA/Canada transmission grid, it may be required to "trip check" its circuit breakers and relay schemes every six years. Liberty recognizes that conducting trip checks requires substantial preparations by engineers and technologists. The trip checking procedure must be carefully executed, in order to prevent unintended breaker operations. The practice helps technologists to understand fully the Hydro transmission protective relay schemes, producing knowledge useful for successful restorations following equipment failure events.

Malfunctioning air-blast circuit breakers were also causal factors of the events at Sunnyside and Holyrood terminal stations.[39] The phenomenon may also have contributed to the Western Avalon transformer failure (as discussed later). Hydro's old air-blast circuit breakers are near the end of their reliable lives. Age-related issues should lead Hydro to enhance its maintenance on the old air-blast circuit breakers, until they are retired. Hydro has fifty-one 230kV and twelve 138kV air-blast circuit breakers in its thirty-three transmission terminal stations. Liberty did not find that the nature and extent of Hydro's planned maintenance of these old 230kV air-blast circuit breakers conforms fully to the needs of the aged equipment. The ages of these breakers range from 35 to 47 years.[40] Many utilities replaced their 1960s and 1970s air-blast circuit breakers many years ago, because of reliability issues in cold weather, and because of the expense and resources required to maintain them in reliable operating condition.

Hydro has overhauled most of its air-blast circuit breakers since 1999.[41] Nevertheless, the company should enhance maintenance activities for them, while they remain in use. Three of these air-blast circuit breakers malfunctioned on January 4 and 5, 2014 and one of the breakers malfunctioned during the January 2013 outage events.

Hydro has scheduled the eventual replacement of all remaining 63 air-blast circuit breakers to occur between 2014 and 2031.[42] Some of these breakers will be replaced to meet the operational needs of the new DC line. Accelerating the replacement of the air-blast circuit breakers would provide the greatest reliability. We recognize, however, that the cost to replace a 230kV breaker runs to about $800,000 and the cost to replace a 138kV breaker to about $600,000.[43] These costs may practicably restrict how much Hydro can accelerate the breaker replacement program. In any event, the need for a lengthy replacement period underscores the need for enhancing maintenance practices on the remaining breaker population.

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[39] Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[40] Response to RFI #PUB-NLH-098.
[41] Response to RFI #PUB-NLH-098.
[42] Response to RFI #PUB-NLH-096.
[43] Response to RFI #PUB-NLH-097.

Liberty recommends that:

20. Hydro should conduct operation tests (exercise) all air-blast circuit breakers in 2014, preferably in cold weather, and continue exercising them on an annual basis, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

21. Hydro should catch up on overdue testing and maintenance on its critical air-blast circuit breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

22. Hydro should change its air-blast circuit breaker proactive maintenance program cycle from six to four years, until retirement of these breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.[44]

23. Hydro should periodically operate each of its circuit breakers from protective relays, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

c. *Lack of a Protective Relay Scheme to Address Coincidental Transformer and Breaker Failures*

The Sunnyside terminal station experienced a 230kV breaker malfunction coincidentally with a transformer failure. The lack of "breaker failure" protection there contributed to the major outage event at the terminal station.[45] Some of Hydro's terminal stations have existing breaker failure schemes that can be modified for a transformer failure/230kV breaker malfunction. Some other substations do not have any breaker failure protection.

Liberty recommends that:

24. Hydro should redesign its existing breaker failure relay protection schemes to provide that breaker failure will be activated whenever a transformer fails coincidentally with either a 138kV or a 230kV breaker malfunction, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

25. Hydro should formally examine the installation of breaker failure relay protection for transformers in terminal stations where breaker failure relay protection is not in place, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

d. *Loss of Hydro's EMS*

Hydro's restoration efforts were extended by 43 minutes because of the loss of its energy management system ("EMS") between 11:03 a.m. and 11:46 a.m. on January 4, 2014. The emergency generator at the Emergency Control Center supplying power to the EMS shut down because of a cooling system failure. The backup UPS system picked up the energy management

[44] Liberty will review Hydro's and Newfoundland Power's circuit breaker maintenance practices, in depth, for the Fall 2014 Report.

[45] Page 15 and 21, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

system (EMS) load after the generator shutdown, but it remained in operation for only 15 to 20 minutes.[46] Hydro's previous attempts to address the cooling issue on the generator were not sufficient.

Liberty recommends that:

26. Hydro should prepare on a high priority basis a documented analysis of ECC emergency generator availability risk, and maintenance procedures that address regular inspection and repair commensurate with the risks identified, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

3. Western Avalon Tap Changer Failure and Breaker Malfunction

At 12:22 p.m. on January 4, 2014, Hydro's Western Avalon Terminal Station experienced an electrical fault in a transformer tap changer diverter switch and an air-blast circuit breaker malfunction. This event did not cause customer interruptions, but it did delay for several hours the restoration of service to customers already experiencing interruptions.[47]

Illustration 3.3: Western Avalon Transformer T5

The Western Avalon terminal station has one 125MVA transformer (T5), two 41.7MVA 230/138kV transformers (T3 and T4) and two 25MVA 230/66kV transformers, connected on a straight bus. Hydro began attempting to restore the Western Avalon terminal station from the Come-by-Chance terminal station at about 9:30 a.m. on January 4th. Operators attempted to close Western Avalon air-blast circuit breaker B1L37 several times, in order to energize the bus and the transformers. The breaker, however, kept tripping shortly after each closing. The operators finally energized the terminal station by closing another breaker at 12:22 p.m. The 125MVA T5 transformer, however, faulted 12 seconds later. The 230kV bus tie breaker then tripped. This event cleared the T5 transformer fault, and also de-energized T3 and T4 (because they operate in parallel with T5, and connect to common 230kV and 138kV buses). Hydro later determined that the T5 transformer on-load tap changer faulted due to a flash over between the phases of the tap

[46] Technology and Communications Infrastructure Report, dated March 24, 2014.
[47] Page 14, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

changer diverter switch. The tap changer fault caused carbon-contaminated oil to enter the main tank of transformer T5. These circumstances raised five notable issues.

First, a Western Avalon transformer T5 protective device alarm operated at exactly the same time that the Sunnyside T1 transformer failed. Hydro could not determine the exact cause of the alarm, because several alarms are connected to the same alarm point on the data recorder. This alarm came coincidentally with the Sunnyside transformer failure. Such an alarm could indicate the occurrence of a system disturbance (transient overvoltage) affecting the T5 transformer. Unfortunately, Western Avalon's digital fault recorder (DFR) was not fully functional at that time, because of a hard drive failure. Therefore, no record exists to verify the occurrence of a possible transient overvoltage condition. Hydro has engaged a consultant to evaluate whether the Sunnyside T1 transformer failure triggered a "harmonic resonance" condition or some other system disturbance.[48]

Second, data indicated the flow of substantial amounts of "reactive" current between the T5 transformer and the T4 transformer at Western Avalon, during the few seconds prior to the T5 tap changer failure. This phenomenon would indicate differences between T5 and T4 138kV voltages. Hydro continues to examine this issue as part of ongoing system studies.

Third, the B1L37 air-blast circuit breaker kept tripping because one phase of the breaker was stuck, and would not close. The transformers were exposed to "single-phasing" each time Hydro attempted energizing by B1L37. Hydro did not determine whether this condition contributed to the tap changer failure.[49] See Recommendations 20 through 23 above, which discuss preventing air-blast circuit breaker malfunctions.

Fourth, as noted earlier,[50] the 125MVA 230kV/138kV T5 transformer failure did lead to an issue that caused on January 8th a 30-minute interruption of power to about 29,000 Newfoundland Power customers on the Avalon Peninsula, west of Holyrood. Newfoundland Power's 138kV transmission line 64L and its 66kV transmission line 86L tripped off line because Hydro's remaining 230/138kV transformers T3 and T4 at Western Avalon terminal station became overloaded, and tripped off line at Western Avalon terminal station. Newfoundland Power had added load to the T3 and T4 transformer because a second 138kV was out of service in response to a circuit breaker issue at Bay Roberts substation. Newfoundland Power had discussed the need to add load to the 138kV transmission line 64L with Hydro's Energy Management Center prior to the event. Hydro, however, did not inform Newfoundland Power that the transformer capacity for that transmission line was reduced from 208MVA to 83MVA, or that the T5 125MVA transformer was out of service.[51]

Fifth, the losses of the 125MVA T5 transformer at Western Avalon and the 125MVA T1 transformer at Sunnyside have substantially reduced the 230/138kV transformer capacity on Hydro's transmission system. Hydro now also faces the effects of reduced 138kV system reliability resulting from the elimination of the transformer capacity redundancy (*e.g.*, through

[48] Page 22, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[49] Page 23, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[50] See the section earlier in this chapter, titled, "Newfoundland Power Equipment Outages."
[51] Response to RFIs #PUB-NP-052 and #PUB-NP-032.

loss of N-1 contingency). Hydro needs to examine the potential for the Hydro and Newfoundland Power 138kV systems to be disturbed and to suffer collapse, should the T4 transformer at Sunnyside or either of the T3 or T4 transformers at Western Avalon fail before replacement of the T5 or T1 transformers.

Hydro plans to perform onsite the repair of the Western Avalon T5 transformer tap changer and the removal of carbon debris from the transformer windings. It has chosen to do so in order to avoid the wait required to gain access to a transformer facility or to secure and install a new transformer. These latter two approaches would extend restoration of transformer capacity past next winter. Liberty agrees that Hydro can successfully undertake its planned tap changer repair in the field. The concern is whether the company can succeed in the field to remove sufficient carbon contamination in the windings. Utilities generally send failed transformers to repair facilities, which have the capacity to remove windings and the core for cleaning. Failure to remove carbon contamination completely, which will prove more difficult in the field, will increase the risk of future transformer failure.[52]

Hydro had completed maintenance and testing work on this transformer in July of 2012, consistent with its six-year maintenance cycle.[53]

Liberty recommends that:

27. **Hydro should update its event and data recording devices and systems to give each type of transformer alarm its own alarm point, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**
28. **Hydro should develop a priority procedure to repair immediately a malfunctioning digital fault recorder (DFR), beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**
29. **Hydro should complete the studies being conducted to determine whether abnormal system disturbances could have caused the T5 transformer failure at Western Avalon terminal station, and report whether any changes need to be made in systems operations or configuration as a result of these studies, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**[54]
30. **Hydro should seek to locate for Western Avalon T5 a replacement transformer that can be purchased in case: (a) the field repairs are not successful, (b) the repaired transformer fails again later, or (c) the transformer is moved to Sunnyside terminal station, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**[55]

[52] Liberty will monitor the T5 transformer repair procedure and the results of testing indicating winding insulation condition, as part of the work leading to the Fall 2014 Report.
[53] Appendix 3, p.59, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[54] Liberty will review the results of this study for the Fall 2014 Report.
[55] Liberty will monitor the T5 repair work and will indicate its conclusion for the Fall 2014 Report.

4. Sunnyside Restoration Failure and System Collapse

At 3:33 p.m. on January 4th, Hydro experienced a Sunnyside Terminal Station restoration failure and system collapse.[56] This second event led to interruptions affecting 165,000 customers. At 12:57 p.m., after isolating transformer T1, operators successfully energized the 230kV bus. However, when the operators closed the 138kV B3T4 breaker to apply load to transformer T4, the breakers tripped. The transformer T4 disconnect switch opened automatically.

On-site Hydro personnel assumed that the bus differential relays had operated because of fire damage to wiring to the instrument transformers for the bus differential relay scheme. Hydro personnel made wiring changes that defeated the bus differential relay scheme. At 3:33 p.m., operators again energized the terminal station. The 230kV motor-operated switch for transformer T4 opened again, but this time did so under load. The subsequent arcing at the switch caused a bus fault. The bus differential relays could not clear the bus fault, because earlier actions had defeated the bus differential relay protection scheme. Consequently, two transmission lines (TL202 and T206) tripped with delay at the remote ends. These trips caused the Bay d'Espoir generating unit to disconnect from the system, in turn causing the system to collapse again. Newfoundland Power had been restoring customers up to that time, but now experienced interruption again.

This event occurred because the tripped T1 lock out relay (in tripped position following occurrence of the original transformer failure) applied a continuous trip signal to the 138kV breaker B3T4 and to the 138kV breaker failure scheme (recall that there was no 230kV breaker failure scheme). Therefore, when personnel attempted to close the 138kV breaker B3T4, the breaker failure scheme was activated, causing the transformer T4 230kV switch B1T4 to open.

These circumstances produced a number of observations.

First, the wiring modification made by the operators, which defeated the bus differential relay scheme, constituted an incorrect solution.[57] Hydro's approach caused customer interruptions. The proper solution to prevent the opening of transformer T4 switch (B1T4) was to reset (by turning a knob) the T1 lockout relay. The operators were working under adverse conditions; *i.e.*, fire-damaged transformer and other equipment, no lighting, power, or heat in the control building. Nevertheless, had a knowledgeable protection and control technologist been on-site, Hydro would likely have identified the reason why the operators were having difficulty in re-energizing the terminal station.

Insufficient operator knowledge of the relay protection schemes at Sunnyside terminal station was a causal factor of the second major outage event. Hydro personnel at the Sunnyside terminal station on January 4, 2014 did not identify the proper action to take to allow the terminal station to be energized after one of the transformer protection relays tripped. A Protection and Control ("P&C") supervisor was on site, but an experienced technologist was not. Hydro indicated that it did not have an emergency call-out procedure for technologists. Hydro does not currently have a process for technologists to respond to emergency call outs involving investigating and

[56] Page 15, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[57] Page 24, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

modifying protective relay circuits. Operators and P&C supervisors cannot be expected to be knowledgeable of complicated relay and control schemes in some of Hydro's terminal stations.

Second, the breaker failure scheme is connected for a 138kV breaker malfunction when a transformer fails, but not for a 230kV breaker malfunction.[58] See Recommendations 24 and 25 above.

Third, the two air-blast breakers at Bay d'Espoir opened too slowly, causing the disconnection of generation at that location. The backup relays were connected to "slow trip" coils on those breakers.[59] Not having two high speed trip coils per breaker pole (one for the primary relaying and another for the backup relaying) on these old air-blast breakers presents a supporting reason for retiring the breakers.

Liberty recommends that:

31. Hydro should include experienced protection and control technologists with its response teams when addressing Hydro termination station events involving investigating and modifying complicated protective relay schemes, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.[60]

32. Hydro should not employ any "slow trip" coils, where used by backup relay tripping in its air blast circuit breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

5. Failure of Holyrood Air-Blast Circuit Breaker to Open

At 9:27 p.m. on January 5, 2014, a Holyrood Terminal Station air-blast circuit breaker failed to open. This third major customer interruption event affected 110,000 customers.

Illustration 3.4: Air-Blast Circuit Breaker B1L17

[58] Page 24, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[59] Page 10, Protection System Impacts on 4 January 2014 Supply Disruptions – External Protection Report.
[60] Liberty will review Hydro's and Newfoundland Power's P&C staffing and training practices in depth for the Fall 2014 Report.

Hydro had restored Unit 2 and Unit 3 at Holyrood generating station. In preparing to bring Holyrood Generating Unit 1 on-line, operators had to close the Unit 1 switch between the line coming from the Unit 1 step up transformer and the presumably de-energized bus sections between the two breakers on the energized ring bus. The breaker open/close indicators on the control panel and on the breakers for the two air-blast circuit breakers showed both breakers to be in open status. When the operators closed the Unit 1 switch onto the supposedly de-energized bus section, an arcing fault occurred.[61]

Illustration 3.5: Unit 1 Disconnect Switch

The arcing fault occurred because one phase of the 230kV air-blast circuit breaker B1L17 had been closed, even though the three position indicators (one for each phase) showed it as open on all three phases. The linkage to one of the indicators had also stuck. Because of the one stuck phase, single-phase current flowed back through the Unit 1 transformer. The disturbance caused the other two units, all transmission lines, and Holyrood station service to trip, and to disconnect from the system. The loss of the two other units at Holyrood generating station caused the interruption of about 110,000 customers.

Two important observations result from these circumstances.

First, a control rod stuck due to ice and corrosion in the B1L17 air-blast circuit breaker caused the malfunction that led to this event. Hydro found moisture and corrosion upon disassembling the breaker.[62] See Recommendations 34 through 36 below.

Second, Hydro determined that an inappropriate maintenance work practice caused the moisture contamination. This breaker had been disassembled earlier in 2013, in order to permit application in a heated shop of a protective coating on the interrupter external porcelain insulator surfaces. This corrective action resulted from analysis of the January 2013 major outage events. During this work, however, the air receiver portion of the breaker remained in place in the terminal station. Hydro believed that the air receiver was not properly sealed from the weather. In

[61] Page 24, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[62] Page 29, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.

addition, the air receiver was exposed to weather for six weeks rather than the planned two weeks. The work was extended because of re-prioritizing of work at that time.

Liberty recommends that:

33. Hydro should prepare a maintenance practices document addressing the new procedure for applying the protective coating to its air-blast circuit breakers and describing how the new procedure will prevent moisture contamination, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.[63]

C. Impacts of Equipment-Related Outage Events

The following two illustrations provided by Hydro and by Newfoundland Power indicate the effects of the three major outage events caused by Hydro's terminal station equipment issues. The first of the three events occurred at 9:05 a.m. on January 4, 2014, when the transformer failed and the air-blast circuit breaker failed to open to clear the transformer fault at Sunnyside terminal station. The second event occurred at 3:33 p.m. on January 4th, when operator confusion of an inconsistent breaker failure design at Sunnyside resulted in the belated tripping of circuit breakers at Bay d'Espoir. The third event occurred in the evening of January 5th, when Hydro operators closed a Unit 1 switch onto a bus energized on one phase by a defective air-blast circuit breaker.

Illustration 3.6 below, shows how Hydro's sources of power changed as the events unfolded. The blue section shows hydro generation, the red section shows thermal generation, and the green section shows purchases.

Illustration 3.6: Changes in Hydro's Generation Output

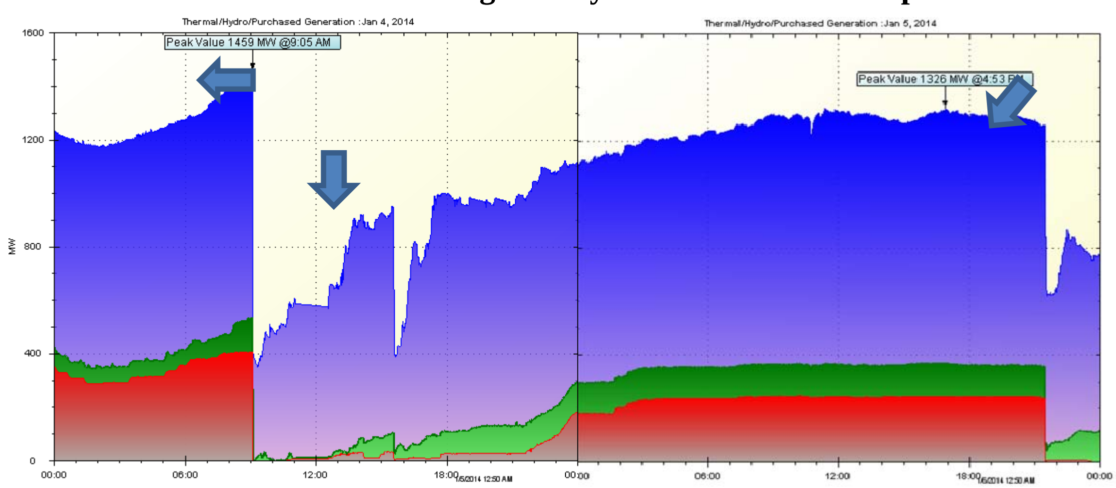
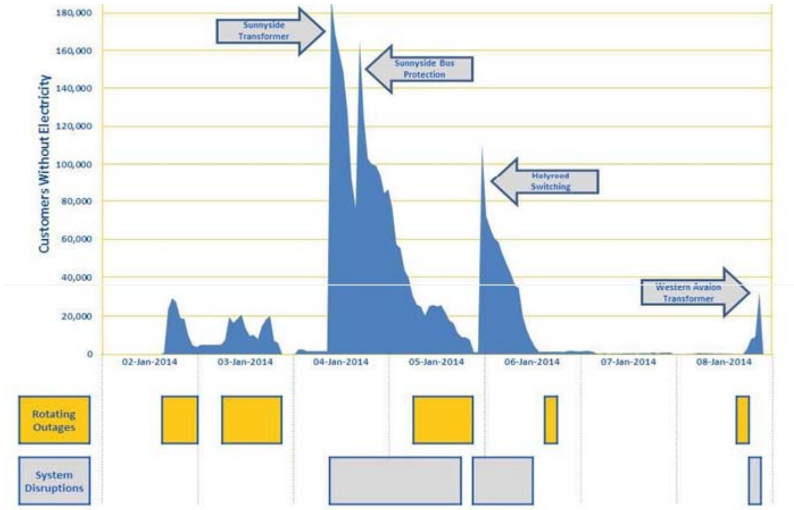


Illustration 3.7 below shows Newfoundland Power customer outages for the time period from January 4th through the 8th. The illustration summarizes the numbers of Newfoundland Power customers without electricity over time, because of the three outage events described above. This

[63] Liberty will review Hydro's terminal equipment maintenance programs and practices in depth for the Fall 2014 Report.

chart also includes the effects on Newfoundland Power customers of the rotating outages addressed elsewhere in this report.

Illustration 3.7: Newfoundland Power Customers without Electricity



D. Hydro Terminal Equipment Maintenance Programs

Most of Hydro's terminal equipment exhibits comparatively advanced age. Such equipment includes power transformers, air-blast circuit breakers, switches, and some relays. A maintenance program for electrical power equipment operating within its 30-50 year reliable service age must be enhanced, or the equipment replaced, as it approaches the end of its reliable service life. Hydro's maintenance programs include short-cycle inspections and long-cycle maintenance jobs. The company uses 120-day inspection cycles and 6-year maintenance cycles for transformers and for air-blast circuit breakers.[64] These maintenance cycles better conform to the needs of less aged equipment. Liberty believes that gaps exist between these maintenance programs and the needs of Hydro's aged terminal equipment. Liberty recommends that Hydro intensify the maintenance schedule for its air-blast circuit breaker (See Recommendation 22 above.)[65]

Liberty also found gaps between Hydro's terminal station equipment maintenance programs schedules and its maintenance practices. Hydro has deferred some maintenance activities, as it has redirected resources to immediate, critical repairs undertaken on a reactive, rather than proactive, basis. Table 3.8 below[66] includes the level of terminal station and relay maintenance work backlogs. The backlog information demonstrates the effect that emerging repair work and staffing limitations have had on completing planned maintenance work in 2013.[67]

[64] Response to RFI #PUB-NLH-082.

[65] Liberty will review Hydro and Newfoundland Power transmission and distribution equipment maintenance practices, including transformer testing and maintenance practices, in more depth for the Fall 2014 Report.

[66] Response to RFI #PUB-NLH-084.

[67] Liberty will review Hydro's terminal station equipment maintenance work backlogs in depth for the Fall 2014 Report.

Table 3.8: Terminal Station and Relay Backlogs

Year	Maintenance / Repair (CM)		Inspection / Testing (PM)	
	Backlog[1]	Completed	Backlog[2]	Completed
2011	247	559	38	819
2012	353	526	62	784
2013	480	586	194	902

1 Up to 30% of CM backlog work orders are priority 4. (See PUB-NLH-083)

2 Up to 17% of PM backlog work orders are low priority.

Liberty believes Hydro's Asset Management program needs to address more effectively the conditions of its equipment. Hydro's asset management processes are thorough in formally and systematically addressing equipment maintenance and replacement activities, and for controlling costs. Hydro's applications and completions of the actual maintenance activities, however, are not always conducted consistent with its maintenance program schedules. Hydro's maintenance activities also do not fully respond to the needs of its aged terminal station equipment. Hydro's resource levels correspond better to the needs of newer equipment, but it is not clear that they do so at the level required for its older equipment. Equipment failures in relation to equipment age generally exhibit a "bathtub-shaped curve." Incidents of failure tend to be high when equipment is new and again after 30-50 years, depending on equipment type.

We also believe that Hydro's ability to provide sufficient skilled manpower resources available for this summer's work load has been an issue. Hydro only has 14 substation maintenance electricians and 8 substation maintenance mechanics. Hydro has not been using substation maintenance contractors to supplement its electricians. Preceding Table 3.8 shows that Hydro could not fully complete maintenance activities on its terminal station equipment consistent with its maintenance programs. Emergent corrective maintenance work and resource limitations drove the resulting backlog in scheduled corrective maintenance activities. It appears that Hydro will require outside resources for the near term, if it is to have the capacity to conduct major repair work that includes: (a) repairing the T5 transformer at Western Avalon, (b) replacing the failed transformer at Sunnyside, (c) conducting the extra work required to exercise the air-blast circuit breakers, and (d) replacing several air-blast circuit breakers, as scheduled for 2014, while (e) completing at the same time its regular maintenance work and its catch up maintenance work consistently with applicable schedules.

Table 3.9 below[68] indicates that Hydro has not increased substation full time employees since 2009. Hydro indicated that it has not considered using the services of qualified substation maintenance contractors.

68 Response to RFI #PUB-NLH-106.

Table 3.9: Skilled Tradespeople by Work Type (FTEs)

	Year				
	2009	*2010*	*2011*	*2012*	*2013*
Transmission					
Lineworker A (Transmission)	23.0	23.0	23.5	22.5	23.0
Distribution					
Lineworker A (Distribution)	42.5	42.5	41.5	40.5	40.5
Substation					
Electrician/Operator (Gas Turbine)	2.0	2.0	2.0	2.0	2.0
Electrical Maintenance A	13.5	13.5	13.5	13.5	13.7
Mechanical Maintenance A – HD Repair	6.0	6.0	6.0	6.0	6.0
Mechanical Maintenance A - Millwright	3.0	3.0	3.0	2.0	2.0

Liberty has concern that Hydro does not have the level of staffing resources necessary to complete all the work scheduled for 2014 and following years.

Liberty recommends that:

34. **Hydro should review its substation and protection and control (P&C) staffing needs for the future, in light of the more intense maintenance needs on its aged transformers and circuit breakers, its protective relay replacement and modification work, and upcoming construction work on the new DC lines, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**[69]
35. **Hydro should use qualified substation contractor personnel, specializing in substation equipment testing and maintenance, to provide the skilled manpower required to assist with the transformer projects and to catch up with regular scheduled maintenance on transformers and circuit breakers, while crews conduct the air-blast circuit breaker operational tests (exercising), beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.**

A qualified substation equipment maintenance and repair contractor can provide the resources needed in the near term and later. There are International Electrical Testing Association ("NETA") certified contractors located in Canada who specialize in testing and maintenance of high voltage substation equipment.

E. Protective Relays

Liberty will review Hydro and Newfoundland Power relay replacement and maintenance practices and any gaps between relay program schedules and relay maintenance completions in depth for the Fall 2014 Report. We address here Hydro's protective relay issues identified to date.

[69] Liberty will review Hydro's and Newfoundland Power's transmission and distribution staffing levels for the Fall 2014 Report.

Protective relays monitor system conditions, and cause circuit breakers to open to clear line, bus, and transformer faults quickly. This function minimizes damage caused by the faults and system disturbances. Hydro's breaker failure schemes contributed to the two major events at Sunnyside in January 2014. Other relays involved, however, performed as intended. Hydro indicated that it plans to address the breaker failure scheme issues at Sunnyside terminal station.

Hydro has been proactively conducting thorough reviews of its transmission system protective relay schemes. In 2010, 2011, and after the January 2013 event, Hydro conducted studies to identify where protective relays were not being effectively applied, where relay settings should be changed, and where relays have not operated as intended. In 2010 and 2011, Hydro hired a consulting firm to evaluate relay applications and settings on ten of its transmission lines. Following the January 2013 event, Hydro's Internal Power System Review and Analysis Committee conducted a similar study to identify how protective relays affected that event. A Power System Performance Review, dated June 2013, presented 20 recommendations related to relay performance. Hydro has formally addressed the recommendations contained in the 2013 study.[70] It also has planned relay replacement work resulting from the 2010 and 2011 studies .:[71] Hydro plans to replace its 20 year old Optimho relays for these transmission lines:

- Line TL203 between Sunnyside and Western Avalon terminal stations in 2015
- Line TL201 between Western Avalon and Hardwoods terminal stations in 2017
- Line TL242 Holyrood to Hardwoods terminal stations in 2017
- Beginning in 2018, upgrading the protection of one line per year for Lines TL202, 206, 207, 237, 218, 236.

Hydro indicated that some of its most experienced protection and relay technologists have retired, and that it plans to hire and train more personnel. Table 3.10 below[72] shows that the number of engineers has decreased by 20 percent since 2010. The number of technologists has remained constant. Hydro will need more engineers and technologists in the future to make the protective relay changes recommended in Hydro's relay protection studies and to design and install relay protection for the new equipment to be installed after DC line installation, while keeping up with the protective relay maintenance schedules. See Recommendation 34 above.

Table 3.10: Hydro Protection and Relay Staffing Changes

<table>
<tr><th>Job Title</th><th>Region/Department</th><th>Location</th><th>2009</th><th>2010</th><th>2011</th><th>2012</th><th>2013</th></tr>
<tr><td>Protection and Control Engineers</td><td>Project Execution and Technical Services</td><td>St. John's</td><td>10</td><td>10</td><td>8</td><td>8</td><td>8</td></tr>
<tr><td>Protection and Control Technologists</td><td>Project Execution and Technical Services</td><td>St. John's</td><td>1</td><td>1</td><td>1</td><td>1</td><td>1</td></tr>
<tr><td rowspan="4">Protection and Control Technologists</td><td rowspan="3">TROC (Central)</td><td>Whitbourne</td><td>3</td><td>3</td><td>3</td><td>4</td><td>4</td></tr>
<tr><td>Bishop's Falls</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td></tr>
<tr><td>Stephenville</td><td>2</td><td>2</td><td>2</td><td>2</td><td>2</td></tr>
<tr><td>TRON (Northern)</td><td>St. Anthony</td><td>2</td><td>2</td><td>2</td><td>2</td><td>2</td></tr>
</table>

[70] Response to RFI #PUB-NLH-160.
[71] Response to RFI #PUB-NLH-108.
[72] Response to RFI #PUB-NLH-107.

IV. Hydro and Newfoundland Power Rotating Feeder Outages

A. Summary

Rotating feeder outages, also referred to as feeder rotations or rolling blackouts, provide a means for an electric utility to reduce peak customer load to meet transitory limits on available sources of supply. North American utilities have had to use the practice rarely and only as the last resort to prevent the collapse of electrical supply systems. Liberty found that during this century, rotating outages have been used a few times in a few locations, including in Texas, California, and Alberta to prevent the system instability caused by the loss of substantial generation or because of transmission system issues.

Hydro and Newfoundland Power used rotating feeder outages during the January 2014 events, causing segments of IIS customers to experience a number of controlled outages. This is the first time that Hydro and Newfoundland Power have used the controlled rotating feeder outage process to sustain overall service during periods of insufficient generation availability. Rotating outages began at 4:13 p.m. on January 2, 2014, due to the unavailability of a portion of Hydro's supply resources during a period of high loads in cold weather.

These outages occurring in the January 2nd through 8th time frame resulted initially, as we discussed earlier in this report, from generation shortages. Hydro and Newfoundland Power were able to employ controlled outages to manage the imbalance between available supply resources and customer demand. Outages later in the period resulted from equipment and operations issues that produced far more widespread (and uncontrolled) outages. To some extent, however, rotating feeder outages also were used to assist in balancing supply resources with customer demand as part of the process of restoring service.

Liberty found that use of controlled, rotating outages ultimately prevented the collapse of electric systems, while limiting the exposure time of the feeder outages to customers. Had the two companies not used the process, more customers would have been exposed to outages from automatic trips of feeder breakers from under frequency relays. Most of the outages resulting from the rotating process lasted an hour or less. However, some operating and equipment issues extended outage times for more than an hour for some Newfoundland Power customers on the first evening. These issues were resolved as the company continued through its cycles of feeder outages.

When Hydro recognized the need to implement rotating outages, it requested Newfoundland Power to commence de-energizing and restoring feeders on a rotating basis, based on the extent as necessary to meet real time generation availability. Hydro did the same with its distribution feeders. The utilities exempted feeders serving critical loads, such as hospitals and "warming centers," from the rotating outage process. They also exempted some remote rural feeders from consideration for rotating outages, where the loads were insufficient to have a material impact on load reduction. The selection of the feeders for rotation considered feeder loads and whether the operators could control the feeder circuit breakers or reclosers via remote control.

To minimize the effect of the feeder rotations on customers, and particularly to limit temperature drop in homes and businesses in the cold weather, the utilities tried to limit customer outages to one hour or less. Hydro was able to comply with this limitation. Its feeders are less loaded and it did not have any operating issues. Newfoundland Power did have some difficulties when it implemented the feeder rotations on January 2nd on some feeders that were highly loaded or very lengthy.

The difficulties Newfoundland Power encountered during the evening of January 2nd, which extended the duration of the rotating outages for some customers, included an electrical phenomenon called "cold load pickup." This phenomenon occurs when load is instantaneously restored on feeders that have been out of service for some time. In such circumstances, a feeder's load at the instant it is restored can reach levels double those existing when the feeder was de-energized. Cold load pickup occurs because all loads come on at one time, including heaters on a cold day and because of the inrush of current that occurs when motors start to run. The temporary overload condition that occurs when a feeder is restored can cause circuit breakers to trip and line fuses to blow.

When Newfoundland Power personnel experienced tripping of circuits in January 2014, it had to send personnel out to sectionalize feeders manually, in order to reduce the effects of cold load pickup. In some cases, the personnel temporarily increased trip settings on circuit breakers or reclosers. Newfoundland Power operators soon learned from this experience during the evening of January 2nd. By the morning of January 3rd, the company had begun to sectionalize feeders proactively, before attempting the re-energize. Sectionalizing served to reduce the blocks of feeder load coming back at any given instant. Newfoundland Power accomplished sectionalization through the use of SCADA control or through the use of field personnel manually to open line reclosers or fuses on some highly loaded or lengthy feeders.[73]

Cold load pickup currents occurring during feeder restorations also sometimes reduced system frequency. Newfoundland Power complied with Hydro's requests to achieve the load reductions required to maintain a balance with supply availability. Newfoundland Power also monitored system frequency when it restored feeders. It sometimes experienced the need to de-energize two feeders before re-energizing one feeder, in order to maintain acceptable system frequency and to prevent unwanted tripping of feeders from under frequency relays.

Newfoundland Power reported that virtually all circuit breakers and reclosers performed as intended through the process of executing rotating feeder outages. The company nevertheless experienced some mechanical operation issues, as the cold weather caused problems with a small number of circuit breakers and reclosers. These problems delayed re-energizing on a few feeders, extending their outages past the hour duration established as a goal. Newfoundland Power corrected these issues immediately where it could. Otherwise, it transferred loads from the defective breaker to another feeder.

Newfoundland Power demonstrated that it learned how to manage cold load pickup and other issues it experienced during the early part of its rotating outage process.

[73] Response to RFI #PUB-NP-022.

B. Execution of the Rotating Outages

Recognizing that rotating outages had become the only remaining, feasible means for maintaining service more broadly (at least for the immediate present), we found that Hydro and Newfoundland Power conducted their rotating outages as planned, except for some difficulties Newfoundland Power experienced.

Newfoundland Power complied with Hydro's continuing communications for load reduction needs. During the first evening of rotating outages, some Newfoundland Power customers experienced outages exceeding the one hour goal. Newfoundland Power was able with reasonable dispatch to identify the cold load pickup problems underlying these longer durations. Using this knowledge, the company was able to identify, communicate to its employees, and effectuate actions needed to reduce outages to less than an hour. Table 4.1 below shows the improvement gained by Newfoundland Power in succeeding outage cycles.[74]

Table 4.1: Newfoundland Power Feeder Rotations Timeline

Outage Dates	Interruption Durations	Feeder Rotations (Number)	Average Duration (Minutes)
Thursday, January 2nd	4:13 p.m. to 10:45 p.m.	77	88
Friday, January 3rd	6:57 a.m. to 7:36 p.m.	141	44
Sunday, January 5th	7:23 a.m. to 8:29 p.m.	158	54
Sunday, January 6th	5:17 a.m. to 10:48 a.m.	39	47
Wednesday, January 8th	3:28 p.m. to 5:42 p.m.	32	25

Hydro had fewer feeders and most of its feeders are rural and lightly loaded. It therefore did not experience any significant operational issues. Hydro initiated its feeder rotations at 4:56 p.m. on January 2. Table 4.2 below shows that Hydro was able to maintain the length of its feeder outages to less than one hour, on average.[75]

Table 4.2: Hydro Feeder Rotation Timeline

Outage Dates	Interruption Durations	Feeder Rotations (Number)	Average Duration (Minutes)
Thursday, January 2	4:56 p.m. to 10:50 p.m.	6	30
Friday, January 3	7:00 a.m. to 7:30 p.m.	25	30
Sunday, January 5	5:04 p.m. to 7:03 p.m.	5	60
Wednesday, January 8	3:32 p.m. to 4:30 p.m.	3	30

C. Remote Feeder Control and Sectionalizing

Many other utilities employ a greater level of remote-controlled feeder sectionalizing capability. Greater availability of remote-controlled feeder control and sectionalizing would have allowed Newfoundland Power to mitigate some of its cold load pickup issues. Newfoundland Power has 26 automatic line-mounted circuit reclosers on 17 of its feeders. Only three of these have

[74] Page 5, Sequence of Events –Internal Review of Supply Disruptions and Rotating Outages, Volume I.
[75] Page 5, Sequence of Events –Internal Review of Supply Disruptions and Rotating Outages, Volume I.

SCADA control capability. The primary purpose for these devices is to improve distribution reliability and restoration during normal ("blue sky") conditions and to a lesser, but still important degree during major storm events that cause the loss of feeders (such as tree contacts or ice loading). The extreme rarity of the use of rotating outages to address generation shortages means that facilitating reconnections during such outages is not a justification for the expense involved. Our Fall 2014 Report will address more broadly longer term reliability and restoration issues affecting the systems of the two utilities. We anticipate a more complete review of the configuration of feeder systems, recognizing that any changes are longer term in nature.

D. Hydro's Rotating Feeder Outages Process

Liberty found that Hydro's system operators effectively directed its distribution operators and Newfoundland Power operators in the timely requesting of load reductions, and that Hydro's distribution operators effectively conducted its feeder rotations.

The primary duties of Hydro System Operations related to the rotating feeder outage process were: (a) to monitor in real time the system loads versus Hydro's generating availability, and (b) to communicate on a timely basis the load reduction needs to its distribution operators and to Newfoundland Power's operators. Hydro distribution operators were responsible for conducting its rotating feeder outage.

Hydro serves directly only a small percentage of IIS electrical retail customers. Many of these end users take service from lightly loaded rural feeders. Therefore, shedding Hydro's distribution loads via feeder rotations can produce only a comparatively very small benefit in maintaining service as broadly as possible under circumstances such as those occurring in early January 2014. Hydro did, however, directly participate in the feeder rotation process. Hydro included in its feeder rotations 10 of its distribution feeders (out of 34 in total) that the System Operators at Hydro's Energy Control Centre can control with the use of SCADA. Hydro also excluded feeders with critical loads. Hydro de-energized various feeders 39 times over the January 2nd through January 8th time period, except for the periods on January 4th and 5th, when the terminal station equipment failures caused the three major outage events. Feeders were de-energized for an average of one hour or less, as illustrated by the time line indicated in the table above.

E. Newfoundland Power's Rotating Feeder Outages Process

Liberty found that Newfoundland Power operators effectively conducted its feeder rotations, following a learning process carried out through its earliest cycles.

Newfoundland Power Operations duties were to select feeders best fitting the need for load reduction at specific times, as requested by Hydro. Newfoundland Power has 305 distribution feeders, which operate at voltages between 4 and 25kV. Newfoundland Power can remotely control about 60 percent of the circuit breakers for these feeders via its SCADA capability.

At the request of Hydro, Newfoundland Power initiated its rotating feeder outages procedure at 4:13 p.m. on January 2, 2014. In preparation for rotating outages, and following the January 2013 outages, Newfoundland Power had compiled a list of distribution feeders to be considered for its rotating feeder process. The list indicated information such as peak loads, critical customers, and whether the feeder breakers or reclosers have SCADA control. Newfoundland Power operators worked closely with Hydro operators, on a continuous basis, to identify the load shedding requirements. Newfoundland Power would select feeders to de-energize, based on actual loading and power frequency control requirements at that time. Newfoundland Power has by far the most IIS distribution feeders and many of these feeders are highly loaded (typically with 10 MW of load). These factors made rotating its feeders particularly more effective in relieving load on the generators.

Newfoundland Power conducted 447 feeder rotations between January 2nd and January 8th. Its current complement of personnel have had no prior experience conducting rotating outages. Early in the process of rotating outages, Newfoundland Power experienced unexpected difficulties that caused some customer outages to exceed one hour. The company materially reduced the average length of its rotating outages by the second day.

F. Newfoundland Power Feeder Restoration Issues

Newfoundland Power was confronted with some feeder restoration issues, particularly during the first evening, including cold load pickup issues. Newfoundland Power quickly learned that it had to sectionalize some feeders, or de-energize two feeders, before restoring a feeder.

Newfoundland Power also encountered another issue. Nine circuit breakers and reclosers would not close, because the cold weather had caused "stuck" mechanisms. Newfoundland Power determined that in some cases worn door seals allowed the heated air in the mechanism cabinets to escape. Repairs were made, sometimes after transferring loads to other feeders, when necessary.[76]

G. Recommendations

36. Formally incorporate by June 15, 2014 lessons learned about Newfoundland Power's service restoration issues, such as cold load pickup, into emergency response procedures and training of employees.

[76] Response to RFI #PUB-NP-024.

V. Customer Service and Communications

Liberty examined Hydro's and Newfoundland Power's responses to the winter 2013 and 2014 supply and power outages as they concern customer service and communications capabilities that support communications with customers and inter-utility coordination of customer outage communications. Liberty's review of customer outage communications focused on the following areas:

- Customer Service Accessibility & Response
  - Call Center Operations & Telephony Infrastructure
  - Self-service Communications (Web, Mobile, IVR)
  - Use of Social Media
  - Call Center Outage/Storm Planning
- Public & Media Communications
  - Outage Communications Planning
  - Ability to Provide Accurate Estimated Restoration Times.

A. Customer Service Accessibility & Response

1. Background

When the power goes out, most customers pick up the phone and call their electric utility, as a natural response. Customers want answers to the same basic questions:

- Does the utility know the power is out?
- What caused the outage?
- When will power return?

Storms present unique challenges for utility customer service. Many customers can simultaneously lose power, causing a flood of calls. Smart phones have increased visits to outage-focused websites; nevertheless, many customers still pick up the phone and call the utility. Electric utilities subject to extreme weather conditions must be prepared for inevitable events that will interrupt service to large numbers of customers and ensuing, extreme and often extended call volume peaks.

Solutions evolving over the years have benefitted from the development of various technologies and service providers. Most utilities have embraced the use of Interactive Voice Response (IVR) technology to offer self-service outage reporting and status updates via telephone. The number of calls, however, can still exceed in-house capacity during a large outage. After-hours outages prove especially challenging, coming with more customers at home and fewer agents on hand to answer calls. Configuring an in-house IVR system large enough to handle the largest expected spike in call volume proves cost prohibitive. The same holds for attempting to staff a call center to handle these calls. A more economical approach lies in outsourcing or offloading overflow to a third party IVR when call volumes threaten to exceed capacity. This approach equates effectively to "renting" the required capacity on an as needed basis. Either by choice or by default, utilities have adopted three basic approaches to "peak" call handling:

- Block calls (busy signal to customers) to reduce them to a manageable level (within the capacity of call center staff and IVR system)
- Provide an upfront informational "message" to many callers; then immediately terminate the call or let queue limitations in the IVR or agent-queue force callers to "choose" to

abandon if hold times become too long. Newfoundland Power has opted for this solution. Since 1999, it has contracted with Bell Aliant to provide a High-Volume Call Answering Service ("HVCA"), which provides one-way recorded messages to callers, customized to eight geographical regions.

- Let all customers who call or otherwise contact the company (*e.g.*, through the website) notify the company of an emergency, report an outage, or inquire about restoration status, with the help of self-service technology (*e.g.*, IVR or Web). This approach reflects industry best practice, and offers the highest customer satisfaction. It permits as many callers as necessary access to self-report outages and receive customer-specific outage status updates.

Newfoundland Power's Customer Contact Centre ("CCC") normally remains open from 8 a.m. to 5 p.m., Monday through Friday, offering the capability to respond to customer inquiries and requests for service. Newfoundland Power's System Control Center handles after-hours emergency calls, unless the company has opened the CCC and staffed it to handle an outage event. Customers can use Newfoundland Power's automated phone services at any time to hear account balance information or the same outage messaging available on the HVCA.

Following the January 2013 system outages, Newfoundland Power implemented changes to strengthen its outage communications capabilities, including:[77]

- Upgrades to the company's Contact Centre
- Additional T1 line added 24 trunks
- Menu on overflow message to direct callers to emergency queue
- Regional Menu prompts callers for the customer's calling region if phone number not recognized
- Company personnel identification and training in second-roles to assist the phone center during a large outage or event
- Conduct of a "storm scenario" test day ahead of the 2013/2014 winter season to revisit procedures and evaluate new improvements
- Upgrades to the website
- Ability to modify the website during events to highlight specific outage messaging
- Deployment of an interactive outage map, list of known customer outages and informational messages/outage status on its website
- Deployment of a web application to permit customers to report outages online.

Hydro's Customer Call Centre supports 38,000 customers, of which 25,700 are on the IIS. Hydro handled 50,000 calls during the January 2013 events.[78] Hydro routes after-hours, emergency and outage calls through an IVR system to the Energy Control Center ("ECC"). When the ECC receives a high volume of calls, contacts to Customer Service determine if the Call Centre should open after hours to handle high volumes. Customers may use either of Hydro's Customer Service toll-free numbers to access the Power Outage and Emergency System ("POES"). The POES

[77] Response to PUB-NP-105.
[78] Response to PUB-NLH-135.

enables customers to obtain dates and times of scheduled outages for specified communities and updates on current unscheduled outages for specified communities.[79]

The January 2014 outages challenged communications between the utilities and customers. Newfoundland Power's customers bore the brunt of the outages. Our review therefore focused primarily on the Newfoundland Power customer experience. We also examined communications coordination between the utilities, as it relates to this outage.

2. Hydro Call Centre Staffing

Hydro appropriately staffed its Contact Centre to handle calls during the outage events. The brunt of the impact of outages fell upon Newfoundland Power customers. Hydro, however, did receive many calls over the course of the outages. Hydro's Customer Contact Centre has normal open hours of 8 a.m. to 4 p.m., Monday through Friday. On January 2nd, when the rotating outages began for Newfoundland Power customers, Hydro closed its call center at 4 p.m. The call volume was not high enough to warrant reopening the center. However, with rotating outages expected to begin early on January 3rd, the Contact Center extended its hours, opening an hour earlier (at 7 a.m.), and remaining open until 8 p.m.

Hydro's ECC contacted the Customer Service manager asking for help on Saturday, January 4th, in anticipation of a storm. Customer Service representatives became available on Saturday, from noon until 6:30 p.m. Hydro received 50 calls on Saturday, with the majority from Newfoundland Power customers. In these cases, Hydro call center representatives could only provide general information to these callers, and refer them back to Newfoundland Power.

Call volumes did not warrant opening the Contact Centre on Sunday, January 5th. Hydro returned to normal business operations on January 6th and 7th. However, as rotating outages were resumed on January 8th, Contact Centre hours were extended until 7:30 p.m.

3. Newfoundland Power Call Centre Staffing

Newfoundland Power was able to ramp up Call Centre staffing as needed to respond to customer calls. Newfoundland Power was at its minimum staffing level for the year in the days leading up to the January 2014 outages. Ten new Customer Account Representatives started a four-week training program on January 13, 2014.[80] Newfoundland Power proved able to draw upon a significant pool of trained, second-role employees to supplement staffing levels in the Customer Contact Centre. Newfoundland Power extended its Contact Centre hours from 5 p.m. to midnight on January 2, 2014, in order to support customers during the rotating outages. On January 3rd, Newfoundland Power opened the Customer Contact Centre two hours earlier (at 6 a.m.), and again maintained operations through midnight. The Customer Contact Centre opened at 7 a.m. on January 4th, and remained open on a 24-hour basis through January 7th. Staffing levels peaked on January 4th, from noon through midnight. Normal business hours resumed on January 9th.

Because the rotating outages began shortly after 4 p.m. on January 2nd, Newfoundland Power could ask its existing staff to work overtime to accommodate an extended shift. This request

[79] Review of Supply Disruptions and Rotating Outages Volume II.
[80] Response to PUB-NP-101.

helped to ensure that resources remained available to support customers affected by rotating outages.

When the equipment-related outages occurred over the weekend, Newfoundland Power was able to draw upon its pool of second-role employees to supplement staffing. This reliance continued throughout the duration of the outages. Newfoundland Power was able to ramp up Call Centre staffing as needed during the January events to respond to customer calls.

4. Getting Through to Newfoundland Power

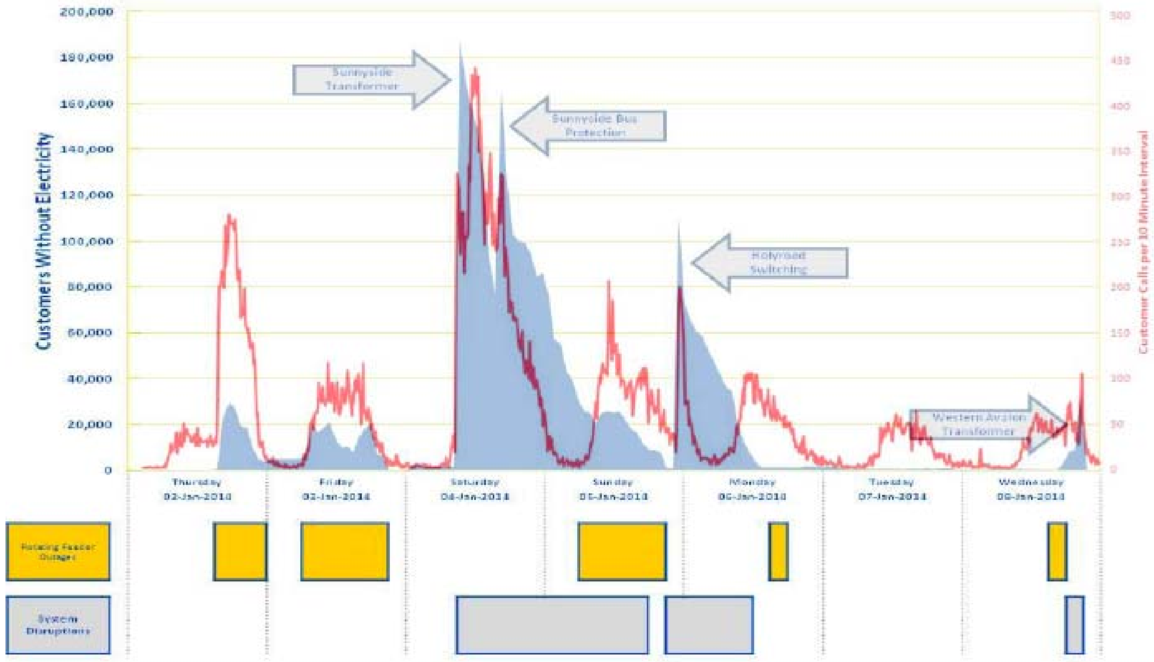
One in five calls received by Newfoundland Power during the January event would have experienced what is generally defined as a "poor customer experience;" *i.e.*, a "call back later" message, a busy signal, or abandoned waiting for a customer account representative.

Newfoundland Power received 139,335 calls during the January 2 – 8, 2014 events.[81] Customers placed calls to Newfoundland Power's Outage Line (800-474-5711) and to its Customer Service Line (800-663-2802). Of the 103,614 callers into Newfoundland Power's Outage Line, 56 percent hung up after hearing the outage. A total of 44 percent opted to remain on the line to speak with a customer account representative. The size of this second group created a lengthy queue and wait for an agent, which eventually forced many customers to look for other options.

Customers called Newfoundland Power when they lost power, either as a result of the planned rotating outages or the equipment-related outages. Illustration 5.1 below overlays the number of calls received by Newfoundland Power during the January outage events on top of the number of customers without electricity.

[81] Response to PUB-NP-113.

Illustration 5.1: Calls to Newfoundland Power during January 2014 Outages



Newfoundland Power's Customer Service Line received 52,612 calls during the January event (including 16,891 overflowed from Outage Line). However, 46 percent of these calls were received at a time when all incoming lines were in use. As a result, 24,073 callers received a "polite disconnect" notice, as shown from the Overflow Menu[82] quoted below:

> *Due to high call volume, Newfoundland Power is unable to take your call at this time. To report an emergency of public safety hazard such as a wires down or broken pole, please press 9. To report an outage or get the latest restoration times visit us online at newfoundlandpower.com or call 1-800-474-5711. For all other inquiries, please try your call again later.*

A conflict on one Newfoundland Power Contact Centre trunk line caused the blockage of 1,500 calls into the Centre. The trunk had not been set up correctly as an inbound trunk. Calls routed to this trunk heard the message "your call cannot be completed as dialed." Newfoundland Power reconfigured the trunk as soon as it discovered the problem, limiting the blockage to the 1,500 calls affected. In summary, one-fifth of calls to Newfoundland Power's Outage and Customer Service line during the event would have received an unsatisfying experience: "please try your call again later" (18 percent), a busy signal/blocked (1 percent), or abandoned the queue (1 percent).

Lack of information or a sense of need to report an outage caused many callers to remain on the line after hearing the HVCA messaging, in hopes of speaking with a representative. Overall, 56 percent of callers hung up after hearing the HVCA message. A total of 44 percent opted to remain on the line, causing significant blockage of the Outage lines into the Customer Contact Centre. Newfoundland Power has designed its Call Center to send overflow from the Outage

[82] Response to PUB-NP-108.

lines to the Customer Service lines. The Customer Service lines, however, generally flooded at the same times as the Outage lines. Calls would therefore route to the overflow menu/message and get "politely disconnected" ("we are busy, call us back later"). This result occurred at several points during the event. A total of 24,073 calls were blocked in this manner. The volume of callers opting to remain on the line overwhelmed the Contact Centre infrastructure.

Additionally, Newfoundland Power's telephone-based self-service ("IVR") does not let customers report an outage. Such reporting must take place through a customer account representative or on the website. The IVR offers customers the same messaging available on the Outage Line ("HVCA").[83]

The intention of the HVCA is to satisfy as many callers as possible with the regional outage status messaging. This approach permits Contact Centre representatives to help customers with emergencies and other questions. In this situation, the majority of callers wanted to remain on the line in order to get more specific information, tell the company about outages, or report an emergency. Newfoundland Power reduced the number blocked in this event, as compared to the outages of January 2013. Nevertheless, there remains an opportunity to improve high-volume outage response. The HVCA configuration does not enable it to operate interactively. Callers therefore must wait in queue to get to the IVR or the call center agent.

The telephony capacity added earlier has helped reduce the level of call blockage, as compared to its performance during the 2013 event. Newfoundland Power can still, however, improve the caller experience during a large event or storm. To be responsive, Newfoundland Power has to be prepared to accommodate a large number of calls following an outage. The extremely high volume of calls following a large outage dictates the need for a technology solution. It is not cost effective or feasible to answer this many calls with agents.

Third-party solutions exist for handling call-overflow during peak calling periods. Newfoundland Power recently investigated options for these services through an RFQ process[84]. However, Newfoundland Power has decided not to pursue any solutions to increase the capacity or performance of its HVCA or Call Centre telephony. It has chosen to focus on other solutions to communicate with customers during a large outage. These efforts include approaches such as text messaging, email, and outbound voice messaging.[85]

Liberty agrees with pursuing proactive multi-channel communications options, but it is also important to pursue improvements to Contact Centre technologies, to enable effective communications with customers choosing to call the Companies. Customer acceptance of non-traditional communications channels tends to be slow. While acceptance will grow in the future, there remains for the present the need to remain responsive to customer phone inquiries and to eliminate the "call back later" overflow messaging. It is also important to conduct the appropriate customer research to maximize these new channels.

Hydro is currently evaluating options to improve its Customer Contact Centre capabilities,

[83] Response to PUB-NP-104.
[84] Response to PUB-NP-122.
[85] Response to PUB-NP-127.

including evaluating the need for expanded after-hours coverage. Hydro has also begun work on drafting a Customer Service Strategy that addresses elements of outage communications as well as day-to-day customer support.

It is important to develop an outage communications strategy to focus efforts on improving the customer experience and improving outage communications, both now and going forward. It will be critical to take steps before the next winter season to improve outage communications, especially the messaging. Some of the technology solutions; however, may take longer to implement.

There exists a need to continue to provide effective handling of customer calls during a large storm or outage and a need to address the high percentage of callers (1 in 5) unable to communicate with Newfoundland Power during the January outage.[86]

37. As a first step, Newfoundland Power and Hydro should develop a joint 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.

A key first step in developing a strategy to improve customer communications is to incorporate customer needs and expectations. Newfoundland Power and Hydro should conduct customer research, whether through polling, focus groups, or other surveys, to better understand customer expectations for service—both during normal business as well as during an outage or emergency situation, including understanding:

- The preferred and optional channels of communication; how customers want to contact the company and other ways that might be quicker
- What information customers need and at what points in time
- Whether proactive ways to communicate and alleviate the need for the customer to contact the utility exist and in what situations
- How and why customers want to report the outage
- What will make customers feel more confident that the company knows about their power outage at their location
- What efforts are underway to restore service.

Both utilities should also conduct research with other key stakeholders to better understand each groups' individual communications needs, including government officials, large customers, critical care customers, EMO coordinators, other emergency and public safety organizations, and the media. Both utilities should pursue focus groups, debriefings, follow-up meetings, pre-season meetings, and other approaches to understand how to better communicate and work with all stakeholders in future events. Both utilities should also analyze customer complaints and other customer feedback to determine whether additional outage communication improvements are necessary.

[86] Liberty will review Customer Contact Centre improvement strategies and options for both companies in more detail for the Fall 2014 Report.

38. 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.[87]

5. Stress Testing of Response Systems

Newfoundland Power has not conducted needed stress tests on the Outage Management System or Contact Centre Telephony and Systems.

Except for normal weather and equipment-related outages, Newfoundland Power has not conducted any planned stress tests on its Outage Management System or Contact Centre Telephony and Systems.[88] This winter brought the second consecutive one exhibiting high call volume and significant call blockage. There is risk that this pattern may continue without a substantial improvement in the level of self-service offered to customers without power; *i.e.*, the ability to obtain customized messaging about a caller's location and the ability to self-report an outage.

It is good business practice to stress test customer-facing systems, especially those that are expected to handle high volumes, such as the HVCA and customer website. It is not sufficient to rely on storms or large outages to "stress test" customer-facing technologies. The risk of poor performance and customer dissatisfaction is too high.

As Newfoundland Power reconfigures its Customer Contact Technologies to improve communications during large outages and storms, it should stress test these technologies to ensure proper performance. The test should place great demands on Newfoundland Power's existing customer-facing technologies, in order to validate effective system performance under extremely high volumes. This testing will help Newfoundland Power confirm the upper limitations of its technologies in terms of simultaneous callers, queue build-up, and systems response. The test will also provide important feedback in terms of how the system works as a whole, from the public network to the high-volume service, to the IVR, and to an agent. Testing should measure system response, time in queue, and document any errors or exceptions, like hang-ups. Most importantly, Newfoundland Power will be able to identify any issues and problems and resolve them prior to the winter storm season.

Stress testing should place great demands on existing customer interfaces, simulating thousands of calls per hour or thousands of simultaneous website visits. The results will help Newfoundland Power confirm the upper limitations of its customer-facing technology in terms of simultaneous callers, queue build-up, and systems response. The test will also provide important feedback in terms of how the system works as a whole, from the public network through the HVCA and to an agent as well as the overflow to the Customer Service queues.

[87] Liberty will review Customer Research efforts and results for both companies in more detail for the Fall 2014 Report.
[88] Response to PUB-NP-106.

39. 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.

6. Loss of Power at Hydro

Hydro lost use of some key customer service and storm response systems when it lost power to its building on January 4th.[89]

As a result of the power disruptions on January 4th, Newfoundland Labrador Hydro lost power to its headquarters building at 9:05 a.m. on January 4th. Corporate headquarters staff, the Energy Control Centre and the Customer Contact Centre groups work from this facility. Hydro's backup generators worked for about two hours, but then stopped due to overheating as a result of a ventilation issue. Backup batteries were depleted by 11:03 a.m.

At that time, key systems were interrupted and non-functional, including the Energy Management System, company website, company email system, Contact Centre Telephony, Customer Information System, and other administrative support systems.

Power was restored within a few minutes and the EMS was restarted and restored after about 45 minutes. Nevertheless, other key systems (noted above) were not fully restored for another four hours. Customers could not talk with Contact Centre representatives or access the company website during this four-hour period.[90]

40. Hydro should review and refresh business continuity plans and contingencies to ensure continual operation and availability of critical outage response support systems, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.[91]

7. Use of the Website

Newfoundland Power's website provided a key communications channel during the January outage events.

Following the January 11–13, 2013 system outages, Newfoundland Power implemented changes to strengthen its website to support outage communications capabilities, including[92]:

- Ability to modify the website during events to highlight specific outage messaging
- Deployment of an interactive outage map, list of known customer outages and informational messages/outage status on its website
- Deployment of a web application to permit customers to report outages online.

[89] Discussed earlier in the subsection titled, "Loss of Hydro's EMS."
[90] Review of Supply Disruptions and Rotating Outages Volume II.
[91] Liberty will review Hydro's outage response support systems business continuity plans and contingencies in more detail for the Fall 2014 Report.
[92] Response to PUB-NP-105.

These improvements played a key role in opening Newfoundland Power's website as a primary communication channel during the January 2014 outages. Recognizing the importance of the website at this time, Newfoundland Power turned the front page of its website into an event outage page as of January 2, 2014. This transformation made it easier for visitors to find relevant outage information. Doing so comprises standard industry practice during large storms or outage events.

In addition, callers unable to reach Newfoundland Power's Contact Centre to speak with a representative received a "polite disconnect" message that directed callers to the website to report an outage or get updates on restoration status.

In total, Newfoundland Power received 947,219 web visits during the January 2 – 8, 2014 outage event. Website visits[93] peaked on January 4th at 219,000 visits and again on January 5th at 200,000 visits. In contrast, Newfoundland Power only received 156,500 web visits during the prior year's outage event (January 11 – 13, 2013).

Newfoundland Power's website proved generally reliable during the January outage events. On several occasions, however, response was very slow or the server was unavailable due to overloading. On January 2nd the website was unavailable to customers for 44 minutes. On January 5th the website was unavailable for 13 minutes. During these incidents, the website would have displayed a message to some customers that the server was too busy.[94]

As a result, Newfoundland Power took steps to improve the reliability of its website following the January 2014 events, including installing a load balancing device in front of the two duplicate sites (1 active/1 standby). The changes brought significant improvement to the website, effectively doubling capacity to accommodate visitors during high traffic moments. Newfoundland Power's website provided a key communications channel during the January outage events, and is now positioned to effectively support more visitors in future events.

8. Use of Social Media

Social media offered provided a key and effective communications channel for both utilities during the January 2014 events.

Newfoundland Power gained 6,561 new Twitter followers and 4,119 Facebook "likes" during the January 2014 outage events.[95] Newfoundland Power's Facebook page was visited 166,000 times. During the course of the outage, Newfoundland Power issued 350 tweets (Twitter), and retweeted Hydro's outage-related tweets numerous times. In addition, Newfoundland Power's YouTube channel was available, with videos of the power restoration process and safety. These videos were viewed 575 times during the January event.[96] In contrast, only 240 email inquiries were received by Newfoundland Power during the outage event.[97]

[93] Response to PUB-NP-025(Rev1).
[94] Response to PUB-NP-036(Rev1).
[95] Response to PUB-NP-025(Rev1).
[96]Response to PUB-NP-116.
[97] Response to PUB-NP-025(Rev1).

These forms of social media provided critical communications tools for distributing messaging and gaining direct feedback from customers. The availability of social media feeds from both companies made it easier for local media/radio to feature on their websites and social media outlets, further extending the reach and distribution of outage related information to the public. Social media as a communications tool has witnessed growth in usage and acceptance in the industry. Social media appeals to younger customers, and serves the same role as radio/TV does for older generations. An outage communications presence on Twitter, Facebook, and YouTube to reach customers now comprises industry best practice. Use of social media also provides the opportunity for two-way communications, helping utilities keep in touch with the current customer experience.

Newfoundland Power experienced a significant increase in web and telephone traffic during the January outage events, as discussed earlier. The website was overloaded twice. At both times, customers were reaching out to notify Newfoundland Power that their power was out and to learn how long until it would take to restore. Neither the website nor the phones could handle the demand. Many reached out through social media.

Neither Newfoundland Power nor Hydro has the capability to communicate with customers by SMS (text). Texting is a very popular communications channel, one that has been leveraged by some utilities to provide outage restoration status updates during large storms and outages.

The capability exists to let customers sign up for outbound texts, by providing a mobile number and indicating their location/region. These messages can be used to keep customers up-to-date on steps that can be taken to prepare for a storm, preparations leading up to a storm, how the storm impacted the region, and the latest on restoration efforts both across the service territory and the location/region of choice. Customers can also text their postal code to a specific number and receive an update based on the postal code.

SMS texts can be used to deliver proactive alerts for outage notifications, estimated restoration time updates, and restoration notifications, as well as two-way text message communication. SMS communication provides another easy communication channel for customers. Texting is much quicker and easier than calling or visiting a website. Utilities have also used SMS text messaging to send alerts and requests for energy conservation.

Outbound outage alerts can be delivered by SMS text message, email, and text-to-speech voice message (outbound calling). Broadcasting ad hoc messages about storm activity to customers registered for alerts can be an effective communication that relieves some of the burden off telephone and web channels.

These communications options provide opportunities for utilities to customize communication based on customer preference, a trend that is now common for many financial institutions, such as receiving a “low balance” text message from your bank. Custom service options generally lead to higher customer satisfaction.

41. 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.

B. Public and Media Communications

1. Background

In addition to responding to customer inquiries and outage notification calls, utilities must be prepared to communicate storm restoration status to the general public and to officials and community leaders. One of the most vital functions of a utility's corporate communications department during a major storm is to make sure that all employees present the same information about storm restoration to their contacts outside the company. In addition, a company must effectively disseminate storm restoration status information to stakeholders; *e.g.*, government officials, large industrial customers, the media, employees, and customers. Again, the goal is to deliver the same message to the press, legislators, government officials, and the next customer calling into the call center.

To manage and disseminate information effectively, Corporate Communications must work closely with the Emergency Operations Center ("EOC") to gather information on restoration progress, the number of customers out of power, and projected restoration times. Ultimately, the outage management system is the repository and source for this information. It effectively links the field with other areas of the company to manage the restoration effort and communicate progress.

Storm restoration progress reports timed for release around the local news media cycles; *i.e.*, early morning, noon, 5 p.m. and 11 p.m. can best be featured on local radio and television newscasts. Equally important is the need to coordinate with operations prior to each release so the numbers are fresh and accurate. Concurrently, call center representatives and other key employees working with community and public officials, key accounts, and state emergency agencies can receive the same messages.

Community Relations comprises another key utility function during major outage events, especially keeping provincial and local government officials informed. This role usually falls to community relations, quite often filled by district or division management. No one knows their communities better than the people who work in them day-in and day-out.

On an ongoing basis, it is important to play an educational role in communities regarding outage and storm restoration. An excellent way to involve the community and open the lines of communication between local officials and the company is to host community workshops promoting outage response awareness. These forums also provide an opportunity for the utility to gather feedback and learn expectations. To be effective at community relations, utilities need to emphasize training for community relations representatives and other employees actively interfacing with the community and public. Training should familiarize employees with sources of outage information and with how best to interact with the public, governmental officials, and community leaders.

This section contains the primary findings, analysis, and detailed descriptions of the systems and processes that supported media and public communications during the January 2014 outages.

2. Timeliness of Conservation Requests

The initial Customer Communications request for customer conservation was not issued jointly with Newfoundland Power, was issued too late on January 2nd to be effective, and made no mention of potential outages.

The decision to request customer conservation was made too late in the day on January 2nd to be actionable. The conservation request advisory was released in the mid-afternoon, when many Newfoundland Power customers were at work. In addition, Hydro did not incorporate Newfoundland Power's input into the advisory, nor did it provide a copy to Newfoundland Power prior to release.[98]

The initial public advisory, issued by Hydro did not mention the possibility of rotating outages. Newfoundland Power did not release an advisory on January 2nd. As a result, customers had no advance warning of the planned rotating outages. As seen in the prior section, one of the peak calling periods during the outage was when the rotating outages were initially started at 4:13 p.m. on January 2nd.

Newfoundland Power should develop advance notification procedures for future rotating outages. Notification should include the areas targeted for outages, the starting time and estimated duration. The companies should develop a joint strategy for future rotating outages that will permit Newfoundland Power to provide customers with, for example, a two-hour window estimate of the starting time of the outage. Planned outage notification information should be posted on the website, IVR and other self-service channels.

Should Newfoundland Power wish to request the assistance of its customers in energy conservation, clear, specific instructions should be communicated, specifying the actions and timing that will be most beneficial. In addition, the request should be made to customers well enough in advance so that customers can take appropriate actions before leaving their residences.

Newfoundland Power should continue to enhance and improve this process going forward, incorporating customer feedback and analysis of prior performance.

42. 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.

3. Effectiveness of Conservation Requests

Newfoundland Power and Hydro have not conducted the analysis necessary to determine the effectiveness of conservation requests made during the January outage events, nor have the

[98] Response to PUB-NP-116.

companies surveyed customers to understand how customers received information from the companies related to requests for conservation. This should be done.

Considering the level of effort needed to effectively communicate the need for conservation to residents of Newfoundland, it makes sense to measure the impact or, at a minimum, estimate the potential impact of such conservation. Other utilities provide this information to their customers, and rely on it to ensure customer cooperation in future events. This should be used to guide the decision to request conservation in the future. In addition, this effort should dovetail with efforts to research customer needs and expectations research recommended earlier in this chapter.

43. 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.

4. Newfoundland Power's Communications Hub

Newfoundland Power's Communications Hub plays a key outage response role. Nevertheless, it does not (but should) comprise a formal part of its outage response plan. Newfoundland Power created the Communications Hub concept following the January 2013 outage event. A cross-functional team comprised of individuals from operations, customer relations, communications and information services has responsibility for the assembly, update, and dissemination of outage information to key employees, such as the Contact Centre, Systems Control Centre, Field Operations, and the Communications Team. The Communications Hub was in place and Newfoundland Power's Customer Contact Centre was up and running when the rotating outages began on January 2, 2014.[99]

Outage status messaging is critical. Outage communications is a necessary element of the outage restoration process. Whether for a big storm or a small outage, there is still a need to communicate effectively with customers. Now that both utilities have been through the January 2014 events, it is important to solidify the proper protocols and templates that will ensure effective outage communications in future events. While each outage or storm is relatively unique, there are many aspects that are common.

Best practice utilities have developed an *Outage Communications Plan* to address all the steps that should be taken during an event. The plan will identify the outage communications team, specify roles and responsibilities, and provide a checklist of actions and templates of key communications. It will be structured to stipulate the correct response based on the impact to customers and degree of severity of the storm or outage. Both utilities just went through a severe outage event. Now offers an excellent opportunity for joint work to update outage response communications plans, protocols, and templates. They need to be actionable and accessible when the next event occurs.

[99] Response to PUB-NP-116.

44. 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.[100]

5. Media Involvement

Both companies were very actively involved with the media during the January outage events.

Newfoundland Power conducted more than 100 media interviews, including six news conferences or media scrums. Newfoundland Power also used digital and mass media to send broader messages to customers about the outage-related events. These activities included 598 website postings and 302 social media posts. Newfoundland Power also re-tweeted 160 Hydro and other government posts during the event.

The focus was on local media primarily; however, national media requests were also covered. In addition to supporting the interviews, Corporate Communications conducted facility tours of the Customer Contact Centre, System Control Centre, and other operational locations. Newfoundland Power also issued joint public advertising with Hydro and Government using radio, print, social media, and web.

Hydro also used traditional, social, and digital media to provide outage information and Hydro spokespersons were readily available to media during and after the supply disruptions.

Newfoundland radio also focused on the event, with some stations running 15-hour call-in shows surrounding the event. Post event analysis conducted by Newfoundland Power reveals that most customers relied on the radio as a source of information during the outages in January (75 percent of customers surveyed) versus television (19 percent), demonstrating the importance of supporting the media during an event such as this.[101]

A public survey conducted post-event indicated that while respondents said that Hydro could have provided more information/updates during the outages, respondents also indicated that Hydro's communication with the public was one of the top things that Hydro did well during the events.

Customers were frustrated with the lack of information provided during the outage. Many called and many others visited the company websites, trying to understand how long they would be without power. This is indicative of insufficient public messaging. If the message provided to the media is vague or unable to answer customers' most basic questions, a high volume of customers will still try to learn more by calling to speak with a company representative or visiting a website.

[100] Liberty will review Hydro's and Newfoundland Power's Outage Communications Plans in depth, for the Fall 2014 Report.
[101] Response to PUB-NP-126.

6. Communications Lessons Learned

Following the January 2014 events, both utilities have identified many items to address to improve the outage communications process. This identification comprises an important, continuous improvement step that they should formalize into a post-event and lessons-learned process.

Equally important is the need to conduct a joint lessons-learned session between the Communications teams of both utilities. Conducting lessons-learned sessions following a large storm or outage is an industry best practice. Through this process, both utilities will identify opportunities to improve coordination and joint utility outage communications. Formal meeting notes should be taken of the topics discussed during the sessions. In addition, all action items should be assigned for follow-up and a process should be put in place to document the actions taken to resolve issues, to report progress, and to communicate results.

The Communications Teams from Hydro and Newfoundland Power have not yet conducted a joint “lessons learned” session to review the January outage event.

45. 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.

VI. Coordination between Hydro and Newfoundland Power

The preceding chapters addressed a number of areas where the two companies face opportunities to improve their coordination in a variety of operations and customer communications and research areas. We address coordination separately because the opportunities cut across subjects addressed in the preceding chapters of this report, and because Liberty believes that Hydro and Newfoundland Power will benefit from a focused, concerted effort to address them under the sponsorship of joint, senior executive management.

Hydro considers operations-related communications between itself and Newfoundland Power to have been effective. Newfoundland Power agrees that communications regarding the initiation and execution of rotating outages worked well, but seeks improvement in information regarding:

- A series of real-time data points about conditions on Hydro's system that may affect Newfoundland Power operational preparedness and decisions
- The process for optimum dispatch of Newfoundland Power hydro units by Hydro.

Both coordination matters raised by Newfoundland Power comprise subjects of current discussions between the two companies. Newfoundland Power has submitted a request for many data points to Hydro. Meanwhile, the two companies have agreed to a new dispatch protocol. Newfoundland Power will control when its units will be made available for economic dispatch. On the other hand, Hydro will make the decision when system security is the motivator. Neither of these two potential issues led to or influenced the nature or consequences of the capacity problems.

The preceding report chapter discusses a number of customer information and communications needs that the two companies should pursue jointly.

Our discussions with each company demonstrate conceptual commitments in a number of areas. They recognize that the unique relationship of the two in serving IIS customers creates a number of areas where goals, joint structures or teams, protocols, programs, and activities can and should be in common. A clear approach, assignment of resources, and action plans and schedules have, however, yet to occur. It is time for these activities to commence, in order to provide traction to the process of enhancing coordination between the two companies.

Liberty recommends that:

46. 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.[102]

[102] Liberty will examine progress in this area as part of work leading to the Fall 2014 Report.

Appendix A: List of Recommendations

1. Hydro should complete the modifications or replacement of Nostradamus by December 1, 2014 in order to enable improvements in the accuracy of short-term forecasts under extreme weather conditions.
2. By December 1, 2014, Hydro should incorporate into its short-term forecasting process any significant load changes, from losses or otherwise, resulting from varying system configurations.
3. In the interim, Hydro should implement the Ventyx recommendation to consider weather extremes via sensitivity analysis in all forecasting and supply planning evaluations and decisions.
4. By September 1, 2014, Hydro should: (a) evaluate and reach resolution on a formal change to the planning process to use a greater than 50 percent probability weather variable, (b) propose that criterion to the Board for use in future capacity decisions, and (c) continue to conduct sensitivity analysis for extreme weather, but around the new weather variable.
5. Before December 1, 2014, Hydro should: (a) re-evaluate the deviations between its forecasted winter peak and the multiple times it was exceeded during the winter of 2014, and (b) determine what, if any, common factors were responsible and what changes, if any, they suggest for the forecasting process.
6. Before September 1, 2014, Hydro should: (a) strengthen its ability to reconstruct the peak load when peaks have been significantly affected by artificial means such as those employed by the generation shortage protocol, and (b) use those improved techniques in the recommended evaluation of 2014 forecast deviations.
7. Hydro should follow through on its plans to assure consistency in future reliability analyses by focusing on the IIS, as opposed to the Hydro system alone.
8. For the near-term, Hydro should abandon the LOLH of 2.8 criterion, and the associated low reserve requirements, in favor of an “as low as practical” objective.
9. For the long-term, Hydro should evaluate, taking account of stakeholder input a new supply reliability criterion with a logically associated level of reserves, and seek Board concurrence to use that criterion as a basis for long-term supply planning.
10. By June 15, 2014, Hydro should formalize its established plan to implement an aggressive availability improvement program focused on all generating assets, especially focusing on the Holyrood units and the two CTs.
11. Hydro should formalize its maintenance program for Holyrood generating station and the CTs in a submittal to the Board by June 15, 2014, covering the period through November 30, 2014, with the submittal to include, at least: (a) a listing of all key maintenance activities planned for each unit, (b) a critical path schedule for each planned outage of a unit including major work items, (c) a sequencing plan for planned outages showing the relationships among planned outages and how, if at all, an outage at one unit restrains an outage at another, and (d) bulk production curves for maintenance activities at each unit by number of work orders or whatever measure Hydro finds preferable.

12. Hydro should formalize by June 15, 2014, a generation master plan for winter preparation, including the above availability improvement activities and tasks addressing emergency preparedness.
13. Hydro should, on a monthly basis, and starting no later than June 30, 2014, formally provide updates of the plans under the three preceding recommendations, and meet with the Board Staff to review and observe progress.
14. No later than June 15, 2014, Hydro should provide to the Board a detailed report on decisions and pending actions regarding spare parts for Holyrood generating station and the CTs, including: (a) a listing of all critical plant components, (b) the results of risk analyses of such critical components, (c) the decisions on which parts should have spares, either on site or at a vendor, and (d) the action plan to procure any unsecured such parts before November 30, 2014.
15. Hydro should treat the securing of new generation as a first priority; reach a prompt decision on a preferred option and proceed expeditiously towards an in-service date of December 1, 2014 or, if not possible, by December 1, 2015 at the latest.
16. Hydro should continue discussions with appropriate industrial customers who might make a material contribution to interruptible load with a goal of securing economically available interruptible loads.
17. Hydro should intensify DGA testing of its critical transformers exhibiting questionable levels of combustible gases, and take actions necessary to minimize failures, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
18. Hydro should catch up on overdue testing and maintenance on its critical transformers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
19. Hydro should complete system studies to verify that its plan to relocate the repaired T5 transformer from Western Avalon terminal station to replace the failed Sunnyside T1 transformer will not unduly reduce the reliability of the Western Avalon terminal station and of the transmission system as a whole, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
20. Hydro should conduct operation tests (exercise) all air-blast circuit breakers in 2014, preferably in cold weather, and continue exercising them on an annual basis, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
21. Hydro should catch up on overdue testing and maintenance on its critical air-blast circuit breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
22. Hydro should change its air-blast circuit breaker proactive maintenance program cycle from six to four years, until retirement of these breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
23. Hydro should periodically operate each of its circuit breakers from protective relays, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
24. Hydro should redesign its existing breaker failure relay protection schemes to provide that breaker failure will be activated whenever a transformer fails coincidentally with either a 138kV or a 230kV breaker malfunction, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

25. Hydro should formally examine the installation of breaker failure relay protection for transformers in terminal stations where breaker failure relay protection is not in place, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
26. Hydro should prepare on a high priority basis a documented analysis of ECC emergency generator availability risk, and maintenance procedures that address regular inspection and repair commensurate with the risks identified, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
27. Hydro should update its event and data recording devices and systems to give each type of transformer alarm its own alarm point, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
28. Hydro should develop a priority procedure to repair immediately a malfunctioning digital fault recorder (DFR), beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
29. Hydro should complete the studies being conducted to determine whether abnormal system disturbances could have caused the T5 transformer failure at Western Avalon terminal station, and report whether any changes need to be made in systems operations or configuration as a result of these studies, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
30. Hydro should seek to locate for Western Avalon T5 a replacement transformer that can be purchased in case: (a) the field repairs are not successful, (b) the repaired transformer fails again later, or (c) the transformer is moved to Sunnyside terminal station, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
31. Hydro should include experienced protection and control technologists with its response teams when addressing Hydro termination station events involving investigating and modifying complicated protective relay schemes, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
32. Hydro should not employ any “slow trip” coils, where used by backup relay tripping in its air blast circuit breakers, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
33. Hydro should prepare a maintenance practices document addressing the new procedure for applying the protective coating to its air-blast circuit breakers and describing how the new procedure will prevent moisture contamination, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
34. Hydro should review its substation and protection and control (P&C) staffing needs for the future, in light of the more intense maintenance needs on its aged transformers and circuit breakers, its protective relay replacement and modification work, and upcoming construction work on the new DC lines, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
35. Hydro should use qualified substation contractor personnel, specializing in substation equipment testing and maintenance, to provide the skilled manpower required to assist with the transformer projects and to catch up with regular scheduled maintenance on transformers and circuit breakers, while crews conduct the air-blast circuit breaker operational tests (exercising), beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.

36. Formally incorporate by June 15, 2014 lessons learned about Newfoundland Power's service restoration issues, such as cold load pickup, into emergency response procedures and training of employees.
37. As a first step, Newfoundland Power and Hydro should develop a joint 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.
38. 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.
39. 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.
40. Hydro should review and refresh business continuity plans and contingencies to ensure continual operation and availability of critical outage response support systems, beginning with preparation by June 15, 2014 of a detailed plan and schedule for doing so.
41. 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.
42. 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.
43. 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.
44. 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.
45. 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.
46. 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.