Prudence Review of
Newfoundland and Labrador Hydro
Decisions and Actions
Final Report

Executive Summary

Presented to:

The Board of Commissioners of Public Utilities of Newfoundland and Labrador

Presented by:

The Liberty Consulting Group

July 6, 2015

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Executive Summary

Report Purpose and Scope

- The Board of Commissioners of Public Utilities of Newfoundland and Labrador ("Board") retained The Liberty Consulting Group ("Liberty") to review the prudence of certain decisions and actions of Newfoundland and Labrador Hydro ("Hydro"), and to determine the costs related to these decisions and actions.
- Most of the decisions and actions within the scope of the review concern Island Interconnected System ("IIS") outages experienced during the preceding two winters of 2013 and 2014. Some concern earlier decisions and actions where the Board deferred recovery of the associated costs, pending further review.
- Liberty conducted its review according to accepted standards for examining the prudence of utility decisions and actions. These standards include:
    1. The utility's decisions and actions must be reasonable in the context of information that was known or should have been known at the time.
    2. The utility must act in a reasonable manner and use a reasonable standard of care in its decision making process.
    3. Hindsight is not to be used in assessing prudence; decisions and actions must be evaluated on the basis of circumstances existing at the time.
- Avoiding the use of hindsight comprises a central element of the prudence standards. This element requires that management operate on the basis of information known or knowable through appropriate diligence at the time. The standards also require consideration of an appropriate range of alternatives. Where management chooses as a result of such consideration an alternative within the range of reasonable alternatives, the resulting decision or actions chosen are deemed prudent, subject to the appropriateness of their implementation.
- Where a utility's actions are determined to be imprudent, the costs of such actions should be determined to the extent practicable, to support decisions about their exclusion from rates paid by the utility's customers. Regulators generally do not allow utilities to recover from customers the costs attributed to imprudent actions.
- Liberty has extensive experience working with utility regulators on a full range of areas involving the provision of reliable, safe and cost effective utility service and has worked for regulators in some 40 North American jurisdictions, and has undertaken work for a similar number of North American energy utilities. Liberty has conducted a number of prudence reviews, most recently for the Nova Scotia Utility and Review Board.

Overall Conclusions

- The scope of Liberty's review as established by the Board included twelve Hydro decisions or actions (eleven specific projects or programs and one deficiency account established by Hydro to reflect a shortfall in its 2014 revenue).
- Most of the twelve items examined by Liberty involved requests to the Board for approval of the underlying work or for deferral of certain costs. Hydro typically made those requests using estimates. Hydro reported to Liberty that actual costs (some offset by insurance recovery) have proven lower in some cases. Liberty began its work on the basis

of estimated costs, but where Hydro has provided updates to reflect what it described as actual costs, Liberty reports them.

- Liberty understands that subsequent General Rate Application review by others will address revenue requirements in detail. Liberty thus did not verify Hydro's statements of actual costs, but merely reports them as a foundation for subsequent review in Hydro's General Rate Application.
- Liberty found Hydro's decisions and actions imprudent in seven of the eleven specific projects or programs set for examination by the Board. Liberty identified adverse cost consequences associated with six of these seven projects or programs, laying a foundation for consideration of the propriety of their recovery from customers. Liberty found planning and execution of the seventh project imprudent, but concluded that Hydro would have borne essentially the same costs even in the absence of such imprudence.
- Of the remaining four specific projects or programs, Liberty found that Hydro had acted prudently with respect to three. Liberty did observe significant weaknesses in the supply planning process related to one of these projects, the new combustion turbine, but not to a degree that would constitute imprudence. For the fourth, Liberty concluded that while Hydro acted prudently in making its decision, some of the costs incurred were influenced by imprudent prior actions.
- The twelfth area of Liberty's review consisted of an identification of 2014 actual capital costs and operating expenses that could be attributed to imprudence. This identification lays a foundation for later efforts that seek to identify any such expenses that may form part of Hydro's estimation of a 2014 Revenue Deficiency of $45.9 million.
- Liberty found that the costs that Hydro could have avoided in the absence of the instances of imprudence found by Liberty were:
    - Actual 2014 capital costs of $10.9 million (as reported by Hydro)
    - Actual 2014 operating expenses of $13.4 million.
    - Estimated 2015 operating expenses of $2.6 million.
- The implications for Hydro's 2014 and 2015 test year revenue requirements for the capital projects found by Liberty to be imprudent are discussed later in this report.
- The next section describes the twelve subject areas reviewed and Liberty's conclusion with respect to each.

Subject Areas Reviewed by Liberty

Projects Found to be Prudent

1. The New Holyrood Combustion Turbine

Hydro has invested an estimated $119 million in a new 100 MW (nominal) combustion turbine ("CT") at the Holyrood site. Liberty identified significant weaknesses in Hydro's supply planning process, but these deficiencies did not rise to the level required to find them imprudent. Liberty therefore, found Hydro's planning, procurement, and installation of this new facility prudent. Even if Hydro had acted earlier to install new capacity as may have occurred had more appropriate planning been done, costs would not likely have proven less than the amount for which Hydro now seeks recovery.

2. Supply Related Costs

Supply constraints following the January 2014 outages caused Hydro to call upon a capacity assistance agreement with Corner Brook Pulp and Paper, and to use its own and some Newfoundland Power units with comparatively high fuel costs at a cost of about $9,650,000. Liberty concluded that Hydro acted prudently in making the generation-related decisions that required the use of the additional expensive sources of generation. However, equipment failures on Hydro's transmission system also caused supply issues for customers. Liberty attributed those equipment failures to imprudent Hydro execution of maintenance practices. The failures caused a four-day outage of Holyrood Unit 1, which Liberty estimates to have led to $2,189,110 of the total supply costs proposed to be recovered by Hydro. Hydro could have avoided this amount in the absence of imprudence.

3. Holyrood Unit 3 Forced Draft Fan Motor

In late December 2013, a forced draft fan motor at Holyrood Unit 3 failed. The Unit returned to full output on January 12, 2014. Absence of the motor pending repair limited Unit 3's output from its normal 150 MW to 50 MW. The lost 100 MW made up a significant part of the unavailable generation that resulted in supply shortages and rotating blackouts in early January 2014. Prior to the failure, Hydro received a 2011 consultant's conclusion that the Unit 3 motors would not last for Holyrood's remaining life. Hydro's evaluation of the risks versus the costs of two alternatives available (*i.e.*, replacing the motors or procuring spares to keep at the site) led it to reject both of these alternatives. Liberty believes that Hydro acted with knowledge of the necessary information, and chose a reasonable alternative (to take the risks of failure). Therefore, Liberty found Hydro's decisions prudent.

4. Black Tickle

A March 2012 fire caused significant damage to the diesel plant that provides the only source of power for the Labrador community of Black Tickle. Hydro expended capital costs of about $1.4 million (net of insurance) to return the plant to service. Hydro's failure to act earlier on fire suppression in diesel plants may have been unsound, but prompter action still likely would not have occurred prior to the Black Tickle fire. Liberty concluded that Hydro's decision not to reduce the capacity of the plant to reflect the loss of a major source of load in the community fell among the reasonable range of alternatives, considering the circumstances. Liberty also found management of the restoration prudent and costs reasonable.

Projects Found to be Imprudent

5. Sunnyside Replacement Equipment

Two failures combined to lead to widespread outages on the IIS, beginning on the morning of January 4, 2014. First, the Sunnyside T1 transformer failed. Second, the Sunnyside B1L03 air blast circuit breaker failed to open in response to the resulting fault. The delay in clearing the transformer fault caused a transformer fire that also damaged nearby equipment. Hydro replaced the fire-damaged equipment, and installed an additional 230kV breaker with breaker failure protection. Liberty found that Hydro acted imprudently in systematically and broadly failing to adhere to appropriate transformer and breaker maintenance cycles for a number of years. This failure deprived Hydro of the opportunity to identify and address the causes of the transformer and breaker failures before they occurred. Liberty therefore attributes the $3,149,184, in 2014 actual capital and 879,800 in operating expenses that Hydro reported as the costs to repair the transformer and damaged equipment to imprudent conduct.

6. Western Avalon Terminal Station T5 Tap Changer Replacement

Following the onset of widespread IIS outages on the morning of January 4, 2014, the Western Avalon T5 transformer failed as Hydro attempted to energize it. The tap changer for Transformer T5 experienced damage. The incident required Hydro to replace the damaged tap changer and to clean the transformer windings. Hydro's systematic failure to adhere to appropriate breaker maintenance cycles deprived the Company of the opportunity to identify and address the cause of the breaker failure before it occurred. Liberty found this action to be imprudent. Liberty attributed the resulting 2014 actual capital costs, which Hydro reported to have been approximately $1 million, to this imprudence.

7. Overhauls of the Sunnyside B1L03 and Holyrood B1L17 230kV Breakers

The combination of two failures (the Sunnyside T1 transformer failure and the Sunnyside B1L03 air blast circuit breaker) led to IIS outages that began on the morning of January 4, 2014. The failure of the Holyrood air blast breaker B1L17 on January 5, 2014 caused another wide-spread outage. Hydro overhauled the Sunnyside and the Holyrood breakers in the spring of 2014. The Company requested authorization for about $500,000 to cover the overhaul costs.

Liberty concluded that Hydro imprudently executed maintenance practices for Sunnyside breaker B1L03 and imprudent maintenance work procedures on breaker B1L17 caused internal ice accumulation that caused its failure. Liberty attributes the amount required for the two overhauls to imprudent decisions and actions by Hydro.

8. Extraordinary Transformer and Breaker Repairs

Hydro has proposed increased 2015 expenditures to accelerate work to bring maintenance on transformers and air blast circuit breakers into conformity with its established six-year cycles for such work. The request also includes costs associated with shortening the breaker maintenance cycle to four years, beginning in 2015. The Company's current rate filing seeks to amortize over five years $1.2 million in 2015 expenditures to perform catch-up maintenance work. Liberty found that the shortening of the cycle for breakers is appropriate.

The 2015 expenditures that Hydro proposes to amortize include both transformer and air blast circuit breaker costs that Hydro would not have had to incur in the absence of imprudent deferral of maintenance work. For similar reasons, Hydro's 2014 program of transformer and breaker maintenance work catch up caused it to incur expenses that it would have avoided in the absence of such imprudence.

Six-year maintenance costs in 2014 for transformers would have been about $411,870 and for breakers about $257,544, had Hydro required only normal levels of work to meet annual requirements associated with normal schedules. Liberty attributes 2014 costs above these normal levels to imprudence. In 2015, Hydro would be expected to spend about $411,870 for work on six-year maintenance assuming normal levels of work. Acceleration of the breaker maintenance cycle to four years in 2015 would amount to about $398,021. Liberty attributes 2015 costs for four-year air blast circuit breaker maintenance above $398,021 and six-year maintenance costs for transformers above $411,870 to imprudent maintenance deferral.

9. Black Start

Hydro leased and installed eight 1.825 MW diesel generators to provide interim black start capability at Holyrood. Hydro secured approval from the Board in 2013 for capital expenditures of $1,263,400 and for the creation of a deferral account for lease and other infrastructure costs estimated at $5,763,200. Hydro has reported to Liberty that its actual 2014 capital costs were $761,977, 2014 operating expenses were $160,485, and 2015 forecast operating expenses are $ 1,089,375 (including the amortization of lease costs for the 8 diesel generators).

Black start capability is critical in allowing Holyrood to restart when disconnected from other sources that can provide the power needed for restart. Liberty concluded that a series of decisions and actions by Hydro left Holyrood without black start capability for an extended period of time. Liberty concluded that Hydro did not choose from a reasonable set of alternatives for providing black start. Hydro's imprudence produced too short a "used and useful" period to justify the expenditures made to implement black start. Liberty, therefore, concludes that the amounts spent by Hydro for this project are attributable to imprudence.

10. Holyrood Unit 1 Turbine Failure

A January 2013 terminal station failure resulted in isolation and tripping of all three units at the Holyrood Plant. Adequate lube oil supply was lost to the Unit 1 turbine-generator, causing major damages and a prolonged outage. A root cause analysis identified several contributing causes for the lube oil failure. The primary factor was failure of the DC lube oil system to function as intended.

Upon Hydro's request, the Board approved capital expenditures of $12,809,700 for the repair of the Unit 1 turbine, but did not approve these expenditures for inclusion in the rate base, pending a future Order. Hydro has reported to Liberty 2014 actual and 2015 test year capital costs of only $5.5 million and $4.6 million, respectively, which reflect reduced construction costs from estimates and insurance proceeds. Operating costs of $2.4 million (including 2014 turbine vibration repairs and replacement power) in 2014 and $1.0 million of depreciation in the 2015 test year are also a result of the turbine failure. The factors contributing to this catastrophic event are numerous and complex. Liberty believes that Hydro's imprudence contributed to the damage. Liberty therefore attributes the costs of repair to imprudence.

Liberty believes that there is reason to believe that the lube oil protection schemes continue to present the risk of common mode failure. The resulting potential for future failures and subsequent damage to one or more Holyrood turbines makes prompt attention by Hydro appropriate for the future.

11. Labrador City Terminal Stations

Hydro's 2009 Capital Budget included a project to increase capacity at its Labrador City Terminal Stations. Hydro based its plans for the project on inadequate information. The need to perform work well in excess of what those initial plans contemplated caused a delay in construction and increased costs. Actual final costs of $16,844,000 substantially exceeded (by $4,194,000) the revised budget approved by the Board. Hydro failed to consider a number of required elements in forming earlier project estimates. Later estimates that did consider such elements produced major cost increases.

Hydro imprudently executed project planning, design, and estimating by failing to acquire available information and to use information in its possession. Resulting errors, however, did not cause an increase in project costs or affect customer service. The gaps that caused earlier estimates to be too low involved work that had to be performed in any event. Delay in completion of such projects often causes costs to increase, however, that consequence did not occur here.

12. 2014 Revenue Deficiency

Hydro carries a $45.9 million deferred asset that reflects the difference between a calculation of 2014 revenue requirements and those used most recently to establish rates for electricity service. Hydro made its revenue deficiency calculation using five months of actual and seven months of estimated 2014 costs. Using actual costs, Liberty identified $10.9 million of actual capital expenditures associated with imprudence concerning projects or programs undertaken or in service in 2014 that Liberty found to be imprudent. Liberty also identified $13.4 million in actual 2014 operating costs as avoidable but for the January 2014 outages. Hydro incurred these avoidable costs for the 11 projects and programs within the scope of Liberty's prudence review, as well as professional services, incremental overtime, and transfers of salary costs to Hydro from Nalcor executive and financial personnel.

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Table of Contents

List of Charts, Tables, and Figures

Chapter One: Introduction

A. Summary

This report presents the results of The Liberty Consulting Group's ("Liberty") review of the prudence of certain decisions and actions by Newfoundland and Labrador Hydro ("Hydro" or "the Company") on projects and activities whose costs recovery remain outstanding. This review includes 11 projects and programs, most, but not all of which, relate to 2013 and 2014 supply and outage issues that Liberty addressed in a December 2014 report to the Board. This report also addresses a 12th item, the actual 2014 costs resulting from projects or programs that Hydro would not have been expected to undertake in the absence of any instances of imprudence found by Liberty. The difference between Hydro's proposed 2014 revenue requirements and those used to set current rates have formed the basis of a significant deferral amount. Recovery of the costs that form that deferral also await Board consideration.

Liberty conducted this review according to established standards and principles for prudence reviews. Liberty began with extensive knowledge of the facts underlying most of the subjects within the scope of its examination. Liberty examined much additional written information, and conducted a number of working sessions with Hydro.

B. Background

The Board of Commissioners of Public Utilities of Newfoundland and Labrador (the "Board") retained Liberty to examine the prudence of certain decisions and actions by Hydro and to determine the impacts on resulting costs of any decisions Liberty determined to be imprudent.

C. Scope of Liberty's Examination

The Board identified twelve subject areas for Liberty to examine. For the most part, these subject areas address work related to the supply and transmission issues that Liberty examined in connection with its review of 2013 and 2014 supply issues and power outages on the Island Interconnected System ("IIS"). Liberty issued a December 17, 2014 report describing that review and its results. The scope of this prudence review also included two projects unrelated to the scope of Liberty's prior review. The subject areas within the scope of this review include the following:

1. **Black Start:** Order No. P.U. 38(2013) deferred the question of recovery of proposed capital expenditures and lease costs to install eight 1.825 MW diesel-generators to provide temporarily black start capability at the Holyrood generating station.
2. **New Combustion Turbine:** Order No. P.U. 16(2014) approved the purchase and installation of a 100 MW (nominal) Combustion Turbine at Holyrood station, but deferred consideration of the recovery of the costs.
3. **Restoration of Holyrood Unit 1 Turbine Generator:** Order No. P.U. 14(2013) approved expenditures to repair damage caused when the unit tripped during a January 11, 2013 storm, but deferred consideration of the recovery of the costs.
4. **Sunnyside Replacement Equipment:** Order No. P.U. 29(2014) approved expenditures to purchase and install a new transformer and associated equipment and undertake modifications at the Sunnyside terminal station, following extensive damage from a

January 4, 2014 transformer failure and a subsequent fire, but deferred consideration of recovery of the costs.

5. **Western Avalon Terminal Station T5 Tap Changer Replacement:** Order No. P.U. 32(2014) approved expenditures to replace the tap changer and clean and dry the transformer following damage after the transformer experienced a fault in January 2014, but the Board deferred consideration of the recovery of the costs.
6. **Capacity Related Supply Costs:** Order No. P.U. 56(2014) permitted deferral of costs to address supply shortages experienced in 2014, but deferred consideration of recovery of the costs.

7.a **Holyrood Unit 3 Forced Draft Fan Motor:** Order No. P.U. 23(2014) approved expenditures to repair Holyrood Unit 3's east forced draft fan motor, which failed on December 26, 2013, but deferred consideration of recovery of the costs.

7.b/c. **Overhauls of Sunnyside B1L03 and Holyrood B1L17 230 kV Breakers:** Order No. P.U. 23(2014) authorized expenditures to overhaul these two breakers, which failed in early January 2014, but deferred consideration of recovery of the costs.

8. **Restoration of Black Tickle Diesel Plant:** Order No. P.U. 27(2014) excluded costs of restoring the diesel plant in Black Tickle, damaged by fire, servicing an isolated Labrador system, pending consideration of their reasonableness.
9. **Labrador City Terminal Station Over-Budget Expenditures of $4,194,000:** Order No. P.U. 42(2013) deferred recovery of expenditures above the last approved amount for the facilities required to increase the capacity of the system serving the area, pending consideration of their reasonableness.
10. **Extraordinary Transformer and Breaker Repairs:** Hydro's November 2014 Amended General Rate Application included a request for deferral and amortization of costs associated with accelerating maintenance work on transformers and breakers.
11. **$45.9 Million Revenue Deficiency in 2014:** Order No. P.U. 58 (2014) permitted deferral of $45.9 million based on a comparison of 2014 revenue requirements with the 2007 costs used to set current rates, but deferred consideration of recovery of this amount.

D. Prudence Review Standards

The standards or tests for determining prudence have been discussed in a number of jurisdictions. While the standards may be described differently among the various jurisdictions, they generally contain certain common principles that we describe below.

The Nova Scotia Utility and Review Board ("NSUARB") has adopted the following definition of prudence as set out in a decision of the Illinois Commerce Commission:[1]

> *prudence is that standard of care which a reasonable person would be expected to exercise under the same circumstances encountered by utility management at the time decisions had to be made. Hindsight is not applied in assessing prudence…A utility's decision is prudent if it was within the range of decisions reasonable persons might have made…The prudence standard recognizes that reasonable persons can have honest differences of opinion without one or the other necessarily being imprudent.*

The NSUARB further determined that while the definition of imprudence may vary among jurisdictions it has the following fundamental principles:

- Were the utility's decisions reasonable in the context of information which was known or should have been known at the time?

- Did the utility act in a reasonable manner and use a reasonable standard of care in its decision-making process?
- The imprudence test should relate to the circumstances at the time in question and not to hindsight.

The approach to a "prudence" review used by the Ontario Energy Board, which contains similar elements to the principles articulated by the NSUARB, has been considered and upheld by the Ontario Court of Appeal.[2] The approach, referred to with approval by the Court, establishes the course of a prudence review as follows:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.

Liberty took the approach to prudence reviews outlined by these decisions into account in conducting its review.

E. Principles Guiding Liberty's Prudence Review

Utility management must act with prudence in making decisions and taking (or deciding not to take) actions that involve or affect assets, personnel and operations related to the provision of service to customers. Their decisions and actions must be focused on promoting the delivery of safe, adequate, reliable and least cost service to their customers.

Prudent decisions and actions require that management:

- Identify all relevant information
- Identify a reasonable range of alternative solutions
- Test those solutions through the application of criteria and values consistent with such delivery of service
- Choose an option that falls within the range of those properly determined to be reasonable
- Act with the level of dispatch and care as is consistent with the timing needs for making a decision or effectuating actions.

In determining whether an action or decision was prudent, Liberty considered:

- Information that was known or ought to have been at the time of the decision or action (or inaction)
- Whether the utility applied reasonable foresight; perfect foresight is not required
- Whether the solution selected was within the range of reasonable alternatives.

The questions of imprudence and customer impact are distinct. Because the future is unknown, imprudent actions can produce either higher or lower customer costs than would have occurred under a prudent course of action. Similarly, prudent actions can produce either higher or lower customer costs than would have occurred under an imprudent course of action. Where actions were found to be prudent by Liberty, no examination of resulting cost impacts was required to assess customer impacts. Where actions were found to be imprudent, Liberty examined where and by how much costs would have differed under a prudent course of action.

F. Work Methods

Liberty began its work by reviewing the information that has been filed to date by Hydro and other parties, including Hydro's applications, responses to requests for information and Board orders. Liberty met with Hydro representatives a number of times to review relevant information and issued a number of formal requests for information. Liberty conducted a number of sessions to review documents with Hydro personnel. Liberty also conducted a working session with Hydro to review the completeness and accuracy of the factual information Liberty prepared to use in forming conclusions about prudence and for methods used for quantifying the impacts of imprudent decisions and actions.

Liberty began its work on the basis of estimates of expected Hydro costs in the areas subject to prudence review. In many cases, Hydro has reported to Liberty that actual costs ultimately differed from those contained in these starting estimates. Where applicable, Liberty has reported both those estimates and Hydro's provided actual costs, but has not verified actual costs reported to Liberty by Hydro in this review. Liberty understands that the relevant costs will undergo later review in Hydro's current rate application. Liberty thus offers Hydro's reported costs to facilitate that review by others, and not as a confirmation of completeness or accuracy. Liberty has sought to make clear the specific cost types and areas associated with imprudent actions, leaving to others the work required to determine the magnitude of those costs, based on subsequent inquiry.

G. Liberty's Team

Liberty employed essentially the same team that was used to conduct the review leading to the December 2014 Report, with one change. Liberty added a senior electric utility veteran whose management experience includes financial cost analysis and prudence reviews. Each team member has spent 30 years or more in the industry. Liberty's president and one of the firm's founders, John Antonuk, led Liberty's examination. He received a bachelor's degree from Dickinson College and a juris doctor degree from the Dickinson School of Law (both with honors). He has led some 300 Liberty projects in more than 25 years with the firm. His work extends to virtually every U.S. state and he has performed many engagements for the Nova Scotia Utility and Review Board across a period of about ten years.

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

Richard 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 has over 40 years of experience in the electrical power industry, and 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 and Florida. He holds a B.S.E.E. degree, has served as president of the International Electrical Testing Association, and has been active in developing ANSI electrical equipment maintenance specifications.

Randall Vickroy has over 30 years of experience in utility finance, planning and rates, first as a financial manager at Public Service Co. of Colorado (now Xcel Energy), and for the last 20 years as a senior management consultant with Liberty. He has worked on dozens of Liberty projects. These projects include qualifications for the prudence, rate and financial issues reviewed in this matter.

On Liberty's engagement involving Commonwealth Edison for the Illinois Commerce Commission, Mr. Vickroy served as lead consultant in addressing the capital expenditure programs and approvals and resource allocation restrictions that resulted in delays in infrastructure projects. He also serves as Liberty's expert in financial, planning, contracting, valuation and power supply economics. He complements his nearly 20 years of experience with Liberty with previous service as a manager of the Corporate Finance staff at Xcel Energy. He has performed over 20 reviews of utility finance, budgeting, and governance for Liberty, including the review of rate and accounting impacts and utility financing, liquidity issues, utility ring-fencing, bankruptcy issues, and access to and costs of capital.

Mr. Vickroy holds a B.A. in Business Administration from Monmouth College and an M.B.A. in Finance from the University of Denver.

Chapter Two: The New Holyrood Combustion Turbine

A. Summary

Hydro has requested inclusion in rates of costs associated with the procurement and installation of a 100 MW (nominal) combustion turbine (CT) at the Holyrood Plant, at an estimated cost of $119 million. Order No. P.U. 16(2014) approved the project, and deferred consideration of costs and cost recovery to a future order. While Liberty identified a number of significant weaknesses in Hydro's planning processes, Liberty found Hydro's decision not to move forward with the new CT until after the January 2014 outages to be prudent in the circumstances Hydro faced. Moreover, had Hydro acted earlier to install new capacity, costs to customers would not likely have proven less than the amount for which Hydro seeks recovery.

B. Project Background

Hydro's 2010 generation supply planning indicated the need for new generation in 2014. Planning in 2012 confirmed that need. At that time Hydro planned for the late 2017 addition of Muskrat Falls and the Labrador-Island Link ("LIL"). Hydro therefore faced the need for new supply in the intervening years. Hydro adopted plans for a new 50 MW CT located at Holyrood to be in service for the winter of 2015-16 beginning on December 1, 2015. Despite indications of a need for added supply by late 2014, to meet the 2014-15 winter peak, Hydro decided to plan for an in service date in 2015.

In the winter of 2013-14, Hydro experienced an IIS supply shortage. Early January 2014 brought higher-than-expected plant outages, harsh weather and transmissions failures. Hydro initiated rolling blackouts to help alleviate the shortages. In the aftermath of this event, Hydro sought to advance the timing of the new CT, initiating a project seeking an in-service date in December 2014. This advancement required a very aggressive schedule.

Hydro's ability to acquire an already manufactured machine in storage at the time proved central to accelerating the schedule. This machine would also provide twice the capacity of the unit originally planned. Hydro came notably close to achieving its planned in-service date. The unit went into service in January 2015.

C. Prudence Analysis

Liberty examined Hydro's initial decision to defer installation of new generation to a date after the indicated need, the decision in 2014 to purchase the CT, and project execution and costs. The pertinent questions include:

- The quality of the underlying supply planning processes and decisions
- Whether the new Holyrood CT should have been installed sooner
- The choice of the machine and the strategy for its installation
- The quality of project management
- The prudence of costs expended.

D. Supply Planning Process

Prior to the January 2014 outages, Hydro conducted supply planning processes whose principal elements had not changed for many years. Calculation of loss of load hours ("LOLH") has formed a central focus of those processes. This widely used approach models the generation system, considering factors such as load forecasts and estimates of power plant outage rates. The calculation seeks to identify the future time at which supply will become insufficient to meet load. The approach calls for a solution (such as the addition of supply resources) at such time as LOLH calculations project that the number of hours that load is expected to be lost in a future year exceeds an established maximum amount.

Hydro has for many years used a maximum LOLH of 2.8 hours for supply planning purposes. In practice, this value means that Hydro can be expected to face an inability to supply its load every five years. Liberty's experience with North American electric systems indicates a less frequent exposure; *i.e.*, once every 10 years. Hydro has justified the use of the five year expectation on the basis that the more reliable standard would cost too much, considering that the IIS operates in isolation. Interconnected operation generally provides some mitigation of outage risk due to supply-related contingencies.

The use of Hydro's approach, which entails comparatively greater outage risk due to supply contingencies, underwent consultant and stakeholder review in past years, without raising concern. Its applicability for the future may be in doubt, however, when the introduction of Muskrat Falls and LIL will interconnect the IIS with the North American grid. More immediately, Liberty believes that circumstances following the January 2014 outages justify a conclusion that reliance on historical notions of IIS customers about reliability no longer apply. In particular, a comparatively high percentage of customers using electric heat demonstrates the criticality of reliable service in the winter season.

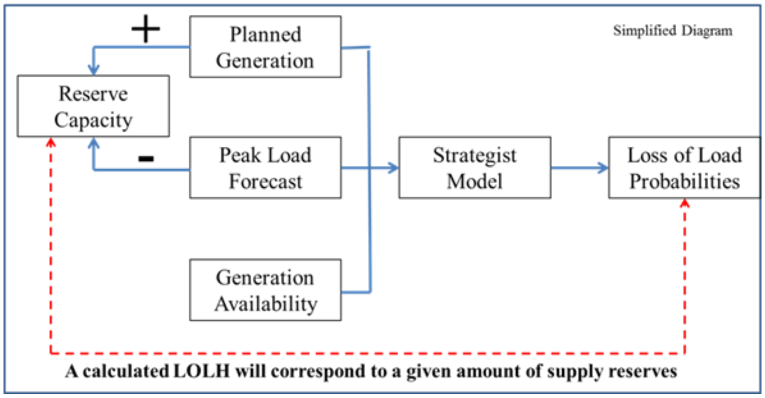
Liberty's earlier investigation of the January 2014 outages included a detailed study of Hydro's planning processes. Liberty's December 2014 report made a number of recommendations to improve supply planning. Hydro and the Board largely agreed with them. Hydro has already implemented or nears implementation of most of these recommendations. The Company has significantly improved its supply planning processes. However, the processes and their application at the time of the key decisions under review are those relevant to this prudence review. In this regard, three shortcomings merit consideration:

- The narrow focus on LOLH, especially at the expense of reserve requirements
- The use of "average" weather in load forecasts
- The failure to consider the higher losses that occur under high loads and low available generation on the Avalon Peninsula.

1. Focus on LOLH

North American utilities commonly use, as Hydro does, an LOLH or similar measure. The more relevant question is how one chooses to use it. Utilities calculate LOLH in order to determine the level of supply (reserves) required to provide a desired level of supply reliability. The calculated LOLH therefore corresponds to a certain level of reserves and the extent to which the utility can count on those reserves to meet system peak loads. The following diagram illustrates this relationship.

Illustration 2.1: LOLH and System Reserves



LOLH and reserves have a direct relationship. That relationship changes when the assumptions in the planning model Hydro uses change. For example, the very same LOLH has resulted from reserves that vary across a fairly wide range; *i.e.*, from approximately 12 to 18 percent. Despite the same LOLH, the level of reliability that results from 12 percent versus 18 percent reserves is not likely to be the same.

Generally, one can more readily understand reliability in terms of reserves, as opposed to LOLH. Moreover, from a simple common sense perspective, reserves can prove more material. For example, consider the case where 200 MW of reserves serves to meet maximum acceptable LOLH. If such a company, like Hydro, has a largest unit of 175 MW, the loss of that unit would leave the system on the edge of shortages. LOLH may reflect a more sophisticated approach, but not necessarily one that proves conclusive. Using an LOLH calculation certainly reflects good practice. Good planning, however, also requires examination of the reserve levels that result, in relation to the kinds of supply contingencies that merit consideration.

The failure to address reserves in this manner comprises a shortcoming in the Hydro supply planning processes. We also have concern about the lack of reserve-level transparency. For example, testimony in Hydro's general rate proceedings in 2001, 2003 and 2007 indicated reserve levels had decreased from 18 to 15 percent in this time period. The Company provided no additional information to stakeholders on reserves until their state became apparent during analyses associated with the 2014 outage investigation.

Liberty found the lack of focus on reserves to be problematic, but not to a level that we believe is required to meet the standard for imprudence. Hydro has followed a consistent approach to supply planning for many years. Until recently, the Company has not applied new criteria, techniques, approaches, insights, or significant changes of any kind. Hydro has also consistently reported on its processes in its regulatory proceedings, with language describing the processes remaining constant. A number of consultants, including ones retained by the Board, reported no issues following examination of Hydro's LOLH criteria. It should be noted however, that the reserves were 18 percent when last reviewed by the Board's consultant in 1999. While unfortunate, it appears that LOLH became the total focus without adequate consideration of the system reserves in place. The longstanding nature of the planning practices applied by Hydro and their frequent review make their application reasonable in the context of Hydro's particular circumstances.

2. "Average" Weather

Generation planners must prepare accurate long-term projections of system load. Those projections specifically include the peak use expected in each year. Many factors influence peak load, with weather being the dominant driver. Utilities use historical data for various weather parameters most likely to influence future load. Wind chill comprises the parameter most frequently used by winter-peaking companies. Utilities examine an extended timeframe and key locations around the system. Hydro uses 30 years. It records the worst wind chills for each year.

Possessing the worst wind chills for each of the last 30 years, the forecaster must select which value to use in determining future peak loads. Hydro has traditionally selected the average of the 30 years as its "weather variable." In any given future year, there exists about a 50 percent probability that the "average" will be exceeded. Hydro terms this weather variable the "P50" forecast. Taken alone, use of a P50 forecast seems problematic, suggesting that the ability to supply peak loads will come into question every other year. One cannot, however, judge the use of a P50 value in isolation. Supply planning must account for many factors. The use of conservative values for a number of them may well render use of a less conservative weather variable appropriate.

Liberty did not, however, find any such compensating assumptions or elements in Hydro's forecasting. Accordingly, Liberty recommended that the Company use a more conservative weather variable; *e.g.*, one likely to be exceeded only once in ten years (P90). Hydro continues to use the P50 forecast for its planning base, but now tests the effects of a P90 forecast on supply-related decisions.

Had Hydro used a P90 forecast in the past, the need for new generation would have been more apparent earlier. Hydro, however, has used a P50 forecast for a long time. It too has undergone scrutiny by Hydro's external consultants without apparent challenge. When Liberty recommended a change in 2014, Hydro promptly implemented the P90 sensitivity approach. Given these circumstances, Liberty found use of a P50 load forecast to lie among a reasonable range of alternatives, albeit one that Liberty would not recommend.

3. Atypical System Losses

Electrical lines lose energy due to heating when carrying electricity over long distances. The amounts of loss can become considerable, depending on the amount of current flowing in, and the length of the line. Consider for example the case where local resources, such as Holyrood, supply load on the Avalon Peninsula. Loss of those sources requires generators at further distances to provide supply. Using central and western Newfoundland to supply large amounts of energy to the Avalon Peninsula can cause losses to escalate sharply. This phenomenon occurred during the January 2014 supply emergency, but Hydro did not anticipate it. The system experienced an unexpected appearance of 40 MW of load. Hydro took some time to recognize the issue, and to adapt its planning and operating schemes accordingly.

Supply planning decisions need to consider system losses appropriately. Hydro appears not to have built this loss scenario into its analyses. Had it done so, Hydro may have recognized an increased planning peak and in turn there would have been an indication of an earlier need for new supply resources.

Liberty considers Hydro's handling of system losses in its planning process erroneous, but not imprudent. The consequences of Hydro's actions may have made the operating situation in early January 2014 more awkward and difficult to address. More significantly in terms of supply planning, higher losses would influence future generation plans. Liberty determined, however, that there does not exist a basis for concluding that a more effective consideration of losses earlier would have altered decisions about adding supply before 2014.

4. Hydro's Planning Processes Prudence Summary

Compared with what Liberty has observed elsewhere, Hydro's planning processes prior to January 2014 contained a number of significant weaknesses. Their application in other locations might well be deemed imprudent. A principal difference here is that the Hydro processes followed approaches long applied, and reviewed on a number of occasions without the finding of any material exceptions. They had also proven generally successful in providing sufficient supply consistently with a general philosophy of leaning on the side of cost avoidance in making the tradeoffs that all utilities must make between cost and service reliability risk.

The advancements that Hydro has made since the January 2014 supply emergency bring the Company closer to the North American mainstream. Liberty believes it is proper to view those advancements as reflecting a move toward a more robust view of security of supply.

Despite Liberty's finding of prudence, however, Hydro needs to be more transparent with regard to the results of its processes. Also, as noted in Liberty's December 2014 report, Hydro must give more attention to system reserve levels, a broader range of weather conditions, and must reflect the effects of high system loads on losses. Liberty considers the improvements Hydro has made in response to Liberty's recommendations in these three areas significant.

E. Timing of the New CT

It has been apparent since as early as 2008 that Hydro would likely require new generation before the arrival of Muskrat Falls in 2017. Hydro's 2010 and 2012 generation planning analysis indicated an LOLH exceeding its 2.8 maximum during the winter starting December 2014.[3] Hydro decided to install a new 50-60 MW CT for service beginning late in 2015. The gap of one year between the identified need and planned in-service dates merits examination. Hydro explained to Liberty that,[4] "... it was anticipated, based on data available at the time, that the new [50 MW] CT could not be acquired and installed until the fall of 2015." Through the January 2014 supply emergency, however, Hydro did not take actions that would support an in-service date for the unit in late 2015, despite findings going as far back as the 2010 generation planning report.

Hydro reported that a new 50 MW unit would require about three years to install. However, the Company proved able in 2014 to install a unit more than twice that size in less than a third of that time. Liberty did not find the "based on data available at the time" rationale provided by Hydro to be credible. Extensive discussions with Hydro, however, did disclose the following rationale that Liberty does consider sufficient to support a delay in the new unit:

- The apparent need for new generation was a moving target, as forecasted load regularly failed to develop.
- The planned arrival of Muskrat Falls generation in 2017 would likely push back the need for other new generation for a long time.
- The history of Hydro's operations exhibited a tolerance for limited outages and interruptions as part of the operating strategy.

The choice to add or defer new generation is a risk decision. While a criterion such as the LOLH is presented as black-and-white, the many underlying uncertainties preclude a blind application of the numbers. It was therefore reasonable, in fact required, that Hydro exercise due diligence before committing the money required for a new generating unit. As Hydro considered this important decision, its managers struggled with the possibility that the forecasted load would not materialize, just as it had not in prior years. It was a possibility that the new unit could be built and then be proven unnecessary, at least by a year and perhaps much more.

Hydro has stated the following with respect to its evaluation of risks:

> *Based on previous experience and given that the criteria violation* [in 2014-15] *was slight and limited to the winter period of 2015, the risk associated with the brief criteria exceedance was deemed to be low.*[5]

Hindsight showed the risk, however low, to have been real, as supply disruptions occurred in January 2014. The more appropriate question, however, lies not in what hindsight makes clear, but in what circumstances at the time demonstrated. It was correct for Hydro to consider the customer rate impacts of a decision to proceed. Some might argue that Hydro's decision was not optimum, but we cannot conclude that it was imprudent, given the circumstances.

Moreover, even if one concluded otherwise on the question of prudence, there remains the question of how outcomes would have differed had Hydro's decisions and actions differed. Liberty does not consider it reasonable to postulate better results had a different decision been made in 2012, because:

- The unit would not have been in-service in time for the 2013-14 winter emergency under any circumstances. Neither Hydro's original planning nor subsequent acceleration were intended to support a need by that date.
- Hydro's planning criteria called for the unit for the winter of 2014-15. The unit actually went into service at that time in any event.
- Hydro may have saved some expediting costs by committing sooner, but it would have committed to a smaller unit, with the result that Hydro would likely be planning another new unit (and additional expenditures as a result) now.
- The costs associated with the project (discussed below) make it doubtful that an earlier commitment would have produced lesser rate effects.

In summary, Liberty concludes that Hydro acted prudently with respect to the timing of the unit. In any event, its decision produced no tangible economic cost penalties for customers when compared with alternatives.

F. Choice of Machine and Project Approach

Early in the investigation that led to Liberty's December 2014 report on the January 2014 outages, Liberty advised of a "continuing and unacceptably high risk of supply-related emergencies until Muskrat Falls comes into service." This conclusion precipitated immediate discussions with Hydro. Executive management promptly made addition of new generation a top priority. Liberty found this commitment necessary and appropriate.

The decision to proceed has produced substantial benefits. Hydro secured a larger unit and an in-service date better than was expected. With respect to unit size, the supply situation was tenuous in the first quarter of 2014. The doubling of the unit's size (compared with earlier plans) and its early availability proved to have considerable value.

Liberty found Hydro's actions in framing the project as it did prudent.

G. Project Management

Hydro made an early decision that it required a strong, dedicated team to achieve the accelerated schedule for the new CT in a cost effective manner. The Company selected well-regarded vendors to manage field operations, thoroughly vetted the machine supplier and the equipment involved, and assembled a capable project management team, headed by trusted contractors. The management team applied proven management techniques, proactively identified and acted to mitigate risks, and adjusted staffing as issues emerged. Late in the schedule, electrical issues in the field resulted in limited schedule delays and the need for more aggressive mitigation strategies. In the broader context, and in light of what initially appeared to be a particularly aggressive schedule, final results proved very strong.

Hydro provided status reports on the new CT to the Board and Liberty throughout the project on a bi-weekly basis. Liberty's review of the reports disclosed no reason to question the prudence of the project management effort.

H. Project Costs

The capital costs for the new CT amount to approximately $119 million, or about $1,000 per kW. Hydro recorded about $95.4 million in 2014 actual capital expenditures, but the unit was not placed in-service until early 2015.[6] Liberty examined the reasonableness of the costs from two perspectives: first, the quality of management and the work effort (addressed above), and second, how costs compared to those of similar North American projects.

Despite some late project problems, costs generally stayed on target and management systems offered no suggestion of cost issues. On a comparative basis, costs also appear reasonable. Liberty considered published sources of cost data. Our analysis (described below) put costs on a comparable in-service date basis by adjusting costs by three percent per year to a 2015 in-service date. Where appropriate, we added AFUDC at eight percent annually over a two-year project schedule. Liberty also adjusted for size differences, with the 0.8 exponent shown in the accompanying formula. Finally, we converted Holyrood costs to U.S. dollars, using a 10 percent exchange factor. Liberty did not convert the other Canadian data point, because, at the time of that estimate, the Canadian and U.S. dollars were essentially at par.

$$\frac{\mathrm{Cost}_1}{\mathrm{Cost}_2} = \left(\frac{\mathrm{Size}_1}{\mathrm{Size}_2}\right)^{0.8}$$

We consider the US Energy Information Agency ("EIA") data to be the most credible when studying construction costs for power plants. They have published such data for many years and have established a sound and consistent methodology. In addition, they keep the data up-to-date with annual revisions. This agency's most current data, with Liberty's adjustments, shows the following comparisons with the new Holyrood CTs:

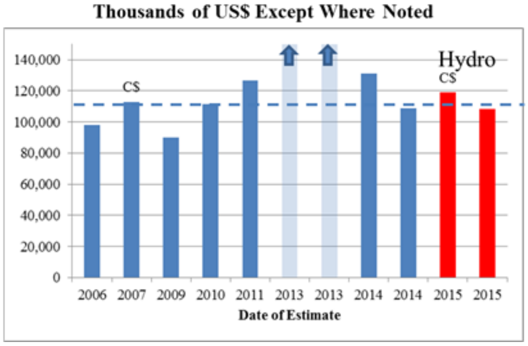
- EIA Conventional CT: US$ 131 million
- EIA Advanced CT: US$ 109 million
- Actual Holyrood CT: US$ 108 million

The EIA estimates classify as an advanced CT those installations employing an F-class turbine. The EIA classifies as conventional those installations using an earlier vintage E-class. The F-class turbine can operate at higher temperatures, whose greater efficiencies produce heat rates in the range of 1,000 Mbtu/kwh.

The Holyrood costs appear to be well in line with the EIA expectations.

Table 2.2: Simple Cycle CT Construction Costs

Thousands of US$ Except Where Noted



Normalized to:

- 2015 US$
- 123 MW
- All in costs, including AFUDC

Average ($111 million) excludes the two outliers

Liberty also considered seven additional data points in addition to the EIA plants. These plants were located throughout the US and British Columbia. The complete population, shown in the preceding table, confirms the competitiveness of the Holyrood CT. Holyrood's costs fall just under the average (the table's dashed horizontal line).

Liberty found no reason to question the reasonableness of the costs of the new Holyrood CT.

Chapter Three: Supply Related Costs

A. Summary

Hydro sought Board approval in October 2014 to defer expenses of $9,650,000 of increased costs during the first quarter of 2014 incurred to address the consequences of supply shortages experienced during that period.[7] Following the early January 2014 events, supply problems persisted through the rest of the winter. Hydro called upon a capacity assistance contract with Corner Brook Pulp & Paper ("CBP&P"), and had to use its own and some Newfoundland Power units with higher fuel costs. Hydro reported that it incurred actual costs from CBP&P for capacity assistance of about $ 6.2 million and additional costs for energy from its gas turbines and diesels of about $ 5.5 million. Hydro reports net 2014 costs are $9.79 million, after taking into account offsetting credits to reflect costs Hydro would have incurred in the absence of these additional sources of capacity.[8]

Liberty concluded (see Chapter Two of this report) that Hydro acted prudently in the generation-related decisions underlying the supply portfolio conditions of 2014 that required the use of additional expensive sources of generation. However, equipment failures on Hydro's transmission system also caused supply issues for customers. Liberty attributed those equipment failures to imprudent Hydro execution of maintenance practices. The failures caused a four-day outage of Holyrood Unit 1, which Liberty estimates to have added $2,189,110 to supply costs. Liberty attributes these costs to imprudent actions and decisions by Hydro.

B. Background

The supply shortage of January 2014 resulted in rotating blackouts in early January. Hydro continued to experience supply issues across the balance of the first quarter. Supply deficiencies resulted in higher energy costs, as Hydro relied upon more expensive generators to meet load. Hydro terms these costs "extraordinary."

Replacement sources of supply took two primary forms for Hydro during the first quarter of 2014. A capacity assistance agreement that Hydro made with CBP&P accounted for about 55 percent of the net added supply costs cited by Hydro. The balance resulted from the cost of added high cost generation, netted against the amount that would have resulted from the use of Holyrood.

C. Prudence Analysis

The degree to which Hydro acted prudently in its supply planning processes raises a threshold question. Specifically, the issue is whether failings in those processes imprudently allowed the supply emergency to come about in early January 2014. Chapter Two of this report addresses those supply planning processes in the context of the new Holyrood Combustion Turbine. Liberty concluded that the underlying processes incorporated a number of significant flaws, and that Hydro has acted to adopt a number of improvements following the January 2014 outages. Nevertheless, Liberty found the planning efforts leading up to the 2014 supply shortage prudent. The prudence issues that remain thus become:

- Whether the driving factors behind the added costs were substantially out of Hydro's control
- The appropriateness of the CBP&P agreement.

Addressing these two issues fully requires separating the first quarter of 2014 into two successive periods: the early January emergency and the post-event timeframes. This split reflects the fact that problems associated with the January emergency were unique, and contributed to added supply costs in a different way.

1. The January Emergency Period

In the early January emergency period, Hydro faced two distinct problems. First, it had to deal with emergency circumstances caused by the unavailability of 233 MW of generation, with high loads due to low temperatures (-18^{o}C) and extreme wind chill factors. These factors required institution of rotating blackouts. A few days later, Hydro still remained seriously capacity-constrained. On January 4 and 5, 2014, unrelated failures on the transmission system occurred. Additional problems continued to affect the operation of the system.

In examining the prudence of the supply planning decisions and actions prior to the January 2014 events, Liberty concluded that:

- Hydro's supply planning processes contributed to the shortage of supply. They exhibited a number of shortcomings, but Liberty concluded they were prudent. (See Chapter Two of this report, which addresses the new Holyrood CT.)
- With respect to the high level of unavailable generation, Liberty was critical of the unavailability of the CTs entering the winter season and the failure to have critical people available to be called for emergency repairs that were necessary during the holidays. (See Liberty's Preliminary Report of April 24, 2014.) Liberty also concluded that most of the outages were either weather-related or reflected the typical types of failures one would expect. The causes of the shortage included the Holyrood Unit 3 forced draft fan motor failure (see Chapter Four of this report). That failure made a large contribution (100 MW) to the unavailable generation. Liberty did not find that Hydro acted imprudently in addressing the failure of that motor.

Liberty did not find a basis for imprudence with respect to supply planning and management of unit availability during the relevant period. From a transmission perspective, however, Liberty did conclude that Hydro's imprudence in executing transformer and air blast circuit breaker maintenance did play a role in the early January 2014 system perturbations (see Chapters Five through Seven of this report). It therefore becomes appropriate to examine the degree, if any, to which the transmission system's problems affected the supply costs at issue here. The next table summarizes the added costs on a daily basis:

Table 3.1: Daily Added January 2014 Emergency Supply Costs

	Units Unavailable (MW)							
Date	Total	HR1	HR2	HR3	CTs	Other Hydro	Cost ($)	Temp °C
1-Jan	231		25	100	75	31	186,949	-15
2-Jan	232		25	100	75	32	928,590	-18
3-Jan	227		20	100	75	32	1,170,057	-18
4-Jan	207			100	75	32	794,546	-15
5-Jan	374	165		100	75	34	1,202,978	-11
6-Jan	361	165		100	75	21	978,293	-11
7-Jan	360	165		100	75	20	4,819	-6
8-Jan	358	165		100	75	18	674,291	-9
9-Jan	221			100	100	21	63,281	-11
10-Jan	192			100	75	17	525,331	-13
11-Jan	183			100	75	8	59,199	-5
12-Jan	183			100	75	8	23,460	2

Attention should focus on Holyrood Unit 1 during the January 5-8 period (shaded). Liberty found no reason for prudence concerns about the other units. The January 5-8 Unit 1 outage, however, did occur due to failure of the Holyrood breaker. Liberty attributed the failure of that breaker to imprudence (see Chapters Five and Seven of this report). Therefore, the inability to operate Unit 1 and the need to find more expensive sources of replacement power are a consequence of that same failure.

No straightforward process for estimating the added costs attributable to the unavailability of Holyrood Unit 1 exists. Total costs across the 12-day period shown in the table can vary as a function of unavailable capacity, temperature, and load. Load is further subject to the widespread outages in the middle time window that corresponds to the unavailability of Unit 1. The costs in that middle window would have been much higher had there been load that Hydro could serve. Given the complexities, Liberty approximated the costs attributable to prudent conduct as the increment above the final four days of the emergency. That approximation is shown below:

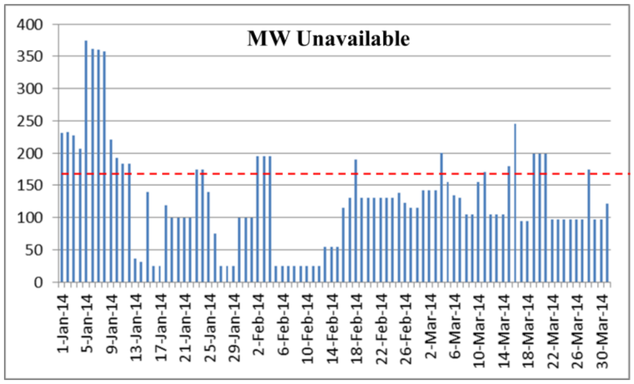
Costs from January 5-8	$2,860,381
Less Costs from January 9-12	$ 671,271
Estimated Prudence-Related Costs	$2,189,110

Liberty stresses that this estimation is a rough one. It is likely higher than strictly applicable from one perspective, given that temperatures were more benign in the January 9-12 period. That factor would decrease the costs of this period. On the other hand, the estimate above would appear low in that the artificially depressed load suggests that perhaps there would have been no cost additions at all without the absence of Holyrood Unit 1. Given the uncertainties and complexities that apply, Liberty considers this approximation appropriate.

2. The Post-Event Period

After the extraordinary first 12 days of the month, the extreme levels of unavailability and high replacement costs did not recur. Numerous examples of higher than expected unavailability, lower than expected temperatures, and higher supply costs, however, did occur. Hydro attributes the higher supply costs in the post-event period to lower unit availability and more severe weather. The next figure shows the amount of capacity unavailable on each day in the first quarter. The dotted line denotes the equivalent of the loss of the largest unit (170 MW). Such a loss places the system in a position where another significant contingency could potentially produce a loss of load. This condition existed on an additional 13 days in the quarter. This seems high and warrants further study.

Figure 3.2: MW Unavailable



A breakdown of the 13 days shows that essentially all of the high replacement costs (90 percent) resulted in only three days (shaded in the next table table). Two major factors outside Hydro's control occurred on those days; *i.e.*, very cold weather and the unavailability of CBP&P additional capacity for two of the three days.

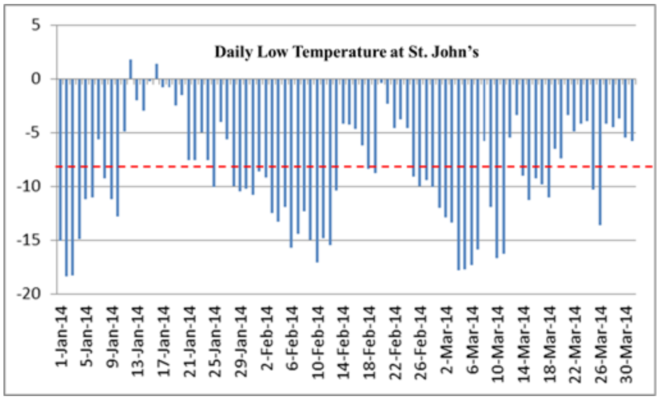
Table 3.3: Days in Which Unavailable Capacity Exceeded 170 MW

(Early January excluded)

	Units Unavailable (MW)							
Date	Total	Bay d'Espoir	Holyrood	CTs	Other Hydro	CBP&P	Cost ($)	Temp °C
23-Jan	175		75	25	75		37,665	-5
24-Jan	175	75	75	25			0	-8
2-Feb	195		170	25			0	-9
3-Feb	195		170	25			0	-13
4-Feb	195		170	25			178,484	-13
18-Feb	190	75	30	25		60	183,021	-8
4-Mar	200	75	30	35		60	217,386	-18
15-Mar	180	75	30		75		0	-11
16-Mar	245	75	170				0	-9
19-Mar	199	154	20	25			27,630	-7
20-Mar	199	154	20	25			39	-7
21-Mar	199	154	20	25			0	-3
28-Mar	174	154	20				0	-5

We next examine the effect of weather. The next chart denotes -8° C with a dotted line. When considering the worst temperature in each of the last 30 years, -8° C is the average of the worst annual temperature over those 30 years.[9] Note that this is not the temperature variable used for planning purposes. That variable incorporates wind chill. Wind chill data was not available for this analysis. Given that the -8° C average is a worst case in each year considered, it would be statistically unusual to expect to see it develop on more than a few days in any given year. Yet the chart is clear; in the post-event period for the balance of the first quarter (78 days), the temperature was lower than -8° C on 50 days.

Figure 3.4: Daily Low Temperature



One can clearly describe such circumstances as extraordinary. When considering costs during the post-event period, it is not surprising that the majority of such costs occurred on the low temperature days, as shown below.

Table 3.5: Post-Event Period Costs on Cold Days

Total costs on post-event days	$1,800,302
Costs on days when temperature $\leq$-8°C	$1,520,137
% of costs on days when temperature $\leq$-8°C	84.4%

In summary, the unavailability of units, which is largely under Hydro's control, had a minimal impact. Weather, which is not in Hydro's control, had a major impact. Accordingly, Liberty finds no evidence of imprudence during the post-event period.

3. Capacity Assistance

By definition, interruptible load is, and should be, expensive to acquire. Permitting interruption can have major impacts on the providing customer. Despite the high costs and negative impacts, however, it can produce value to the utility, as the January 2014 events illustrated.

When it became aware of the seriousness of the supply shortage, Hydro negotiated with CBP&P to provide up to 60 MW of capacity assistance through the supply of interruptible load. Such agreements typically require the utility to pay both a capacity charge (which amounts to a reservation fee) and an energy charge for each MWh of load reduced. It is best to base such charges as much as possible on their real value, or avoided cost, to the utility. Otherwise, the economic signals can get out of kilter, which induces problems for both the providing customer and the utility.

The initial CBP&P agreement, effective December 31, 2013, provided for up to three blocks of 20 MW each over four hours. The payment to CBP&P escalated disproportionately, with the customer receiving 4.5 times the one block charge when providing three blocks. On a $/MWh basis, this approach amounted to 50 percent higher payments. The payments are high, but so are the avoided costs in those extreme circumstances when interruptible load is urgently needed. The costs appear to provide appropriate value when system conditions warrant.

Hydro envisioned using the CBP&P agreement for a very limited time. As supply concerns persisted, however, Hydro adjusted the agreement to cover the rest of the quarter. The parties added a fixed payment, or capacity charge. Liberty found this addition reasonably priced. Hydro reported net capacity assistance costs from Corner Brook of about $5.4 million in 2014.[10]

The next chart shows when Hydro called upon CBP&P's interruptible load during the first quarter. Even with three 20 MW blocks, Hydro required considerably more four-hour periods than planned. Virtually all of the calls for interruptible load were in the first 10 days of the quarter. More than 90 percent of this cost came in the first ten days.

Table 3.6: CBP&P Interruptible Load

Date	MWh
1-Jan	171
2-Jan	1,042
3-Jan	1,378
4-Jan	557
5-Jan	1,379
6-Jan	1,326
8-Jan	885
10-Jan	472
4-Feb	91
5-Mar	403
10 days	7,704

D. Prudence Summary

The question of prudence relating to the CBP&P agreement is rather straightforward. The supply problems were real, and did lead to an inability to serve load. There was no choice but to obtain all of the supply (or demand reduction) that Hydro could. Had the CBP&P load not been available, rotating blackouts would have been more extensive. Hydro has confidence that the system would have held together had further rotating interruptions been required, but this is by no means a certainty. Accordingly, the interruptible load made a major contribution to system reliability in this challenging period. There is therefore no reason for Liberty to challenge the prudency of that agreement.

E. Costs

The supply-related costs generally arose from extreme weather and above-average unavailability of generating units, some of which was also caused by weather. Hydro reportedly incurred additional capacity and energy costs during 2014 of about $ 9.79 million.[11] Liberty examined these added costs and concluded all were prudent, with the exception of a four day period in which Holyrood Unit 1 was unable to connect to the grid because of a breaker failure. Liberty attributed that breaker failure to imprudence, meaning that one should attribute added supply costs of $2,189,110 to Holyrood Unit 1's unavailability as a consequence of that imprudence.

Chapter Four: Forced Draft Fan Motor

A. Summary

In late December 2013, a forced draft fan motor at Holyrood Unit 3 failed. A spare motor was not available at the Plant. A local facility repaired the motor and Unit 3 returned to full output on January 12, 2014. Absence of the motor pending repair limited Unit 3's output, normally 150 MW, to 50 MW. The lost 100 MW made up a significant part of the unavailable generation that, in early January 2014, resulted in supply shortages and rotating blackouts.

In 2011 Hydro received a consultant's opinion that the Unit 3 motors would not last for Holyrood's remaining life. The consultant estimated a remaining five year life for the motors. Hydro made a risk decision not to replace the motors and not to procure spares. Liberty believes this decision was among those that were reasonable under the circumstances. Liberty, therefore, concluded that Hydro acted prudently in making this decision.

B. Background

Hydro requested on April 11, 2014 an addition to the Allowance for Unforeseen Items, which included costs of $82,687 to repair Holyrood Unit 3's east forced draft fan motor. Order No. P.U. 23(2014) approved the expenditures, with recovery of the expenditures to be addressed later. Hydro has recently reported that 2014 actual capitalized repair costs amounted to about $76,000. The fan motor's failure on December 26, 2013 caused the unit to run back to 50 MW, a drop of 100 MW. Hydro expeditiously obtained technical support, diagnosed the problem, removed the motor, and transported it to a local shop for repair. These efforts resulted in a restoration of full power on January 12, 2014, 17 days after the initial failure. Hydro provided an estimate of the replacement power costs incurred due to the loss of 100 MW for January 1-12, 2014 at about $2.0 million.[12]

The outage resulting was partial and contained. The failure, however, coincided with an already weakened supply situation at a time when extreme weather produced record peak demand on the IIS. Less than a week after the fan failure and before its return to service, Hydro had to institute rotating blackouts, because remaining supply could not keep up with load. The failed forced draft fan motor comprised the biggest contributor to generation unavailability at that time. Hydro subsequently addressed the wisdom of providing spares for this type of motor, deciding to purchase some selected spare motors in late 2014.

Hydro has in place an asset management program that includes formal condition assessments of important equipment. The forced draft fan motors at Holyrood underwent such an assessment in 2011. An outside consultant's evaluation concluded that the motors would not survive until 2020 and suggested a remaining life of about five years. In the intervening two years between this conclusion and motor failure, Hydro took no action regarding the purchase of a new motor or spares.

The motor that failed had undergone regular maintenance and Hydro refurbished it in 2006. There were no indications of pending failure. Excessive dirt, resulting from the motor's location near a large door, may have contributed to the motor's failure.

C. Prudence Analysis

The central issue concerns whether Hydro should have acted when advised that the motor would not reach the forecasted end of life for the Holyrood Plant. Liberty understands that the consultant did not qualify its conclusion, but expressed the firm view that the motor *would not* survive. Specifically, when addressing "Capability to Reach End of Life," the consultant stated an unqualified "No" for both Unit 3 forced draft fan motors.[13]

With the Holyrood Plant expected to operate only for eight more years at the time of the condition assessment, consideration of immediate motor replacement would appear to have been in order. Delaying procurement would mean that the new motors would have decreasing value as Holyrood retirement approached. The Company would risk failure in the meantime. The wisdom of considering a "spare," as opposed to a replacement unit, also merits examination. In such cases, it is usually appropriate to install a replacement and use the old unit for the spare.

Hydro considered such options, and settled on a "run to failure" strategy. In other words, Hydro decided not to replace the component for as long as it would remain functional and safe. Such a strategy has many effective applications. Run to failure can serve appropriately to minimize further investment in an asset with a short remaining life. However, applying it soundly for an important contributor to reliability requires more than simply letting the component die. Continued, and perhaps even enhanced maintenance, often proves effective and economical in lengthening the time to failure.

A run to failure approach requires a proper consideration of risk. The owner balances the risk and consequences of an interim failure against the cost to replace the equipment before failure. In applying this decision-making to the forced draft fan motors, a number of factors have weight:

- Hydro believed that failure was five years away, minimizing the need to spend the replacement money immediately.
- Spare motors offered an expensive solution because different motors were needed for all three units; a single spare would not suffice.
- Although the likelihood of failure would increase with time, the consequences did not appear to be catastrophic.
- AMEC's analysis helped frame the likelihood and timing of a predicted failure, but did not change the underlying economics, which made replacement or spares difficult to justify.
- The remaining life of Holyrood encourages avoidance of spending. The effective alternatives were either to provide a replacement immediately or decide not to provide one at all, recognizing that deferring replacement would quickly make the value of a replacement too transitory to be economical.

Hydro appears to have entered into a run to failure strategy on the basis that; (a) failure was not imminent, (b) it might not occur for years, and maybe never, and (c) if failure did occur, the consequences would be minimal. In retrospect, the motor died at the worst possible time. Hydro's decision took account of all available information. Given the risks and the time horizon considered, the option chosen by Hydro falls among those a reasonable person could have selected.

The root cause report on the motor failure cited dirty conditions around the motor that may have contributed to the failure. Dirt tends to blow into the area when a large door nearby remains open. Hydro plans actions in the future to minimize open times. Liberty did not find reason to question prudence in this regard. Access doors are often left open, especially during outages that involve heavy traffic of personnel and materials.

D. Costs

The approach that Hydro took with respect to forced draft fan motor replacement falls within a reasonable range of alternatives and Liberty therefore found it prudent. Reported capital expenditures amounted to $76,407 in 2014.

Chapter Five: Sunnyside Replacement Equipment

A. Summary

The combination of two failures led to widespread outages on the IIS, beginning on the morning of January 4, 2014. First, the Sunnyside T1 transformer failed. Second, the Sunnyside B1L03 air blast circuit breaker failed to open in response to the resulting fault. The delay in clearing the transformer fault caused the transformer fire that damaged nearby equipment. The fire damage caused a delay in restoring the Sunnyside terminal station that day. Hydro replaced the fire-damaged equipment, and installed an additional 230kV breaker with breaker failure protection. Hydro requested approval for expenditures of $8,424,200. Hydro reported 2014 actual costs after insurance recovery of $3,236,684 with estimated 2015 expenditures increasing the total to $5,145,800.[14] Hydro enhanced the 230kV protection for the T1 transformer by installing a 230kV breaker dedicated solely for the T1 transformer and by installing breaker failure protection for this new 230kV breaker. The costs for these enhancements ($87,500 for 2014 and $1,229,494 for 2015)[15] were included in the totals shown above. .

Liberty found the new 230kV T1 transformer breaker and breaker failure protection installations appropriate. However, Hydro's systematic failure to adhere to appropriate transformer and breaker maintenance cycles deprived the Company of the opportunity to identify and address the causes of the transformer and the breaker failures before they occurred. This failure by Hydro was imprudent. The replaced transformer had a limited remaining life, which makes recovery of the new transformer's costs appropriate at some future date. Moreover, if Hydro can demonstrate any tangible difference in maintenance costs of the replaced equipment, versus those for equipment of the vintages of that replaced, then current costs are, to that extent, lower than they would have been but for the actions that Liberty has found imprudent. Liberty was not able to calculate with the available information any credit that should be considered for these factors.

B. Prudence Analysis

Key issues associated with the damage to the Sunnyside transformer and breaker include:

- The decision not to provide the T1 transformer with 230kV breaker failure protections
- The decision to install a 230kV T1 transformer breaker with breaker failure protection following the January 2014 outages
- The failure of Hydro to adhere to its established maintenance cycles for transformers and air blast circuit breakers
- Uncertainty about the causes of the B1L03 breaker failure
- The failure of Hydro to follow up on the causes of an increase in acetylene gas observed in the Sunnyside T1 transformer.

1. Breaker Failure Protection

In Liberty's opinion, good utility practice generally calls for breaker failure protection for critical transformers. Such protection assures that a "back up" breaker will immediately trip if a breaker protecting a transformer fails to trip for a transformer fault. Hydro employs breaker failure protection for the 138kV circuit breakers that protect the T1 transformer at the Sunnyside terminal station. It chose not to provide similar protection to Sunnyside's 230kV circuit breakers because of the cost involved. Management considered the risk of a breaker failure at the same time as a transformer fault too low to justify the costs required to mitigate the harm that could result from these two simultaneous contingencies. Options for providing breaker failure protection include: (a) providing breaker failure transfer tripping of breakers at the remote ends of 230kV lines, or (b) installing a breaker dedicated to the T1 transformer with breaker failure protection that trips other 230kV line/bus breakers in the Sunnyside terminal station. Hydro has relied on a history of good performance by its transformers and circuit breakers in making the tradeoff in favor of cost savings over increased system protection.[16]

Liberty considers that good utility practice generally requires the provision of 230kV breaker failure protection for transformer faults in its terminal stations. The breaker failure scheme at the Sunnyside Terminal Station, however, did conform generally to past and understood practice for the IIS. Liberty did not find its application imprudent in these circumstances, but that application was not ultimately material to Liberty's conclusions about prudence in connection with the January 2014 Sunnyside equipment failure. Liberty, as discussed below, finds that each of the two failures resulted from imprudent execution of transformer and breaker maintenance cycles.

On a forward looking basis, Hydro has changed its approach to addressing equipment configuration at its 230kV terminal stations. The Company completed a root cause analysis (the "Review of Supply Disruptions and Rotating Outages: January 2-8, 2014").[17] That analysis led Hydro to relocate the station service equipment and to install in 2015 an additional 230kV breaker (B1T1) with breaker failure protection. The new T1 transformer breaker and the 230kV breaker failure protection provides an additional layer of protection to Hydro's 230kV transmission system, in case of another T1 transformer failure. Hydro is examining the benefits of similar 230kV transformer breaker and breaker failure protection configurations at other locations.[18] Liberty considers this studied approach to each location a better reflection of good practice, as opposed to Hydro's previous practice of not having 230kV breaker failure protection for transformer faults at the Sunnyside Terminal Station. The reconfiguration already made at Sunnyside reflects a prudent approach to providing additional protection. The costs of the enhancement, versus those required to replace the destroyed transformer and other equipment, are appropriate for recovery from customers.

2. Maintenance Practices

Good utility practice requires a structured and comprehensive approach to maintenance. Such an approach identifies and provides for the regular performance of inspection and repair activities designed to keep equipment in good working order, prolong its life, and protect against service failures with material consequences. Those consequences can include either or both avoidable damage to equipment and disruption of service to customers. Good practice calls for the identification of appropriate cycles for the performance of recurring maintenance activities. Those cycles need to consider factors unique to the utility's particular circumstances. Those factors include equipment configuration, its condition, and the environment in which it operates. Hydro, for example, generally operates comparatively aged equipment, which tends to decrease maintenance cycle length.

Hydro has for a long time used six-year maintenance cycles for the equipment classes that include the Sunnyside T1 transformer and the B1L03 air blast circuit breaker.[19] Liberty found, as described in its December 2014 Report, that those planned cycles conform to good utility practice. Hydro has not, however, come close to following them. Moreover, the scheduled time for work on both the transformer and the air blast circuit breaker at the Sunnyside Terminal Station had passed when the events of early January 2014 occurred. The age of the equipment and the lack of 230kV breaker failure protection increase the risks of failure, particularly in the absence of attention according to Hydro's established standards.

Liberty concluded that Hydro took an unduly risky approach to maintenance execution for a number of years leading up to the January 2014 events. In 2010, Hydro recognized that it was not operating an effective asset management plan. Its practices called for the same six-year maintenance cycles then, but Hydro was generally failing to meet them. Recognizing the risks imposed by deferring maintenance, Hydro formed a goal of accelerating work. It sought a pace that would place work on equipment including transformers and breakers like T1 and B1L03 back on schedule by 2015.[20] Prudence required the adoption of a plan of this type. It also required making substantial progress in reaching the plan's goal, but that did not happen before January 2014.

Hydro indicates that it deferred transformer and breaker maintenance to provide resources to address more critical issues. Failing to make progress reasonably in accord with plans for four years for this reason does not reflect good practice. Maintenance backlogs across the two equipment classes at issue remained high. Table 5.1[21] shows the numbers of terminal station transformers overdue (at year end) for maintenance under Hydro's six-year cycle in the years prior to the January 2014 Sunnyside events. Hydro has 105 terminal station transformers.[22]

Table 5.1: Overdue Transformer Maintenance

Year	Number
2007	11
2008	16
2009	23
2010	18
2011	17
2012	17
2013	27

Table 5.2 [23] shows the number of 230kV air blast circuit breakers overdue for such maintenance. Hydro had about fifty 230kV air blast circuit breakers.

Table 5.2: Overdue Breaker Maintenance

Year	Number
2007	17
2008	19
2009	13
2010	11
2011	14
2012	15
2013	18

Hydro's practices have for a number of years failed to conform to the needs of its system. It has permitted considerable maintenance delays going at least as far back as 2007. Hydro determined that it needed a programmatic approach to eliminating those delays in 2010. Liberty considers that determination both appropriate and necessary. However, deferrals continued on a widespread and systematic basis, up to the January 2014 events. Both the Sunnyside T1 transformer and the B1L03 air blast circuit breaker were a number of months behind schedule when those events occurred (the T1 transformer by 3 months and breaker B1L03 by 5 months). The systematic and widespread deferral of required maintenance was not prudent. It deprived Hydro of an opportunity that regular maintenance is designed specifically to provide; *i.e.*, to identify and correct potential sources of equipment failure.

Justifying deferrals over a period of many years on the basis of other planned or emergent unplanned work with higher priority does not conform to good utility practice. Hydro did not make substantial progress in returning to maintenance normalcy after 2010. Consequently, the T1 transformer and the B1L03 air blast circuit breaker were both past due for maintenance work. Hydro had not even placed either on a schedule for performing the required maintenance. The breadth of Hydro's maintenance deferrals and the lack of identified dates for performing overdue maintenance on the T1 transformer and the B1L03 air blast circuit breaker call into question how long Hydro was willing to let them go without the attention they needed.

3. Causes of Breaker Failure

Just as bad outcomes may follow prudent decisions and actions, imprudent conduct does not necessarily produce bad outcomes. Crossing a busy street without looking both ways is imprudent whether or not a pedestrian makes it safely across. This construct raises the question of causation; *i.e.*, the link between imprudence and adverse consequences to customers.

Hydro cannot determine, despite substantial efforts by its personnel and consultants, the causes of the Sunnyside breaker failure on January 4, 2014. Liberty cannot do so either. Hydro has observed that conditions unobservable through inspection or unrelated to performance of maintenance or repair may have caused both failures. That may be so, but no evidence supports that conclusion.

The malfunction of the Sunnyside Breaker B1L03 on January 4, 2014 was that it remained in a closed position when it should have come open (termed "stuck closed"). Hydro speculated that a latching mechanism or DC control trip circuit problem may have caused this condition. Hydro, however, cannot provide sufficient evidence to support this explanation of cause. Using assistance from an outside expert, the team studying the malfunction could not replicate it.

There is clearly a strong causal connection between conducting maintenance and avoiding malfunctions. Whether there exists a cause and effect relationship in any given situation can prove, as is the case here, impossible to determine. Clearly, one who questions prudence should undertake the burden to demonstrate that imprudence has occurred. The combination of Hydro's programmatic approach and the circumstances specifically applicable to the B1L03 air blast circuit breaker reflect a risk of failure that resulted from an unacceptable risky approach by

Hydro. Liberty considers that approach imprudent. Maintenance occurs to prevent equipment from failing when needed.

Where causation is not determinable, despite good faith and capable effort, it is sufficient to make the categorical level connection, as exists here, between conducting maintenance and avoiding malfunction. To assign no consequence to imprudence under such circumstances, when adverse consequences have occurred, has the inevitable effect of lessening diligence and care in operating facilities required to serve the public and for which customers also bear cost responsibility.

4. Breaker Maintenance Prudence Summary

Hydro acted imprudently in not conforming its maintenance practices sufficiently close to the cycle it established. Such conformance was required, because Hydro did know or should have known that timely maintenance is critical, given the age and condition of its system and the connection between maintenance activities and equipment performance and failure. The failure to adhere to appropriate maintenance cycles was not occasional, but rather systematic. Occasional deferral of necessary and prudent maintenance work can prove appropriate when justified by emergent work and consideration of its effects on equipment whose work will experience delay. A long standing pattern of widespread maintenance deferrals, as existed here, however, does not represent a prudent method for operating equipment critical to system operation. After considering the standard for imprudence set out in Chapter One of this report, Liberty has concluded that a reasonable utility with the information known at the relevant times, would not have systematically deferred required maintenance as Hydro did.

Nobody can say with confidence that performing maintenance when and as required would have avoided the Sunnyside transformer and breaker failures on January 4, 2014. However it is clear that a purpose of such maintenance is to identify and address potential failure causes before failure happens. It is also clear that a systematic approach consciously adopted by Hydro deprived Hydro of the ability to accomplish a result that maintenance seeks to produce, which is continuity of performance and protection of the equipment involved.

Hydro’s imprudence with respect to breaker maintenance deprived it of the chance to avoid the widespread IIS outages that continued until January 8, 2014. The transformer damage and the avoidable 2014 and 2015 actions necessary as a result of the January 2014 outages thus also resulted from imprudent action by Hydro.

5. Causes of the T1 Transformer Failure Prudence Summary

The Sunnyside T1 transformer was also late for maintenance on January 4, 2014. The same systematic maintenance issues that affected breaker maintenance apply to transformers as well. Therefore, in examining the failure of the T1 transformer, Liberty reaches the same conclusions with respect to the prudence of maintenance and with respect to the causal connection between imprudence and consequence.

Hydro, with outside assistance, determined that a bushing failure caused the transformer fault. The activities included in maintenance work to be performed every six years include power factor tests. Those tests can identify bushing defects. Power factor testing has allowed Hydro to identify prior to equipment failure some 14 bushing issues since 2000.[24]

The T1 transformer was past due for maintenance (including power factor tests) by several months in January 2014. Its class of equipment too had suffered widespread maintenance delays since at least 2007. Hydro failed to reduce substantially its backlogged six-year transformer maintenance work between 2010 and 2013. Like Sunnyside Breaker B1L03, it had no scheduled maintenance date when it failed.

Had Hydro conducted power factor tests in 2013, consistent with the six-year program, it would have had a reasonable opportunity to identify and correct the defective bushing before transformer failure.

Hydro's maintenance of the T1 transformer failed in another substantial way as well. Hydro periodically conducts dissolved gas analyzes (DGA) on the oil in its transformers. This testing conforms to good utility practice. The levels of these gases in the oil provide indicators for incipient transformer defects. One of the gases measured, acetylene, can indicate arcing in a transformer. Even very low levels of acetylene can provide such an indication. A small jump in readings of acetylene gas occurred a few months before the failure. That jump's potential indication of an abnormal transformer condition warranted investigative action.

Hydro's laboratory recommended that Hydro "consider investigative sampling," which would involve taking DGA samples from this transformer soon and often. The samples would permit Hydro to monitor the possible increase of acetylene until determining whether the acetylene increase indicates an incipient defect. Hydro did not perform the recommended sampling.[25] Good utility practice calls for monitoring suspicious levels of acetylene gas frequently and closely, in order to determine whether to perform maintenance work. Hydro chose not to perform such intensified monitoring, which deprived it of another opportunity (in addition to not completing the required six-year maintenance work on time) to determine and to address transformer failure risks before January 4, 2014. Hydro did not take any action because it assumed that oil leaking from the tap changer compartment into the transformer oil had caused the increase in the acetylene gas level.

Hydro's decision to attribute sudden increase in acetylene gas to non-threatening causes without monitoring was imprudent. Information known to Hydro required follow-up analysis, which Hydro failed to perform.

Hydro's failure to perform maintenance when due on the T1 transformer and its failure to appropriately monitor the level of acetylene gas as required by good utility practice led to a finding of imprudence by Liberty.

C. Costs

Order No. P.U. 29(2014), approved the capital costs to replace damaged equipment and to install an additional 230kV breaker with breaker failure protection at Sunnyside terminal station for an estimated cost of $8,464,200. Hydro's reported actual 2014 expenditures of $5,062,684 were offset by the receipt of insurance proceeds, which left a reported net 2014 amount of $3,236,684. Estimated additional 2015 expenditures bring the total to $5,145,800.[26]

For the new 230kV T1 transformer circuit breaker, Hydro reported actual 2014 expenditures of $87,500 and estimated 2015 costs of $1,229,494[27] which are included in the total Sunnyside capital amounts shown above.[28] Hydro also included the costs for the installation of breaker failure protection in the engineering costs for the new T1 transformer. Hydro reports only a nominal 2015 cost (about $5,000) for modifications to existing breaker failure protection.[29] This reconfiguration to provide a new 230kV T1 transformer breaker and 230kV breaker failure protection comprise a sound enhancement to the Sunnyside terminal station. Liberty finds the costs of these enhancements (reported by Hydro as $87,500 for 2014 and $1,229,494, plus $5,000 for breaker failure modifications) appropriate. Liberty attributes the remaining costs associated with the capital project ($3,149,184 in 2014 and $3,911,306 in 2015 Test Year) addressed in Order No. P.U. 29(2014) with Hydro's imprudence.

Hydro also incurred Operating Expenses for this project. The next table shows costs as previously estimated, and reported 2014 actual and 2015 test period costs. Note that reported 2014 actual operating costs net of insurance proceeds were substantial, amounting to about $880,000. [30]

Table 5.3: Sunnyside Replacement Equipment Costs

	Order No. P.U 29 (2014)	**Hydro 2014 Actuals**	**Hydro 2015 Test Period**
Sunnyside Replacement Equipment Capital	$8,464,200	$3,236,684 (net of insurance proceeds)	$5,145,800 (net of insurance proceeds)
T1 Transformer Circuit Breaker and Mods (not related to imprudence)	Included above	$87,500	$1,234,494
Sunnyside Net Capital (related to imprudence)	$8,464,200	$3,149,184	$3,911,306
Sunnyside Replacement Equipment Expenses			
Operating Expenses (excluding Transportation)		$680,500	
Removal Costs	0	$30,400	0
Loss on Disposal		$515,000	
Depreciation Expense	0	$3,900	$133,285
Transformer Transportation Costs)	0	$824,000	0
Less: Insurance Proceeds		$(1,174,000)	
Net Operating Expenses	**0**	**$879,800**	**$133,285**

The age of the transformer and equipment replaced gave it at the time of its failure an expected operating life shorter than what can be presumed for the new, replacement equipment. Operating, rather than accounting life, is material in assessing the length of that remaining life. Customers would have been spared the cost of new equipment for some time absent the January 2014 events, but not indefinitely. Also, Hydro has indicated that maintenance costs for the older equipment exceed that for what replaced it. If so, then customers may also be spared some costs that would have been included in the calculation of revenue requirements in the current rate filing. It was not possible based on the available information to calculate any appropriate credit to reflect these factors.

Chapter Six: Western Avalon Terminal Station T5 Tap Changer Replacement

A. Summary

Following the onset of widespread IIS outages on the morning of January 4, 2014, the Western Avalon T5 transformer failed when Hydro was attempting to energize it. The tap changer for Transformer T5 experienced damage. The incident required Hydro to replace the damaged tap changer and to clean the transformer windings. Hydro requested authorization of about $1.5 million for this work, eventually spending a 2014 reported amount of $1,013,900. The failure of breaker B1L37 to operate as intended led to the damage. Hydro's systematic failure to adhere to appropriate breaker maintenance cycles (as discussed in Chapters Five and Seven of this report) deprived Hydro of the opportunity to identify and address the cause of failure before it occurred and led to the damage that required these expenditures. This failure to adhere to appropriate maintenance cycles was imprudent. Therefore, Liberty associates these expenditures with such imprudence.

B. Prudence Analysis

The issues associated with the damage to the Western Avalon T5 transformer tap changer include:

- The cause of the T5 transformer tap changer failure
- Hydro's actions in energizing the transformer
- The failure of Hydro to adhere to its established maintenance cycles for air blast circuit breakers.

1. Transformer Tap Changer Failure Cause

Following the Sunnyside transformer failure and the subsequent system-wide outage on the morning of January 4, 2014, Hydro operators attempted to restore the Western Avalon terminal station. The Western Avalon 230kV Breaker B1L37 tripped about a second after operators energized Western Avalon transformer T5. Operators had no indication of the cause of the breaker trip. Operators attempted, without success, to close the breaker two more times. A few hours later, Hydro operators energized the T5 transformer via another 230kV breaker (L01L03). However, the T5 transformer failed after about 24 seconds, and the lock out relay tripped the transformer off line.[31]

The tap changer for Transformer T5 at the Western Avalon experienced damage as a result of the incident. Utilities require means for voltage regulation in order to maintain system voltages within required limits. Utilities fit tap changers to virtually all transformers above 10MVA to provide for voltage regulation. Tap changers provide a source of variable control to remain within those limits. Transformer T5 also required other work to address the consequences of the incident.

During the follow up investigation, Hydro determined that a phase to phase fault occurred across the Western Avalon T5 transformer load tap changer diverter switch. The fault damaged the transformer. That damage required that Hydro later replace the tap changer, and clean contamination from the transformer windings. Hydro applied to the Board on June 19, 2014 for approval of capital expenses of $1,452,500 to replace the tap changer and to perform other work on Transformer T5. Hydro has since reported to Liberty that the work required actually cost $1,013,900.[32]

Hydro's review of system data led it to conclude that the transformer experienced overvoltages of about fifteen percent and that one phase of breaker B1L37 had failed to close (stuck open) when operators had closed the B1L37 breaker. Following the event, Hydro was not able to replicate the breaker malfunction and the Company could not identify the cause of the malfunction when subsequently overhauling the breaker. [33]

A consultant retained by Hydro later conducted a formal engineering study of system harmonics during the Sunnyside and Western Avalon events. The consultant determined that energizing the transformer with only two phases several times caused an abnormal magnetic condition in the transformer. This condition continued to exist when operators later energized the transformer with all three phases. This abnormal magnetic condition caused the overvoltage condition that caused the tap changer failure. [34]

The failure of the 230kV B1L37 to close on one phase was the cause of the T5 tap change failure. The investigation did not identify any T5 transformer conditions or circumstances contributing to the tap changer damage. Hydro had completed maintenance and testing work on this transformer in July of 2012, consistent with its six-year maintenance cycle.[35]

2. Repeated Efforts to Energize Transformer T5

Closing the breaker three times with only two phases may have contributed to the transformer's magnetic condition that caused the overvoltage. This overvoltage condition in turn caused the tap changer to fail. Hydro's operators, however, had no means to determine that this two phase condition existed. Only as a result of its post-event investigation did Hydro secure data concerning the detailed sequence of events and relay information. Hydro concluded from this data that Breaker B1L37 had not closed on all three phases. The operators' contribution to the magnetic condition was inadvertent, and resulted from reasonable actions to attempt service restoration. The January 2014 outages on the IIS warranted exceptional action to minimize widespread customer disruption.[36]

3. Maintenance Practices

Hydro installed 230kV Breaker B1L37 in 1968, and overhauled it in 2005. The Company planned to replace Breaker B1L37 in 2018. As discussed in Chapters Five and Seven, Hydro's maintenance practices called for maintenance work every six years on such breakers. On January 4, 2014, this breaker was overdue for such maintenance by about two and a half years.[37]

Chapters Five and Seven describe the nature and importance of Hydro's maintenance cycles for air blast circuit breakers. Those chapters also detail the reasons why Liberty concluded that Hydro imprudently executed those practices generally and with specific reference to certain equipment failures during early January 2014. That imprudence extends to Breaker B1L37 and its condition and operation on January 4, 2014.

C. Costs

Liberty relates Hydro's imprudent execution of air blast circuit breaker maintenance generally, and specifically with respect to 230kV Breaker B1L37 at the Western Avalon terminal station to the need for replacement and repair costs. Hydro estimated those costs at $1,452,500 when requesting Board approval of the expenditures. Hydro has since reported to Liberty 2014 actual capital expenditures of $1,013,900, actual depreciation of $41,000 in 2014, and $41,000 forecast for depreciation in the 2015 Test Year.

Chapter Seven: Overhaul of the Sunnyside B1L03 and Holyrood B1L17 Breakers

A. Summary

Chapter Five addressed the failure of the Sunnyside air blast breaker B1L03 and its connection with the Sunnyside T1 transformer fire and the system-wide outage on January 4, 2014. The failure of the Holyrood air blast breaker B1L17 on January 5, 2014 caused another wide-spread outage. Hydro overhauled these breakers in the spring of 2014 to permit them to operate until their replacement in October of 2014. The Company requested authorization to increase its Allowance for Unforeseen Items by $497,313 to cover the overhaul costs.

Liberty concluded in Chapter Five that Hydro imprudently executed maintenance practices with respect to Sunnyside breaker B1L03. Inadequately performed maintenance on Holyrood breaker B1L17 caused internal ice accumulation that caused it to fail. These work practices were imprudent. Liberty associates the costs of the overhauls to that imprudence.

B. Prudence Analysis

The first question raised by the January 2014 events concerns the widespread, systematic deferral of breaker maintenance by Hydro over a number of years. Chapter Five addresses that issue with respect to the Sunnyside 230kV Breaker B1L03. The remaining prudence questions about the breaker overhaul concern:

- The nature and quality of work performed in 2013 on the Holyrood B1L17 230kV Breaker
- The wisdom of overhauling the breakers after January 2014, considering plans to replace them in October 2014.

1. Sunnyside Breaker B1L03 Maintenance Deferral

As Chapter Five concludes, Hydro acted imprudently in deferring the maintenance work required by its six-year maintenance cycles for air blast circuit breakers in general and specifically with respect to the Sunnyside B1L03 breaker.

Hydro’s Sunnyside’s breaker B1L03 was one of its oldest type DCVF breakers. Hydro installed it in 1966, refurbished it in 2002, and scheduled it for replacement in 2015. Hydro “overhauled” the Sunnyside breaker B1L03 in 2003, “re-lubricated” it in 2007, and last function-tested it in 2011. Maintenance under the six-year cycle applicable to this breaker was overdue by five months in January 2014.[38]

2. The 2013 Disassembly of Holyrood Breaker B1L17

On January 5, 2014, Holyrood breaker B1L17 malfunctioned, as one phase remained stuck in the closed position. Hydro’s investigation of the malfunction found water, ice, and rust inside sealed elements of the breaker. These conditions caused a control rod to stick. Hydro installed this type DLF breaker in 1973.

Hydro reportedly had scheduled the breaker for overhaul in 2015 and replacement in 2026. In January 2013, however, this breaker experienced an insulator flashover that resulted from salt contamination. Hydro decided then to disassemble the breaker, primarily for electrical safety considerations, on February 24, 2013. Disassembly would permit application of RTV ("Room Temperature Vulcanized Silicone Rubber") protective coating on the breaker insulators in a shop; *i.e.,* out of the weather. Hydro also overhauled one of the interrupting heads during this disassembly. The Company reassembled the breaker on March 23, 2013, and conducted six-year maintenance tests on April 4, 2013.[39]

There was no deferral of planned maintenance on the Holyrood breaker B1L17. A poor maintenance work procedure, however, did cause the malfunction. That procedure permitted water to enter the breaker. Water freezing caused the breaker to mechanically seize on one phase on January 5, 2014. Hydro had removed the breaker head columns and interrupting chambers, in order to apply the RTV protective coating. The receiver tanks, located underneath the breaker head columns and interrupting chambers, thus became exposed to the elements. Each phase's receiver tank contains a driving rod. This rod connects inside the tank, and extends up through the top opening of the receiver tank. Hydro reported that it had secured waterproof covers over the tank and the driving rod.[40]

The Company considered this measure sufficient to prevent the ingress of water. Hydro, however, allowed the temporary covers to remain in place, exposed to weather, for about a month. A limit of a few days is reasonable. The extended period resulted because Hydro deferred applying the RTV coating in the shop to address other work commitments deemed more critical. However, Hydro did not take appropriate action to protect the equipment for this extended period. Hydro inspected the top of the receiver tanks before reassembling the breaker, but did not later test the compressed air in the tank for moisture content. Hydro cannot explain how water entered the receiver tank for the phase that later seized, but acknowledges that water did somehow enter the tank while the temporary cover was installed.

This approach subjected the equipment to clear and knowable risks, which Hydro could have mitigated through reasonably available actions. Liberty therefore found the actions that permitted water ingress imprudent.

Liberty concluded that Hydro acted imprudently by failing to take necessary and appropriate actions, during its RTV insulator coating project, to ensure that the covers used to prevent the ingress of water in the Holyrood breaker B1L17 were effective. The receiver tanks remained exposed to weather for a long, one-month period. Permitting this exposure to remain does not comport with good utility practice. Based on information available at the time, Hydro did not act reasonably in protecting the equipment. The ingress of water was the cause of the breaker malfunction on January 5, 2014.

3. Breaker Overhaul

After overhaul, the two breakers remained in service only for seven months, until their replacement in October 2014. Despite the preceding conclusions about imprudence, Liberty found it appropriate for Hydro to respond to the post-January 2014 circumstances by expediting the work needed to overhaul the breakers, despite plans to retire them in the immediate future. Hydro required them to be available in order to restore the configuration necessary to maintain N-1 protection (connecting two breakers to the system in case one fails) at Sunnyside and Holyrood terminal stations as quickly as possible.[41]

Hydro could not replace these two air blast circuit breakers with new SF6 breakers until October of 2014. Hydro found it imperative to return these breakers to service for the spring, summer and fall of 2014. Overhaul of the two breakers mitigated the risks of more misoperations, pending their replacement. Accelerating the overhaul of the breakers required substantial amounts of overtime payments and use of consultants to return to the N-1 contingency configurations at Sunnyside and Holyrood terminal stations.

Without these breakers, many Hydro customers would remain exposed to vulnerabilities that could cause major outages. With the Sunnyside breaker B1L03 out of service, the 230kV ring bus remained open. Any faults on transmission lines 202 and 207 would affect customers on both the Burin Peninsula and on the Avalon Peninsula. With the Holyrood breaker B1L17 out of service, only one connection existed between Holyrood Unit 1 and the transmission system. If the second Unit 1 breaker failed, Unit 1 would be unavailable to the transmission system, affecting reliability to the Avalon Peninsula.

Although Hydro's response to post-January 2014 conditions was sound, it does not change Liberty's conclusion about customer responsibility for the costs of the overhaul. However, Hydro will perform other breaker overhauls in the future. The removal from service of the two overhauled breakers makes parts used in their overhauls available for use in other overhauls. To the extent that the Company has used or will use such parts in other overhauls customers may obtain benefit from the expenditures associated with the overhauls. Should Hydro subsequently demonstrate effective equipment reuse to be a prudent application for such future use, it would be appropriate to include recognition (based on cost analysis undertaken at that time) of at least some of the cost of the parts in revenue requirements.

C. Costs

On April 11, 2014, Hydro requested approval to add $580,000 to the Allowance for Unforeseen Items. That request included $497,313 to overhaul Sunnyside 230kV Breaker B1L03 and Holyrood 230kV Breaker B1L17, both of which failed in January, 2014. Hydro has since reported 2014 actual capital costs of $522,243, and depreciation and disposal expenses of $164,000.[42] Liberty associates these costs with imprudent maintenance and repair actions involving these breakers. Hydro has since replaced the overhauled breakers. Their parts have been or are likely to be used for the overhaul of other breakers.[43] To the extent that Hydro makes effective use of those parts, customers may obtain benefit at levels equal to at least some of the costs of acquiring them.

Chapter Eight: Extraordinary Transformer and Breaker Repairs

A. Summary

Hydro has proposed increased 2015 expenditures to come into conformity with its six-year cycles for performing maintenance on transformers and air blast circuit breakers. The request also includes costs associated with shortening the breaker maintenance cycle to four years, beginning in 2015. The Company's current rate filing seeks to amortize over five years $1.2 million in 2015 expenditures to perform this catch-up maintenance work. Liberty found that the shortening of the cycle for breakers is appropriate.

The 2015 expenditures that Hydro proposes to amortize include both transformer and air blast circuit breaker costs that Hydro would not have had to incur in the absence of imprudent deferral of maintenance work, as discussed in Chapters Five through Seven of this report. For similar reasons, Hydro's 2014 catch-up work for transformer and breaker maintenance caused it to incur expenses that it would have avoided in the absence of such imprudence.

Six-year maintenance costs in 2014 for transformers would have been about $411,870 and for breakers about $257,544 had Hydro required only normal levels of work to stay on schedule in that year. In 2015, Hydro would be expected to spend about $411,870 for transformer work on six-year maintenance assuming normal levels of work. Acceleration of the breaker maintenance cycle to 4 years in 2014 would have amounted to about $398,021.

Liberty finds that 2015 costs for four-year air blast circuit breaker maintenance above $398,021 and six-year maintenance costs for transformers above $411,870 resulted from imprudence.

B. Maintenance "Catch-up"

Hydro's November 10, 2014 amended general rate application ("GRA") included an estimated $1.2 million in 2015,[44] which it sought to amortize over five years, at $240,000 annually, starting in 2015. As discussed in Chapters Five through Seven of this report, Hydro had been deferring transformer and air blast circuit breaker maintenance work for many years. Liberty concluded that these deferrals were imprudent. Hydro planned in 2010 to return maintenance work to its six-year schedule, but failed to make substantial progress in reducing the amounts and lengths of deferrals prior to the January 2014 outage events.

Hydro has since accelerated such maintenance. Hydro expected that "catch up" six-year maintenance on transformers and air blast circuit breakers would occur in 2014 and 2015. The work required would produce significantly higher transformer and breaker maintenance costs in these two years, when compared with expenditures in previous years. Hydro's request to defer and amortize $1.2 million of 2015 non-recurring maintenance on these two asset categories recognizes the company's "catch-up" work required to complete the original six-year cycle.

1. Transformer Maintenance Acceleration

Hydro established a program in 2010 to bring its maintenance practices into conformity with six-year cycles, as Chapter Five describes. Hydro scheduled an equal number of assets in each group for maintenance during each year from 2010 to 2015. The next table illustrates the 2010 plan's scheduling of maintenance on 17 or 18 of its 105 transformers in each year. This pace would complete a six-year cycle by the end of 2015. Hydro fell far behind this plan (by 19 transformers at the end of 2013).

Hydro's June 2, 2014 report to the Board on terminal station transformers and air blast circuit breakers noted that it would perform catch-up six-year maintenance on the transformers and breakers in 2014 and 2015.[45] Hydro's 2014 maintenance work included 37 transformers; *i.e.*, twice the annual amount required to sustain a six-year cycle. The next table shows actual maintenance completions and costs for 2010 to 2014, and estimated for 2015. Substantial increases in work drove costs for such maintenance to a level ($846,622) far above those of previous years. Hydro also based its 2015 transformer estimate on average maintenance cost per transformer in 2014[46].

Table 8.1: Transformer Six-Year Maintenance

Cycle	Planned	Completed	Cost
Year 1 (2010)	18	15	$303,644
Year 2 (2011)	17	11	$257,837
Year 3 (2012)	17	14	$342,224
Year 4 (2013)	17	10	$145,600
Year 5 (2014)	18	37	$846,622
Year 6 (2015)	18	-	$411,870
Total	**105**	**87**	

2. Air Blast Breaker Maintenance Acceleration

The 2010 maintenance acceleration plan called for six-year maintenance on 10 or 11 of Hydro's 69 air blast circuit breakers annually. This pace would complete an actual six-year cycle by the end of 2015. Hydro also fell well behind on this catch-up plan. The next table shows that actual maintenance work had fallen 20 air blast circuit breakers behind by the end of 2013.

Hydro performed accelerated six-year maintenance on its air blast circuit breakers in 2014 and 2015. The 2014 maintenance addressed 31 breakers. This number represents almost three times as many per year as a six-year schedule would require. The next table shows that this additional work increased 2014 program costs to $725,807. This amount far exceeded amounts for previous years. The 2015 estimate is based on the average maintenance cost per breaker in 2014.[47]

Table 8.2: Air Blast Circuit Breaker Six-Year Maintenance

Cycle	Planned	Completed	Cost
Year 1 (2010)	10	4	$45,256
Year 2 (2011)	11	3	$62,322
Year 3 (2012)	11	7	$118,125
Year 4 (2013)	11	9	$61,946
Year 5 (2014)	11	31	$725,807
Year 6 (2015)	15	0	$351,197
Total	**69**	**54**	

Prior to 2014, Hydro used a six-year cycle for breaker maintenance. Review by the Company in 2014 resulted in a shortening of the cycle to four years in the future.[48]

C. Prudence Analysis

Chapters Five through Seven discuss the reasons why Liberty found Hydro imprudent in deferring transformer and breaker maintenance in the years leading up to the January 2014 outages. Prudent management would have maintained a cycle conforming to the six-years adopted by Hydro as its standard. Had Hydro acted prudently in executing this cycle, it would have needed no acceleration in 2014 and 2015. Thus, in the absence of imprudence, one would expect 2015 work to include only a normal amount of maintenance activity. Instead, Hydro plans work substantially above that normal yearly amount, and has included costs for such increased work in its GRA filing. Similarly, 2014 work above normal yearly levels caused Hydro to incur substantial costs in that year.

D. Costs

In the absence of imprudence, Hydro would ordinarily perform maintenance on the 18 transformers it had scheduled for both 2014 and 2015 (see Table 8.1). The table indicates an average 2014 maintenance cost of $22,882 per transformer. Applying that cost to a normally expected 18 transformers produces a 2014 cost of $411,870. The table shows the same number of 18 transformers scheduled for maintenance in 2015. Hydro assumes the same unit costs in 2015 as it experienced in 2014. Therefore, $411,870 also represents the costs one would expect for 2015 under a normal maintenance schedule.

Liberty considers all 2014 and 2015 costs for six-year transformer maintenance that exceed $411,870 to comprise costs that Hydro would not have incurred in the absence of imprudent transformer maintenance deferral. Total costs for 2014 were $846,622, leaving $434,752 in costs that Liberty associates with imprudence. 2015 costs are currently forecast at $411,870.

Liberty used the same approach to identify 2014 air blast circuit breaker six-year maintenance costs exceeding what Hydro would have incurred in the absence of imprudent maintenance deferral. Table 8.2 indicates an average 2014 maintenance cost per breaker of $23,413. Applying that amount to the 11 breakers scheduled by Hydro for maintenance in 2014 produces a cost of $257,544. Liberty considers all 2014 costs for six-year air blast circuit breaker maintenance that exceed $257,544 (*i.e.*, a total of $468,263 in avoidable costs) to comprise amounts that Hydro would not have incurred in the absence of imprudent breaker maintenance deferral.

Liberty considers Hydro's recent change to a four-year maintenance cycle for these breakers appropriate. Addressing all 69 breakers on this cycle equates to about 17 per year. As it did for transformers, Hydro provided a 2015 cost per breaker equal to its actual 2014 costs per breaker. Thus, one would expect cost for a 2015 year that addressed a normal number of breakers to amount to $398,021. Liberty considers all 2015 costs for four-year air blast circuit breaker maintenance that exceed $398,021 to comprise costs that Hydro would not have incurred in the absence of imprudent breaker maintenance deferral.

To the extent that Hydro's amortization request includes costs of work above normal six- year transformer and breaker (and in the case of 2015, four-year breaker) maintenance activity, it includes costs that Hydro would not have incurred in the absence of imprudent deferral of maintenance.

Chapter Nine: 2014 Revenue Deficiency

A. Summary

Hydro now carries a $45.9 million deferred asset that reflects in essence the difference between a calculation of proposed 2014 revenue requirements filed in the GRA and those used most recently to establish its rates for electricity service. Costs associated with the 11 projects and programs whose prudence Liberty examined influence a calculation of the 2014 revenue requirements, to the extent that they involve 2014 capital and operating costs.

Liberty determined 2014 capital costs that resulted from decisions and actions by Hydro found to be imprudent by Liberty. Liberty also sought to determine 2014 operating costs that Hydro would not have incurred but for imprudent decisions and actions related to the 11 projects and programs within the scope of Liberty's prudence examination.

Hydro made its revenue deficiency calculation using five months of actual and seven months of estimated 2014 costs. Liberty used actual costs for the full year, as provided by Hydro. Using actual costs, Liberty identified $10.9 million of actual capital expenditures associated with projects undertaken or in service in 2014 that Liberty found to be imprudent. Liberty also identified $13.4 million in actual 2014 operating costs as avoidable but for the January 2014 outages. Hydro incurred these avoidable costs for the 11 projects and programs, professional services, incremental overtime, and transfers of salary costs to Hydro from Nalcor executive and financial personnel.

B. Background

In November 2014, Hydro applied to the Board for approval to defer and recover a $45.9 million forecasted revenue deficiency for 2014. Hydro calculated this amount by using five months of actual and seven months of forecasted 2014 operating costs and calculated returns on rate base. Hydro then compared the resulting amount with the 2007 costs used to set current rates, offset by higher revenues. The Board found insufficient opportunity in late 2014 to assess these proposals and potential issues and impacts. The Board acknowledged Hydro's concern about potential negative financial consequences in 2014, but recognized the need to test Hydro's proposal fully, in order to ensure protection of customer interests and just, non-discriminatory rates.

The Board approved a $45.9 million deferral account to segregate an amount associated with the 2014 revenue requirement, and retained jurisdiction to undertake subsequent review of the appropriateness of granting any recovery to Hydro.[49]

Liberty undertook a review of Hydro's 2014 capital expenditures and operating expenses to identify those that Hydro would not have incurred but for imprudent decisions and activities falling within the scope of Liberty's prudence review. Liberty identified actual 2014 costs, as provided by Hydro to Liberty, falling into this "but for" category. Data did not exist to make practicable a reconciliation of those actual dollars with the partially estimated costs that Hydro used in its 2014 revenue requirements calculation. Neither could Liberty reconcile the actual 2014 costs that Hydro provided to Liberty with the five months of actual cost data the Company used in making that 2014 revenue requirements calculations.

The scope of Liberty's prudence review (and therefore the dollars subject to the 2014 revenue requirements calculation) include those 11 projects and programs listed in Chapter One of this report. Costs related to those subjects might involve 2014 costs of three general types that Hydro would not have incurred in 2014 but for imprudent decisions or activities:

- Actual 2014 operating expenses associated with the 11 projects and programs that would not have been incurred but for imprudence
- 2014 revenue requirements associated with actual capital expenditures for the 11 projects and programs that would not have been incurred but for imprudence
- Other actual 2014 costs outside the scope of the 11 projects and programs to the extent that such costs would not have been incurred but for imprudence in connection with the 11 projects and programs.

C. Costs Associated with Imprudence

The table below lists by each project the 2014 actual costs that Hydro provided to Liberty. As noted in the other chapters of this report (addressing those 11 projects and programs) these actual reported costs differed, sometimes significantly, from amounts that Hydro estimated in various requests to the Board seeking authorization or approval for the costs involved. The table highlights in green those projects for which Liberty concluded that management acted prudently. The table highlights in red those projects for which Liberty concluded that management made imprudent decisions or undertook imprudent actions. The costs set forth in the table reflect actual 2014 costs as provided by Hydro to Liberty. They do not address the following costs, which in some cases may differ substantially:

- Project estimates included in Board Orders responding to Hydro requests for authorization or approval
- Hydro's 2014 "Test Year" estimates included in the revenue deficiency calculation supporting the $45.9 million deferral
- 2015 "Test Year" estimates Hydro included in in its current General Rate Application filing.

1. Capital Costs

Hydro reported actual 2014 capital expenditures of $112.2 million for the eleven projects and programs reviewed. Liberty determined that $10.9 million of these capital expenses were related to imprudent decisions or actions, for reasons addressed in this report.

Table 9.1: Summary of Adjustments to 2014 Revenue Requirements Calculation

2014 Capital Expenditures - Recommendations	2014 Expenditures Reviewed	Recommended for Recovery	Recommended for Prudence Disallowance
Combustion Turbine 2014 Capital Expenditures	$ 95,435,547	$ 95,435,547	Note: Not in-service in 2014
Holyrood 3 Draft Fan 2014 Capital Expenditures	$ 76,407	$ 76,407	
Sunnyside New 230 kv Breaker	$ 87,500	$ 87,500	
Black Tickle Restoration 2014 Capital Expenditures	$ 1,418,900	$ 1,418,900	
Labrador City Terminal (excluded in PUB Order 42)	$ 4,194,000	$ 4,194,000	
Recommmended for Rate Recovery		*$ 101,212,354*	
Black Start 2014 Capital Expenditures	$ 761,977		$ 761,977
Holyrood 1 Turbine Generator 2014 Capital	$ 5,500,000		$ 5,500,000
Sunnyside Equipment Capital	$ 3,149,184		$ 3,149,184
Western Avalon Tap Changer	$ 1,013,900		$ 1,013,900
230 kv Breaker Overhauls	$ 522,243		$ 522,243
Recommended for Prudence Disallowance			*$ 10,947,304*
2014 Capital Expenditures Reviewed	$ 112,159,658		

2014 Operating Expenses - Recommmendations	2014 Expenditures Reviewed	Recommended for Recovery	Recommended for Prudence Disallowance
Regulated Hydro Professional Services-Consulting Fees	$ 3,264,312	$ 712,299	
Holyrood 1 2013 Replacement Power	$ 902,825	$ 902,825	
Capacity & Energy Purchases, Replacement Generation	$ 9,791,790	$ 7,602,680	
Holyrod 3 Draft Fan Replace Power - Jan 1-12, 2014	$ 1,990,270	$ 1,990,270	
Black Tickle Depreciation	$ 55,000	$ 55,000	
Labrador City Terminal 2014 Depreciation Expense	$ 451,745	$ 451,745	
Extraordinary Repairs (Transformers and Breakers)	$ 1,572,429	$ 669,413	
Recommended for Rate Recovery		*$ 12,384,232*	
Regulated Hydro Professional Services-Consulting Fees	$ 3,264,312		$ 2,552,013
2014 Outage Salary Transfers	$ 511,000		$ 511,000
2014 Regulated Operations Incremental Overtime	$ 3,584,428		$ 3,584,428
Black Start Operating Expenses	$ 160,485		$ 160,485
Holyrood 1 Turbine, 2014 Repairs, Depreciation, Replacement Power	$ 2,419,400		$ 2,419,400
Sunnyside Replacement Equipment 2014 Net Operating Expenses	$ 879,800		$ 879,800
Western Avalon T5 2014 Operating Expenses	$ 41,000		$ 41,000
Capacity & Energy Purchases, Replacement Generation	$ 9,791,790		$ 2,189,110
230 kv Breaker Repair 2014 Operating Expenses	$ 164,000		$ 164,000
Extraordinary Repairs (Transformers and Breakers)	$ 1,572,429		$ 903,016
Recommended for Prudence Disallowance			*$ 13,404,252*
2014 Operating Expenses Reviewed	*$ 25,788,484*		

2. Operating Costs

Liberty's review of 2014 operating expenses addressed about $25.8 million in costs attributable to imprudent decisions and activities. That review determined that Hydro spent $13.4 million that would have been avoided but for imprudence found by Liberty and addressed in this report. The preceding table summarizes those costs. The $13.4 million falls into three categories:

- Operating costs incurred directly in connection with 9 of the 11 projects and programs
- Operating costs incurred directly in connection with a 10th; *i.e.*, work in 2014 to catch up on maintenance work on transformers and air blast circuit breakers
- Other professional service costs, consulting fees, overtime, and salary transfers from Nalcor executives to Hydro that would not have occurred in the absence of imprudence as described in this report's earlier chapters.

a. 2014 Professional Services Costs

Chapter Five describes Liberty's reasons for concluding that the January 2014 outages resulted from imprudence. Liberty therefore examined 2014 costs to determine whether they included expenditures that Hydro would have avoided in the absence of imprudence. If they do, then Hydro's 2014 revenue requirements calculations supporting the $45.9 million deferral are likely to include such costs.

Liberty identified 2014 professional services costs as a significant, potential source of such costs. Liberty secured summaries and work papers for regulated utility 2014 fees for professional services. Liberty reviewed the summaries provided and questioned Hydro about the activities covered. Hydro provided explanations of the services by business unit and service type. Liberty then requested invoices and additional work papers for items that the preceding, initial review disclosed as potentially "outage-related." Liberty reviewed invoices for 2014 Hydro professional services invoices covering more than 95 percent of professional service fees.[50]

Liberty's review of the information identified about $2.55 million in professional fees falling into the "but for" or imprudent category. Some of the larger professional service charges included in this amount are:

Source	Amount
Outage Inquiry legal fees	$876,000
PUB Outage Inquiry*	$958,000
Intervenor Outage Inquiry*	$250,000
Sunnyside Environmental Remediation	$346,000
Event Engineering Investigation	$ 74,000

The asterisked items represent estimates; final costs are not yet available.

b. 2014 Overtime

Overtime comprised another likely category of 2014 costs influenced by the January outages. Liberty requested a summary of overtime hours and payments for 2013 and 2014. Liberty compared the levels to determine whether reasons existed to believe that overtime hours for 2014 were atypical. Liberty reviewed 2013 and 2014 overtime information segregated by Hydro business unit and by capital and expense charges. The data reviewed included overtime hours, total employee overtime payments, and data for permanent and temporary employees. Hydro's total 2014 overtime charges exceeded those of 2013 by $4.3 million. The size of the gap led Liberty to conclude that it would be appropriate to perform a comparison against a longer historical basis, in order to account for circumstances that may have made 2013 a less typical year against which to compare. Liberty also sought information on a monthly basis in order to determine whether any clear patterns in overtime use during 2014 existed.[51] Liberty used the annual average overtime hours for the 2011 through 2013 period as a basis for comparison against 2014 data.

For most business units, Liberty did not observe significant divergence between the base and the 2014 data. However, overtime for permanent employees in the Regulated Operations unit clearly diverged from recent year experience in 2014. This business unit includes Hydro Generation, Thermal Generation, and Transmission and Rural Operations.[52] Using average overtime hours for 2011-2013 as a baseline for measuring incremental 2014 overtime yields a differential of more than 81,000 overtime hours. Data from Hydro supports application of an average cost of $51.43 per overtime hour. At that cost, the incremental hours amount to a cost of $4,176,952. A further analysis of overtime hours was performed by Hydro that determined that $592,524 of these incremental overtime dollars were charged to the capital projects that Liberty was examining and should be removed from the overtime calculation to avoid "double counting".[53] Liberty recommends that the incremental overtime for 2014 be reduced to $3,584,428, and associate this full net amount to the "but for" category.

Hydro has stated that it may be able to perform an analysis at a more detailed level, in order to associate specific overtime hours with specific causes. If so, it may be possible to identify some portion of the 81,000 hours that Hydro would have spent for overtime in 2014, even without the outages. Note, however, that Liberty's analysis already excludes a normalized level of overtime, thus indicating a need to identify other factors unique to 2014 that would have justified above normal overtime.

Liberty's calculations of capital costs in other areas may already capture some of the 81,000 overtime hours calculated here. To the extent that Hydro has a method for determining the overlap, an adjustment would be in order. Hydro continued to examine such methods at the time of the completion of this report.

c. Salary Transfers

Executives and support employees of Nalcor routinely charge Hydro for time spent on utility matters. Liberty sought to determine whether those charges increased in 2014. In the course of Liberty's review, Hydro acknowledged that certain executives and support employees of the executive leadership and finance and CFO organizations performed work related to the outages, and charged the costs of their time in doing so to the utility. Liberty asked Hydro to identify for personnel not "home based" in Hydro time charges incremental to annual salary percentages typically charged to the utility. Such cases existed. For example, Hydro reported that the Nalcor-based President and CEO significantly engaged in oversight of the operational response to the January 2014 interruption of supply events. Subsequent inquiry processes also engaged a number of Nalcor-based executives.[54]

Hydro provided Liberty with a listing of transfers of salary costs to Hydro. Salary transfers related to outage response by 13 Executive Leadership and Finance employees occurred in 2014. The total transfer for such activity was about $511,000.[55] Liberty also sought to determine whether Project Engineering and Technical Support not home based at Hydro charged significant time in connection with the outages. Hydro responded that the only salary transfers for this business unit were by the Manager of the Office of Asset Management, who transferred $48,000 of salary to Hydro.[56]

Liberty concluded that the $511,000 in executive leadership and finance cost transfers would not have occurred in the absence of the outages. Liberty also concluded that there was not material level of time charged by other non-Hydro based employees to Hydro in 2014 as a result of the outages.

3. Integrated Action Plan Costs

Hydro filed a 2014 Integrated Action Plan with the Board. This document addressed actions Hydro proposed to take in response to the 2014 supply disruptions and power outages. The action plan included 79 discrete actions that would require action by personnel across a wide spectrum of activity types. Liberty reviewed the list with Hydro employees, in order to determine whether it included activities that would: (a) produce costs incremental to those that Hydro would experience even in the absence of the need for response to the outages, and (b) not already be captured by Liberty's cost calculations associated with the 11 projects and programs.

This initial review identified six areas of work that might have involved such incremental costs. Liberty examined actual 2014 costs provided by Hydro for each work area and formal explanations of the scope of the work. Liberty determined that maintenance work on critical transformers and air blast circuit breakers remained of interest.[57] Liberty determined that costs for the work in these areas duplicated those addressed in Chapter Eight of this report, which addresses catch up maintenance on such equipment. Hydro did perform work in the other four areas as a result of its assessment of the January 2014 outages. However, even in the absence of those outages, good utility practice justifies the work activities and levels undertaken in 2014.

Liberty's review of 2014 costs Hydro incurred to implement its Integrated Action Plan therefore did not identify any costs falling into the "but for" category.

D. Costs

Liberty's review of capital expenditures determined that expenditures on the following projects resulted from prudent decisions and actions, making it proper to consider them (by whatever revenue requirements calculation methods and standards apply) in a 2014 revenue requirements calculation:

- New Combustion Turbine ($95.44 million), noting that the asset did not go into service in 2014
- Holyrood Unit 3 Forced Draft Fan Motor ($0.08 million)
- Black Tickle Restoration ($1.42 million)
- Labrador City Terminal ($4.19 million) above approved budget of $12.65 million.

However, Liberty considers $10.9 million of the capital expenditures in the projects it reviewed to have resulted from imprudent decisions and actions:

- Black Start ($ 0.76 million)
- Holyrood Unit 1 Turbine ($5.50 million)
- Sunnyside Replacement ($3.15 million)
- West Avalon Tap Changer ($1.01 million)
- Breaker Overhauls ($0.52 million).

Liberty's review of 2014 operating expenses identified $13.4 million as avoidable but for the January 2014 outages:

- Operating expenses on the 11 projects and programs of $6.76 million
- Professional Service fees of $2.55 million
- Overtime expenses of $3.58 million
- Salary transfers to Hydro of $511,000.

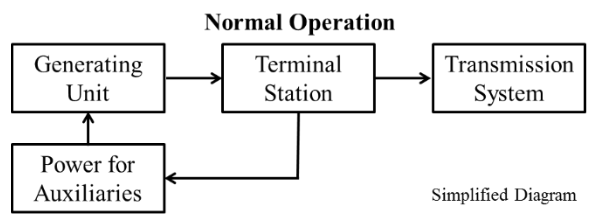
Chapter Ten: Black Start

A. Summary

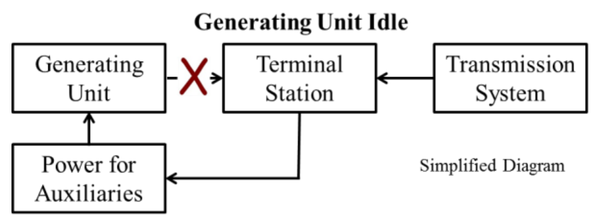
Hydro leased and installed eight 1.825 MW diesel generators to provide interim black start capability at Holyrood. Black start capability allows a generation source to restart when disconnected from other sources that can provide the power needed for restart. Liberty concluded that the decisions and actions of Hydro associated with attempting to provide interim black start capability at Holyrood were imprudent.

B. Defining "Black Start" Capability

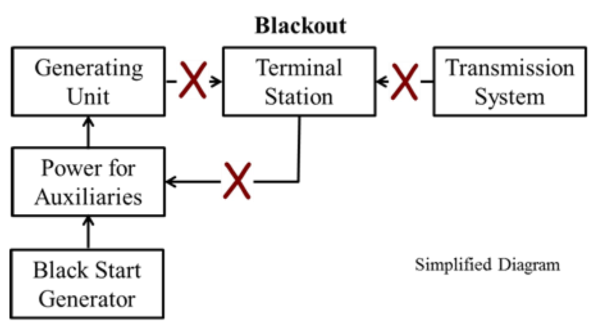
Power plants consume some of the electricity they generate to operate internal systems and components necessary for power generation. The industry terms the internal electrical loads as "auxiliaries." The power to supply them is known as auxiliary power, sometimes termed station use, or station service. The balance of the generation, known as net output, goes to the system to supply customers.



When the plant is not running, it still requires a source of auxiliary power, for example, to maintain the plant in an idle condition or to provide the power to start a generating unit. Under normal shutdown conditions, the auxiliary power supply comes from the transmission system, via the plant's terminal station connection to the transmission system.



In certain unusual circumstances, such as a system blackout, the plant becomes detached from the transmission system. Under such conditions, the unit cannot operate, because there is nowhere for the power to go. The transmission system in these conditions also cannot provide an auxiliary power source. The plant effectively becomes disabled, and cannot restart until an auxiliary source is provided and a path out for the power is restored.



To accommodate such circumstances, some power plants install a black start capability. This capability includes an on-site generation source that provides enough power to start the auxiliaries needed to start the plant's generating units. All plants have emergency generation sources to supply essential plant services, such as those required for safety, security, and the protection of equipment in a blackout. Those generators are not sized for black start, however, which requires substantial capability to start large motors.

Hydro has somewhat downplayed the criticality of on-site black start capability on the grounds that while isolated, there is no way for the plant to start generating anyhow. Even when transmission system outages leave nowhere for the power to go, it is still necessary to start units, bringing them to a least a standby condition. Without black start capability anywhere, one could never restart the system at all. Some units somewhere must have the ability to "bootstrap" themselves to begin the process of adding islands of load and rebuilding the system. The less black start capabilities exist, the longer it takes to restore the system and service to customers.

In addition, it is particularly critical for a fossil plant like Holyrood, to keep the units fired-up, hot, and ready-to-go when a connection can be made to the system. Allowing such units to go cold significantly extends the time needed for startup. Effective configuration of the system thus requires strategically placed sources of black start capability.

C. History of the Black Start Project

Hydro requested Board approval for the lease and installation of eight 1.825 MW diesel generators to provide interim black start capability at Holyrood. The Board, in Order No. P.U. 38 (2013):

- Approved capital expenditures of $1,263,400
- Approved creation of a deferral account, estimated at $5,763,200, for lease costs and other infrastructure
- Deferred questions of cost recovery to a future time.

Black start at Holyrood has gone through a long chronology of changing approaches. Hydro maintained for several decades a gas turbine capable of black starting Holyrood station. Its condition deteriorated over time. In early 2010, public safety inspectors ordered that it no longer be operated. This order was withdrawn about a year later but with the condition that the turbine operate only in emergency conditions. A condition assessment of the gas turbine later that year found it too dangerous to operate under any circumstances. In January 2012, Hydro prohibited any use of the turbine. Hydro did not inform the Board at that time of the loss of this black start resource.

Black Start Chronology

3/10	Stop work order on existing HR black start turbine
2/11	HR turbine approved for emergency use only
1/12	AMEC report precludes further operation of HR turbine
6/12	Decision to use Hardwoods for black start
1/13	Hardwoods option fails when needed
1/13	PUB learns of the AMEC report and shutdown of the turbine
4/13	NP mobile turbine connected at Holyrood and disconnected shortly thereafter when found to be inadequate
10/13	PUB insists upon immediate solution
7/14	Subject project in service

Hydro then began efforts to provide an alternate source for black start. A study by an outside consultant offered a number of options, including refurbishing the turbine, installing two new or used 5 MW turbines, or installing five new or used 2 MW diesel generators. The consultant recommended two new 5 MW turbines.

In the meantime, Hydro was planning a new 50-60 MW combustion turbine for late 2015 as its next new supply source. Hydro chose Holyrood as the preferred site for that new unit. Location there would make the new unit a logical source of black start capability for Holyrood. With the new Holyrood unit viewed as the permanent black start solution, Hydro shifted its focus to meet the interim need before the new CT would be installed.

The temporary nature of the need made it appropriate for Hydro to give strong consideration to costs, in light of the short expected time period over which any interim solution would be in place. However, Hydro's evaluation process made concessions that produced a decision Liberty has concluded was unsound. The Company decided to rely on the existing Hardwoods CT to provide a source of black start for Holyrood. Hardwoods is about 20 km from Holyrood. Hydro did not inform the Board of this decision at that time.

An early 2013 unusual weather event led to the loss of the system and the tripping of all three Holyrood units. This was the design-basis event for black start capability – the very reason one installs such capability in the first place. Unfortunately, with the terminal station at Holyrood locked out and the transmission system dead, there was no way for the Hardwoods capacity to help Holyrood, an outcome that was predictable. The resulting inability to keep Units 2 and 3 hot and ready for restart resulted in an 11 hour delay in restoring the system. Unit 1 was seriously damaged during the event and could not be restarted under any circumstances. It was only as a result of this event that the Board learned that the original black start capability at Holyrood had been taken out of service a year earlier.

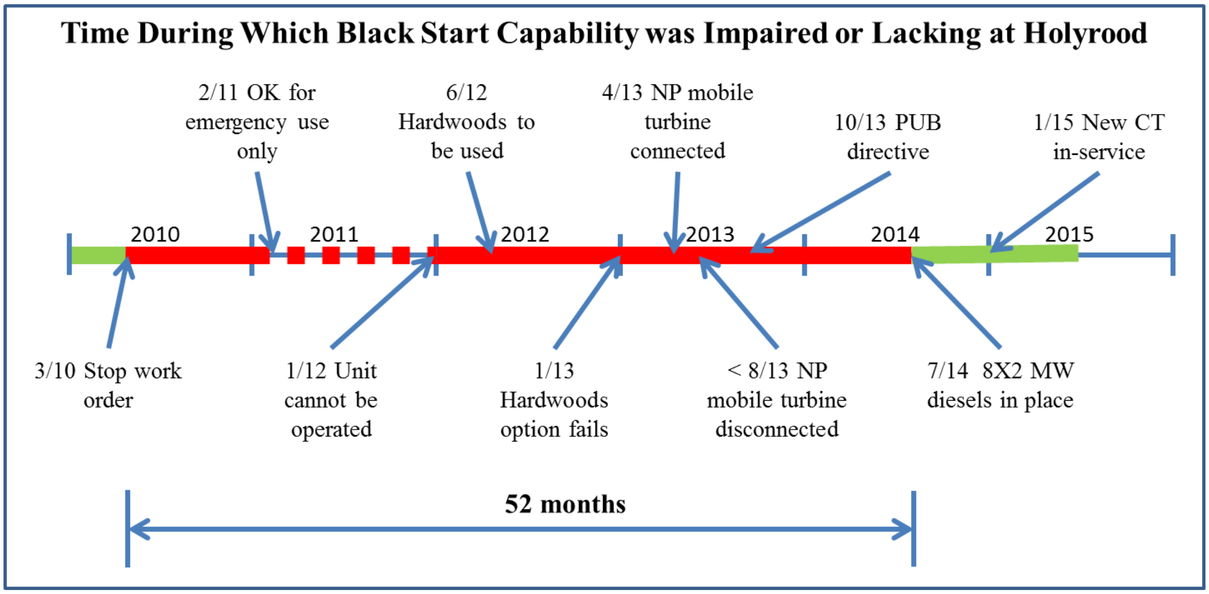
Hydro responded to the 2013 events by returning to a consideration of black start alternatives for Holyrood. Following the events and the loss of Holyrood Unit 1 for a prolonged period, Hydro requested capacity assistance for the Avalon Peninsula from Newfoundland Power. That request encompassed Newfoundland Power's mobile GT and a smaller diesel generator. Hydro analyzed the suitability of this combination as a new interim source of black start capability. Its studies disclosed that such capability was marginal. Hydro moved the two units to Holyrood and tied them into the Holyrood system, in order to permit them to feed station auxiliaries.

When tests showed that the units could not start a boiler feed pump motor, it was clear that the Newfoundland Power units would not work. Hydro abandoned this approach to black start, but did not advise the Board that Holyrood was again without black start capability.

By October 2013, more than three years had passed since authorities first ordered cessation of use of the gas turbine. The Board directed Hydro to provide a black start solution.[58] Hydro responded with the proposal for the installation of the eight leased 1.825 MW diesel generators. The Company completed installation of the last of these generators in mid-2014. Thus Holyrood passed through another winter without black start capability.

The next illustration shows the periods during which Holyrood lacked or had only impaired black start capability prior to completing installation of the eight diesel generators. The illustration shows how long it took Hydro to succeed in providing black start capability that could work.

Illustration 10.1: Black Start Chronology



Hydro has stated that it believes that the winter of 2010-2011 comprises the only time when it lacked black start capability at Holyrood. Hydro has also stated that:

> *For 2013/2014, the [black start for Holyrood] capability was provided by Hardwoods and the Newfoundland Power mobile gas turbine/diesel that was set up at the Holyrood site.*[59]

Liberty found this view unpersuasive, given that the events of 2013 demonstrated the insufficiency of these methods (Hardwoods and the Newfoundland Power units).

D. Prudence Analysis

Liberty's analysis of Hydro's actions has produced a conclusion that Hydro management failed to act prudently in managing black start capability for Holyrood. These actions resulted in a prolonged period during which black start capability was unavailable. Delay in finding a sufficient solution meant that it would only serve a useful function for less than a year. The period during which the facilities will operate does not extend long enough to justify charging them to customers. Liberty reached this conclusion for the following reasons:

- In January 2012, Hydro elected to reject all of the potential solutions offered by its consultant.
- Hydro's decision to rely on an off-site solution, the Hardwoods CT, suffered a number of material flaws.
- The decision to use the Newfoundland Power equipment was marginal and Hydro's failure to act when it proved incapable was not sound.
- Hydro has demonstrated a generally weak approach to reliability issues such that the decisions underlying its black start work lack a good analytical basis.
- The time for which the eight units could provide black start capability was limited because of earlier decisions and delays, giving them at most a limited time to prove used and useful.

Taking these actions relating to the decision process for black start into consideration, Liberty believes that they did not fall within the range of reasonable alternatives. We emphasize that all of these items have been evaluated and judged on the basis of what was known or should have been known at the time. Our conclusions are not based on the failure of Hydro's decisions; rather they are based on the inappropriateness of those decisions at the time they were made.

1. 2011 Consultant Recommendations

In 2011, Hydro commissioned an outside consultant to assess the condition of the Holyrood black start turbine. The consultant found the unit in very poor condition, unreliable, and a safety concern. The consultant's study of options identified three primary options:

- Refurbish the existing Holyrood CT
- Purchase and install two new 5 MW GTs. As an alternate, procure used machines instead.
- Purchase and install five new 2 MW diesel units. As an alternate, procure used diesels.

The consultant believed that these options could achieve in-service dates ranging from February 2013 to May 2013, at costs ranging from $9.5 million through $12.7 million, and recommended the second (two GTs) option.[60] Hydro later observed, however, that "This recommendation was made … without consideration for Hydro's plans to install an additional 50 MW combustion turbine (CT) in late 2015."[61] If so, the study suffers from misdirection. Hydro permitted the consultant to study options outside the range of acceptability.

In any event, the consultant did not identify the Hardwoods option. Hydro selected that option, despite its clear failings, finding it the lowest cost alternative.

Hydro also rejected the option of refurbishing the Holyrood black start turbine, citing its comparatively high cost. Compellingly, a key component of that option's cost was Hydro's requirement that "black start capability must be maintained during any refurbishment or replacement period."[62] Despite this requirement, Hydro eventually made decisions that permitted a lack of full black start capability for 52 months.

Hydro acted imprudently in the following ways with respect to the 2011 outside consultant study:

- Hydro commissioned a study for a permanent solution, but appears not to have informed the consultant that it actually sought an interim solution.
- Hydro rejected all of the consultant recommendations on the sole basis of cost, without consideration of functionality, as demonstrated below in the discussion of the Hardwoods decision.
- Hydro rejected what would have been the least cost option had the requirement for backup black start capability been treated consistently.

2. Reliance on Hardwoods

Hydro has asserted that it never lacked black start capability at Holyrood, with the exception of a period in 2010. We understand Hydro's logic behind this conclusion to be as follows:

- Hardwoods, or by logical extension, any source of generation anywhere on the Avalon Peninsula, could have fed Holyrood to permit restart, after the transmission system became intact after a blackout.
- There is no reason to energize Holyrood before transmission system restoration, because the power has no place to go before that point.
- Hydro could not reasonably have expected the January 2013 blackout, thus making it inappropriate to consider isolation of Hardwoods from Holyrood.

Hydro's assertion creates a shift in the definition of "black start at Holyrood" to "black start of the Avalon Peninsula." This locational shift was revealed by a Hydro response to a question from the Consumer Advocate in CA-NLH-017 in the Black Start Application. The question posed was:

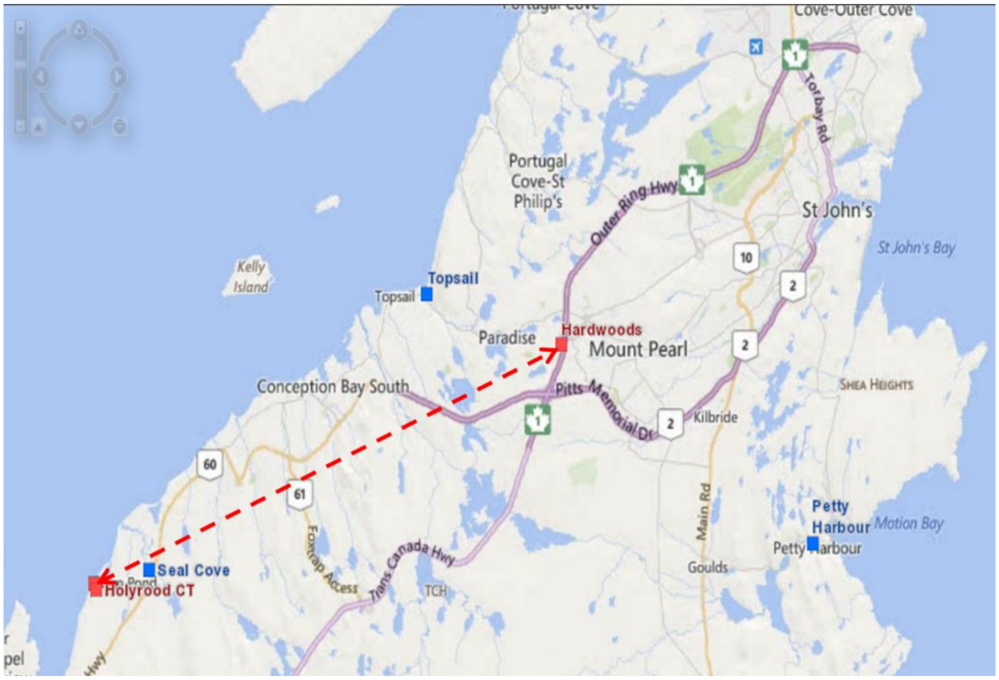
> *Q. In the opinion of Hydro operating staff, can Hardwoods adequately meet black start requirements* *at Holyrood**?* [Emphasis added]

Hydro responded in the affirmative, then proceeded to explain why black start *at Holyrood* is really unnecessary. This explanation addresses why Hydro considers black start capability anywhere else on the Peninsula just as effective. In doing so, Hydro stated:

> *For emergency planning purposes, this isolated area of the system was considered the broader Avalon Peninsula area and not an isolated area adjacent to the Holyrood plant.*

The next map illustrates the degree of geographic proximity between Holyrood and Hardwoods.

Map 10.2: Holyrood to Hardwoods Distance



Liberty found troubling the shift in definition of black start. Consider the North American Electric Reliability Corporation's (NERC) definition of a black start resource:

> *A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System.* [Emphasis added]

The Northeastern Power Coordinating Council (NPCC) defines black start capability as:

> *The ability of a generating unit or station to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.* [Emphasis added]

The consultant working for Hydro in 2011 provided only alternatives that comport with this definition. The Hardwoods option transparently fails the accepted definition of "black start at Holyrood," and it would also ultimately fail in its only actual physical test. Liberty therefore would disagree with the opinion of Hydro's staff (see the response to CA-NLH-017 in the Black Start Application) that, "Hardwoods can meet the black start requirement at Holyrood."

In making the decisions to use Hardwoods for Holyrood black start, Hydro states that it understood the risks. In other words, Hydro understood the risk that an all-lines-out scenario would have black start consequences under the Hardwoods alternative, and deliberately decided to take them. Hydro considers its choice "an informed decision" and a "solid technical decision."[63] Liberty disagrees, and concludes that taking that risk, whether knowingly or not, was not prudent.

This conclusion is based on the following:

- The use of Hardwoods fails to respond to a high priority need to keep the large and important units at Holyrood warm, in order to enable them to contribute as soon as possible after transmission system restoration. Placing black start capability anywhere else but Holyrood sacrifices that need.
- The failure of the 2011 consultant study to offer Hardwoods or any other off-site source confirms that the Hydro criterion applicable at that time did require a capability located at Holyrood. It does not appear that the consultant felt it appropriate to subject any off-site alternate to analysis.
- Hardwoods is particularly unreliable and hence inappropriate for a source of black start capability. It did not exhibit the high probability of starting that a black start resource requires. Utilization Forced Outage Probability (UFOP) measures the probability that a generator will not be available when required. Hardwoods' UFOP averaged over 26 percent from 2008 through 2012.[64]

3. Reliance on the Newfoundland Power Equipment

Hydro next moved to install Newfoundland Power's mobile GT and a small diesel at Holyrood after the January 2013 incident. Adding capacity on the Avalon Peninsula appears to have been the primary reason for the installation. Hydro also considered the addition as a potential source of black start capability. With the units coming anyway, and with the knowledge that Hardwoods would not work, the Newfoundland Power option warranted an attempt at this point.

Hydro performed studies of the capability of these units to provide black start capability. These studies revealed that the units had only "marginal" ability to start a boiler feed pump. May 10, 2013 tests, however, proved the units inadequate for black start. Hydro made no contingency plans for failure of the option. Moreover, the Company took no action with respect to providing black start after the failure until directed to do so by the Board five months later.

Liberty believes this continued reliance on the failed Hardwoods approach was inappropriate. Hydro's failure to act after the Newfoundland Power option's failure in 2013 was also imprudent.

4. Hydro's Approach and Capabilities in Reliability Engineering

Liberty has observed that Hydro's thinking with respect to black start did not comport with industry practices. Examples relevant to black start include:

- The Hardwoods decision provided a remotely located source of black start capability for Holyrood. In the case of a system blackout (a fundamental need for black start capability in the first place), the remote source is manifestly unsuitable.
- In responding to questions on the reliability of the diesels, Hydro provided data about an irrelevant parameter ("operational availability").

In addition, Hydro's discussion of its thinking about contingencies is troubling. Hydro's views about the reliability of the black start system include the statement that: [65]

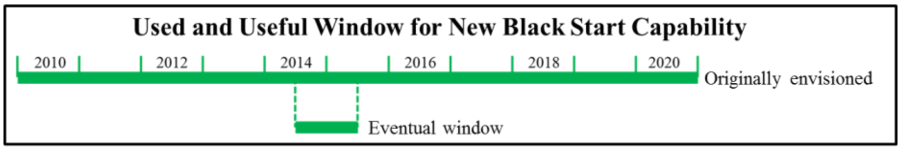
> *In the event of a system outage requiring the black start of the Holyrood plant, Hydro's application of the N-1 criterion is such that all diesel generators are assumed to be available for black start.*

The response suggests that one need not examine the reliability of the black start system because one need consider only one contingency, failure of the transmission system, which has presumably already occurred. Either the need for black start capability does or does not exist. If it exists, it would be illogical to suggest that the reliability of the means chosen to supply it is immaterial. It appears beyond question that black start capability was deemed necessary for Holyrood.

5. The Used and Useful Nature of the 8 X 2 MW Solution

Black start capability at Holyrood became problematic in 2010. The requirement for black start capability would eventually have become unnecessary in 2020 with the retirement of Holyrood. This time frame defined a planning window of 10 years across which a solution would be needed and useful. Hydro's decision in 2012 to install a new 50 MW CT contracted this window of usefulness to 2015; *i.e.,* the expected date for the new CT. The window continued to contract at the front end, as a succession of ineffective solutions brought Hydro ever closer to the date of the new CT's installation. An interim solution finally entered service in mid-2014. In the meantime, the schedule for the new Holyrood CT advanced. It went into service in January 2015, with plans to make it available as a black start source scheduled for later in 2015. The advancement of the new CT's in-service date became known by mid-2014. Hydro's decisions and actions thus reduced the initial "used and useful" window from 10 years to about 1 year, as the next illustration depicts.

Illustration 10.3: Black Start Chronology



The new CT's shortening of the interim black start window represents a positive development, given the reliability benefits it brings. The extended time it took for Hydro to reach a presumably successful solution, however, was the principal contributor in reducing the period of benefit to a very short time period. Hydro's failure to address black start prudently across the first portion of that window thus stands as the principal reason for reducing the period of usefulness.

6. Regulatory Transparency in the Black Start Process

Hydro did not make the issues, its standards, or its actions to address black start transparent to the Board and stakeholders. The Company did not advise the Board of its decisions or of the lack of success in providing black start capability. Hydro determined in early 2012 that the Holyrood black start turbine would no longer serve. Only a year later did that fact become transparent to the Board. Moreover, even at that time the knowledge came not from any proactive effort by Hydro, but only as a result of the scrutiny that came to bear after early 2013 outages.[66]

Hydro also failed to advise the Board that the Newfoundland Power equipment had proven unsuitable for black start. Hydro learned that this option had failed on May 10, 2013. The Board learned only when it asked in the summer of 2013 for Hydro to confirm that the Newfoundland Power units were in place at Holyrood.[67]

Liberty considers effective management of relationships with regulators to require a utility to proactively inform its regulator of: (a) risks due to unavailability of equipment that might be needed under emergency conditions, (b) risks that the utility has knowingly decided to take, and (c) the loss of a committed capability for an extended time.

E. Costs

Hydro considers the eventual project was the correct one, regardless of what one makes of the succession of approaches attempted over a number of years. Thus, Hydro believes, customers should be expected to pay for it, regardless of concern about when it was implemented. Liberty does not agree with this conclusion. Had the project, or a similar one, been proposed, evaluated and installed in 2012, it may have been deemed prudent, and appropriate for inclusion in revenue requirements. The solution in place now does, in fact, bear much similarity with one that Hydro's consultant recommended a number of years ago.

Hydro, however, did not undertake such an evaluation. It would appear that the options that did result from its consultant's study were not limited to interim ones, or even that the study parameter invited consideration of such options. Nevertheless, Hydro rejected those options on the basis that an interim solution was now appropriate, rather than the previously accepted notion of the need for a solution to carry Holyrood to its planned 2020 retirement. The Hardwoods decision superseded all that had been done previously.

Imprudent actions left Hydro without black start capability at Holyrood for an extended period. Moreover, the Company abandoned efforts to regain that capability, shifting to a new definition of black start that did not conform to its prior planning basis or to well-established notions in the industry of what black start means and of what it provides. The Board moved to require Hydro to take action in the fall of 2013. The Board's action does not remove responsibility for Hydro's imprudence that preceded it. Hydro's imprudence has produced only a short period during which the capability that has been in question since 2010 (assuming that the reliability of the units now in place is sufficient) will be useful. That period is too short to justify the recovery of the associated costs from customers.

Hydro has reported to Liberty 2014 capital expenditures of about $762,000 and depreciation, fuel and O&M of about $160,000. For 2015, the deferred lease amortization will start at about $1.05 million, and depreciation expense is estimated at about $41,000.[68]

Chapter Eleven: Holyrood Unit 1 Turbine Failure

A. Summary

In January 2013, a terminal station failure resulted in isolation and tripping of all three units at the Holyrood Plant. During this event, adequate lube oil supply was lost to the Unit 1 turbine-generator, causing major damages and a prolonged outage. A root cause analysis identified several contributing causes for the lube oil failure. The primary factor was failure of the DC lube oil system to function as intended.

Upon Hydro's request, the Board approved capital expenditures of $12,809,700 for the repair of the Unit 1 turbine (Order No. P.U.14 (2013)). The Board did not approve these expenditures for inclusion in the rate base, pending a future Order. Hydro has reported to Liberty that the 2014 actual capital cost for this project was $5.5 million, after the deduction of insurance proceeds of $3.4 million. The 2015 estimated book value of the capital costs is $4.6 million. Hydro reported operating costs in 2014 of $2.4 million, which include 2014 contractor repairs, replacement power and depreciation. Estimated depreciation is $1.0 million in 2015.[69]

The factors contributing to this catastrophic event are numerous and complex. Liberty believes that Hydro's imprudence contributed to the damage. Furthermore, the analysis of the lube oil protection schemes suggests that the lube oil systems remain vulnerable to common mode failure, thus the exposure to future failures and subsequent damage to one or more Holyrood turbines is likely greater than previously thought.

B. Background

The failure to provide a continuous supply of lubricating oil to a large turbine generator produces a catastrophic result within minutes. Accordingly, such equipment requires suitable, redundant backup supply capabilities for the lubricating oil. The consequences of failure in terms of damage to the machine, high cost of repairs, and a lengthy period of unavailability demand particularly high reliability and risk avoidance. Risk decisions balancing cost of redundancy against failure apply in many utility equipment applications. The seriousness of a turbine failure, however, will influence the designer to resolve uncertainty on the side of reliability, not cost. For example, triple redundancy for the supply of lubricating oil to the turbine generator comprises a minimum requirement.

Lube oil supply at Holyrood comes from an AC motor driven pump. The main generator powers that pump. A generator trip will therefore cause the lube oil pump to stop working. Thus, prudence requires the provision of an immediate source of backup supply. Hydro employs a second AC motor driven pump. It secures power from station auxiliary supply. Should that pump fail to start, Hydro's configuration includes a DC motor driven pump designed to deliver sufficient flow to provide adequate cooling of the bearings and to prevent any damage as the unit coasts down in speed.

The trip of Unit 1 on January 11, 2013 stopped the main AC lube oil pump. Due to the initiating event, voltage on the auxiliary bus was severely reduced (to 50kV from 66kV) for seven minutes and the degraded voltage was not sufficient to start the second AC pump. The emergency diesel generator, which is designed to provide backup power to the auxiliary bus, did not start, as it is intended to start only with a complete trip of the bus, not a degraded voltage situation. The diesel was eventually started manually, but too late to effectively bring the backup AC pump into play. Meanwhile, the DC motor, which was the third and final line of defense, started as intended, but damage resulted anyhow. The bearings overheated with significant damage and small local fires resulting. While the DC pump had indeed started, it did not deliver adequate flow of oil to the bearings, resulting in their failure. The unit suffered an extended outage with repairs originally estimated by Hydro to be almost $13 million.

C. Prudence Analysis

Liberty's examination of prudence identified the following issues:

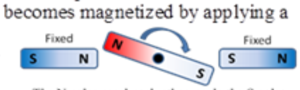
- Hydro's ability to have identified and corrected technical inadequacies in the DC motor by following established standards and processes
- A lube oil system testing weakness that allowed the inadequacy of the DC motor to go undetected for years
- A weakness in the backup AC system that prevented the system from functioning in a degraded voltage situation
- A weakness in the lube oil protection scheme that made it vulnerable to common mode failure.

1. DC Motor Inadequacies

Hydro's analysis of the incident revealed that a number of failings contributed to the events of January 11, 2013.[70] The analysis identified failure of the DC system to deliver adequate flow as the primary cause of the event. The pump started as intended, but nevertheless did not produce adequate flow. Hydro discovered that the motor was unable to reach the speed required to permit the pump to deliver adequate oil flow. Specifically, Hydro found the pump capable of reaching only about 2,800 rpm, compared to its rated and required speed of about 3,500 rpm. Hydro acknowledges that this disabling condition appears to have existed for many years, likely before 2009.

Simplified Workings of a DC Motor

Consider a DC motor as two sets of magnets. One set is fixed on the permanent frame of the motor. The other set is the rotating part of the motor, which becomes magnetized by applying a direct current to it. Magnets have two poles – north and south. The north poles of two magnets will repel each other while the N and S poles of two magnets will attract each other. Therefore, if the rotating N pole is near the fixed N pole, the motor will turn, as the rotating N pole is repelled away from the fixed N pole and drawn to the fixed S pole at the other side of the motor.



The N poles repel each other, as do the S poles, forcing the motor to rotate

In this scenario, the motor will go through a half turn and then stop as the rotating N pole reaches the fixed S pole at the other side of the motor and is attracted to it. This of course does us no good. But what if, at just the right moment, we could change the polarity of the rotating magnet? Specifically, if we changed the flow of the direct current that is forming the rotating magnetic field, we would change the polarity instantaneously. Then, as the motor coasts to the other side from the first magnetic push, the poles change and again are repelled, continuing the rotation. The current changes with every half rotation, and the motor runs continuously.

When the N and S poles become aligned, the motor will stop, as the poles are attracted to each other

But if the polarity of the rotating magnet is suddenly changed, we are back to the original configuration and the motor continues to rotate.

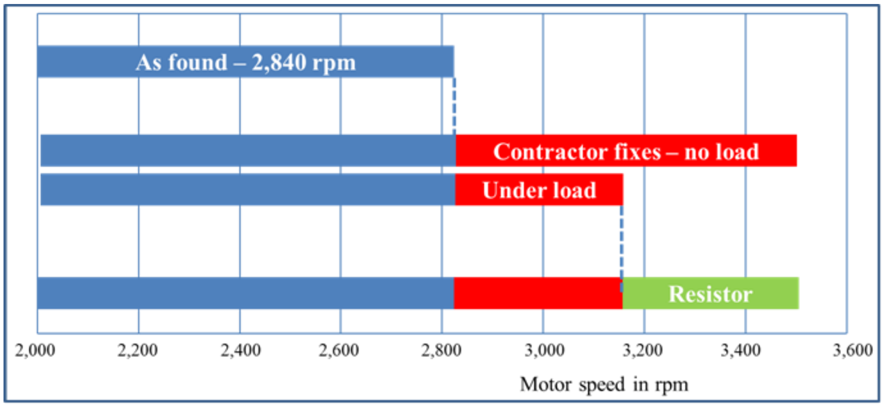
Now let us apply these principles to our immediate case of the Holyrood DC lube oil pump motor. First, the DC current that is applied to the rotating part of the motor is delivered via "brushes". These are simply fixed conductors that ride along the rotating surface of the motor and deliver the DC supply that creates the magnetic field. In the case of Holyrood, the root cause analysis tell us that "the brush boxes were offset". This would impact the current delivered and the resulting strength of the magnetic field, hence affecting speed.

The root cause analysis also tells us that "the motor neutral plane was improperly adjusted". In our diagrams above, it should be obvious that the timing of the change in polarity is critical. If it is too soon or too late, the motor will slow down. The optimum point of polarity change is "the neutral plane" or neutral zone, and that was not properly aligned at Holyrood.

Finally, we have seen that the amount of current to the rotating field affects the strength of the field and hence the speed. In a motor like the Holyrood motor, a resistor is provided in the field circuit that adjusts the strength of the field. The root cause analysis tells us that "the adjustable resistor in the field circuit of the DC lube oil pump motor was moved."

In an effort to determine the cause of the motor's inadequacy, Hydro sent it to a contractor for testing. The contractor also could not attain a speed of more than about 2,800 rpm. Further testing found that: (a) the motor's brush boxes were offset, and (b) the motor's neutral plane was misaligned. The accompanying insert explains how such flaws affected the motor. After the contractor corrected both items, the motor was able to reach its rated speed of 3,500 rpm under no load conditions. After its return to the Plant, Hydro connected the motor to the pump, but it again was unable to come to speed, reaching only about 3,100 rpm. Subsequent adjustment of a resistor setting allowed the motor successfully to reach rated speed under load. The next diagram illustrates this evolution.

Diagram 11.1: Evolution of Motor Repairs



The root cause analysis addressed the source of these problems, which appear about equally responsible for the motor's failure to perform. The root cause analysis attributed the misalignments to quality issues at a maintenance vendor, indicating that the resistor setting "was moved." Hydro has stated that the maintenance vendor operated under a standard that required speed testing of the motor before its return. Hydro also states that the vendor did perform the required testing. However, neither Hydro nor the vendor provided documentation sufficient to verify the conduct of speed testing. Hydro recently submitted a copy of the vendor's invoice, which under the description of the work, included the following notation:[71]

> *Assemble with new bearings, ran and test OK.*

Hydro also observes:[72]

> *The contractor has confirmed to Hydro that the relevant test would have been carried out on the motor as per the contract.*

From a quality assurance perspective, neither the "ran and test OK" notation nor the confirmation, four years later, "that the relevant test would have been performed," amounts to sufficient evidence that a speed test was done and that the motor achieved rated speed. Further, Hydro does not explain how the faulty condition of the motor could have existed since 2009 or earlier if it had been tested in 2011.

These facts indicate that: (a) the test was probably not performed, (b) had the required test occurred, it would have discovered the motor's deficiency, and (c) Hydro failed, in overseeing the vendor's performance, to verify that the records validated the performance of required testing. Liberty concludes that Hydro's practices relating to the maintenance of this critical motor were inadequate and imprudent. Hydro's imprudent practices allowed a faulty motor to remain in a high priority service capacity for many years.

Additionally, the root cause analysis concluded that the resistor was incorrectly set in the plant at some unknown time in the past. Hydro has dismissed this issue as having "lesser impact." [73] This assessment differs from Liberty's conclusion that the alignment issues and the resistor setting contributed about equally. Our conclusion was based on the relative improvements in motor speed:

Contractor alignment adjustments	2,840 → 3,160	improvement of 320 rpm
Hydro resistor setting	3,160 → 3,500	improvement of 340 rpm

Liberty therefore concludes that the erroneous resistor setting did contribute significantly to the events of January 2013.

The failure of the motor to function was therefore the direct result of a series of failures on the part of Hydro and its vendors, which failures continued over an extended time period. Hydro's failures amount to imprudence.

2. Inadequate Lube Oil Test Procedure

One would normally consider the resulting inability of the DC backup system to function over a period of many years to be impossible in a power plant. Regular tests of essential systems, especially those protecting large equipment, seek to avoid such circumstances. The tests for this DC system, however, simply verified that the motor would be energized when the appropriate signal was sent. Procedures did not include testing that would verify the pump could reach and maintain rated speed, and provide adequate flow of oil to protect the equipment.

Good utility practice and basic common sense dictates that any system test sequence should be designed and executed under the primary criterion that the system function as intended. Other intermediate criteria (*e.g.*, relays operating, temperatures maintained, current remaining reasonable, or vibration acceptable) may be included. The fundamental question that testing should answer, however, remains whether the system works as it is supposed to and whether it will do so when needed. Hydro did not design or execute its testing to answer these central questions. The consequences proved severe.

Hydro justifies the prudence of its testing by stating that it followed the manufacturer's test procedures. Thus, the manufacturer, not Hydro, bears responsibility for the absence of measures that would have prevented the causes of the January 2013 damage. Hydro has owned this plant for nearly 40 years. At some point, the owner must take accountability for basic plant operations. Failing to spot gaps in manufacturer procedures is more excusable in the first few years of ownership, but has greatly diminished force after four decades of ownership and operation.

Hydro has in recent years adopted a sophisticated asset management program for its supply resources. Liberty reviewed that program in its December 2014 report, finding it generally sound in design. Hydro's asset management approach reflected in this program should encourage continuous questioning and testing of processes, with managers and technicians asking "why are we doing this," "is it effective," and "how can we improve"? Had such an approach been functioning, which Liberty believes is a goal of Hydro's asset management initiatives, the inadequacy of the testing process would have been revealed.

Liberty recognizes the value in reliance on vendor and contractor expertise. That reliance becomes particularly important with respect to sophisticated technological specialties. Utilities cannot afford to have specialists in every area, and cannot possess all the skills a vendor can. The systems involved here do not rise to a high level of sophistication, however. The testing of a lube oil system is not complex. In this case, the testing gap appears to have resulted from a simple oversight that persisted for years.

Liberty concluded that prudent conduct by Hydro would have discovered the test inadequacies during the long period of time it has owned and operated the Holyrood Plant. Thus, Hydro was operating without the benefit of information that it would have known had it followed prudent practices. That information would have required a change in its testing and monitoring procedures to address the conditions that led to the January 2013 incident. The test in question is basic and critical and the failure to execute it correctly is a serious error constituting imprudence by Hydro.

3. Secondary AC Pump Failure

Following the Unit 1 trip, the emergency diesel did not start, and the degraded voltage of the auxiliary supply proved insufficient to start the second AC pump. This sequence raises two issues:

- Whether the pump motor should have been designed to start under degraded voltage conditions
- Whether the emergency diesel power supply should have been designed to start under degraded voltage conditions, thereby allowing the AC motor to start as required.

The root cause analysis recommended adjustment of the AC pump motor to support its start under degraded voltage conditions; Hydro has made this adjustment. Had Hydro incorporated this configuration in the original design, it would have prevented the January 2013 damage. Motors are normally designed to start under some level of reduced voltage, but not extreme reductions. Starting under seriously degraded voltage is not normally considered a design requirement in such circumstances. Accordingly, Liberty found no basis to conclude that Hydro's approach with respect to voltage degradation was imprudent.

Liberty also addressed whether the protection scheme should have been designed to start the diesel under degraded voltage conditions. Hydro's root cause analysis followed a similar line, recommending a study of starting the emergency diesel under brownout conditions. Hydro responded that industry practice generally does not provide for the start of emergency diesels under a brown-out scenario. Hydro provided supporting evidence from one of its consultants.[74] Thus, Hydro's configuration at the time of the incident conformed to industry experience, and was, therefore, a reasonable approach.

Liberty therefore accepted Hydro's technical justification that the emergency diesel would only start in blackout, but not in brownout conditions. It later became known, however, that even in the blackout condition, and following a successful start of the diesel, the secondary AC lube oil pump would still not function adequately. As Hydro explained:

> *The emergency diesels which back up the essential services motor control centres (MCCs) at the Holyrood plant were tested, to verify the amount of time that it takes for them to restore voltage, once called upon. The restoration time is in excess of the time it took for bearing damage to occur during the January 11, 2013 Holyrood Unit 1 incident (keeping in mind that the emergency DC pump was not functioning properly at the time).*"[75]

Thus, while failure to design to brown-out conditions was acceptable, the inability to function under blackout conditions is obviously contrary to the design intent. Functioning under blackout conditions had never before been in question. Hydro's recent revelation, however, raises serious new issues. The next section of this chapter discusses the potential consequences and the ramifications for prudence and for future operations.

4. Overall Reliability of the Three Lube Oil Systems

Hydro's conclusion about the inability of the diesels to protect the turbine via the secondary lube oil system raises a significant question. Losing off-site power causes the loss of both the primary and backup AC lube oil systems. This loss therefore leaves only the DC system to provide required protection. In this scenario, the design of the system provides only double redundancy, not the triple redundancy intended. The loss of two systems from the same fault constitutes a "common mode failure." In this case, Holyrood's isolation from the system causes both the main AC lube oil system and the backup AC system to fail simultaneously.

Hydro makes reference to a technical paper that analyzed the failure of a large nuclear turbine at the San Onofre Nuclear Generating Station.[76] That event occurred in 2001. Interestingly, the technical paper discusses loss of off-site power as the initiating event. The design of Holyrood and San Onofre differ somewhat with respect to lube oil configurations. The same initiating event (loss of off-site power), however, produced the same result (disabling of both the primary and backup lube oil systems). When the DC system failed to function, both at San Onofre and Holyrood, the damage occurred. The lesson learned at San Onofre, which applies at Holyrood as well, is the need to protect against common mode failures; *i.e.*, loss of two of the three lube oil sources via one failure (*i.e.*, loss of off-site power).

Hydro acknowledges the current situation, stating:

> *Hydro fully recognizes its vulnerability to a multi-contingency lube oil system failure, such as loss of AC power together with a simultaneous functional failure of the DC lube oil system on the Holyrood generating units.*[77]

The continued existence of this vulnerability could be judged as imprudent. It does not, however, have relevance to the January 2013 circumstances. The reason is that Hydro did not face a blackout scenario at that time. Nevertheless, the exposure that exists now warrants careful study, as Hydro is clearly now aware of its exposure to a future turbine failure due to a common mode failure.

The concern becomes magnified when one considers that the initiating event (loss of off-site power) will trip all three Holyrood units, not just one. In order to prevent turbine damage, the third backup vehicle on all three units must function properly.[1] If even one of them fails, catastrophic turbine failure will be the result. To rely on three such systems having to function perfectly in a loss of off-site power incident is a case of a high stakes, high risk decision. It should be noted that these backup systems failed at San Onofre, they failed at the Holyrood Plant and they failed in at least five different fossil plants in early 2001, as described in the aforementioned San Onofre technical paper. This potential common mode failure should be further examined by Hydro.

D. Costs

The DC motor's failure to function was the primary and direct cause of the damage to the Holyrood Unit 1 turbine in January 2013. The motor's inadequacies existed for years and maintenance by a Hydro vendor failed to detect them. Hydro failed in its oversight of third party maintenance. The information available indicates that the vendor likely did not test the motor. Finally, an erroneous resistor setting, which resulted from actions within Hydro's Holyrood organization, also contributed to the inability of the motor to perform. Liberty considers these failures to represent imprudence on the part of Hydro.

In addition, had Hydro implemented an effective periodic test of the lube oil system, the motor's inadequacies would have been discovered and rectified long before 2013. The failure to recognize and respond to the need for such testing also constitutes imprudence on the part of Hydro.

Finally, weaknesses persist in the overall lube oil protection scheme in the form of vulnerability to loss of off-site power, which immediately will disable the first two lines of defense on all three Holyrood units. This should be further studied by Hydro.

The next table shows the restoration costs originally estimated by Hydro, 2014 actual costs that Hydro has reported, and 2015 Test Year costs.

[1] Liberty has not studied the protection schemes on the other two Holyrood units, although we understand Unit 2 to be the same setup as Unit 1. We believe another approach may have been chosen for Unit 3.

Table 11.2: Holyrood 1 Turbine Restoration Costs[78]

	Order No. P.U. 14(2014)	Hydro 2014 Actuals	Hydro 2015 Test Period
Holyrood 1 Turbine Restoration Capital	$12,809,700	$5,500,000 (net of insurance proceeds)	$4,600,000 (net of insurance proceeds)
Holyrood 1 Turbine Expenses			
Contract Labour/Other	0	$914,800	0
Depreciation Expense	0	$1,000,000	$1,000,000
Replacement Power	0	$504,610	0
Operating Expense Totals	**0**	**$2,419,410**	**$1,000,000**

The Board approved capital expenditures of $12,809,700 for the repair of the Unit 1 turbine (Order No. P.U.14(2013)). The Board did not approve these expenditures for inclusion in Hydro's rate base, pending a future Order. Hydro has reported to Liberty actual 2013 capital costs of $5.6 million, net of insurance proceeds of $3.4 million. Hydro reports 2014 actual capital at $5.5 million and estimated 2015 test year capital at $4.6 million. The reduction in anticipated capital expenditures for the Unit 1 turbine repair, including the impact of insurance proceeds, makes the imprudence finding to be of a lower financial effect than originally expected.

On the other hand, Hydro has provided actual 2014 operating costs related to the Unit 1 turbine repair that were also unexpected. Hydro reported that it had experienced residual vibration issues with the turbine in 2014 following the turbine repair. Hydro hired an external contractor to conduct specialized maintenance on Unit 1 in the fall of 2014. This work resulted in contract labor costs of $914,800 in 2014. Upon Liberty's request, Hydro has also estimated the replacement power costs for the period that Unit 1 was in an outage in 2014 for vibration repairs at $504,610. Depreciation on the 2013 repairs of $1,000,000 was a third area of operating expense for 2014; total operating expenses were over $2.4 million. Depreciation of $1,000,000 for 2015 was also estimated and provided by Hydro.[79]

Chapter Twelve: Labrador City Terminal Station

A. Summary

Hydro included in its 2009 Capital Budget a project that would increase capacity at its Labrador City Terminal Station, which it acquired many years ago from the Iron Ore Company of Canada. Hydro forecasted that it would need the increased capacity by 2011 to serve new loads expected to result from expansion of mining operations in the area. Liberty found that Hydro based its plans for the project on inadequate information. The need to perform work well in excess of what those initial plans contemplated caused a delay in construction. Hydro also failed to consider a number of required elements in forming earlier project estimates. Later estimates that did consider such elements produced major cost increases.

Hydro was unable to complete the project until 2013. The need to perform work that should have been completed earlier (through sounder up-front planning and design) contributed to the delay. Load forecasts continued to support earlier completion, but expected loads did not materialize at levels that would have produced adverse service consequences until after completion in 2013. Therefore, customers did not experience service quality problems due to delays in completion.

Hydro's execution of project planning, design, and estimating for this project were inadequate to a degree that calls for a conclusion of imprudence. However, the errors and omissions resulting did not cause an increase in project costs. The gaps that caused earlier estimates to be too low involved work that had to be performed. Effective planning and estimating would have made the scope of work clearer earlier, but would not have avoided the need for spending money on required work. Delay in completion of such projects often causes costs to increase. The delay in completing the work in this case did not contribute to cost increases, however. The pattern that Liberty observed in cost escalation on key work elements indicates that costs would not have been materially different for 2011 or 2013 completion dates.

B. Project Background

The western Labrador town of Labrador City has a population of about 9,000 and its economy centers largely around the operations of the iron ore mining operations of the Iron Ore Company of Canada. Proposed expansion of mining operations has formed an important part of Hydro's system planning activities for the area. Hydro included the Labrador City Terminal Station Project in its 2009 Capital Budget at a forecast cost of $9,900,000 and a completion date of 2011. The Board's later Order No. P.U. 2(2012), approved a revised project budget of $12,650,000. Actual final costs at completion in May of 2013 amounted to $16,844,000. This amount exceeded the 2012 approved amount by $4,194,000. Liberty's examination focused on the sources of this approximately $4.2 million increase.

The Labrador City Terminal Station project was to provide necessary terminal station capacity for the Labrador City distribution system. Hydro's peak load forecast in the fall of 2007 indicated that Labrador City's 4kV distribution system was approaching the applicable design standard, which calls for reinforcement when projected loads exceed 100 percent of system capacity. A 100 percent standard is in keeping with general practice in the industry.

Hydro prepared in 2007 a conceptual plan and cost estimate for increasing system capacity, recognizing that it was approaching capacity. Hydro forecasts from the fall of 2008 indicated that peak loads could exceed the 100 percent of system capacity standard in 2011. Hydro had just learned of the anticipated expansion of mining operations, which was the driver of increases that would push load above system capacity. Hydro's 2009 Capital Budget included the project, which assumed a 2011 completion date and used the 2007 conceptual plan and accompanying cost estimate as the basis for the budget item.

The 2007 plan contemplated expanding the two existing stations and increasing the voltage to 25kV. Hydro did not undertake detailed analysis of the feasibility of this conceptual approach. Had Hydro undertaken even a fairly high-level examination at the time, it would have realized that new construction, rather than expansion of the existing stations, would be required. New construction would clearly require land acquisition, and would extend the required completion date past 2011.

Even after 2009 high-level design work disclosed that the initial plan was not feasible, Hydro failed to reflect added costs in its project estimate. Doing so would have provided significantly increased and more accurate cost projections. Prompt and effective re-estimating, for example, would have captured the costs of missing work elements. It would also have accounted for very high escalation rates being experienced in key cost elements (such as construction labor).

Hydro did not complete land acquisition and surveying until the middle of 2010. Civil construction work began in late 2010, and continued into 2011. Hydro did not award electrical construction contracts and some major components contracts for the stations, including control buildings, until 2011. While annual cost escalation ran at high rates through 2010, it leveled in 2011. Thus, Hydro likely did not pay a premium by awarding these contracts in 2011 versus 2010. Late delivery of the control buildings caused project completion to extend to May 2013.

Hydro addressed the significant scope changes occurring after the 2009 Capital Budget inclusion by requesting approval for more funds for the 2012 Capital Budget. As indicated in "D. Project Costs," below, based on its 2009 budget of $9,990,000 for 2009 through 2011 and its 2011 budget for 2012 and 2013 of $5,973,000,[80] Hydro should have requested approval for $15,963,000, rather than $12,650,000. The actual project cost of $16,844,000 exceed the budgeted cost of $15,963,000 by only $881,000, which is attributed to Hydro's failure to realize in 2011 the scope of work required to commission the stations, the engineering labor costs associated with contract supervision and support, the commissioning support, the project close out, and the cost to complete commissioning in 2013 because of the control building supplier.

C. Prudence Analysis

Hydro completed the project some two years past the original forecast completion date and at a cost of about $4.2 million more than last authorized by the Board. The project was beset by a number of planning, design, and estimating errors. Liberty's analysis focused on the following issues:

- Service consequences of the failure to meet a 2011 in-service date
- Quality of planning, design, and estimating activities

- Sources and reasonableness of cost increases
- Cost consequences of completion date delay.

1. In Service Date - Load Forecasting

Annual peak loads in Labrador City increased from 47.5 MW in 2005 to 49 MW in 2007, and remained the same in 2008. However, Hydro's 2006 and 2007 forecasts indicated that peak loads in the areas could reach the Labrador City system capacity of 52 MW in 2011. The 2008 forecast indicated that 2011 peak load could reach 53.1 MW.[81] Anticipated mine expansion that came to Hydro's attention in 2008 primarily drove the increase.[82] The loads projected by the 2008 forecast for 2011 could create low voltage issues in the absence of system capacity increase.

Hydro had already prepared a conceptual plan (having a cost estimate of $9,900,000) to increase station capacity in Labrador City, and to increase the distribution voltage from 4kV to 25kV to address what it saw following the 2007 forecast as a looming capacity issue in the area. Hydro included the project as conceptually planned and estimated in its 2009 Capital Budget. Hydro plans for system reinforcements of this type to provide capacity increases by the date when forecasted loads exceed 100 percent of existing capacity, accords with common utility practice.

While Hydro's forecasts continued to show growth that would push peak loads past system capability, it was not until 2013, however, that the actual peak exceeded 52 MW.

Liberty found the 100 percent of capacity standard for triggering reinforcement is a common utility practice, and is prudent. Liberty also believes it continued to be necessary to complete the project promptly, given that load forecasts continued to show near term exhaustion of capacity in the system serving Labrador City.

Hydro completed the project in 2013. Customers, however, experienced no adverse service consequences because loads in excess of pre-increase capability came only after project completion.

2. Planning, Design, and Estimating

Hydro's 2007 conceptual plan did not take appropriate account of field conditions. Hydro did not install the existing terminal stations, which the mining company had done. Later work by Hydro identified a failure of the stations as constructed to conform to Hydro's standards and requirements. As a result, it was necessary to install new stations. Hydro's lack of knowledge about the stations caused its conceptual plan to be deficient. Undertaking a conceptual design without a full understanding of facilities acquired from a third party was not prudent. Hydro only learned of the resulting need for new, versus expanded stations when it undertook work in 2009 to prepare high-level engineering plans.

Good utility practice would have required that Hydro undertake more thorough planning and estimating efforts in 2008, in recognition of the need to begin work in 2009 and a plan to complete the project in 2011. Hydro's estimating should have more promptly recognized the impacts that labor cost increases of 9.3 percent in 2008 and 34 percent in 2009 would have on the project.[83]

3. Work Progression and Annual Costs

In 2009, Hydro first came to understand that buildings, switchgear, and land areas for the existing stations would not support the required expansion. Conceptual planning to that date had also failed to consider safety issues raised by construction within the existing energized stations. The plan also did not recognize difficulties, including lengths of required outages, in transferring feeders from 4kV to 25kV within the stations. The conceptual plan and estimate also omitted a number of work and cost sources (*e.g.*, land, control buildings, foundation construction purchases). Factors like these would cause about a year's delay in construction.[84]

Hydro had to delay work in 2009 because acquiring land proved troublesome. Acquiring the land for the new Quartzite station from the Town of Labrador City stalled due to a significant difference in valuation between Hydro and the owner. Hydro-owned land for the new Vanier station proved to be unacceptable. The process to purchase land from IOC became lengthy. Hydro had planned in 2009 to complete high level designs of the stations, the ordering of transformers, circuit breakers, and reclosers, and the purchasing of land. Hydro only ended up being able to complete high level design of the stations and the tendering for power transformers. Actual 2009 costs of $292,000 ran close to the budget of $283,000.[85]

Hydro did not resolve land purchase and surveying until the middle of 2010. Civil work (site preparation and the installations of foundations for the equipment in the stations) did not begin until late 2010.[86] In 2010, Hydro completed transformer purchase agreement award, high level design, tendering for buildings, protection panels, battery banks, and ordering of major terminal station equipment. Reported actual 2010 costs of $1,693,000 underran the year's budget of $3,895,000. It appears that the actual costs reported failed to include $1,100,000 spent for civil work in 2010.[87]

In 2011, Hydro awarded contracts for buildings, protection panels, battery banks, structural steel, electrical construction labor, fiber-optic cable and labor to install the cable. Civil construction work and detailed electrical, tele-control, and protection and control designs continued. Actual reported 2011 costs of $6,023,000 ran reasonably close to the budget of $5,812,000.[88] Liberty believes that the early planning failures caused these contracts to be awarded a year late, even considering that the revised completion had now become 2012. The delay, however, did not have a material cost impact. Contractor labor costs in Newfoundland and Labrador increased about 43 percent between 2009 and 2010, but did not increase in 2011. Therefore, earlier contracting would likely have produced agreements in the same cost range.

In 2012, Hydro completed the civil works, the construction of the stations, the installation of the control buildings, the protection panels, and the battery banks. Late contractor performance in providing control buildings and other items caused delays in installing protection panels and commissioning the equipment. The Quartzite station commissioning occurred in December 2012. Vanier station commissioning occurred in May 2013.

Schedule delays in projects of this type often produce a need for overtime work to recover lost time. Hydro's use of overtime during the project, however, remained moderate and well within expectations. Hydro incurred about $99,000 in overtime differential costs for labor by employees. Contractor labor came under fixed price contracts, making payments for premium time inapplicable for contracted labor.[89]

D. Project Costs

The project operated under an estimate of $9,990,000 from 2009 through the end of 2011. The scope of the project had changed considerably since the Board's 2009 approval. Hydro requested and obtained Board approval in 2012 for $ 12,650,000. However, based on its 2012/2013 project budgets, Hydro should have requested $15,963,000 at that time. This sum was necessary to reflect accurately the $5,973,000 Hydro had budgeted for 2012 and 2013. [90] The total cost of the project was $16, 844,000.

Liberty found that the errors and omissions in project planning, design, and estimating for this project were of such a magnitude that they were beyond the range of actions that a utility would reasonably have undertaken for such a project. Liberty, therefore concludes that Hydro acted imprudently in the project planning and execution of this project. However, the work covered by the omissions and errors was necessary and the project as finally completed was required. Final actual costs were $881,000 ($16,844,000 actual less $15,963,000 budgeted) greater than Hydro's budgeted expenditures for 2009 through 2013.[91] Liberty found that increase justifiable, and observed no reason for questioning the reasonableness of the costs of earlier work.

Chapter Thirteen: Black Tickle Restoration

A. Summary

A March 2012 fire caused significant damage to the diesel plant that provides the only source of power for the Labrador community of Black Tickle. Hydro expended capital costs of about $1.4 million (net of insurance) to return the plant to service. The Company sought approval for the capital expenditure as a supplement to the Allowance for Unforeseen Items category. Board Order No. P.U. 27(2014) excluded the Black Tickle expenditures from the 2012 rate base, pending future consideration.

While Liberty found Hydro's failure to act sooner on fire suppression issues in the diesel plants may have been unsound, given the priority assigned to Black Tickle in the overall plan for the diesel plants, action to require fire suppression at Black Tickle still likely would have come after the fire had occurred. Liberty concluded that Hydro acted prudently in not reducing the capacity of the plant to reflect the loss of a major source of load in the community. Liberty also found management of the restoration prudent and costs reasonable. Liberty did not consider as part of this review whether the proper regulatory compliance process had been followed.

B. Project Background

Black Tickle is a small community on an island off the southeast coast of Labrador. A small power plant consisting of three diesel generators serves the community's approximately 100 customers. A March 14, 2012 fire at the plant damaged all three units, producing an outage that left the community without power for nearly two days.

Hydro temporarily restored power by getting the least damaged unit back in service. A few days later, Hydro increased capacity after energizing a mobile generator delivered by a Coast Guard icebreaker. Finally, about a week later, Hydro got another unit at the plant working.

With service fully, albeit temporarily, restored, Hydro continued to work towards a permanent restoration of the plant. Hydro committed to restoring the plant to its pre-fire condition, and acted urgently to identify the scope of the damage, design a repair scheme, and implement the required fixes. Order No. P.U. 27(2014) approved a net cost of restoration at $1,417,031, after insurance recovery of $274, 801.

Hydro did not seek prior approval of these funds. The Company proceeded instead under the Allowance for Unforeseen Items. Over the next two years, Hydro submitted the following applications for recovery of the associated Black Tickle costs:

- On September 27, 2012, Hydro submitted an application (not approved) to top up the Allowance for Unforeseen Items.
- On September 9, 2013, Hydro submitted another top up application. The Company did not secure approval, because the Board was continuing to review the expenditures.
- Hydro requested inclusion of Black Tickle costs in the proposed 2012 rate base. On July 18, 2014, the Board denied this request, but ruled that Hydro could propose inclusion later.

C. Prudence Analysis

The potential areas of prudence involve three principal issues:

- Lack of a fire suppression system at Black Tickle and the failure to provide such a system as part of post-fire restoration
- Not reducing the size of the plant during restoration, in light of the closure of an area fish plant
- Reasonableness of restoration project costs.

The decision by Hydro to proceed under the Allowance for Unforeseen Items has also been raised. Liberty did not consider this regulatory compliance question within the scope of a prudence review.

Hydro's view that it urgently needed to restore the plant prior to the next winter becomes central to the analysis of the first two of the issues that Liberty examined. To the extent that this consideration was sound, it would clearly rule out the making of any changes to the plant, whether they involve fire suppression or a reduction in size. A substantial rebuilding effort ordinarily provides an opportunity to perform desirable work. Where, the need for completion is critical, however, prudence will generally call for the elimination of work that threatens the project's critical path.

Hydro considered changing the existing configuration was too risky. Its reasons included harsh Labrador weather, lack of confidence in the reliability of temporary fixes for an extended period, and the uncertainties already inherent in a significant repair effort. As a result, Hydro pushed ahead without detailed consideration of other options. Hydro's approach necessitated use of the Allowance for Unforeseen Items process. Restoration on the schedule it considered necessary would not allow time for normal prior approval processes.

A hallmark of the North American utility industry is the paramount priority of "keeping the lights on." Bad weather, an isolated community, and a threatened system call for a sense of urgency in responding. Sound management requires that this sense be tempered by the need to consider the consequences of urgent action. Nevertheless, the circumstances faced by Hydro, and more importantly the group of isolated customers involved, do call for a risk averse approach to restoring capability reliably and in the shortest time available.

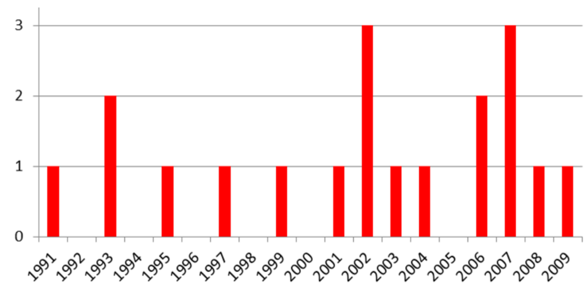
Hydro took such an approach, which we consider appropriate. Hydro did have the option of continuing to rely on temporary repairs until the next winter. That approach would have provided time for a study of its alternatives. It may even have produced a solution that would have better optimized reliability, recognizing cost considerations. Liberty, however, does not consider it imprudent for the Company to have proceeded on the premise that it was essential to provide before the next winter season an approach that would mitigate the risks that temporary restoration meant for customers. Hydro acted with a reasonable base of information from which to assess the risks of proceeding on a temporary basis, and its choice to accelerate installation of a permanent solution by maintaining the existing design and configuration was logical.

1. Fire Suppression

Hydro operates 26 isolated diesel systems, including Black Tickle. There, and in most other cases, the systems provide a community's only power source. Hydro takes steps to enhance reliability in these cases; *e.g.*, installing facilities that can continue to meet peak loads following the loss of one generator. The unmanned units on systems such as Black Tickle are susceptible to fire. An alarm system transmits notice of the fire and equipment shut down follows. The plants, however, do not generally have mechanisms for suppressing a fire. Moreover, personnel are not normally present to fight a fire.

In 2011, Hydro commissioned a study by an external consultant to revisit its approach of not providing fire suppression for such systems.[92] That study produced a risk matrix and plan for a long term effort to phase in fire suppression systems at the isolated plants. The study noted, as the next chart illustrates, a significant number of fires (19) at isolated systems since 1991.

Chart 13.1: Reported Fires at Isolated System Plants



Moreover, the study cited the possibility of others that may have gone unreported.[93] A rate of roughly one fire per year, with some producing catastrophic damage, would suggest that revisiting the fire suppression study was overdue. Hydro's root cause analysis of a 2008 event appears to have triggered the outside study. It is not clear why it came three years later. Liberty believes that it would have been appropriate for Hydro to have addressed the frequent rate of fires earlier. Its isolated systems had experienced 10 fires in the six-year period (2002-07) preceding the 2008 event that led to the 2011 study.

Hydro's approach applicable at that time not to provide fire suppression systems in isolated plants conforms to a risk philosophy (observed in Liberty's December 2014 report on the January 2014 outages and elsewhere in this report) that tended to err on the side of cost avoidance. Hydro has very recently begun to make changes in balancing risk and cost. In any event, it was not alone in its 2011 approach with respect to isolated system fire protection. The consultant's report cited BC Hydro and Hydro-Quebec as having similar practices. Manitoba Hydro and Hydro One did provide fire suppression systems.

Hydro adopted a plan to install fire suppression systems after the consultant's report in 2012. Liberty believes that a more timely re-examination of the issue should have been undertaken (*i.e.*, without the three-year delay from the precipitating 2008 event). Had the study come sooner, however, it does not appear likely that it would have occasioned changes at Black Tickle prior to the early 2012 fire there. The external study provides a priority ranking list of systems for suppression system installation. Black Tickle ranked 11th on that list. Hydro advanced that ranking to 7th when forming its installation plans. That ranking led to a projected 2019-2020 installation date for Black Tickle. Therefore, even with an earlier study and a major acceleration of suppression installation schedules, Black Tickle would have remained without protection at the time of the 2012 fire in question.

The need for restoration work at Black Tickle following the fire raises the possibility that Hydro might have added fire suppression while post-fire work took place. Certainly, at that time, Hydro had reached the decision that the installation of a suppression system would happen at some point. We consider the urgency of repair completion a sufficient reason to decide not to add work that would threaten completion of permanent restoration activities before the next winter period.

2. Plant Capacity

A seasonal fish plant had provided Black Tickle's primary source of employment for many years. Unfortunately, the plant closed, shortly after the March 2012 fire. This plant comprised half of the system's peak load. Such a major change makes it proper to inquire into the decision to reestablish the pre-fire level of capacity permanently. Liberty found the decision to proceed without redesign and reconfiguration to lower capacity sound, for several reasons:

- Procuring smaller machines and reconfiguration of equipment and controls would have unduly jeopardized the schedule.
- Elimination of capacity would have precluded the possibility of a future re-start of the fish plant.
- Hydro has reported that no cost savings would have resulted from such a change.[94]
- Liberty has no reason based on its understanding of the work and of the already fairly small overall magnitude of the costs involved to conclude that Hydro could have achieved material costs savings sufficient to override the reliability risks of the temporary restoration and fish plant reopening considerations.

Accordingly, Liberty found Hydro's decision to leave the plant capacity unchanged prudent.

3. Project Costs

Hydro proceeded expeditiously to make the requisite repairs. Hydro submitted a project budget estimate in September 2012 of about $2.2 million plus contingency and completed the project for well under that amount. When project schedules drag out and indecision is present costs tend more frequently to rise. Performing the work expeditiously mitigated this risk. Liberty found no basis to question the prudence of the management of Black Tickle costs.

D. Costs

Hydro had for some time evidence of growing safety and property damage issues stemming from fires at isolated facilities well before the 2012 Black Tickle incident. Nevertheless, a more timely recognition of these concerns would not have prevented the fire. Further, Hydro's aggressiveness in restoring the units to their pre-fire condition was prudent. Liberty found no basis to question Hydro's cost. Hydro has reported capital expenditures of $1,418,900 and $1,417,000 for 2014 actuals and the 2015 test period, respectively. Reported depreciation expense is $55,000 for each of these periods.[95]

[1] Decision NSUARB-NSPI-P-881, 2005 NSUARB 27
[2] Enbridge Gas Distribution Inc. vs. Ontario Energy Board, 2006Can LII 10734:41 Admin LR (4th) 69, (to appeal to CSC denied) and Power Workers' Union, Canadian Union of Public Employees, Local 1000 v. Ontario (Energy Board) (365 D.L.R. (4th) 247).
[3] PUB-NLH-047, Appendix A
[4] PR-PUB-NLH-120
[5] PR-PUB-NLH-120
[6] PR-PUB-NLH-121
[7] PUB "Amended General Rate Application Prudence Review," February 27, 2015
[8] PR-PUB-NLH 132, 137, and PU Order 56
[9] PUB-NLH-158
[10] PR-PUB-NLH-132
[11] PR-PUB-NLH-132
[12] PR-PUB-NLH-133
[13] PR-PUB-NLH-142, Attachment 1
[14] PR-PUB-NLH- 152 Revised and 154
[15] PR-PUB-NLH-70, Rev 1
[16] PR-PUB-NLH-075 and 076
[17] Application – Sunnyside Equipment Replacement, June 19, 2014
[18] Integrated Action Plan Item #28
[19] PR-PUB-NLH-074
[20] PR-PUB-NLH-052
[21] PR-PUB-NLH-169
[22] PR-PUB-NLH-170, Revision 1, June 11, 2015
[23] PR-PUB-NLH-167
[24] PR-PUB-NLH-073
[25] "A Review of Supply Disruptions and Rotating Outages"; January 2-8, 2014, Schedule 8, Appendix 3, Page 11 of 102.
[26] PR-PUB-NLH- 152 Revised and 154
[27] PR-PUB-NLH-070, Revision 1, June 19, 2015
[28] PR-PUB-NLH-070, Revision 2, July 3, 2015
[29] PR-PUB-NLH-070, Revision 1, June 10, 2015
[30] PR-PUB-NLH-152 Revised
[31] Discussion of 230kV breaker B1L37 failure to trip from "A Review of Supply Disruptions and Rotating Outages: January 4-8, 2014," dated March 24, 2014.
[32] PR-PUB-NLH-035
[33] Discussion of 230kV breaker B1L37 failure to trip from "A Review of Supply Disruptions and Rotating Outages: January 4-8, 2014," dated March 24, 2014.
[34] The Transgrid Solutions Report "PSCAD Investigation of the Western Avalon T5 Transformer Failure," dated November 26, 2014
[35] Appendix 3, p.59, Hydro's Root Cause Investigation of System Disturbances On January 4 and 5, 2014, dated March 2014.
[36] PR-PUB-NLH-059
[37] PUB-NLH-098 and PR-PUB-NLH-033

[38] "A Review of Supply Disruptions and Rotating Outages: January 4-8, 2014," dated March 24, 2014.
[39] PR-PUB-NLH-066
[40] PR-PUB-NLH- 066,067, AND 068
[41] PR-PUB-NLH-063 and 064
[42] PR-PUB-NLH-037
[43] PR-PUB-NLH-036
[44] 2013 Amended GRA filing, page 3.23
[45] RFI #PR-PUB-NLH-045
[46] RFI #V-NLH-089 (Revision 1, May 13-15)
[47] RFI #V-NLH-089 (Revision 1, May 13-15)
[48] RFI #PR-PUB-NLH-047
[49] PUB Order PU 58 (2014)
[50] RFI #PR-PUB-NLH-101, Attachments 1 and 2
[51] RFI #PR-PUB-NLH-86
[52] RFI # PR-PUB-NLH-89, Attachment 1
[53] PR-PUB-NLH-186
[54] RFI #PR-PUB-NLH-379
[55] RFI #PR-PUB-NLH-92 and 94
[56] RFI #PR-PUB-NLH-95
[57] RFI #PR-PUB-NLH-91
[58] PUB October 17, 2013 letter to Hydro
[59] PR-PUB-NLH-003, Page 1
[60] PR-PUB-NLH-002, Attachment 3, Page 2
[61] PR-PUB-NLH-002, Attachment 3, Page 2
[62] PR-PUB-NLH-002, Attachment 1, Page i
[63] Rob Henderson in May 29, 2015 discussions with Liberty and the PUB staff
[64] August 5, 2013 Hydro letter to the PUB, Page 4
[65] PR-PUB-NLH-110
[66] November 18, 2013 Hydro letter to the Board, Page 4
[67] Hydro's August 5, 2013 letter to the PUB
[68] PR-PUB-NLH-113, 114 and 115
[69] PR-PUB-NLH-129 and 129 Revised
[70] "Holyrood Unit 1 Failure, January 11, 2013, Root Cause Analysis: Final Report"
[71] PR-PUB-NLH-182, Revision 1, Attachment 2
[72] PR-PUB-NLH-182, Revision 1, Page 2
[73] PR-PUB-NLH-181, Page 2, Revision 1
[74] PR-PUB-NLH-184
[75] PR-PUB-NLH-126
[76] PR-PUB-NLH-178
[77] PR-PUB-NLH-180
[78] PR-PUB-NLH- 129-Revised and 130
[79] PR-PUB-NLH-129-Revised
[80] PR-PUB-NLH-042
[81] PR-PUB-NLH-082

[82] PR-PUB-NLH-082
[83] PR-PUB-NLH-083
[84] PR-PUB-NLH-038
[85] PR-PUB-NLH-160
[86] PR-PUB-NLH-042
[87] PR-PUB-NLH-042
[88] PR-PUB-NLH-042
[89] PR-PUB-NLH-044
[90] Based on data in PR-PUB-NLH-042
[91] PR-PUB-NLH-042
[92] PR-PUB-NLH-014, Attachment 1
[93] Hatch study, Page 4
[94] PR-PUB-NLH-151
[95] PR-PUB-NLH-185