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August 7, 2015

The Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, Newfoundland & Labrador
A1A 5B2

**Attention: Ms. Cheryl Blundon**
**Director Corporate Services & Board Secretary**

Dear Ms. Blundon:

**Re: Newfoundland and Labrador Hydro – 2013 AMENDED General Rate Application Prudence Review – Liberty's Report – Hydro's Reply**

Enclosed please find the original plus 12 copies of Hydro's Reply with regard to the above-noted matter.

Should you have any questions, please contact the undersigned.

Yours truly,

***NEWFOUNDLAND AND LABRADOR HYDRO***

Tracey Pennell
Tracey L. Pennell
Legal Counsel

TLP/bs

cc: Gerard Hayes – Newfoundland Power
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Danny Dumaresque
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn
Genevieve M. Dawson – Benson Buffett

ecc: Roberta Frampton Benefiel – Grand Riverkeeper Labrador

**IN THE MATTER OF** the *Electrical Power Control Act*, *1994*, SNL 1994, Chapter E-5.1 (the *"EPCA"*) and the *Public Utilities Ac*t, RSNL, 1990, Chapter P-47 (The *"Act"*), as amended, and regulations thereunder; and

**IN THE MATTER OF** a general rate application filed by Newfoundland and Labrador Hydro on July 30, 2013; and

**IN THE MATTER OF** an amended general rate application filed by Newfoundland and Labrador Hydro on November 10, 2014; and

**IN THE MATTER OF** a prudence review relating to certain Actions and costs of Newfoundland and Labrador Hydro.

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***Newfoundland and Labrador Hydro***

***Reply Evidence***

***August 7, 2015***

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**TABLE OF CONTENTS**

## 1. INTRODUCTION

Newfoundland and Labrador Hydro (“Hydro”) is in receipt of the Liberty Consulting Group’s (“Liberty”) Final Report dated July 6, 2015 on the prudence review of Hydro’s decisions and actions (“Final Report”), and Liberty’s responses dated July 31, 2015 to Hydro’s Requests for Information on the Final Report.

Hydro has worked diligently over the past many months to respond to Requests for Information (“RFIs”) from Board staff, Liberty and various intervenors in the public Outage inquiry into supply issues and power outages on the Island Interconnected System (“Outage inquiry”) and the prudence review to assist with the Board’s ultimate determinations in relation to these matters.

In Hydro’s response dated February 5, 2015 to the Phase One Report by Liberty in the Outage inquiry Hydro confirmed its acceptance of the majority of Liberty’s Phase One recommendations, most of which were consistent with Hydro’s own findings and conclusions arising out of Hydro’s analysis of the January 2014 outages.

In its Final Report on the prudence review (which deals with both outage and non-outage related matters) Liberty has made various statements related to Hydro’s actions, some of which Liberty has suggested should lead to a disallowance of certain costs.

Hydro will not address each of the numerous statements made by Liberty in its Final Report, but rather this Reply Evidence will focus on key areas where Hydro concurs with Liberty’s statements or disagrees with the requirement for or magnitude of any proposed disallowance.

As a preliminary point, Hydro would note that during the RFI stage of the prudence review process Hydro was requested to provide various cost and related data to Liberty, the ultimate use for which Hydro was of course not necessarily aware at that time. Accordingly, in certain instances set out in the remainder of this Reply Evidence, Hydro will reference some of this cost information and related data and provide additional context in light of the comments made by Liberty and the use to which it put this information.

Hydro also believes in light of various statements in Liberty's Final Report that it is important to provide further context in which Hydro's actions at the relevant times need to be understood and evaluated.

As an initial comment it is important to note that the issue of prudence has only been raised in the context of a very limited number of Hydro's projects. Hydro's track record on the overwhelming majority of its work has not been questioned. It is also important to understand that asset management is a comprehensive undertaking, comprised of multiple elements carried out over a substantial period of time. Focusing on any one discrete element at a particular point in time, at the exclusion of the overall program over time, is not an appropriate approach whether in actual planning and execution practice or from a subsequent review perspective. All of the elements of asset management over time need to be considered together when planning and executing an asset management program, as prioritization needs to be addressed in the overall context and keeping in mind the overall balancing of cost versus reliability, as well as resourcing, safety and environmental considerations. The overall planning and coordination of asset management needs to be considered when planning, executing and/or reviewing a utility's actions at any particular point in time.

As stated in Hydro's response to PUB-NLH-342 in the Outage inquiry, Nalcor's approach (which includes Hydro) to asset management is:

> "the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, and equipment replacement or retirement as necessary to achieve maximum value for the stakeholders based on the required standard of service to current and future generations."

This approach is a cradle to grave program applicable to all assets, based on a twenty (20) year planning horizon, which considers numerous inputs.

The asset management process consists of long-term planning, short-term work planning and scheduling, work execution, and operations. The management of these assets follows a process of determining service levels, acquiring and renewing assets, operating those assets, and maintaining them. Aspects deemed critical in making asset management effective include: (a) knowing the condition of critical assets, (b) understanding how they are performing, and (c) maintaining, renewing, or replacing those to minimize the risk of unexpected failure.

As noted in Hydro's response to PUB-NLH-039 in the Outage inquiry, in 2006 Hydro recognized the magnitude and potential impacts of its aging asset base and related customer reliability considerations. As a result, it initiated a comprehensive, long-term asset management plan. The response to PUB-NLH-039 describes in detail the significant asset management practices undertaken by Hydro over the past five years to address concerns with its aging plant and equipment.

Hydro's twenty-year plan is in place and contains significant capital works for refurbishment, rebuild, replacement and new build. The significant increase in the capital budget reflects Hydro's commitment to recognizing long term planning and execution.

As part of the preventative maintenance and corrective maintenance (PM/CM) program which is described in detail in Hydro's responses to PUB-NLH-378 and 379 in the Outage inquiry, a list of PM/CMs are regularly scheduled for completion when a planned or unplanned outage occurs, or when the offpeak maintenance season is underway. This backlog list is a normal part of the asset management process as work has to be planned in a manner that minimizes impact on customers. One key element of Hydro's comprehensive asset management plan is the ongoing planning and execution of PMs and CMs. The plan has a significant focus on operational matters in the context of our aging asset base.

Hydro recognized in 2009 that the rate of completion for certain PM work was beginning to lag and implemented a recovery plan for the period 2010 to 2015. This was a balanced and considered action taken by Hydro. During execution of the recovery plan, capital works grew significantly as well.

The requirements for the recovery plan, increased capital work, and break in work to deal with critical issues as they arose, required adjustments to resources to ensure the most critical and time sensitive work was completed cost effectively as necessary.

Hydro's recent history of overall asset management planning and execution demonstrates that Hydro plans, checks, implements and adjusts as necessary. This is evidenced by our asset management approach since 2006, our safety and environmental approach, our organizational adjustments and our improving capital project execution.

The current PM backlog is being closely monitored and Hydro's program is on track to fully catch up on the maintenance work that is outside our general maintenance cycle by the end of 2015. The regular backlog will continue to be closely monitored going forward and adjustments to work and resources made where warranted to ensure reliable and cost effective service delivery to Hydro's customers.

Hydro's overall asset management approach has been proactive, comprehensive, and cost effective, and recognizes our aging asset base. All decisions and approaches to Hydro's overall asset management plan have been done in a considered fashion, and are adjusted appropriately as our plan proceeds.

Neither Hydro, its expert consultants or Liberty could find any direct linkage between deferred maintenance work and the issues that caused the outages under review. Rather than being imprudent, Hydro's actions have been considered within the context of a prudent overall asset management plan and Hydro has and will continue to actively monitor and adjust its plan on a regular basis.

## 2. THE NEW HOLYROOD COMBUSTION TURBINE

Hydro notes that with respect to the new combustion turbine ("CT") 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, Liberty found that the cost to customers would not likely have proven less than the amount for which Hydro is seeking recovery had Hydro acted earlier to install new capacity. Liberty also specifically noted that it found no reason to question the reasonableness of the costs of the new Holyrood CT, and Liberty provided data which confirmed the competitiveness of the Holyrood CT price.

While Liberty made various statements with respect to Hydro's supply planning process (similar to those they made in their interim and final reports in the Outage inquiry) regarding the perspective which Liberty takes on supply planning, Liberty specifically acknowledged that Hydro's processes in this regard follow approaches long applied and which were reviewed on a number of occasions without the finding of any material exceptions. Liberty further confirmed that the advancements that Hydro has made since the January 2014 supply outages reflect a move toward a more robust view of security of supply, and that Liberty considered the improvements Hydro has made in giving more attention to (1) system reserve levels, (2) a broader range of weather conditions and (3) the effects of high system loads on losses to be significant. Hydro has set out the actions it has taken and proposes to take on a go-forward basis with respect to power supply planning at pages 9-16 of Hydro's February 5, 2015 Reply to Liberty's Phase one Outage inquiry report and has no additional evidence to put on the record at this time in regard to this matter.

## 3. SUPPLY RELATED COSTS

Liberty concluded that they did not find a basis for imprudence with respect to supply planning and management of unit availability during the relevant period reviewed. As well, Liberty also concluded that most of the outages during the relevant period were either weather-related or reflected the typical types of failures one would expect. Liberty went so far as to describe the number of low temperature days during the relevant period as “extraordinary”, and concluded that the unavailability of units, which is largely under Hydro’s control, had a minimal impact on the supply related costs, and weather which is not in Hydro’s control had a major effect. With respect to the Corner Brook Pulp & Paper (“CBP&P”) capacity assistance, Liberty noted that the interruptible load available from CBP&P made a major contribution to system reliability in this challenging period, and had the CBP&P load not been available, rotating blackouts would have been more extensive. Liberty found no reason to challenge the prudency of Hydro’s arrangement with CBP&P.

That all being said, Liberty was of the view that for the four day period (January 5-8, 2014) in which Holyrood Unit 1 was unable to connect to the grid because of an air blast circuit breaker failure, the added supply costs related to the unavailability of Holyrood Unit 1 should be disallowed. Hydro does not agree that a disallowance is appropriate in the circumstances. This issue is discussed further below under the heading Holyrood Unit 1 Turbine Failure. In this section of Hydro’s Reply Evidence, Hydro will comment on the calculation for disallowance purposes if the Board were to agree with Liberty that the breaker failure related to Holyrood Unit 1 was due to the actions of Hydro.

Liberty states at page 17 of their Final Report, that “no straightforward process for estimating the added costs attributable to the unavailability of Holyrood Unit 1 exists”. They then go on to develop an estimated prudence-related costs disallowance of $2,189,110 by approximating the costs they attribute to the purported imprudent conduct during the four days January 5-8 as the increment above the supply costs for the final four days of the outage period, January 9-12.

Liberty specifically “stresses that this estimation is a rough one”. Yet they nevertheless go on to state that “given the uncertainties and complexities that apply, Liberty considers this approximation appropriate.”

Hydro’s view is that prudence-related disallowances cannot and should not be based on rough estimations. Further, the approach taken by Liberty is “a rough estimation” at best.

As an initial comment, the total Holyrood Unit 1 related costs for January 5, $477,647 were due to the unit vibration issues on restart (i.e. from 0000 hours to 2127 hours), and are already included in a separate proposed Liberty disallowance in Table 11.2 of the Liberty Final Report in the line item Replacement Power. The Replacement Power figure of $504,610 (which includes the $477,647) is part of the Holyrood Unit 1 turbine restoration costs operating expense total of $2,419,410 also shown in Table 11.2 of the Final Report, for which Liberty is suggesting there be a separate disallowance apart from the supply related costs. Accordingly, this amount should not be double counted as part of any potential Holyrood Unit 1 supply related cost disallowance (if any). To avoid double counting, Liberty’s proposed rough estimate disallowance would at a minimum need to be reduced by $477,647.

With respect to Liberty’s methodology to determine a disallowance figure, if Liberty’s approach were used but the comparison made to the first four days of the period (notably a colder period), rather than the last four days, no disallowance would be suggested. If Liberty’s approach were followed but using the average of the replacement power costs for the first four days (January 1-4) and the last four days (January 9-12) of the period in question, the disallowance would be $984,674, (subject to further reduction to account for the double counting issue noted above).

As well in its response to PR-NLH-PUB-002, Liberty acknowledged that “Given the “rough” nature” of its estimate it also did not make any adjustment on account of Holyrood Unit 1 coming back on line at approximately 1530 on January 8.

Hydro believes Liberty's approach simply lacks the rigour to justify a disallowance of the size it suggests. If any disallowance is determined appropriate, which Hydro does not believe is justified, employing Liberty's methodology but utilizing an average of costs in both the first and last four days of the period in question (and adjusting for any double counting) is much more appropriate, especially in light of the fact that Holyrood Unit 1 was not even offline for the entirety of the January 5-8 period.

## 4. **FORCED DRAFT FAN MOTOR**

Hydro notes that Liberty has concluded that Hydro's determination not to have a spare forced draft fan motor for Holyrood Unit 3 took account of all available information, and was – given the risks and the time horizons considered – among those decisions a reasonable person could have selected. Hydro concurs. Liberty also acknowledged that: (1) the motor that failed had undergone regular maintenance, (2) Hydro refurbished it in 2006, (3) there were no indications of pending failure, and (4) "in retrospect the motor died at the worst possible time". Hydro has no additional evidence to put on the record at this time with respect to this issue.

## 5. **SUNNYSIDE REPLACEMENT EQUIPMENT**

### General

With respect to this issue (and similarly with respect to the Western Avalon Terminal Station T5 Tap Changer Replacement), Liberty has stated that, in their view, the fact that Hydro did not complete its transformer and breaker maintenance within Hydro's identified maintenance cycles deprived Hydro "of the opportunity to identify and address the causes of the transformer and the breaker failures before they occurred".

However, Liberty has not been able, nor has Hydro, to find a causal connection between the failure of the equipment in question and the fact that certain of the equipment had not had its most recent maintenance carried out within Hydro's then current maintenance cycles.

At page 28 of the Final Report, Liberty states:

> "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."

Hydro does not agree that where causation is not determinable it is sufficient to simply make a "categorical level connection" between conducting maintenance and avoiding malfunction. Rather, Hydro's understanding of the regulatory jurisprudence is that even where imprudence may be found (which Hydro does not necessarily agree is the case in this situation as dealt with in greater detail below), a cost disallowance cannot be justified unless the conduct brought into question was the real and proximate cause of some additional cost to customers. In order to disallow a recovery of costs, the Board must find both that (1) Hydro acted imprudently and (2) such imprudence resulted in harm to its ratepayers. Harm to ratepayers in relation to additional incurred costs requires proof of causation. Liberty itself, however, has stated in relation to this issue that causation is not determinable, despite the good faith and capable efforts carried out to determine the cause.

Despite this, in its response to PR-NLH-PUB-003, Liberty stated that in the absence of Hydro being able to demonstrate a cause not related to the delay of maintenance, Liberty "judged it appropriate to associate the failure with the lack of the conduct of appropriate maintenance". It is in Hydro's view inappropriate to ascribe an unproven cause to any particular issue simply because the actual cause has not been determined, particularly where appropriate efforts were taken to determine the cause.

At page 26 of its Final Report, Liberty notes that Hydro indicated that it deferred transformer and breaker maintenance to provide resources to address more critical issues. Despite Hydro's evidence supporting its requirement to provide resources to address more critical issues, Liberty concluded that the deferral of the required maintenance was not prudent. Liberty went on to note that in its view this action "deprived Hydro of an opportunity that regular maintenance is designed specifically to provide; i.e. to identify and correct potential sources of equipment failure". However, the post-incident analysis which involved specific root cause analyses did not identify any link between the failure to provide maintenance on the Sunnyside T1 transformer or the B1L03 air blast circuit breaker as a specific causal factor for the issues at Sunnyside.

It is instructive to highlight key portions of the record already supplied by Hydro in this regard. In its response to PR-PUB-NLH-052, Hydro noted in part as follows:

> "Hydro deferred some six-year maintenance on air blast circuit breakers and power transformers in order to ensure resources were deployed on the **most critical** work for customer supply. In particular, Hydro deferred this maintenance where it was necessary to address unplanned corrective maintenance work due to either: (a) equipment breakdown or issues identified from equipment testing and inspections; or (b) addressing unplanned capital work (arising from equipment failure or a requirement for greater resourcing than originally anticipated for a capital project)."
>
> [Emphasis added]

In its response to PR-PUB-NLH-167 (Revision 1, June 10-15) dealing with air blast circuit breakers, Hydro reiterated its comments in PR-PUB-NLH-052 noted above and further stated as follows:

> "The decision to defer involves personnel with responsibility for short-term planning and scheduling, long-term asset planning and work execution and operations. Hydro was faced with a significant amount of priority break in corrective maintenance and capital work in 2013 and as a result more preventative maintenance of a lesser priority was deferred into 2014 and 2015."

Hydro then further noted in that RFI response that:

> "Hydro's investigation, which involved third party expertise, did not determine that the deferred maintenance resulted in the equipment failures. In particular, the breakers involved in the transformer damage were examined and no cause for the misoperation was determined. Both breakers had been operated successfully prior to the events. Furthermore, the breaker in Western Avalon operated successfully following the event. The Sunnyside breaker was closely examined with no problems found. **Despite extensive review, there has been no link found between the deferred maintenance and equipment failures experienced on January 4, 2014**." [Emphasis added]

Transformer T1

With respect to transformer T1, Hydro described its transformer maintenance practices in detail in PR-PUB-NLH-050 and noted that with the maintenance information which Hydro had at the relevant point in time "there was nothing directing Hydro to treat T1 transformer maintenance as a top priority". This response also noted that:

1) Doble Engineering confirmed that the power factor tests (including the last power factor test done on T1) did not indicate a concern with the bushings;
2) Preventative maintenance only identified bushing defects in 2% of transformers since 2000; and
3) Choosing to defer the maintenance allowed Hydro to carry out priority work as part of its ongoing asset management program.

Furthermore, the failure of the transformer in and of itself would have caused limited system issues. As a result of breaker B1L03 failing to open the fault was present for an extended period of time and consequently a fire developed with the consequent results. As discussed below Hydro does not believe its actions caused the breaker B1L03 failure.

Hydro had no indication of any specific concern with the Sunnyside T1 transformer which required time sensitive intervention requiring strict adherence to the general six year maintenance cycle. Hydro's approach to ensuring completion of priority work and adjusting its maintenance programs as necessary to ensure critical, time sensitive repairs are conducted is a normal asset management practice.

The transformer was also only outside of the maintenance cycle by a period of three months at the time of the incident, and the delay in the carrying out of preventative maintenance within the six-year cycle was due to Hydro's requirement to conduct more critical maintenance activities as discussed above. With the knowledge available to Hydro at the time, the actions it took in deferring the T1 transformer maintenance were simply not imprudent.

With respect to Liberty's discussion of the dissolved gasses issue at page 29 of the Final Report, Hydro explained in PR-PUB-NLH-023 and at pages 13-14 of its "Response to the Liberty Consulting Group Interim Report of April 24, 2014", that the information available to Hydro at the relevant time was (1) variations in gas content in this particular transformer design had been seen since the early 1990s, (2) the OEM's opinion was that it appeared to be due to gas migrating from the tap changer component to the main transformer tank, and (3) for the reasons detailed in PR-PUB-NLH-023 Hydro's approach was to monitor the gas levels so that increasing levels could be identified and acted upon. Hydro has recently completed a leak test on the Stony Brook T2 transformer (a similar transformer to Sunnyside T1) which test has confirmed that gas is migrating from the tap changer to the transformer tank, further validating Hydro's understanding of this issue with respect to transformers of the design and vintage of Sunnyside T1.

It is important to highlight that the gassing levels were not an identified cause of the issues with transformer T1 in any event, and Hydro's actions to monitor the gas levels were both reasonable and appropriate in light of the information available to Hydro at the relevant time, and further supported by Hydro's recent testing.

<u>Breaker B1L03</u>

With respect to Sunnyside breaker B1L03, Liberty correctly notes at page 35 of its Final Report that Hydro function-tested the breaker in 2011. B1L03 was also operated successfully in August 2013 (see PR-PUB-NLH-051). Thus, there was no concern with this breaker at the relevant time, and although the maintenance for this breaker was outside the general six-year maintenance cycle by five months at the time of the Sunnyside incident, it was in order to carry out more critical maintenance activities.

Neither Hydro, despite substantial efforts by its personnel and consultants, nor Liberty could determine the causes of the Sunnyside breaker failure. Further, and again as Liberty correctly noted, the team studying the malfunction, including outside expertise, could not replicate the issue that occurred, i.e. that the breaker remained in closed position when it should have come open.

It is also important to recall, as noted by Liberty, that Hydro experienced sustained cold weather during much of the outage period which can have an impact on circuit breaker performance.

Liberty was unable to determine any specific causal connection for the Sunnyside incidents and thus relies on its suggested approach that where causation is not determinable it is sufficient to make the "categorical level connection" between conducting maintenance and avoiding malfunction. For the reasons discussed above, Hydro does not believe this is a supportable regulatory conclusion, especially when breaker B1L03 had operated successfully prior to the January 2014 incidents and the post-incident testing could not replicate the issue that occurred, or for that matter, identify any incomplete maintenance which likely caused the breaker not to operate.

Notwithstanding the lack of any evidence supporting a finding that delaying maintenance beyond the regular maintenance cycle specifically contributed to the Sunnyside issues, Liberty suggests a full disallowance for the Sunnyside equipment capital costs (net of insurance proceeds) and the related net operating expenses.

Fully Recoverable Costs

Breaker B1L03 would have been replaced in the next couple of years in any event as part of Hydro's air blast breaker replacement program. B1L03 was replaced by a new SF6 breaker in accordance with this program, at a cost of $527,740. Accordingly, there is no rationale to disallow this cost, particularly as Liberty agrees that the air blast circuit breakers should be replaced. Thus, any potential disallowance on account of Sunnyside Net Capital as set out in Table 5.3 of the Final Report should be reduced by $527,240.

Liberty does appropriately find that the costs incurred by Hydro to provide a new 230 kV T1 transformer breaker and 230 kV breaker failure protection comprise a sound enhancement to the Sunnyside terminal station and that these costs should be recovered.

Liberty also appropriately notes that the replaced transformer had a limited remaining life, which means that recovery of the new transformers' costs reflecting when the old transformer would have ultimately been replaced is appropriate in any event. In this regard, Hydro retained Gannett Fleming, Inc.[1] ("Gannett Fleming") to provide a betterment report with respect to the Sunnyside and Western Avalon capital additions, a copy of which is attached to this Reply Evidence as Appendix A. The results of Gannett Fleming's work are set out at pages 6-7 of their report. These results show the recoverable costs for the Sunnyside replacement equipment on a betterment basis.

[1] Gannett Fleming is a leading depreciation, valuation and ratemaking consultant firm servicing public utilities.

Table 5.3 of the Final Report includes Liberty's proposed disallowance of $879,800 for Sunnyside Equipment 2014 Net Operating Expenses (also shown on Liberty's Table 9.1). However, the development of this figure includes $824,000 related to actual Transformer Transportation Costs which were not included in the 2014 test year revenue requirement and for which Hydro has not sought recovery from ratepayers. This reduces the amount of the proposed disallowance in relation to this item to $55,800.

Table 5.3 also includes Liberty's proposed disallowance of $515,000 for actual Loss on Disposal. However, Hydro only included $450,000 on account of this item in its 2014 test year revenue requirement, which thus requires a further $65,000 reduction to Liberty's proposed disallowance. As a result, no Sunnyside Equipment 2014 Net Operating Expense disallowance is required to be made to the 2014 test year revenue requirement.

## 6. WESTERN AVALON TERMINAL STATION T5 TAP CHANGER REPLACEMENT

As noted previously, Liberty approaches this issue in a similar manner to the Sunnyside Replacement Equipment. They state that the failure of breaker B1L37 to operate as intended lead to the damage in question, and that in their view Hydro's failure to adhere to its general breaker maintenance cycle deprived Hydro of the "opportunity to identify and address the cause of failure before it occurred".

Following the event, Hydro was not able to replicate the breaker malfunction, nor could Hydro identify the cause of the malfunction when it subsequently conducted the PM on the breaker. Similar to the situation with the Sunnyside Replacement Equipment, Liberty suggests a <u>complete</u> disallowance of the replacement and repair costs for the T5 Tap Changer solely on the basis that Hydro had not carried out its regularly scheduled maintenance on breaker B1L37 within Hydro's general maintenance cycle.

As stated above, following the incident in question Hydro was not able to replicate the breaker malfunction. One phase of breaker B1L37 had failed to close when operators had closed the breaker. The breaker, in fact, operated successfully following the event.

Notwithstanding that Hydro was unable to even replicate the failure following the incident, Liberty takes the view that the entire costs associated with repair and replacement of the T5 Tap Changer should be the responsibility of Hydro. This is solely due to Liberty's view that costs should be disallowed in full upon the loss of an opportunity to identify a problem during earlier maintenance that may have prevented the failure, even absent any evidence that the maintenance would have prevented the failure.

As noted under the discussion with respect to the Sunnyside Replacement Equipment, Hydro does not understand this to be the accepted regulatory standard, especially where deferred maintenance occurred to prioritize more critical work.

As noted above, the Gannett Fleming report deals with the Western Avalon betterments as well as Sunnyside and the results of Gannett Fleming's work are found at pages 6-7 of their report. These results show the recoverable costs for the Western Avalon replacement equipment on a betterment basis.

## 7. OVERHAUL OF THE SUNNYSIDE B1L03 AND HOLYROOD B1L17 BREAKERS

Breaker B1L03

Liberty's suggestion of a disallowance with respect to the overhaul of the Sunnyside 230 kV Breaker B1L03 rests again solely on the fact that maintenance for this breaker was overdue by five months in January 2014. For the reasons noted above with respect to this breaker, Hydro does not believe this supports the disallowance proposed by Liberty.

Furthermore, at page 37 of the Final Report, Liberty proposes a disallowance of actual depreciation and disposal expenses of $164,000 in relation to the Sunnyside breaker. However, the response to PR-PUB-NLH-160 (Revision 1, June 17-15) indicates that $161,000 of this amount was on account of the disposal costs, and Hydro has not sought any recovery of these costs from its ratepayers as part of the 2014 test year revenue requirement. Thus, there are no costs to disallow on account of this item.

<u>Breaker B1L17</u>

With respect to the Holyrood Breaker B1L17, post incident investigation of this malfunction determined that the most probable cause of the failure was moisture in the “A” phase receiver tank. (see Hydro’s response to PR-PUB-NLH-067)

As Liberty noted, Hydro had disassembled the breaker to permit application of a RTV (room temperature volcanizing) protective coating on the breaker insulators to prevent future flash over events such as occurred in January 2013. As part of this process, Hydro had removed the breaker head columns and interrupting chambers in order to apply the RTV protective coating. Hydro also secured waterproof covers over the then exposed receiver tank and the driving rod.

Hydro deferred applying the RTV coating in the shop to address other work commitments which were more critical (see Hydro’s response to PR-PUB-NLH-066 for the specific prioritized work), and the waterproof covers remained in place for about a month.

Liberty concluded at page 36 of its Final Report that “the receiver tanks remained exposed to weather for a long, one, month period”. Hydro does not agree with this characterization. Hydro acknowledges that water apparently did somehow enter the tank, and that in hindsight the cover appeared to have been inadequate to prevent moisture entering the tank. However, Hydro had no reason to believe that this would happen at the time, and it had taken prudent steps to prevent exposure to the weather for the duration that the breaker and interrupters were removed. Hydro knew that the equipment should be protected from the weather, took appropriate steps to do so, and had no indication at the relevant time that there was any issue with the actions it had taken.

As noted in PR-PUB-NLH-066 "Hydro ensured that [the receiver tanks] were securely covered to address the issue of potential moisture ingress from snow and rain". And in the response to PR-PUB-NLH-067, Hydro specifically noted that:

> "Hydro was aware that it was important to ensure that no water from the weather (such as snow and rain) should be allowed to enter the tank. Accordingly, there was a waterproof cover placed and secured over the tank and the driving rod."

There was never any indication to Hydro at that time that the waterproof cover over the tank and the driving rod was in any way insufficient, and there is no evidence as to specifically how or when water actually entered the equipment.

As noted in responses PR-PUB-NLH-066-068, after being re-assembled, the breaker went through a complete set of tests to check timing and proper operations, and prior to re-installing the insulating columns and interrupting heads of the breaker, crews performed a visual inspection of the tank from the top.

Furthermore, Hydro exercises its breakers prior to putting them back into service utilizing clean dry air from the compressed air system, and has been performing regular dew points tests on its compressed air systems consistent with the practice of other utilities. Hydro had no reason to check for moisture in the receiver tank based on its prior experience and testing practices.

The record does not support that Hydro's actions with respect to Holyrood Breaker B1L17 were imprudent. Hydro was aware of the parts of the breaker that would be exposed and it provided a waterproof cover over those areas during the period of the repair. The extension of the time period to carry out the repair work was required to deal with more critical work that arose, and

Hydro had no reason to believe that the waterproof cover would in any way fail to prevent water from entering the receiver tank. With perfect hindsight it was determined that water did at some point apparently enter the receiver tank (unknown as to when or how) but this does not support a conclusion that Hydro's actions were in any way imprudent.

## 8. EXTRAORDINARY TRANSFORMER AND BREAKER REPAIRS

Hydro had developed a target in 2010 to bring the maintenance of its breakers and transformers in line with its applicable maintenance cycle by the end of 2015. Hydro was not able to accomplish this at the planned pace as it was necessary to defer certain maintenance in order to deal with other break in or critical issues. In order to accelerate this and get this back in line, Hydro developed a plan with associated cost which Hydro provided to the Board in 2014. This is the extraordinary repair (catch up) costs which Hydro is requesting recovery of, as it is indisputably required work. With respect to this issue Liberty is of the view that Hydro should be denied recovery for costs related to catch up work on transformer and air blast breaker maintenance which are in excess of the costs to carry out such work at a normal level over the applicable maintenance cycle.

Such an approach, however, does not take account of the fact that in order for Hydro to have complied strictly with its maintenance cycle Hydro would have had to incur additional costs in prior years as well as in the 2014 and 2015 test years which were the last two years of Hydro's recovery plan. Further, Hydro's understanding is that both Liberty and the Board are supportive of Hydro bringing all of its transformers and air blast breakers current within the applicable go-forward maintenance cycles. Hydro has been diligent in carrying out the necessary work and is requesting recovery of the costs as forecast in the plan provided to the Board in June of 2014.

Hydro does not believe it is appropriate or warranted to disallow costs to carry out deferred work specifically desired by all parties simply because the work is outside the general maintenance cycle. This is especially the case where the maintenance was deferred to carry out higher priority work on a considered basis, and if the work was done previously additional costs would have needed to be incurred in any event. However, Hydro does agree that it is extraordinary in nature in that it is completed within the test year forecasts period and therefore recommended its deferral and recovery over a five-year period.

## 9. **2014 REVENUE DEFICIENCY**

In this section of the Final Report, Liberty correctly notes that with respect to 2014 Hydro made its revenue requirement calculation using five (5) months of actual and seven (7) months of estimated 2014 costs, whereas Liberty in its analysis used actual costs for the full year, which were subsequently available. Liberty specifically noted in this regard at page 42 of its Final Report that:

> "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 5 months of actual cost data the Company used in making that 2014 revenue requirements calculations."

For the reasons previously noted, and those that follow with respect to the issues of Black Start and the Holyrood Unit 1 2013 turbine failure, Hydro disagrees with Liberty's proposed disallowances on various matters, which disallowances are reflected in Liberty's Table 9.1. To the extent that the Board may accept any of Liberty's recommendations, Hydro is providing the following comments, to ensure clarification regarding Liberty's use of actual costs in comparison to Hydro's filed revenue requirement.

<u>2014 Professional Services Costs</u>

Liberty takes the position that since, in their view, the January 2014 outages resulted from certain imprudence on behalf of Hydro, 100 percent of all professional services costs related to the inquiry should be disallowed. At page 45 of its Final Report, Liberty states that it identified about $2.55 million in professional fees falling into the “but for” category (i.e., in their view, but for Hydro’s actions these costs would not have been incurred).

Liberty provides a breakdown of this figure by source in its table on page 45 of the Final Report. The first four items from that table are addressed below.

(i) Outage Inquiry Legal Fees

With respect to the Outage inquiry legal fees of $876,000 referred to by Liberty, the accounts in question include costs incurred by Hydro with respect to both Phase 1 and Phase 2 of the Outage inquiry, as well as costs incurred with respect to both the combined CT / Black Start Applications, and the Application for a Third Transmission Line from Bay D’Espoir to Western Avalon, which were simply covered in the same invoices. Further, these accounts also include fees in relation to Hydro’s Application for the supply related costs which Liberty themselves found were substantially outside the control of Hydro. Accordingly, there is no basis to find that the totality of these costs should be disallowed. The following is a breakdown of the applicable costs in relation to the above-noted categories.

| | **Allocation** | | | |
|---|---|---|---|---|
| **Amount** | **Phase 1** | **Phase 2** | **Supplemental Capital Applications** | **Supply Costs** |
| **$ 875,799.00** | **$ 622,742.68** | **$ 126,528.16** | **$ 55,356.07** | **$ 71,172.09** |

It was various intervenors in the Outage inquiry, and not Hydro, who supported the extension of the inquiry to also deal with post-Muskrat Falls reliability issues. No aspect of that forward-looking review of a future system configuration is related to the events of January 2014. To the extent that the Board, and intervenors, were of the view that it was appropriate at this time for the Board to consider future reliability aspects of the Newfoundland and Labrador electricity system post-Muskrat Falls, clearly the costs associated with such a proceeding should be recoverable by Hydro.

If any disallowance is approved by the Board with respect to this cost category, which Hydro does not believe is justified as it believes its actions were prudent in the prevailing circumstances, such disallowance should at most be only in relation to the Phase 1 costs, in the amount of $622,742.

(ii) PUB and Intervenors Outage Inquiry Costs

With respect to the referenced PUB outage inquiry costs of $958,000 (estimate), Liberty was unable to confirm the portion of those costs in relation to Phase 2 of the Outage inquiry (see Liberty's Response to PR-NLH-PUB-010). As Hydro noted in Note 2 of Attachment 2 of its response to PR-PUB-NLH-101 (page 4 of 4), the Board has indicated Board accumulated costs relating to the Outage inquiry of approximately $1.275 million. The Board has confirmed to Hydro that this amount includes Liberty's costs, legal costs and other costs. With respect to such portion as may be related to the review of Hydro versus Newfoundland Power activities, regardless of the Board's findings with respect to the January 2014 outage, costs related to Phase 2 should be fully recoverable as they are clearly not related to any imprudence on behalf of Hydro. A breakdown of these costs between Phases 1 and 2 would be required to make the appropriate adjustment.

Similarly, with respect to intervenor Outage inquiry costs which Hydro may incur, if any, such costs referable to Phase 2 issues should be fully recoverable.

(iii) Sunnyside Environmental Remediation

With respect to the Sunnyside environmental remediation costs of $346,000, Liberty includes these in its recommended disallowance as part of the $2.55 million in professional services and consulting fees, but $335,900 of this amount is already also accounted for as part of Liberty's proposed disallowance in respect of the Sunnyside replacement equipment 2014 net operating expenses in Table 9.1 of the Final Report.

Thus Liberty's recommendations double count the majority of this suggested disallowance, and an adjustment is required if the Board determines these costs are not recoverable by Hydro. Further, the $346,000 appears to include an invoice for $13,400 for "Toxicology & Chemistry Analysis" which is unrelated to Sunnyside, and the applicable invoices are all specifically identified as "Site Professional Services, Environment Remediation, Sunnyside, NL". Thus, a reduction to the $346,000 would also be required to address this amount, if any such disallowance is applied.

2014 Overtime

Liberty compared the overtime in 2014 to the annual average overtime hours for the period 2011-2013 and recommended a disallowance of approximately $3.6 million on the basis that this incremental overtime would not have been required but for the actions of Hydro, which Liberty determined not to be prudent. In determining their proposed adjustment, Liberty noted that a portion of the overall incremental overtime dollars spent by Hydro was in relation to the capital projects that Liberty was examining and thus was appropriately removed from the overtime calculation to avoid double counting. However, Liberty's development of the approximately $3.6 million disallowance is based upon their comparison of 2014 actual expenditures versus 2011-2013 average actuals. Hydro is not applying for recovery of 2014 actuals but is applying for recovery based on its 2014 test year filing. It is obviously not appropriate to impose a disallowance based on actual dollars spent where those are not the dollars being sought for recovery in the first place. Any proposed disallowance must only relate to the costs being sought for recovery by Hydro.

Thus, using the same methodology as Liberty by using 2014 test year revenue requirement instead of 2014 actuals the revised calculation (excluding total capital overtime) yields a figure of $493,145. As with Liberty's analysis, the calculation is net of capital in relation to capital projects Liberty was reviewing, to avoid double counting. As well, Hydro does not believe there is any rationale to disallow costs for capital overtime in relation to prudently incurred capital projects.

Salary Transfers

Liberty has suggested a disallowance of $511,000 on account of executive leadership and finance cost transfers which in Liberty's view would not have occurred in the absence of the outages. However, all of these costs are not part of the 2014 test year. As set out in Hydro's response to V-NLH-88 in its 2013 General Rate Application, Hydro has only sought recovery of $424,000 for inter-company salaries and thus any disallowance would only be in relation to this amount.

Liberty properly concluded, as noted on page 16 of the Final Report that:

> "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 high 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."

With the exception of the unavailability of Holyrood Unit 1 as a part of the unavailable generation (discussed above) Liberty was clear that it "did not find a basis for imprudence with respect to supply planning and management of unit availability during the relevant period" and that the weather conditions being faced by Hydro were extreme. Accordingly, additional executive leadership and related inter-company resources would have been engaged in a review of the early January situation which led to rotating outages even absent the transmission related issues. To disallow 100 percent of those costs sought for recovery is simply not supported, since all of those costs are not even attributable to issues related to Liberty's view of Hydro's prudence. Further, as dealt with elsewhere in this Reply Evidence, Hydro does not concur with Liberty in regards to various of its imprudence findings.

Further, a portion of this cost category is in relation to Hydro's response to matters related to Phase 2 of the inquiry, which would by necessity have required extra executive leadership and associated involvement.

In fact, in the next section of its Final Report, at pages 46 and 47, Liberty indicated with respect to Hydro's 2014 Integrated Action Plan ("IAP"), that Liberty's review of Hydro's costs incurred to implement its IAP did not identify any costs falling into the "but for" category. The IAP addressed actions Hydro proposed to (and has) taken in response to the 2014 supply disruptions and power outages. Liberty concluded that the majority of the costs were either costs that Hydro would experience even in the absence of the need to respond to the outages, or which would be justified by good utility practice. The only exception was catch up maintenance work on critical transformers and air blast circuit breakers dealt with above.

The development of the IAP at Hydro's initiative in response to the supply disruptions and power outages was appropriate and justified. This process also engaged executive leadership and associated resources.

If required to modify any potential disallowance by the Board with respect to this cost category, Hydro will carry out the necessary specific adjustments to Liberty's proposed disallowance on account of the above noted factors as part of its ultimate compliance filing in the General Rate Application.

## 10. **BLACK START**

At page 51 of the Final Report, Liberty concluded that Hydro management failed to act prudently in managing black start capability for Holyrood, and that these actions resulted in a prolonged period during which black start capability was unavailable. Liberty then found with respect to the eight leased 1.825 MW diesel generators that "...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." As a result, Liberty concluded that ". . . [t]he period during which the facilities will operate does not extend long enough to justify charging them to customers."

### Proposed Disallowance

Liberty's proposal to disallow the 2014-2015 black start costs because this capability was only available for a limited period is inconsistent with the general application of the "used and useful" regulatory principle. In this case, Hydro incurred an investment to obtain black start capability (in accordance with a direction of the Board) that was "used and useful" during the 2014-2015 time period. Hydro is seeking recovery only for the amount it ultimately incurred for the service provided, not for any costs associated with the provision of the service over a longer time period.

Liberty has not claimed that the black start capability was not required during the period nor that Hydro incurred excessive costs on behalf of its ratepayers to provide this service.

It would not be appropriate for the Board to disallow costs that were legitimately incurred in accordance with Board direction solely due to the fact that another or similar investment could have potentially been made to provide the service at some earlier point in time. Further, prior in time Hydro had put in place what it viewed as appropriate capability based on its best information at the relevant times. This is discussed further below.

Thus, regardless of the Board's ultimate findings regarding Hydro's various actions to ensure black start capability following the determination that the then existing Holyrood black start turbine could not be continued to be used, with respect to the actual costs for which Hydro is seeking approval there is no grounds for disallowance.

Furthermore, Hydro has determined that $567,113 of the capital costs allocated to the original Black Start Diesel project are capable for use to connect the new Combustion Turbine to the plant for Black Start purposes. If utilized for this purpose there is clearly no rationale to disallow those expenditures.

In relation to Liberty's proposed Black Start Operating Expenses disallowance on Table 9.1 of the Final Report, in PR-NLH-PUB-007, Liberty noted that this figure includes actual operating costs of $72,000 from PR-PUB-NLH-115. Those costs were in relation to the Newfoundland Power mobile unit. However, only approximately $52,000 was included in the 2014 test year revenue requirement in this regard, and any potential disallowance would be limited to that amount.

As well, the reason for moving the Newfoundland Power mobile unit to Holyrood was to keep the ancillary equipment at Holyrood in a warm state to enable the plant to start quicker in case of a repeat of the January 2013 event, which also provided additional generating capacity on the Avalon. As such, there is no rationale to disallow any costs in relation to this item on account of the black start issue as this was not its primary purpose in any event. (See Hydro's response to PR-PUB-NLH-003).

Prudence

That all being said, Hydro also disagrees with Liberty that the various steps it took between 2010 and 2014 were not appropriate in light of the information available to Hydro at the relevant time periods.

Due to Hydro's concerns with Liberty's characterization of Hydro's actions on this issue and the Holyrood Unit 1 turbine failure issue, following receipt of the Final Report, Hydro retained La Capra Associates, Inc. ("La Capra") an independent energy regulatory consulting firm, to provide an independent view on Hydro's actions and Liberty's findings in regard to these two issues. La Capra's report is attached as Appendix B to this Reply Evidence.

La Capra's findings are consistent with Hydro's views respecting its activities in relation to this issue, and their report provides La Capra's opinion that Hydro's actions were not imprudent. In addition to La Capra's findings with which Hydro is in agreement, Hydro also has specific comments on two issues raised by Liberty in its Final Report.

At page 42 of the Final Report, Liberty states that AMEC did not identify the Hardwoods option for black start, and that Hydro permitted the consultant to study options outside the range of acceptability as Hydro was considering the installation of a 50 MW CT in late 2015. These statements are simply out of context. As specifically indicated in the Executive Summary at page (i) of the AMEC Holyrood Thermal Generating Station Gas Turbine Condition Assessment & Options Study (December 19, 2011) (found at PR-PUB-NLH-002, Attachment 1), AMEC "was contracted by NL Hydro to conduct a Condition Assessment and Refurbishment/Replacement Study for the Holyrood Black Start Gas Turbine Generator and balance of plant equipment". Hydro wanted this study so as to have the necessary information to feed into Hydro's management's decision making. It did not seek, nor require, an AMEC study regarding potential use of Hardwoods for black start, nor was it final as to what Hydro was going to do with respect to the CT. Hydro acted prudently in obtaining the refurbishment/replacement study to provide additional information to inform its decision making. The AMEC study in no way "suffers from misdirection" as alluded to by Liberty.

At page 55 of the Final Report, Liberty cites Hydro's response to PR-PUB-NLH-110 that "Hydro's application of the N-1 criterion is such that all diesel generators are assumed to be available for black start", and then states that this "response suggests that one need not examine the reliability of the black start system because one need consider only one contingency". Hydro has never suggested that there was no need to examine the reliability of the installed solution. Rather its response was in the context of Liberty's question which referred to the system requiring eight components. If, for example, Hydro was using one 16 MW unit, it would anticipate its availability notwithstanding the potential failure of various components of that unit. Hydro has not treated the present configuration any differently.

In any event, Hydro also noted in its response to PR-PUB-NLH-109 that:

> Hydro has the alternative to blackstart Holyrood Unit 3 instead of Unit 1 or Unit 2. The boiler feed pump motors on Unit 3 are 2500 hp motors. Analysis has confirmed that seven 1.825 MW diesel units are required to successfully start the 2500 hp boiler feed pump of Unit 3. Successful blackstart of Unit 3 using seven diesel units would then enable start of Holyrood Units 1 and 2.

And in its response to PR-PUB-NLH-104 (Revision 1, June 10-15) that, "Testing of the blackstart diesels on July 25, 2014 confirmed that the diesels could start the largest motor in the plant, namely a Stage 1 boiler feed pump and therefore could blackstart the plant. The test on that day actually started a boiler feed pump on Unit 1 with only seven of the eight diesels, thus confirming the sufficiency of the eight diesel configuration."

## 11. HOLYROOD UNIT 1 TURBINE FAILURE

As noted above, La Capra's independent report addresses this issue as well as the Black start issue, and Hydro concurs with La Capra's findings.

On one issue raised by Liberty, Hydro has an additional comment. Liberty notes in its response to PR-PUB-NLH-018 that apparently its reference to "common mode failure" is in relation to "a hypothesized blackout situation" in which a unit is separated from the system by a single event, the theorized loss of offsite power. However, with respect to the Holyrood Unit 1 event, the loss of both the primary and backup AC lube oil systems was due to the loss of all five transmission lines connecting to the Holyrood station (see for example Hydro's response to PUB-NLH-029 in the Black Start proceeding). The loss of all the transmission lines into Holyrood was due to various causes and was not a common mode failure, and Hydro does not agree that the loss of AC power (where such requires multiple transmission failures) undermines the redundancy of the lube oil system. Hydro further notes La Capra's consistent comments in this regard at pages 18 and 19 of its report.

With respect to Liberty's proposed capital disallowance of $5,500,000 on account of Holyrood Unit 1 Turbine Generator 2014 Capital costs, set out in Table 9.1 of the Final Report, this figure includes depreciation expense of $1.0 million as noted in PR-PUB-NLH-129 (Revision 1, June 30-15).

However, Liberty has also proposed an operating disallowance of $2,419,400 for Holyrood Unit 1 Turbine, 2014 Repairs, Depreciation and Replacement Power on Table 9.1. The above noted depreciation expense falls in this category as well, as shown on Table 11.2 of the Final Report, and accordingly to avoid double counting, the $5.5 million in capital needs to be adjusted by the applicable depreciation expense, if any disallowance on account of Holyrood Unit 1 capital costs is determined by the Board, which Hydro does not believe is justified for the reasons noted above.

As well, PR-PUB-NLH-129 (Revision 1, June 30-11) identified $914,800 of Contract labour/other expenses, which Liberty also includes in its proposed $2,419,410 disallowance in Table 11.2 of the Final Report. However, this $914,800 was not included in Hydro's 2014 test year and thus Hydro has not requested recovery from ratepayers of this amount, and thus there are no costs to be disallowed in any event.

With respect to the Replacement Power costs of $504,610, which constitute the third and final component of the proposed $2,419,410 disallowance, double counting in relation to this amount has been addressed earlier in this Reply Evidence under the heading Supply Related Costs.

12. **LABRADOR CITY TERMINAL STATION**

Liberty noted that there were certain errors and omissions in the overall project planning, design and cost estimation for this project, but confirmed that the work covered by the changed requirements was in fact necessary and the project as finally completed was required. Further, Liberty noted that the final actual costs were $881,000 greater than Hydro's budgeted expenditures, but that increase was justifiable and Liberty observed no reason for questioning the reasonableness of the costs of earlier work.

Hydro agrees that the project planning, design and estimation for this specific project could have been carried out in a more efficient manner. That being said, Hydro's processes have improved since the time this project estimate and schedule was created (see Hydro's responses to PR-PUB-NLH-40 and 41), and Hydro agrees with Liberty's conclusions that the ultimate expenditures were appropriate and are fully justified. Thus Hydro has no further evidence to add to the record on this issue.

13. **BLACK TICKLE RESTORATION**

Liberty did not find any issues of imprudence with respect to the Black Tickle restoration, nor any issues with the costs incurred by Hydro. Hydro has no further evidence to place on the record with respect to this issue.

## 14. CONCLUSION

Hydro appreciates the opportunity to provide this Reply Evidence. As noted above, Hydro does not believe its actions have been imprudent, but rather that it has acted in a responsible manner to provide least cost, safe and reliable electrical service to its customers. If the Board nevertheless determines any disallowances are required, Hydro has provided (or will provide in an ultimate compliance filing) the information required to ensure these amounts are accurately determined.

# NEWFOUNDLAND AND LABRADOR HYDRO

St. Johns, Newfoundland

# 2015 BETTERMENT REPORT

CALCULATION OF ASSET BETTERMENT RELATED TO THE SUNNYSIDE AND WESTERN AVALON TRANSFORMER CAPITAL ADDITIONS

*Prepared by:*

Gannett Fleming

NEWFOUNDLAND AND LABRADOR HYDRO
St. John's, Newfoundland

# 2015 BETTERMENT REPORT

# CALCULATION OF ASSET BETTERMENT RELATED TO THE SUNNYSIDE AND WESTERN AVALON TRANSFORMER CAPITAL ADDITIONS

GANNETT FLEMING CANADA ULC

Calgary, Alberta

August 7, 2015

Newfoundland and Labrador Hydro
Hydro Place, 500 Columbus Drive
PO Box 12400
St. Johns. NL
A1B 4K7

Attention: Mr. Michael Conway

Ladies and Gentlemen:

Pursuant to your request, we have the betterment calculations related to the new capital additions associated with the Sunnyside and Western Avalon main transformers. Our report presents a description of the calculations used in the determination of the betterment related to these assets and detailed a summary of the detailed calculations.

Respectfully submitted,

GANNETT FLEMING CANADA ULC

LARRY E. KENNEDY
Vice President

LEK/hac
Project #059551

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## TABLE OF CONTENTS

# NEWFOUNDLAND AND LABRADOR HYDRO
# 2015 BETTERMENT REPORT
# PART I. INTRODUCTION

## SCOPE

This report sets forth the concepts of a Betterment study to reflect the impact of the replacement of a significant portion of large asset component parts due to interim retirement of the major components. Specifically, this study recognizes the impact of newly replaced large components of transformer assets in the Sunnyside Sub Station and Western Avalon Terminal Station caused by earlier than expected failure of the component or associated equipment.

The service life estimates used in the calculations herein are consistent with average service lives as currently approved by the Newfoundland Board of Commissioners.

## PLAN OF REPORT

Part I Introduction, contains statements with respect to the Scope of this study, the plan of the report, and the basis of the analysis contained within this report. Part II. Development of the Betterment Calculations, presents a discussion of the concept of large asset betterment, a review of the specific betterment calculations, and discusses the impact of the calculations on the remaining life expectations associated with the Sunnyside and West Avalon transformer assets. Part III. Results of Study, presents the results of the study and describes the table which summarizes the betterment calculations.

## BASIS OF THE STUDY

The betterment calculations contained in this study were based on the information provided to Gannett Fleming outlining the asset components that were retired, and the associated costs and accumulated depreciation amounts of the retired assets. Gannett Fleming also reviewed the Prudence Review report prepared by Liberty Consulting Group (the “Liberty report”) to ensure an understanding of the cause of the retirement event that lead to the betterment calculations produced herein. In particular, Gannett Fleming considers that the comments regarding the life expectations of the original and replacement components to have formed a large influence on the Liberty report conclusions. At page 31 of the Liberty report, the following is stated.

> *"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."*

In considering the above comments, Gannett Fleming views, that in fact, the accounting life, which considers a number of forces of retirement that are expected to occur over the entire life of a large operating unit, need to be considered. While the operational life is an important consideration, all forces of retirement must be considered in the determination of remaining life.

## PART II. DEVELOPMENT OF THE BETTERMENT CALCULATIONS

### Asset Betterment

When reviewing the comments within the Liberty report, the concept of "Asset Betterment" must be considered in the context of what constitutes a "Betterment". Virtually all definitions of asset betterment provide for the requirement related to enhancements to the service potential of a capital asset such as:

- an increase in the previously assessed physical output or service capacity;
- a reduction in associated operating costs;
- an extension of the estimated useful life; or
- an improvement in the quality of output.

Review of the above criteria, in concert with the conclusions reached in the Liberty report, indicates that the capital expenditures resulting from the requirement to replace certain components and associated infrastructure clearly result in a betterment of the assets beyond the original expectation of the assets when they were originally installed. While there is no indication that the replacement components would result in any increase to the physical output; service capacity or any improvement in the quality of the output of their transformers, the Liberty report clearly identifies that "*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."* Furthermore it was specifically noted that "*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".*

In reviewing the capital additions at the Sunnyside and West Avalon stations, Gannett Fleming notes that an expenditure that relates to a Betterment can be in one of two forms. Firstly, the expenditure may relate to an asset that is physically a part of (or a component of) a larger asset. For example, the cooling system in a larger electrical transformer may comprise a large component of the transformer cost that can be changed out, and when changed out result in a betterment of the transformer based on the criteria described above. Alternatively, additional equipment may be installed at a location that will provide enhanced protection to equipment that will result in a life extension to the original equipment. For example, enhanced system protection and control equipment may result in a life extension to the electric transformers. In both of these circumstances, the end user of the system receives a tangible benefit of the capital expenditures.

Based on the above, and on the conclusions reached in the Liberty report, it is Gannett Fleming's view that the capital expenditures relate to a betterment of the Transformer assets at both the Sunnyside Sub Station and Western Avalon Terminal Station.

**Asset Betterment Calculations**

Based on Gannett Fleming's conclusion that the capital spending related to the Sunnyside and Western Avalon transformer and breaker replacements constitutes a betterment, the determination of the impact of the capital expenditures on the remaining life expectancy of the assets is required. In making the calculations as provided in Part III of this report, Gannett Fleming required the original cost of installation of the assets; the estimated amount of accumulated depreciation of both the retired and remaining assets; and the estimated remaining life of the asset components. The original cost of the asset components were provided to Gannett Fleming by the company. The estimated amount of accumulated depreciation and estimated remaining life were determined by Gannett Fleming from the approved Iowa curve.

Based on the inputs as described above, Gannett Fleming determined the remaining life of each of the asset components and then calculated the weighted average remaining life of the total asset including the replacement components. Through the development of the weighted average life, the rate-payers are only responsible for the consumption of the service value of the asset components providing utility service at any point in time.

As indicated in the attached Tables 1 and 2 to this report, the retired assets at both the Sunnyside and Western Avalon substations had a significant portion of their estimated life yet to be consumed. In the circumstances of the Sunnyside Station, Gannett Fleming has determined that the remaining value of the retired assets represented 45.09% of the original cost of investment as indicated in Table 1 of this report. As such, the portion of the total expenditure related to the replacement of the consumed portion of the assets is equal to 100% of the investment less the 45.09% yet to be consumed. In this manner the betterment is represented by the fact an asset that has consumed 54.91% of its life is being replaced with a new asset that will have a completely new life cycle. In this manner, the betterment is represented by the 54.91% of consumed value of the retired asset multiplied by the total replacement cost.

Likewise, Table 2 of this report indicated that the assets retired at the Western Avalon terminal station had 28.71% of their service value remaining at the time of retirement. As such, the portion of the total expenditure related to the replacement of the consumed portion of the assets is equal to 100% of the investment less the 28.71% yet to be consumed. In this manner the betterment is represented by the fact an asset that has consumed 71.29% of its life is being replaced with a new asset that will have a completely new life cycle. In this manner, the betterment is represented by the 71.29% of consumed value of the retired asset multiplied by the total replacement cost.

# PART III. RESULTS OF STUDY

## QUALIFICATION OF RESULTS

The calculated percentage of the total consumed service value of the Sunnyside and Western Avalon transformer equipment are the principle results of this study. The calculations representing the total consumed service value represent the estimated amount of the new capital additions that can be considered as a betterment expenditure. Based on the 2014 known and estimated 2015 capital expenditures related to the replacement assets, the percentages as determined in this report can be applied to the capital expenditures to determine the betterment expenditures.

## DESCRIPTION OF DETAILED TABULATIONS

Table 1 at page 8 of this report, provides the assets that were retired due to the January 4, 2014 fire at the Sunnyside Substation. The detail provided for each asset includes the original installation date and cost of each asset; the currently approved Iowa curve used in the depreciation calculations for each asset; the estimated life and value of each assets (estimated based on the approved Iowa curve) as of the date of retirement, and the weighted average remaining life expectancy of each asset (based on the remaining life associated that the achieved age calculated in accordance with the approved Iowa curve). Table 2 at page 9 of this report, provides the same calculations related to the retired assets at the Western Avalon Terminal Station.

## RESULTS

Based on the calculations provided in Tables 1 and 2, the following represent the calculation of the betterment expenditures for 2014 and 2015 for the Sunnyside and Western Avalon Stations. The calculations are presented on the following page.

| **Sunnyside** | **2014 Actuals** | | **2015 Test Year** | |
|---|---|---|---|---|
| Sunnyside Equipment Capital (Net of Insurance) | 3,236,684 | 1 | 5,145,800 | 1 |
| T1 Transformer Circuit Breaker Mods | 87,500 | 1 | 1,234,494 | 1 |
| 230 Kv Breaker (B1L03) | 527,740 | 2 | 527,740 | 2 |
| | 2,621,444 | | 3,383,566 | |
| Total Consumed % | 54.91% | 3 | 54.91% | 3 |
| Betterment Expenditure | 1,439,435 | | 1,857,916 | |
| Sunnyside Equipment Capital (Net of Insurance and Betterment) | 1,182,009 | | 1,525,650 | |

| **Western Avalon** | **2014 Actuals** | |
|---|---|---|
| Western Avalon Equipment Capital | 1,013,900 | 4 |
| Total Consumed % | 71.29% | 5 |
| Betterment Expenditure | 722,809 | |
| Net Western Avalon Equipment Capital (net of betterment) | 291,091 | |

[1] As noted in Table 5.3, page 30 of the Liberty Report.

[2] The replacement costs of the 230 kV Breaker (B1L03) have been deducted in Hydro's reply evidence.

[3] Per Table 1 of this report.

[4] As noted in paragraph 1, Page 32 of the Liberty report.

[5] Per Table 2 of this report.

**NEWFOUNDLAND AND LABRADOR HYDRO**
**TABLE 1. CALCULATION OF THE TOTAL REMAINING SERVICE VALUE OF THE RETIRED ASSETS TO BE USED IN BETTERMENT CALCULATIONS**
**SUNNYSIDE SUBSTATION**

**Sunnyside 13251493**

| Asset | Description | Acquired | Year Acquired | Disposed | Age at 1/1/2014 | UOP | Iowa Curve | Original Cost | Total Remaining | Remaining Life | % of Life | Year Old | Weighted Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5814 | BREAKER,B1L03,SSD TS | 67/01/01 | 1967 | 14/09/30 | 46 | C09 | 55 R3 | 49,956.24 | 14,432.36 | 29% | 71% | 44.15184 | 5% | 2.02676 |
| 5820 | BREAKER,B2T1,SSD TS | 66/01/01 | 1966 | 14/09/30 | 47 | C09 | 55 R3 | 18,251.13 | 5,161.42 | 28% | 72% | 44.68443 | 2% | 0.74939 |
| 5838 | DISCONNECT,B1T1,SSD TS | 66/01/01 | 1966 | 14/09/30 | 47 | D03 | 45 S2.5 | 8,483.40 | 1,789.15 | 21% | 79% | 44.41883 | 1% | 0.34626 |
| 5865 | CT B1L03 A PH,SSD TS | 66/01/01 | 1966 | 14/09/30 | 47 | T05 | 55 R3 | 4,823.05 | 1,363.96 | 28% | 72% | 44.68443 | 0% | 0.19803 |
| 5867 | CT B1L03 C PH,SSD TS | 66/01/01 | 1966 | 14/09/30 | 47 | T05 | 55 R3 | 18,992.11 | 5,370.97 | 28% | 72% | 44.68443 | 2% | 0.77982 |
| 5886 | CT Spare1 138 kV | 66/01/01 | 1966 | 14/09/30 | 47 | T05 | 55 R3 | 4,994.79 | 1,412.53 | 28% | 72% | 44.68443 | 0% | 0.20509 |
| 5887 | CT SPARE2 138 KV | 66/01/01 | 1966 | 14/09/30 | 47 | T05 | 55 R3 | 4,994.79 | 1,412.53 | 28% | 72% | 44.68443 | 0% | 0.20509 |
| 5888 | CT 138 kV SPARE3 | 66/01/01 | 1966 | 14/09/30 | 47 | T05 | 55 R3 | 4,994.79 | 1,412.53 | 28% | 72% | 44.68443 | 0% | 0.20509 |
| 5909 | PT B2 A PH,SSD TS | 67/01/01 | 1967 | 14/12/17 | 46 | T05 | 55 R3 | 3,496.92 | 1,010.26 | 29% | 71% | 44.15184 | 0% | 0.14187 |
| 5910 | PT B2 B PH,SSD TS | 67/01/01 | 1967 | 14/12/17 | 46 | T05 | 55 R3 | 3,496.92 | 1,010.26 | 29% | 71% | 44.15184 | 0% | 0.14187 |
| 5911 | PT B2 C PH,SSD TS | 67/01/01 | 1967 | 14/12/17 | 46 | T05 | 55 R3 | 3,496.92 | 1,010.26 | 29% | 71% | 44.15184 | 0% | 0.14187 |
| 342314 | B1L03, RELUBE (MAT) SSD | 10/12/2007 | 2007 | 14/09/30 | 6 | C09 | 55 R3 | 1,362.71 | 1,216.22 | 89% | 11% | 5.92728 | 0% | 0.00742 |
| 342318 | B2T1 UPGRADE (MAT) SSD T | 10/12/2006 | 2006 | 14/09/30 | 7 | C09 | 55 R3 | 25,922.17 | 22,632.65 | 87% | 13% | 7.00114 | 2% | 0.16676 |
| 367996 | B2T1 UPGRADE, SSD TS | 12/10/2015 | 2015 | 14/09/30 | (2) | C09 | 55 R3 | 51,514.00 | 51,009.16 | 99% | 1% | 0.53911 | 5% | 0.02552 |
| 378361 | CT B1L03 B PH,SSD TS | 13/12/10 | 2010 | 14/09/30 | 3 | T05 | 55 R3 | 38,454.90 | 36,566.76 | 95% | 5% | 2.70293 | 4% | 0.09551 |
| 389604 | INSULATORS 2006 ,SSD TS | 6/12/2014 | 2014 | 14/12/31 | (1) | I03 | 30 L3 | 89.32 | 88.43 | 99% | 1% | 0.30000 | 0% | 0.00002 |
| 99018894 | COMP AIR SYSTEM - BALANC | 67/01/01 | 1967 | 14/12/31 | 46 | C10 | 40 R3 | 5,166.59 | 749.16 | 15% | 86% | 43.94700 | 0% | 0.20864 |
| 99018907 | FOUNDATIONS (CONCRETE) F | 70/01/01 | 1970 | 14/12/31 | 43 | F04 | 57 R4 | 92,823.44 | 28,218.33 | 30% | 70% | 41.81429 | 9% | 3.56653 |
| 99019179 | SWITCHING - H.V. ( LIGHT | 67/01/01 | 1967 | 14/09/30 | 46 | L05 | 58 R3 | 2,443.02 | 783.48 | 32% | 68% | 43.76091 | 0% | 0.09824 |
| 99019180 | SWITCHING - H.V. (LIGHTI | 67/01/01 | 1967 | 14/09/30 | 46 | L05 | 58 R3 | 2,443.02 | 783.48 | 32% | 68% | 43.76091 | 0% | 0.09824 |
| 99019181 | SWITCHING - H.V. (LIGHTI | 67/01/01 | 1967 | 14/09/30 | 46 | L05 | 58 R3 | 2,443.02 | 783.48 | 32% | 68% | 43.76091 | 0% | 0.09824 |
| 99019182 | SWITCHING - H.V. ( LIGHT | 67/01/01 | 1967 | 14/09/30 | 46 | L05 | 58 R3 | 2,443.02 | 783.48 | 32% | 68% | 43.76091 | 0% | 0.09824 |
| 99019183 | SWITCHING - H.V. ( LIGHT | 67/01/01 | 1967 | 14/09/30 | 46 | L05 | 58 R3 | 2,443.02 | 783.48 | 32% | 68% | 43.76091 | 0% | 0.09824 |
| 99019184 | SWITCHING - H.V. ( LIGHT | 70/01/01 | 1970 | 14/09/30 | 43 | L05 | 58 R3 | 2,443.02 | 865.81 | 35% | 65% | 40.97959 | 0% | 0.09199 |
| 99019186 | SWITCHING - H.V. ( LIGHT | 70/01/01 | 1970 | 14/09/30 | 43 | L05 | 58 R3 | 2,443.02 | 865.81 | 35% | 65% | 40.97959 | 0% | 0.09199 |
| 99019187 | SWITCHING - H.V. ( LIGHT | 70/01/01 | 1970 | 14/09/30 | 43 | L05 | 58 R3 | 2,443.02 | 865.81 | 35% | 65% | 40.97959 | 0% | 0.09199 |
| 99019189 | SWITCHING - H.V. ( LIGHT | 70/01/01 | 1970 | 14/09/30 | 43 | L05 | 58 R3 | 2,443.02 | 865.81 | 35% | 65% | 40.97959 | 0% | 0.09199 |
| 99019190 | SWITCHING - H.V. (LIGHTI | 70/01/01 | 1970 | | 43 | L05 | 58 R3 | 2,443.02 | 865.81 | 35% | 65% | 40.97959 | 0% | 0.09199 |
| 99019224 | SWITCHING - H.V. ( 230KV | 70/01/01 | 1970 | 14/09/30 | 43 | D03 | 45 S2.5 | 8,483.40 | 2,046.20 | 24% | 76% | 41.01618 | 1% | 0.31973 |
| 99019294 | POWER TRF - ( ADDT COST | 91/12/31 | 1991 | 14/09/30 | 22 | T05 | 55 R3 | 11,683.28 | 7,282.19 | 62% | 38% | 21.20124 | 1% | 0.22761 |
| 99019335 | POWER TRF - ( ADDT COST | 79/02/24 | 1979 | 14/09/30 | 34 | T05 | 55 R3 | 1,235.05 | 546.02 | 44% | 56% | 32.59001 | 0% | 0.03699 |
| 99019525 | POWER TRANSFORMER - (230 | 78/11/16 | 1978 | 14/09/30 | 35 | T05 | 55 R3 | 675,529.97 | 288,316.19 | 43% | 57% | 33.63194 | 62% | 20.87658 |
| 390338 | TRANSFORMER T8,SSDTS | 70/01/01 | 1970 | 14/12/31 | 43 | | 55 R3 | 25,594.92 | 8,377.22 | 33% | 67% | 40.96844 | 2% | 0.96353 |
| | | | | | | | | **1,088,271.01** | **490,681.14** | | | **Average Age** | | **32.58713** |
| | | | | | | | | **Total Remaining** | **45.09%** | | | | | |
| | | | | | | | | **Total Consumed** | **54.91%** | | | | | |

NEWFOUNDLAND AND LABRADOR HYDRO

TABLE 2. CALCULATION OF THE TOTAL REMAINING SERVICE VALUE OF THE RETIRED ASSETS TO BE USED IN BETTERMENT CALCULATIONS

WESTERN AVALON

| Asset | Description | Acquired | Year Acquired | Disposed | 1-Jan-14 | UOP | Iowa Curve | Original Cost | Total Remaining | Remaining Life | % of life | Year old | Weighted Average | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | BREAKER,B1L37,WAV TS | 68/01/01 | 1968 | 14/09/30 | 45 | C09 | 55 R3 | 52,534.43 | 15,833.88 | 30% | 70% | 43.08755 | 2% | 1.06476 |
| 00006433 | DISCONNECT,L03L17-2,WAV TS | 68/01/02 | 1968 | 14/09/30 | 45 | D03 | 45 S2.5 | 15,784.12 | 3,559.32 | 23% | 77% | 42.71174 | 1% | 0.31712 |
| 00006529 | BREAKER,B2T1,WAV TS | 68/01/03 | 1968 | 14/09/30 | 45 | C09 | 55 R3 | 19,125.00 | 5,764.28 | 30% | 70% | 43.08755 | 1% | 0.38762 |
| 00006525 | BREAKER,B1B3,WAV TS | 68/01/04 | 1968 | 14/09/30 | 45 | C09 | 55 R3 | 52,534.45 | 15,833.88 | 30% | 70% | 43.08755 | 2% | 1.06477 |
| 00323917 | BKR B1L08 UPGRD (MAT), WAV TS | 68/01/05 | 1968 | 14/09/30 | 45 | C09 | 55 R3 | 27,484.86 | 8,283.94 | 30% | 70% | 43.08755 | 1% | 0.55706 |
| 00006522 | BREAKER,B1L08,WAV TS | 68/01/06 | 1968 | 14/09/30 | 45 | C09 | 55 R3 | 52,534.44 | 15,833.88 | 30% | 70% | 43.08755 | 2% | 1.06477 |
| 00288409 | CISCO ROUTER | 68/01/07 | 1968 | 14/09/30 | 45 | R14 | 5 SQ | 26,775.60 | 0.00 | 0% | 100% | 0 | 1% | 0 |
| 00365480 | TRF Upgrade T5, WAV TS (2012) | 68/01/08 | 1968 | 14/09/30 | 45 | T05 | 55 R3 | 29,927.84 | 9,020.25 | 30% | 70% | 43.08755 | 1% | 0.60658 |
| 99018753 | POWER TRANSFORMERS - 75/100/12 | 68/01/09 | 1968 | 14/09/30 | 45 | T05 | 55 R3 | 1,522,003.81 | 458,731.95 | 30% | 70% | 43.08755 | 72% | 30.84789 |
| 99019575 | POWER TRF - (230KV PWR TRF BY | 68/01/10 | 1968 | 14/09/30 | 45 | T05 | 55 R3 | 173,507.71 | 52,295.22 | 30% | 70% | 43.08755 | 8% | 3.51664 |
| 99019652 | SWITCHING - H.V. ( SUSPENSION | 68/01/11 | 1968 | 14/09/30 | 45 | I03 | 30 L3 | 9,382.99 | 1,762.13 | 19% | 81% | 41.12493 | 0% | 0.18151 |
| 99024633 | CONTROL, METERING & RELAYING | 68/01/12 | 1968 | 14/09/30 | 45 | C15 | 30 R1 | 144,301.19 | 23,434.51 | 16% | 84% | 41.77279 | 7% | 2.83545 |
| | **TOTAL** | | | | | | | **2,125,896.44** | **610,353.23** | | | **Average Age** | | **42.44417** |
| | | | | | | | | **Total Remaining** | **28.71%** | | | | | |
| | | | | | | | | **Total Consumed** | **71.29%** | | | | | |

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CONSULTANT REPORT

# Review of Newfoundland and Labrador Hydro Decisions and Actions Related to Outage Events

**Prepared for:** Newfoundland and Labrador Hydro

**Prepared by:** La Capra Associates, Inc.

La Capra Associates

AUGUST 7, 2015

# TABLE OF CONTENTS

# 1. INTRODUCTION

The Board of Commissioners of Public Utilities of Newfoundland and Labrador ("Board") retained The Liberty Consulting Group ("Liberty") to conduct a prudence review of Newfoundland and Labrador Hydro's ("Hydro") decisions and actions mostly related to Island Interconnected System ("IIS") outages experienced during the winters of 2013 and 2014. Some of the scope of the prudence review also covered recovery of Board deferred costs, pending further review, associated with certain decisions and actions.

After the Liberty Prudence Review of Newfoundland and Labrador Hydro Decisions and Actions Final Report ("Liberty Prudence Report") was submitted to the Board on July 6, 2015, Hydro retained La Capra Associates, Inc. ("La Capra Associates") as independent outside consultants to review their decisions and actions relative to two of the specific issues discussed in this report.

In this report, we review the decisions and actions taken by Hydro in relation to the "Black Start" and "Holyrood Unit 1 Turbine Failure" issues. As discussed in detail in the following sections of this report, our analysis concludes that there are insufficient grounds to support a recommendation of imprudence on the part of Hydro on these issues.

# 2. BLACK START

## 2.1 DEFINITION OF ISSUE

This section addresses Hydro's decisions and actions related to the maintenance and retention of Black Start capability for the Holyrood Thermal Generating Station ("HTGS" or "Holyrood"). The prudence review regarding Black Start[1] centers around costs in the Board sanctioned deferral account for lease and other infrastructure costs that cover eight 1.825 MW diesel generators leased and installed by Hydro to provide interim Black Start capability at Holyrood. Liberty's principle findings on this issue are as follows:

- Hydro failed to keep the Board informed as it made Black Start related decisions at Holyrood that could impact overall system reliability.
- Hydro's decision making process was flawed:
    - 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 Combustion Turbine ("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.
- Hydro's failure to address restoring on-site Black Start capability at Holyrood in a timely manner led to the otherwise delayed expense of leasing 16 MW of on-site diesels at Holyrood as a stop gap measure which resulted in a useful period too short to demonstrate usefulness and allow cost recovery.

## 2.2 OUTLINE OF HYDRO'S DECISIONS AND ACTIONS

The following section outlines a detailed chronology of events surrounding Black Start and Hydro's decisions along the way.

- **Date:** June 10, 2008
    - **Event:** Alba Power Inspection Report to Borescope inspection of Avon 37029 1533 70L (Attachment 1 of IC-NLH-12). Recommendations were made to correct poor condition

[1] "Black Start" is a common industry term referring to the ability of a generating unit to restart if it becomes disconnected from the transmission system.

of the intake plenum, water ingress and corrosion, burner leaking due to the failure of the seals in the fuel control unit, the required repair/overhaul due to coating loss, pitting and corrosion, the replacement of combustion cans which, in their condition at that time, could have caused catastrophic failure, increased overhaul/replacement costs, and been a large safety issue.

- **Decision:** Since the Holyrood Gas Turbine ("Holyrood GT") was 42 years old in 2008 and the inspection revealed that a significant amount of work needed to be done to it, "Hydro became concerned that the unit may be approaching the end of its reliable life".[2] However, Hydro also understood that the Holyrood GT was an integral piece of system restoration, as described in the Newfoundland and Labrador Hydro – System Operating Instruction T-022 dated 11/27/1996, when the Avalon Peninsula became isolated from Bay D'Espoir.[3]
  - In 2009, Hydro had the following work completed on the Holyrood GT in order to ensure safe operation: Engine removed, cleaned combustion can replaced, thermocouples checked; Fuel control unit replaced; Fuel pump repaired; Power turbine inspected and future repairs planned; Fuel control solenoid valve replaced; Nitrogen probe repairs; Fuel control unit tuning; and Exhaust transition lagging replaced. After the repairs, Hydro employed an Emergency Response Technician for the 2009/2010 operating season for fire watch over the gas turbine for all times that the unit was running.[4]
  - Also in 2009, Hydro planned on initiating the first year of a four-year program to implement recommendations from the "Hardwoods Gas Turbine Plant Life Extension Upgrades"[5] report it submitted to the Board in the previous year. The life extension upgrades program stemmed from a condition assessment and life cycle cost analysis study of Hardwoods and Stephenville Gas Turbine Plants conducted by Stantec Inc. (an engineering consulting company) in 2007. The detailed scope of the work recommended by Stantec is described in Appendix B of the report to the Board.[6]

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[2] PR-PUB-NLH-002, Attachment 2, page 1 of 3, 2015 Prudence Review. PUB-NLH-022 Holyrood Black Start Diesel Units Application, page 1 of 3.

[3] Customers will be without power until Hardwoods Gas Turbine and Holyrood fossil units are placed in-service and load reconnected. Simultaneous with starting Hardwoods, the Holyrood Thermal Generating Station will be initiating a plant Black Start. The Holyrood units are Black Started using local diesel generation to start the Holyrood gas turbine which in turn supplies fans, pumps and other unit auxiliaries.

[4] PR-PUB-NLH-002, Attachment 2, pages 1 and 2 of 3, 2015 Prudence Review. PUB-NLH-022 Holyrood Black Start Diesel Units Application, pages 1 and 2 of 3.

[5] http://www.pub.nf.ca/applications/NLH2009Capital/files/application/NLH2009Application-VolumeII-Report21.pdf

[6] Hardwoods Gas Turbine Plant Life Extension Upgrades Report, page 3.

- The 2009 program work included:[7] Inlet Air Systems End A and End B; Exhaust Stacks End A and End B; Glycol Cooler for Main Lube Oil; Fuel Oil Storage System; Electrical Systems; and Control and Instrumentation Systems. The estimated cost of the four years of program work was approximately $6.35 million.[8]
- In the 2012 Capital Budget Application, Volume I, August 2011, page E-8, Hydro included a list of Hardwoods projects and costs for 2010-2012.
    - 2010 program work included: Refurbish end B gas turbine equipment; and Site retrofits and upgrades.
    - 2011 program work included: Refurbish end A gas turbine equipment; and Site retrofits and upgrades.
    - 2012 program work included: Refurbish generator and exciter; and Site retrofits and upgrades.
- These ongoing investments by Hydro show that the Company was committed to ensuring the reliability of Hardwoods as a Black Start unit. Hydro specifically states that "[o]nce all recommended work is completed, Hardwoods will be able to operate reliably for the next 15 years".[9]

▪ In 2010, Hydro had the following further work completed on the Holyrood GT in order to continue to ensure safe operation of the unit: Gearbox piping flanges re-gasketed; Gearbox seals modified; Catchment basin installed; Fuel leaks repaired; Engine breather leaks repaired; and Power turbine insulation replaced. After the repairs, "[T]he unit was classified as 'for emergency use only' for the 2010/2011 operating season."[10]

▪ After the 2010 repairs, Hydro determined that a more comprehensive condition assessment of the Holyrood GT was needed "to accurately determine the condition of the unit and the cost benefit of further refurbishment versus

[7] Hardwoods Gas Turbine Plant Life Extension Upgrades Report, pages 3-4.

[8] Hardwoods Gas Turbine Plant Life Extension Upgrades Report, page 17.

[9] Hardwoods Gas Turbine Plant Life Extension Upgrades Report, page 3.

[10] PR-PUB-NLH-002, Attachment 2, page 2 of 3, 2015 Prudence Review. PUB-NLH-022 Holyrood Black Start Diesel Units Application, page 2 of 3.

replacement".[11] Hydro decided to have detailed inspections performed by the Original Equipment Manufacturers ("OEM").[12]

- OEM inspections identified a list of significant capital investment needed in the Holyrood GT in order to sustain the unit. As a result, Hydro added the following list of projects[13] to its five-year capital plan:
    - **2011 –** Overhaul gas turbine and replace gas turbine exhaust stack
    - **2012 –** Replace gas turbine radiator
    - **2013 –** Construct gas turbine equipment enclosure
    - **2014 –** Install sprinkler system at gas turbine, replace GT air intake structure and refurbish gas turbine building structure
    - **2015 –** Refurbish power turbine clutch
- In its 2011 Capital Budget Application ("CBA") to the Board, Hydro proposed "a major overhaul work project on the gas turbine to be completed in 2011."[14]

- **Date:** March 2010
    - **Event:** An inspection of the Holyrood GT by the Department of Government Services, Occupation Health and Safety Inspection Branch ("OHS") resulted in a stop work order.
    - **Decision:** Due to the stop work order, Hydro decided to withdraw the overhaul proposal in the CBA and begin assessing other options for providing Black Start to Holyrood, which included acquiring a replacement facility.[15]
        - Hydro informed the Board about its decision to withdraw the overhaul proposal from its capital program and assess other options. The Board was concerned about the lack of Black Start capability at HTGS though, so Hydro "addressed the

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[11] PR-PUB-NLH-002, Attachment 2, page 2 of 3, 2015 Prudence Review. PUB-NLH-022 Holyrood Black Start Diesel Units Application, page 2 of 3.

[12] These reports are included in the report entitled AMEC Holyrood Thermal Generating Station Gas Turbine Condition Assessment & Options Study, December 19, 2011, filed as Attachment 1 to Hydro's response to NP-NLH-022 Rev.1 ("AMEC Report").

[13] PR-PUB-NLH-002, Attachment 2, pages 2 and of 3, 2015 Prudence Review. PUB-NLH-022 Holyrood Black Start Diesel Units Application, pages 2 and 3 of 3.

[14] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

[15] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

problem by determining new generation options and also addressing the OHS stop work order concerns".[16] Hydro addressed the OHS stop work order concerns and looked into longer term solutions for the plant.

- **Date:** February 2011
    - **Event:** Stop work order removed from the Holyrood GT and it was available with restricted use (only for emergency conditions should the unit be used to Black Start the plant).
    - **Decision:** The stop work order was lifted due to Hydro addressing the OHS concerns and determined new generation options. Hydro reported this update to the Board.[17]
        - Due to the stop work order issued in March of 2010 and the subsequent removal of that order not being lifted until February 2011, the Liberty Prudence Report comments that "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 further believes that by having Hardwoods available the Avalon Peninsula was not left without the ability to Black Start in the event it became necessary.
- Early to Mid-2011
    - **Event:** Hydro engaged AMEC to do a condition assessment of the Holyrood GT.
    - **Decision:** Hydro needed to do a further condition assessment of the Holyrood GT and determine a long-term solution for Black Start at the HTGS, so it hired AMEC Consulting to do a report to assist Hydro in determining alternatives for long-term refurbishment or replacement of the gas turbine at Holyrood.[18]
- **Date:** December 19, 2011 and subsequent meeting on January 17, 2012
    - **Event:** AMEC Consulting report completed by outside consultants on December 19, 2011. A subsequent meeting was held with AMEC on January 17, 2012 to discuss the details in the report.
    - **Decision:**

[16] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

[17] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

[18] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

- Hydro stated that "[T]his report revealed that there was risk of significant catastrophic failure of the gas turbine if it was operated and AMEC recommended discontinuing for any purpose."[19]
    - Due to the information provided by AMEC about the Holyrood GT, Hydro made the decision to stop operating the unit completely, including for Black Start capability.
- Hydro and AMEC further discussed options for providing Black Start capability to HTGS. AMEC's recommendation from the report "was to purchase and install two new replacement 5 MW GTs with an expected in-service of May 2013".[20]
    - Hydro stated that "[p]art of this consideration was that Hydro was preparing an estimate for the new gas turbine to be installed in 2015 on the Avalon Peninsula".[21] At this time, the site of the new gas turbine had not been determined, but the Holyrood site was a possibility.
    - Hydro stated that "[t]his recommendation was made by AMEC without consideration for Hydro's plans to install an additional 50 MW combustion turbine (CT) in late 2015".[22]
- Hydro decided that since the Holyrood GT was not going to be operated, the "Hardwoods gas turbine would be used to Black Start Holyrood under the circumstance that the transmission supply to Avalon Peninsula was interrupted".[23]
    - Hydro further stated that upon review, "[t]he lowest cost option to fulfill this requirement was the development of a procedure (as provided in Hydro's response to CA-NLH-019, Attachment 10) to use Hardwood's gas turbine and existing transmission lines to supply Black Start capability to the Holyrood units".[24]

[19] PR-PUB-NLH-003, Attachment 1, page 70 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 5 of 36, Holyrood Black Start.

[20] PR-PUB-NLH-002, Attachment 3, page 2 of 4, 2015 Prudence Review. PUB-NLH-012, Holyrood Black Start Diesel Units Application, page 2 of 4.

[21] PR-PUB-NLH-003, Attachment 1, page 71 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 6 of 36, Holyrood Black Start.

[22] PR-PUB-NLH-002, Attachment 3, page 2 of 4, 2015 Prudence Review. PUB-NLH-012, Holyrood Black Start Diesel Units Application, page 2 of 4.

[23] PR-PUB-NLH-003, Attachment 1, page 71 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 6 of 36, Holyrood Black Start.

[24] PR-PUB-NLH-002, Attachment 3, page 2 of 4, 2015 Prudence Review. PUB-NLH-012, Holyrood Black Start Diesel Units Application, page 2 of 4.

- The procedure that was developed to use Hardwoods gas turbine to Black Start HTGS was included in the Newfoundland and Labrador Hydro – System Operating Instruction T-007 approved 6/8/2012.
- Hydro reviewed the options provided by AMEC, which ranged in cost from $9.5 to $12.7 million (not including amounts for owner's costs and contingency) and ranged in estimated in-service dates of February of 2013 through May of 2013.
  - None of the options presented by AMEC would have been in-service soon enough to prevent the outage events of January 11, 2013.

- Hydro did not communicate "the decisions and considerations that occurred in January 2012" to the Board, because "there were no pending applications before the Board". Hydro had planned on reporting the status of the Black Start situation "as part of an application to the Board for the proposed replacement Black Start facility".[25]
- Hydro further explains in its November 18, 2013 response to the Board October 17, 2013 letter that there has been no mechanism established which clearly identifies the requirements to report to the Board of changes in equipment status or capability.[26]
- During 2012, Hydro continued to assess the location options for the new 50 MW CT. Hydro concluded that "the least cost option was to locate the combustion turbine in Holyrood. This decision involved a number of factors, one of which was the unit would be able to provide Black Start capability to Holyrood."[27]

- **Date:** January 11, 2013
  - **Event:** Extreme weather event that interrupted all transmission to the Holyrood terminal station, which rendered the Hardwoods Black Start solution ineffective.
    - Subsequent to the event and after further review, Hydro estimated that the lack of pre-warming resulting from the absence of local generation resulted in an 11-

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[25] PR-PUB-NLH-003, Attachment 1, page 71 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 6 of 36, Holyrood Black Start.

[26] PR-PUB-NLH-003, Attachment 1, page 69 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 4 of 36, Holyrood Black Start.

[27] PR-PUB-NLH-003, Attachment 1, page 71 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 6 of 36, Holyrood Black Start.

hour delay in restoring the Holyrood units to supply power to customers after the transmission system was restored.

- **Decision:**
    - Following this weather event, Hydro made arrangements with Newfoundland Power to move their mobile gas turbine and a mobile diesel unit to Holyrood.
        - Electrical infrastructure was established in the station to connect the mobile generation to the plant.
        - Testing of the Newfoundland Power units on May 10, 2013 showed that the units were not able to start a boiler feeder pump motor. However, the units could provide security of alternative generation if the grid is unavailable. Also, all station auxiliary loads could be started, which would keep the Holyrood auxiliaries in a warm state until Hardwoods or supply from another remote source of generation could Black Start the units. Furthermore, the Newfoundland Power units were available for grid support elsewhere on the Avalon Peninsula in the event of a generation contingency.[28]
        - In late May of 2013, Newfoundland Power needed to have the units returned for the annual maintenance program.
        - In the fall of 2013, Hydro made a formal request to Newfoundland Power to relocate the mobile gas turbine unit to Holyrood for the winter of 2013/2014, while it assessed other interim options. Hydro only requested this unit because it was sufficient to meet all station requirements when the grid was interrupted.[29]
    - Also, Hydro still considered Hardwoods as a viable Black Start option for the HTGS until the new combustion turbine could be built in 2015.
        - In an August 5, 2013 response letter regarding the Board's July 23, 2013 questions about Holyrood's Black Start capability, Hydro proposed to use Hardwoods and the associated 230 kV transmission connections between Hardwoods and Holyrood to Black Start Holyrood between 2013 and 2015, until the new combustion turbine at Holyrood could be installed.

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[28] PR-PUB-NLH-003, Attachment 1, page 68 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 3 of 36, Holyrood Black Start.

[29] PR-PUB-NLH-003, Attachment 1, page 69 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 4 of 36, Holyrood Black Start.

- In analyzing the potential Black Start options for Holyrood, prior to the new combustion turbine coming online, Hydro stated that "[t]his existing Black Start capability within the Island Interconnected Transmission System negates the need to lease mobile gas turbine for the two-year period."[30] Hydro reached this conclusion, and the decision to continue to use Hardwoods gas turbine to Black Start Holyrood, using its expertise and knowledge of the Avalon Peninsula's transmission system. Furthermore, according to Hydro, this type of weather and system event had not been experienced by the Avalon Peninsula in at least the last 25 years.

- **Date:** October 17, 2013
  - **Event:** Hydro received a letter from the Board requesting it take immediate action to ensure all possible options have been considered to provide reliable Holyrood Black Start capability.
    - Hydro was required to inquire, investigate, analyze and report within 30 days as to whether an appropriately sized gas turbine is available to be purchased or leased and installed for Holyrood Black Start. Hydro should also advise as to the timeframes and costs associated with refurbishing the existing Holyrood gas turbine.[31]
  - **Decision:** Hydro complied with the Board's request and filed a response to the Board's letter on November 18, 2013.
    - Hydro analyzed several possible solutions, which it provided to the Board in a report titled "Analysis of Options to Provide Black Start Capability to Holyrood Thermal Generating Station".[32]
      - In this report, Hydro recommended that "the least cost option is a 16MW Diesel Plant leased for a period of 18 months to provide Black Start capability to the Holyrood Thermal Generating Station for 2013-2015 heating seasons". Hydro estimates that the diesel plant could be installed within 11 weeks of approval by the Board and internal Hydro.[33]

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30 2013 08 05 Black Start Capability Responses to PUB Questions 1-5.pdf, page 2.

31 PR-PUB-NLH-003, Attachment 1, page 66 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 1 of 36, Holyrood Black Start.

32 PR-PUB-NLH-003, Attachment 1, pages 73-93 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, pages 8-29 of 36, Holyrood Black Start.

33 PR-PUB-NLH-003, Attachment 1, page 93 of 101, 2015 Prudence Review. IC-NLH-010, Attachment 5, page 29 of 36, Holyrood Black Start.

        - Hydro envisioned this asset to be solely for Black Start, so the recommended solution was determined primarily on capital costs.[34]
    - Subsequently, Hydro submitted a supplemental capital application with the Board with the preferred option of a nominal 16 MW diesel plant, on-site, as a Black Start generating solution to be installed and commissioned during the winter of 2014.[35] This unit would be leased for a period of 18 months to provide Black Start capability to Holyrood for the 2013-2015 period.
        - Hydro specifically requested Board approval for the lease of eight 1.825 MW diesel generators to provide interim Black Start capability at Holyrood.
        - In Order No. P.U. 38, the Board approved: capital expenditures of $1,263,400; creation of a deferral account of about $5,763,200 for lease costs and other infrastructure; and deferred questions of cost recovery of the lease payments to a future time.

- **Date:** Mid-2014
    - **Event:** Installation of eight 1.825 MW diesel generators completed.
- **Date:** January 2015
    - **Event:** New Holyrood CT was completed, earlier than originally planned. The eight 1.825 MW diesel generators are still being used to provide Black Start service to Holyrood because the connection of the new CT via the 13.8kV/4.16kV line has not yet been placed into operation and proven.

## 2.3 REVIEW AND CONCLUSIONS

Hydro's principal shortcoming regarding its decision on Black Start is at most not doing more to keep the Board informed of its decision making process and its ultimate decision to accept the loss of on-site "Black Start" on an interim basis until a new CT could be placed in-service at Holyrood as the permanent solution. Although there were no established protocols for such communication at the time, it is reasonable to conclude that given the Board's oversight role, more should have been done to keep them informed on a matter that had the potential to impact system reliability.

However, this communication issue does not mean Hydro's underlying decision process in evaluating the proper course of action relative to on-site Black Start capability at Holyrood was flawed to the point

[34] PR-PUB-NLH-002, Attachment 3, page 3 of 4, 2015 Prudence Review. PUB-NLH-012, Holyrood Black Start Diesel Units Application, page 3 of 4.

[35] PR-PUB-NLH-002, Attachment 3, page 3 of 4, 2015 Prudence Review. PUB-NLH-012, Holyrood Black Start Diesel Units Application, page 3 of 4.

of imprudence as Liberty suggests. It also does not mean there is no room for disagreement. Operational philosophies often can and do vary across jurisdictions, it is the very reason that the North American Electric Reliability Corporation ("NERC") requires the development of system restoration plans, but leaves it to the respective regions to develop their own restoration plan which includes the designation of which units would be counted on for Black Start. What is not debatable is that Hydro management consciously made the decision to tolerate the risk associated with not having Black Start capability at Holyrood on an interim basis until a permanent long term solution could be implemented, thereby relying solely on the Hardwoods Gas Turbine ("Hardwoods") to Black Start the Avalon Peninsula in the event it became separated from the rest of the system.

This decision appears to have been based on the belief that the risk involved was tolerable based on the limited number of times where a Black Start situation for the Avalon Peninsula had presented itself. It is our understanding that since 1990, and prior to the January 11, 2013 event the Black Start scenario had occurred only three times. This limited exposure had to be balanced against the cost associated with its mitigation. Whether this risk is reasonable is subjective. Operational managers are forced to make decisions on a regular basis that involve balancing operational risk against cost concerns. Unlimited resources are not the norm.

What is also clear is that Hydro's management was well aware of the situation. Over the years investments were being made on a regular basis in maintaining both the Black Start capability at Holyrood and the reliability of Hardwoods. Hydro's management revisited the issue on a number of occasions and in each case decisions were made taking account of minimizing the cost to its customers.

Liberty points to the inability of Hardwoods to Black Start Holyrood on January 11, 2013 as evidence of a failed philosophy highlighting the need for an on-site solution. In the case of the events that occurred on January 11, 2013 on-site Black Start generation at Holyrood would have offered limited benefits. Hydro estimates that the outage duration would only have been reduced by 11 hours, the time it took to bring Holyrood from a cold condition to startup or the ability to start serving load. Hydro estimates that on-site Black Start generation would have afforded the opportunity to keep the Holyrood steam units in a warm condition which could have reduced the startup time to 30 minutes rather than the experienced 11 hours.[36] However, the rest of the outage duration would not have been mitigated because all transmission at Holyrood had been locked out. Due to the extreme weather conditions, Hydro personnel were not able to reach Holyrood to reinitiate the transmission system. Without the transmission system there was no way to initiate the restoration of customer service from Holyrood. No amount of on-site generation would have mattered.

The total negative consequence resulting from the decision by Hydro to rely on Hardwoods exclusively for Black Start on the Avalon Peninsula was a delay of 11 hours in service restoration related to the events of January 11, 2013 (i.e. the loss of all transmission at Holyrood combined with the inability to

[36] These are estimates based on functionality testing and training of its operators. Reference Hydro's Black Start Application, page 4.

quickly restore said transmission – a combination of events that had never been experienced by Hydro's management's experience over 30 years). In our opinion the actions taken do not rise to the level of imprudence.

Liberty further argues that because Hydro did not add on-site Black Start generation at Holyrood until 2014, after the events of January 11, 2013 and a direct order from the Board, that it should not be allowed cost recovery. Liberty essentially says that because Hydro waited so long to add on-site Black Start generation at Holyrood the useful time period of the investment is too short to allow cost recovery from its customers. The logic here is flawed for the following reasons:

- Liberty references the AMEC Americas Limited ("AMEC") Consulting report stating essentially that if they had followed the recommendations to install Black Start capability at Holyrood earlier extending the "usefulness" of the leased option would have made the decision more acceptable for cost recovery. The problem here is that if they had pursued on-site generation at that time, the effects of the January, 2013 outage would not have been avoided. Further, in this scenario new generation would not have been available until February, 2013 at the earliest, a difference of less than a year. We are not aware of any time requirement over which an investment needs to be utilized in order to find the investment used and useful; the diesels have been in-service for a number of months and will continue to be until replaced by the new 123 MW CT, which produced first power on 1/2015 and is currently being prepared for Black Start.
- Hydro's ultimate actions were taken in response to a Board directive. Hydro did not have the option of simply ignoring the Board, in which case there would have been no costs to disallow. Hydro's following of that directive from the Board to the best of its ability should not now be considered imprudent.

# 3. HOLYROOD UNIT 1 TURBINE FAILURE

## 3.1 DEFINITION OF ISSUE

On January 1, 2013, a rare weather event caused transmission system issues that ultimately led to a terminal station failure that isolated and tripped the three Holyrood steam units. Unit 1 suffered major damages and a lengthened outage due to the loss of adequate lube oil supply. Hydro conducted a root cause analysis to determine what caused the lube oil failure and found several contributing factors, but the primary cause was found to be the failure of the direct current ("DC") lube oil system not functioning as intended.

In Liberty's prudence review report, the principle findings on this issue are as follows:

- 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 alternating current ("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.

## 3.2 OUTLINE OF HYDRO'S DECISIONS AND ACTIONS

In recognition of recommendations from the root cause analysis, the following outlines a detailed series of actions taken by Hydro's management to ensure the outage events of January 11, 2013 do not reoccur.

- **Causal Factor:** Inadequate DC Pump Test Procedures
    - **Concern:** Hydro employed the following maintenance procedures to test the DC Pump: 1) Procedure 0324, which is a cold start of Units 1 and 2 from a major or minor overhaul; and 2) Turbine and Auxiliaries weekly checks, which was just run on the Units January 10, 2013.[37]
        - The weekly testing of the Units for AC and DC motor Pumps was based on the section of the turbine generator manual titled "PUMP TEST AND AUTOMATIC

[37] Newfoundland and Labrador Hydro, Holyrood Unit 1 Failure – January 11, 2013, Root Cause Analysis: Final Report ("Report"), page 6.

STARTING", which was provided by the original equipment manufacturer, General Electric, when the units were installed in 1969.[38]

- Hydro states that "[t]he test procedures, as written, were confirming the starting circuitry of the pumps (similarly to the OEM test, to come in to operation based on loss of lube oil pressure in the lube oil tank), but did not include a step to confirm that adequate lubricating oil was being delivered to the bearings on the turbine-generator shaft."[39]
  - Nowhere in the OEM turbine generator manual does General Electric ("GE") address testing to ensure adequate lubricating oil is being delivered to the bearings on the turbine-generator shaft.

- **Corrective Actions:**
  - Hydro designed and installed a distributed control system ("DCS") display in the front standard of the turbine-generator assembly on the third floor to indicate the status of existing oil pressure transmitters.[40]
    - After installing the display, Hydro modified its AC and DC Pumps weekly testing procedures to require personnel to incorporate monitoring of the lubrication oil pressure and logging a copy of the pressure trend with the test sheet.
  - Hydro took a further action of creating and implementing new weekly and prior to return to service testing procedures for the AC and DC Pumps.[41]
    - *Procedure #1076, Unit 1 and 2 – AC Standby and DC Turbine Lubricating Oil Test – Weekly*
    - *Procedure #1077, Unit 1 & 2 –Turbine AC/DC Lube Oil Pumps Test Procedure– Return to Service*

- **Causal Factor:** Inadequate System Voltage
  - **Concern:** During the January 11, 2013 event, the Holyrood Terminal Station faulted and there was a loss of system voltage support that caused a system-wide voltage depression. The primary pump for Unit 1, the North AC Pump, was not able to start because when Unit 1 came offline (tripped), the motor was connected to the unit's output terminals which lost their power supply. The backup AC pump for Unit 1, the South AC Pump, was not able to start because the system-wide voltage depression

38 Report, page 7.

39 Report, page 8.

40 Report, page 8.

41 Report, page 8.

caused station service system voltage to be insufficient to start the pump and the pump's backup 600 volt emergency diesel generator, D1, was not triggered to start.

- The January 11, 2013 event caused a brown-out condition, which is a "severe or sustained voltage depression", that was not anticipated by the design specifications. As a result of the brown-out experienced by the Holyrood Terminal Station:[42]
  - (1) The system voltage which is normally supplied was at a level below which the starting coil for the Unit 1 South AC Pump is rated to close; and
  - (2) The voltage level was insufficiently low for the under voltage relays to call for a start of emergency diesel D1.
- In a no-voltage (black-out) or black start condition, the diesel generator would have been called upon by under-voltage protective relaying to re-energize voltage to the motor loads of the Motor Control Center ("MCC") E1.

o **Corrective Actions:**

- Hydro recommended and installed new coils, which had a 50 percent improved low voltage tolerance, in the motor starters of MCC E1 making them far less susceptible to brown-out conditions.
- Hydro assigned its Protection and Controls Engineering personnel the task of examining and evaluating the present under-voltage scheme to consider protection from brown-out and black-out conditions.

- **Causal Factor:** DC Powered Lubricating Pump Not Operating Correctly

  o **Concern:** During the January 11, 2013 event, the two AC pumps for Unit 1, North AC Pump and South AC Pump, were not able to start due to system voltage issues at the Holyrood Terminal Station and system-wide issues. The backup DC Pump was able to start normally, but was not able to maintain adequate lubrication to the bearings. Hydro investigated the DC Pump after the incident and found the following:

  - The DC Pump motor was tested and found to be rotating at approximately 2,800 RPM, which is 700 RPM less than its rated speed of 3,500 RPM. Hydro states that "[t]he maintenance procedures did not include a check of the DC motor speed", so the slow motor speed had not been detected.[43]
    - Hydro has consistently performed weekly function testing conforming to OEM standards on its three generating units to confirm that the DC

[42] Report, page 9.

[43] Report, page 10.

Pump motor starts, in order to manage risk of failure of the DC lube oil system. This testing takes into account Hydro's operational knowledge and experience, which is continually evolving, like it did following the 2013 investigation.[44]

- Pennecon Energy ("PE"), which was used by Hydro to independently analyze the DC motor after the incident, found and corrected the speed issues that resulted from brush boxes being offset and the motor neutral plane being improperly adjusted.
    - Hydro determined that the speed issues resulted from "maintenance of the DC motor performed by a third party service provider". Hydro stated that the "service contract specification did not address the specific required adjustments to ensure motor performance".[45] Even though the contract required testing to prove the motor operated properly, it did not include adjustments that were required to correct the motor. Hydro had a reasonable expectation that the third party provider would have employed proper engineering practices when it performed maintenance on the DC motor to ensure that the motor worked to specification after all maintenance was performed.
- The DC motor also experienced a speed issue related to an incorrect resistor setting, which when it was adjusted allowed the DC motor to reach the specified 3,500 RPM speed.
    - Liberty Consulting concluded that the resistor setting and alignment issues of the DC motor contributed equally to the motor speed, since the RPM speed improvements were 320 RPM after the contractor alignment and 340 RPM after the Hydro resistor setting adjustment.[46]
    - The main finding from the root cause analysis investigation was that the "motor speed was approximately 80% of expected/rated speed".[47] After PE returned the adjusted motor, Hydro was able to attain a speed of 3,100 RPM, which is 90% of the expected/rated speed. The further adjustment Hydro made

[44] PR-PUB-NLH-180, NLH 2015 Prudence Review, page 2 of 2.

[45] Report, page 10.

[46] Prudence Review of Newfoundland and Labrador Hydro Decisions and Actions Final Report, page 61.

[47] PR-PUB-NLH-181 (Revision 1, Jun 19-15), NLH 2015 Prudence Review, page 2 of 2.

to the resistor allowed the DC motor to reach 100% of the rated/expected speed.

- Hydro also discovered during testing that "the motor amperage and oil pressure exhibited a cycling behavior".[48] However, during additional testing Hydro found that this issue only arose under testing conditions and was not an issue when the pump was in service, so it was ruled out as a cause of the DC Pump failing.

- **Corrective Actions:**
  - Hydro further took action by incorporating requirements for adjustment of DC motors and expertise in the technical specifications of the tender document for third party maintenance services.
  - Hydro created and implemented a new maintenance standard, *MSD176: Rotational Speed Check of 258 V DC Motor Emergency Lube Oil Pump*, which requires motor speed to be verified after <u>any</u> intervention with the DC lubrication system.

- **Causal Factor:** Overall Reliability of the Three Lube Oil Systems
  - **Concern:** In Liberty Consulting's Report, it is concerned that:

    > 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.[49]

  - **Corrective Actions:**
    - It is true that before Hydro made the changes to Unit 1 South AC Pump coils, a brown-out condition caused by power system conditions could have caused the loss of both the primary and backup AC lube oil systems.
    - In the GE Turbine-Generator Manual, under "TANK ASSEMBLY", the lube oil tank is described as having "[t]here full-capacity motor pumps [which] are standard – two with AC motors, one with a DC motor".[50] This "standard" design is typical in several generating units and should not be considered a "common mode

[48] Report, page 11.

[49] Prudence Review of Newfoundland and Labrador Hydro Decisions and Actions Final Report, page 63.

[50] Report, Appendix E, page E1.

failure" issue. Also, as Liberty correctly notes, "[i]t does not, however, have relevance to the January 2013 circumstances".[51]

- Hydro can further examine the failure issue, however, given the previously described actions already taken by Hydro to help ensure the lube oil systems reliability any such analysis of costs and benefits needs to also consider the likelihood of occurrence prior to investing in any modifications to the system.

## 3.3 REVIEW AND CONCLUSIONS

The issue here is not whether Hydro's existing processes and procedures relative to the lube oil system could be improved upon. There is no disagreement on that point. The issue here is whether the actions or inactions taken leading up to the outage event rise to the level of imprudence. In our opinion, they do not.

Hydro's root cause analysis clearly identified a number of inadequacies in Hydro's testing practices as they related to the DC Lube Oil System. The issue here revolves around whether Hydro was imprudent in not identifying these issues before they led to a system failure. The fact is that these very same practices have been in place for over forty-five years at Holyrood without incident. Absent any indication there was an issue, why would it be expected that these practices needed to be subject to additional review? In the course of normal operations staff will tend to focus on conditions that warrant attention, rather than those that experience has shown to be functioning well.

On the one hand, Liberty states at page 62 of its report:

> 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.

However, in the very next sentence Liberty states that:

> 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.

There is considerable tension in these two positions.

We believe the above statements by Liberty to be very much in conflict. On the one hand, Liberty acknowledges the value of relying on vendor and contractor expertise. On the other it suggests the testing deficiency resulted from "simple oversight" not a result of any high level of sophistication. So depending on one's very subjective definition of sophistication, Hydro's reliance on vendor and contractor support may or may not be deemed imprudent in Liberty's opinion. In our experience,

[51] Prudence Review of Newfoundland and Labrador Hydro Decisions and Actions Final Report, page 63.

Hydro's reliance on outside expertise is not unusual given the relative small size of their fossil generating fleet. As Liberty also points out, Hydro has been operating this plant for over 45 years and over those 45 years they have been following the same claimed inadequate testing procedures without consequence. Given the wide variety of pressing issues affecting plant operations on a daily basis, is it reasonable to expect Hydro's staff to be focused on redesigning OEM recommended testing procedures, especially when such procedures - up until the point of failure - had been a non-issue? Claiming they should have known the testing practices were inadequate is nothing more than hindsight given the lack of any previous indication there was a problem.

Liberty further acknowledges Hydro's continuing efforts to develop a comprehensive asset management approach, the evolution of which has been a priority. Hydro's effort in this regard is further proof of management's commitment to do everything possible to minimize unforeseen events and maximize the value gained from expenditures made on the customer's behalf.

In response to questions raised by Hydro relative to Liberty's definition of good utility practice in PR-NLH-PUB-017, Liberty makes repeated reference to an Electric Power Research Institute ("EPRI") document "Guidelines for Maintaining Steam Turbine Lubrication Systems" as their basis for determining Hydro's testing and maintenance practices relative to the DC lube oil system were imprudent. EPRI is a well-respected, member-based, for fee research and development organization that has made significant contributions to the evolution of the power industry. However, to our knowledge their work generally results in the development of "guidelines" not "industry standards" such as those referenced and used by Hydro (i.e. ANSI/EASA Standard AR 100-2010) for DC motor testing. Liberty's position appears to be that unless a utility becomes an EPRI member and follows that organizations guidelines, then they are being imprudent. While EPRI certainly provides a valuable source of information, they should not be used as the primary basis for determining prudency in our opinion.

Further, Liberty refers to the triple redundancy in the GE designed lube oil system as susceptible to a common mode failure (such as the AC terminal outage experienced) rendering it potentially at risk in the event of a double contingency failure such as the one experienced. The issue here once again is a matter of perspective. In our experience, the GE system as described is not unusual for power plants of similar vintage and design. The current system has been in place for nearly forty five years (on both Holyrood 1 and 2) without incident, which indicates to me that the likelihood of a repeat event is very low. Even if the very same, unlikely, outage event were to occur, the new practices and procedures put in place by Hydro's management would almost certainly ensure the DC lube oil system's availability, thus preventing any damage.

At some point, a utility needs to ask itself how much redundancy is enough? Any analysis such as this needs to account for not only the costs and potential benefits but also the likelihood of occurrence over the unit's remaining life.

# 4. SUMMARY CONCLUSION

In this report, we have reviewed the concerns regarding the “Black Start” and the “Holyrood Unit 1 Turbine Failure” issues raised in the Liberty Prudence report submitted to the Board on July 6, 2015. While Liberty raises valid concerns about the actions and decisions made by Hydro before and after the January 11, 2013 unusual weather event, many of these concerns are either made in hindsight or do not show sufficient evidence that Hydro’s actions were imprudent in our opinion. Further, the corrective actions taken by Hydro subsequent to the referenced outage events are evidence of Hydro’s commitment to address deficiencies as they are identified to help ensure similar events do not recur in the future.

# APPENDIX A – RESUMES

## Philip DiDomenico

*Managing Consultant*

Philip DiDomenico recently joined La Capra Associates bringing nearly 40 years of experience as an accomplished manager, management consultant and electrical engineer with extensive and diversified experience in electric utility management, planning, and operations. Mr. DiDomenico's areas of expertise range from strategic and capital planning, to resource planning, electric system planning and operations as well as fossil power plant engineering and operations. He has facilitated and advised senior managers on strategic issues including; reshaping business management strategies, financial planning, asset transactions, asset valuations and operations and maintenance practices in both Electric Delivery and Fossil Generating organizations. Mr. DiDomenico has planned and directed comprehensive strategic assessments of electric delivery and fossil generating assets, which served as the cornerstone for infrastructure development. He is also an experienced expert witness in regulatory proceedings, addressing such matters as managing risk in resource planning and fossil generating operation and maintenance practices.

Mr. DiDomenico has an MBA in Management from Loyola College; and a bachelor's degree in Electrical Engineering (with a major in Power Systems) from Northeastern University.

### SELECTED PROFESSIONAL EXPERIENCE

#### *Asset Transaction Services*

Mr. DiDomenico contributed to a number of merchant unit assessments for use by financial due diligence teams and developers. In these assessments, multiple markets are modeled to assess and forecast the market price of power and the competitive positioning of units or portfolios in each market. This modeling is complex and considers a myriad of relevant market factors such as interconnection issues, market rules, customer choice levels, fuel price characteristics, and the operational aspects of the plants.

Long Island Power Authority (LIPA) Acquisition of Long Island Lighting Company T&D Assets—successfully led the effort by LIPA to negotiate and implement a management services agreement with KeySpan Energy to operate and maintain LIPA's transmission and distribution facilities. The agreement was a key component of a comprehensive restructuring plan under which LIPA acquired the former Long Island Lighting Company's transmission and distribution assets as a means of lowering electric rates on Long Island. As LIPA's representative, identified assets to be transferred to LIPA, evaluated the overall condition of T&D facilities, negotiated capital and O&M budgets, established capital project justification guidelines and the criteria for LIPA's review of major capital projects and scheduled maintenance deferral, determined criteria for defining "major storm" events, and reviewed procurement practices.

Western Resources T&D Asset Valuation—led a study to determine the value of the T&D system in preparation for a potential municipalization action. The RCN (replacement cost new) value was determined based on a combination of cost trending, construction costs and field observations.

Long Island Power Authority T&D Facilities Condition Assessment in Support of Bond Financing—Led a T&D facilities condition assessment in support of a $200 million bond offering. Onsite inspections were performed on a representative of sample of T&D facilities. Maintenance records were also reviewed for selected major pieces of equipment.

Long Island Power Authority Generation Acquisition—led a team of consultants that evaluated the strategic value of acquiring 4000 megawatts of generating assets on Long Island. Issues evaluated included; economics under varying purchase prices, potential for operations and maintenance related savings, opportunities for reduced staffing, economics of alternative financing proposals as well as market power related concerns and the likely implications for stimulating a competitive market on Long Island.

Confidential Client: Power and Renewable Energy Market Assessment to Support Potential Acquisition—as project manager led a team of consultants in performing an independent market advisory assessment to support a confidential client's investigation into potential acquisition of several biomass-fueled generation resources in the New England and California power markets. Our team provided insight into the U.S. power industry, including specifically, the wholesale power markets and Renewable Energy Credits (RECs) markets for both of these regions, as well as the related fuel supply markets in New Hampshire and California for wood-waste biomass. Market price projections were developed to support the anticipated revenues from the output of each of the three facilities, including a review of the industry market outlooks for wholesale power, ancillary services, and for RECs. This assessment incorporated our outlook relative to carbon prices and the carbon initiative that are under development in the U.S.; also identified were potential risk implications for each of the three facilities, based on the U.S. market trends and the future of REC markets.

Conectiv Generation Divestiture—based on field observations, identified areas in need of improvement.

### *Organization and Operational Effectiveness Reviews and Audits*

Public Service of New Hampshire Reliability Review—as project manager led a team of consultants that conducted a review of the distribution planning processes, system reliability, and a general system condition assessment for this northeastern utility. The approach to this effort included a reliance on extensive staff and commission interviews, reviews of documentation and reports, investigation into particular issues, sample system condition site visits and reviews, and analysis of the related documentation and information provided. We provided numerous areas that reflected industry standard approaches and offered several recommended changes in processes, information systems, management reporting, and documentation that will serve to improve the reliability of information and system planning at the Company. The report was presented to the commission staff and provided to the commission as part of a regulatory filing process.

Vermont Electric Cooperative—as part of a team of consultants worked with the CEO and Board of Directors of the Cooperative in concert with the Vermont Department of Public

Service to perform a Business Process Review and Audit of the Transmission and Distribution Cooperative as part of a settlement agreement. This effort involved a review of the entire organization including Board activities to assess whether improvements could be made to the organization's structure, effectiveness and execution. Recommendations for improvement were extensive impacting capital investment and cooperative direction for the near term.

Vermont Electric Cooperative - a regulatory strategy was developed to support a request for a rate increase required to finance capital improvements. This support included the redrafting of testimony in all major areas of the filing including; financial, reliability and labor relations. For the first time in VEC's history the rate request was accepted as filed with no modification to the amount of the requested increase.

Southwestern Louisiana Electric Membership Cooperative Organization Review—As project manager led a team of consultants in conducting a review of the organization through interviews with the CEO followed by interviews of key managers and a review of appropriate documentation. We assessed the effectiveness and efficiency of management and business operations through our discussions and document reviews as well as observations of business processes. We evaluated the risks associated with anticipated succession issues over the next decade. Our recommendations included a realignment of responsibilities, acquiring new personnel for several positions, a shift in organizational focus, revised reporting, and new resource training and mentoring plans.

Seattle City Light Organizational Review—as project manager led a team of consultants in support of organizational and process design project management services in which we worked with the senior management team to develop a high level project plan for the transition of the organization changes and for the key projects tied to those changes. In addition we provided advisory services to senior management and other senior personnel by developing an Asset Management RFP and assisting the team in reviewing Asset Management proposals and participating in final contractor interviews.

Hoosier Energy Cooperative—as project manager led a team of consultants in conducting a management evaluation including both business process reviews and a condition assessment of the largest generation asset owned by Hoosier energy. This process involved a series of interviews with senior executives, senior manager and staff throughout the company, relevant document and information reviews, report reviews, several process review teams composed of Company staff and our team members, and an extensive analysis of trends to provide recommendations for changes and improvements to the organization, staffing, planning, business processes, and system applications.

Confidential Plastics Company—Key contributor of the consulting team that provided a targeted business process review of the key marketing and proposal development practices and business process of a Confidential Energy and Chemicals organization in order to better align organizational achievement and practices with management expectations and market demands. Our senior consulting team facilitated executive-level interviews with a cross-section of organizational groups, intended to investigate barriers to business process and their internal controls on the process with regard to their effectiveness, efficiency, and improved win-rates from various stakeholder perspectives. Observations and findings were developed for further discussion with senior management personnel, and were utilized to facilitate open discussions and brainstorming within this leadership group. Our team recommended several areas for immediate improvement that were implemented and documented action items to be addressed in the middle and long term were for continued improvement.

E.ON US—as part of a consulting team worked with a number of separate generating facilities to assess the management and operations practices in place in order to advise E.ON executives (both in engineering operations and planning as well as financial management of the organization) with respect to areas of best practice along with identification of areas needing improvement. The effort involved high level facility inspections and extensive staff interviews to assess operations and planning functions such as maintenance planning, capital budgeting, operations management and communications. Our effort confirmed the independence of the facilities in terms of management and operations standards and identified several approaches to streamlining the operations, introducing standards and centralized planning. Our recommendations were designed to reduce operating costs, improve the effectiveness of operations and reporting, and to align the organization for succession planning purposes.

East Kentucky Power Cooperative Performance Review—an organizational assessment was performed which analyzed and assessed the effectiveness of the existing organizational structure, alignment, performance in achieving results in meeting the utility's core mission. A functional and core process review was performed in order to analyze the as-is processes, policies, and procedures and how these subsequently hinder, impact, or strengthen desired levels of efficiency and effectiveness. This analysis involved reviewing the process activities, looking for improvement opportunities including: areas of inconsistency, disconnects in service, duplication of efforts, sources of rework or errors, bottlenecks that hinder response time, and overall communication barriers.

As part the on-site analysis, interviews, and field observations, the top issues, concerns and opportunities were identified. Key conclusions were summarized along with the potential impacts to the organization. Specific recommendations were developed, including recommendations for improving performance, and recommended changes to organizational structure, functional activities, core processes and proposed staffing levels.

Nova Scotia Power Company—worked with Senior Management of Nova Scotia Power Company to provide advice and counsel relative to their ability to achieve productivity gains and efficiencies in the management and operations of their generation facilities. This effort addressed three of their generating facilities. The review included management talent, standardization of processes, use of procedures, common planning and reporting, and approaches to work management and planning. Recommendations included a greater focus on asset management and the development of an implementation plan that will move the company forward with regard to centralized asset decisions and implications of emission control strategies on operations and asset life.

### *Regulatory Services*

Public Service Commission of the District of Columbia Review of Electric Utility Undergrounding Policies and Practices—as project manager led a team of consultants in conducting an unbiased analysis and assessment of feasibility and reliability issues and information relative to undergrounding. The Study's objectives included:

- A comprehensive review and analysis of previous undergrounding studies including studies and analyses performed by Pepco.

- Development of the cost, feasibility, and reliability implications of select undergrounding alternatives to the existing overhead distribution system.
- Examining the potential impacts of undergrounding projects on the environment, residents, infrastructure, and health and safety.

As part of that process, key government agency and public interest stakeholders were invited to briefings by Shaw Consultants on the findings and recommendations of its study. These briefings were used to gather stakeholder input for use in the development of a future District-wide undergrounding policy.

Long Island Power Authority Review of Electrical Utility Undergrounding Policies and Practices—led a study that evaluated the pros and cons of underground versus overhead construction. Several utilities, communities, and governmental agencies were contacted or researched in order to gain a broad understanding of the issues involved. Key insights were identified. The focus of the evaluations centered on a combination of factors including; system reliability, public safety, aesthetics and economics.

Long Island Power Authority Review of T&D Construction Practices and Their Impact on Public Safety—led a study that reviewed trends in electrical contact cases on Long Island and identified and discussed the public safety implications of alternative T&D construction practices. These practices included; total undergrounding of transmission and/or distribution facilities, undergrounding of transmission and/or distribution facilities near schools, replacement of transmission and/or distribution conductor with covered wire, replacement of transmission and/or distribution conductor with aerial cable, fencing transmission rights-of-way and enclosing substations. These alternative construction practices were compared and contrasted in categories that included; construction cost, environmental impact, reliability impact, and their likely effectiveness in reducing injuries from accidental contact.

### *Integrated Resource Planning Services*

Long Island Power Authority Electric Resource Plan (ERP) Development—working in conjunction with the Authority's staff, supported the development of a multi-faceted, dynamic ERP to meet the energy needs of Long Island. The plan provides a comprehensive and flexible approach to providing a safe, reliable, environmentally friendly and cost efficient supply of electricity to customers well into the future. This is accomplished by investing in customer programs, energy efficiency, conservation, new technologies, encouraging development of merchant transmission and generation, adding off-island transmission interconnection capability, enhancing existing power supply resources and evaluating the need to build additional ones. The ERP includes programs for energy efficiency and renewable technologies.

Long Island Power Authority Resource Planning Process—developed a unique approach to managing the risk inherent in resource planning. The probabilistic Decision Analysis based approach allows decision makers the ability to clearly understand the uncertainties in the planning process and the implications of planning to meet varying levels of uncertainty.

Consumers Energy Company Long-term Integrated Energy Plan—developed a short- and long- term energy resource plan for Consumers Energy Company by working with a diverse senior management team to review and recommend options for the core energy issues affecting resource availability and planning. Topics investigated at both a strategic and detailed analytical level included the use of energy efficiency, load management and demand response programs, the appropriate technologies for short- and long-term resource needs, the impact of the recently operational MISO and its market operations on planning for the energy future, the potential for price volatility and availability issues in fuel markets, the treatment of fuel markets in strategic planning, and transmission constraints and expansion planning. Our team developed a broad set of efficiency programs for potential adoption.

MIT Utility Master Plan—the objective of this project was to establish a long-term plan for MIT's utility infrastructure to support the continued operation and expansion of the Cambridge campus facilities. The plan benchmarked the existing utilities and provided a firm plan for the improvements needed over the next five years with a projection of the improvements that may be needed in years six through ten. Additionally, the plan provides a framework for annual updating so as to continue with an ongoing five year planning horizon. While the plan is based on future development scenarios for the complete build out of the campus, it also provides guidance for incorporating changes in development priorities in the decision making process. A dynamic model was created capable of providing feedback on the impacts that individual building projects would have on the campus system so that utility supply decisions can be made within a broad context.

### *Corporate Strategy Development Services*

Badger Licensing LLC—as part of a consulting team worked with senior management to facilitate a strategic planning process aimed at developing organizational and market strategy for this technology licensor. Initial stages of this process included developing a coordinated understanding of organizational differentiation, merged with insights into the evolving demands of their customer base. Senior management utilized Shaw Consultants' independent facilitation skills to focus and challenge the team, as well as document the process. The team conducted interviews as a means of highlighting key themes of concern to leadership, which were followed by facilitated group meetings with key stakeholders to improve upon the understanding of key issues, and the development of strategic direction and goals for future growth. Throughout the process, key insights were developed and have been utilized in shaping the strategic direction of the organization

### *Utility Management Assignments*

Electric Delivery Process Redesign—as a utility manager, played a key role in transitioning Boston Edison Company's Electric Delivery Organization from a traditional engineering and operations based organization to one focused along process lines. Led the creation of the Asset Management Process predicated on the philosophical separation between decision and action in a business. This separation better match's work and workforce, lowering overall cost, improving service quality and reducing compromises by matching the workforce to the work required as opposed to matching the work to the available workforce. The Asset Management model encompasses those processes, sub-processes and applications (tools) necessary to make consistent, effective and efficient decisions relating to company assets. These decisions deal with optimizing the operation, maintenance, upgrade and design of new portions of the asset, retirement of assets, and the evaluation of investment/business opportunities. Also supported the development of processes in support of Customer Electric Services, Customer Service Connection, Construction & Services and Community Lighting Services.

Management of Electric Delivery System—as a utility manager, played a key role in restructuring and realigning Boston Edison Company's electric distribution operations to reduce costs, improve customer service, and position the company for competition. Directed all facets of the business group's $80-million capital budget, supervised staff of 28 engineers, and developed and implemented competitive business and operational strategies. Facilitated the transition from a traditional engineering based operation to one structured along process lines. Planned and directed a comprehensive, strategic assessment of the present and future needs of the electric delivery system as a guide for addressing infrastructure planning and development. Implemented a reliability-centered maintenance initiative, leading the way to a 40 percent cost reduction and an increase in the effectiveness of the distribution system's maintenance program. Also, developed criteria for performance-based ratemaking.

Management of Engineering Services—as a utility manager, developed and implemented business and operational strategies to support the successful operation of Boston Edison Company's fossil generating units. Directed all facets of the business unit's $30-million capital budget. Achieved a $6-million inventory reduction, far exceeding company goals, by devising highly effective planning and control procedures. Facilitated development of the Production Engineering Planning System, an innovative Oracle and PowerBuilder-based IT application that significantly improved budget accountability and control. Also developed performance criteria for the advancement of fuel cell technology.

Power Supply Planning and Management—as an executive assistant to the utility's Senior Vice President, Power Supply, prepared analyses of alternative operating strategies and emerging generation technologies for strategic evaluation. Planned and mobilized the Power Supply Group's initial business and strategic operating plan, which focused the organization's direction and ensured consistency with overall corporate objectives. Managed the group's $60-million capital budget establishing processes that directly led to excellence in budget performance and the optimal use of resources.

Fossil Power Plant Performance Improvement—as a principal engineer for the utility, developed innovative approaches for improving the operating efficiency of and capital planning criteria for the fossil generating units operated by Boston Edison Company. Developed a new program for monitoring and evaluating the condition of turbine lube oil. Created, analyzed and monitored fossil unit performance goals as a means of predicting operating problems in advance of outages. Extended the time between major turbine overhauls. As the primary witness before the Massachusetts Department of Public Utilities, prepared and offered testimony regarding fossil unit performance. Through effective and thorough presentation of events and their underlying causes, avoided replacement power penalties for an unprecedented three consecutive years.

Energy Supply Planning and Management—as a senior engineer for the utility, performed and directed production cost and financial analyses to evaluate capital investments and to identify power purchase and sales opportunities for Boston Edison Company. Created a unique approach using decision analysis techniques to manage the risks inherent in energy supply planning and capital investment decisions associated with fossil power plants. The Integrated Decision Analysis System (IDEAS) was subsequently presented at the 15th Inter-RAM Conference for the Electric Power Industry in Portland, Oregon, in October 1988. Authored the company's standard "Guidelines for Capital Investment Analysis - Fossil Stations", outlining the financial method to be used in evaluating capital investments. Created the first, comprehensive cost analysis model to integrate the value of generation with financial analysis at the engineer level, thus increasing ownership and substantially improving productivity. Represented the company as an expert witness in energy supply planning before the MDPU.

Underground Distribution Engineering and Construction—as an engineer for the utility, developed construction standards, prepared specifications, and evaluated materials and equipment for Baltimore Gas & Electric Company's underground distribution system. Also responsible for correcting unusual outage and engineering problems related to duplicate 34.5 kV supply to industrial customers and 13 kV supply to large residential subdivisions.

### *Expert Witness*

Testified before the Massachusetts Department of Public Utilities regarding a Generating Unit Performance Program.

Testified before the Massachusetts Electric Facilities Siting Council regarding a Resource Planning Process.

## EMPLOYMENT HISTORY

**La Capra Associates, Inc.** — Boston, MA
*Managing Consultant* — *May 2015–Present*

**Lummus (formerly Shaw) Consultants International,** — Boston, MA
*Principal Executive Consultant, Management Consulting* — *2002–April 2015*

**Navigant Consulting** — Burlington, MA
*Director, T&D Management Services Practice* — *1997–2002*

**Boston Edison Company (Eversource)** — Boston, MA
*Manager, Electric Delivery* — *1995-1997*
*Manager, Engineering Services* — *1993-1995*
*Executive Assistant to Senior Vice President, Power Supply* — *1991-1993*
*Performance & Reliability Coordinator, Production Operations* — *1988-1991*
*Senior Electrical Engineer, Resource Planning* — *1980-1988*

**Baltimore Gas & Electric (Constellation Energy Group)** — *Baltimore, MD*
*Underground Construction Standards & Customer Engineer* — *1976-1980*

## EDUCATION

**Loyola College** — Baltimore, MD

*M.B.A., Management* *1979*

**Northeastern University** Boston, MA
*B.S., Electrical Engineering (Power Systems)* *1976*

## PROFESSIONAL MEMBERSHIPS

**Association of Edison Illuminating Companies**
*Electric Power Apparatus Committee* *1996-1997*

*Power Generation Committee, Distributed Resources Subcommittee* *1994-1995*

**New England Power Pool**
*Unit Availability Task Force* *1989-1992*

*Generation Task Force* *1986-1988*

## ADDITIONAL PUBLICATIONS, PRESENTATIONS & CONFERENCES

*"An Apples to Apples Survey of Utility Measurement." American Public Power Association, Engineering & Operations Workshop Proceedings.*

*"Plant Performance Optimization Using Cost-Benefit Decision Analysis Techniques." Inter-RAM Conference Proceedings.*

*"Guidelines for Capital Investment Analysis - Fossil Stations." Prepared for Boston Edison Company.*

# John G. Athas

*Principal Consultant and Treasurer*

John Athas joined La Capra Associates in 2006, bringing nearly 30 years of diverse electric industry experience. He has substantial, hands-on skills having worked for an electric utility, a competitive retail electric services provider, a power technology manufacturer, and an energy industry consulting firm. Through extensive practical application, he has assumed leadership roles in market pricing and policy, resource planning, analysis of competitive wholesale and retail markets, financial and risk analysis, strategic planning, and contracts and transactions. With expertise in utility regulation, energy marketing and product development, energy policy, asset valuation, mergers and acquisitions, and corporate strategy, Mr. Athas has provided clients valuable insight from his unique blend of experience in strategy consulting, technical evaluations and energy market participation.

Mr. Athas holds an M.B.A. from the University of Connecticut, an M.S. in Mechanical Engineering from Rensselaer Polytechnic Institute, and a B.E. from Cooper Union.

## SELECTED PROFESSIONAL EXPERIENCE

### *Economic Development*

Developed special incentive packages of utility rate discounts and comprehensive energy efficiency investments for large customers in Business Retention and Economic Development circumstances. These packages were coordinated with and integrated into broad incentive packages developed by state and local economic development agencies.

Provided expert testimony before the Nova Scotia Public Service Board regarding the appropriateness of special load retention tariffs for Nova Scotia Power Incorporated.

Managed NU's economic development and special contracting flexible rate tariffs in Connecticut and Massachusetts.

Negotiated special contracts with NU's large customers in Massachusetts, Connecticut and New Hampshire.

### *Rates and Regulation*

Provided expert review and critique for Public Service Organization of Oklahoma's request for proposal for baseload generation in support of the Office of the Attorney General.

Provided review and comment on the Philadelphia Electric Smart Metering Implementation Plan for the Pennsylvania Office of Consumer Advocate.

Drafted changes to proposed demand-side rules in Oklahoma for the Oklahoma Industrial Energy Consumers.

Managed rates and cost-of-service functions for Northeast Utilities (NU).

### *Integrated Resource Planning*

Collaborating to review and critique the Connecticut utilities' 2010 IRP on behalf of the Connecticut Energy Advisory Board (CEAB), including extending analysis and modeling to 2030.

Managing consultant leading IRP planning and related regulatory filings for various New England electric utilities and cooperatives, including Green Mountain Power, Washington Electric Cooperative (VT), Vermont Electric Cooperative, and Vermont Marble Power.

Provided a critique of Public Service of Oklahoma's IRP and Oklahoma Gas & Electric Company's IRP, in response to their joint application to build a base load coal fired generating capacity, on behalf of the Oklahoma Attorney General's Office.

Managed NU's resource planning function from the inception of Integrated Demand/Supply Planning (now IRP) through 1991.

### *Market Analysis*

Project manager and principal lead on analysis for Vermont Combined Heat and Power and Distributed Generation Potential Study in 2010 on behalf of Vermont's System Planning Committee.

Provide principal leadership to the team responsible for the La Capra Associates' Electric Market Model, which is used to support the analysis for numerous client projects.

Conducted scenario planning studies for all North America regional power markets (U.S. and Canada). Provided capacity requirements, resource adequacy assessment, and energy price outlooks.

Conducted scenario planning studies for all North America regional power markets (U.S. and Canada). Provided capacity requirements, resource adequacy assessment, and energy price outlooks.

Charged with the role of principal for power research and consulting for the Eastern Energy Service, providing insight into the interactions of electric and gas markets within the Eastern Interconnect.

Led marketing, structuring and product development for Select Energy's retail energy commodity and energy services business.

Directed market research regarding customer choice and customer satisfaction.

Supervised market modeling activities for North America (U.S. and Canada) for Cambridge Energy Research Associates (CERA).

Analyzed power prices and their impacts on clients in the evolving market structures for ISO New England (ISO-NE), New York Independent System Operator (NYISO) and the PJM Interconnection (PJM).

Supported the development and marketing, while negotiating a power and energy services package to, major retail aggregations and affinity for Select Energy. This includes the largest Municipal Aggregation the Cape Light Compact for communities on Cape Cod and Martha's Vineyard.

### *Stakeholder Facilitation and Process*

Facilitated information exchange and consensus building between the utilities and stakeholders —for Connecticut's first IRP since the 1980s—including multiple generation owners, operators and developers; energy efficiency planners, regulatory oversight groups and public advocate organizations; environmental agency and environmental advocacy organizations, transmission owners and the regional transmission ISO; and consumers.

In 2010, facilitated a greatly-expanded process during the subsequent Connecticut IRP to include nuclear power operators, developers, advocates and opposition groups, natural gas utilities and pipeline operators; energy security experts; and CHP developers, policymakers and commercial/industrial business.

### *Utility Planning*

Project Principal and Witness in the review of acquisition of generation resources in Arkansas (EAI –KGEN Hot Springs, AECC – Suez Hot Spring Plant).

Managed strategic planning analyses for NU including the areas of competition, integrated resource planning (IRP), and utility strategic and organizational goal development.

Representation on the Northeast Utilities Service Company Transmission & Distribution Budget and Planning Committee.

Member of the CL&P – Hartford District Storm Restoration Management Team.

Led the team responsible for analysis and presentation materials for executive planning conferences, including utility diversification into energy services and merchant generation.

Supervised generation planning for a large utility provided economic and financial analysis of power plant construction and capital additions and determined avoided costs.

Developed a New England market entry business plan for Direct Energy's retail business.

Advised the management team at Cape Light Compact on the merits of forming an Electric Cooperative.

### *Expert Witness*

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket 14-118-U In the Matter of the Petition of ENETERGY Arkansas, Inc. Request for Approval of the Acquisition of a Generating Unit at the Union Power Station to Serve its Retail Customers

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket 15-014-U In the Matter of the Petition of ENETERGY Arkansas, Inc. for a Declaratory Order Regarding a Purchase Power Agreement for a Renewable Resource

Presented expert testimony on behalf of the New Brunswick Office of Public Intervenor in New Brunswick EUB Matter 272 IN THE MATTER of a review of New Brunswick Power Corporation's General Rate Application

Presented expert testimony on behalf of the Michigan Environmental Council and the National Resources Defense Council in Michigan 2015 GRC-U-17735 Consumers Energy Company (General Electric Rate Case)

Presented expert testimony on behalf of the New Brunswick Office of Public Intervenor in New Brunswick EUB Matter 271 IN THE MATTER of a review of New Brunswick Power Corporation's Class Cost Allocation Study (CCAS) methodology

Presented independent expert testimony on behalf of the Manitoba Public Utilities Board in 2013/14 NFAT Proceeding Needs for and Alternatives to (NFAT) Review of Manitoba Hydro's Proposal for the Keeyask and Conawapa Generating Stations (In this Proceedings the filing of reports by La Capra Associates were the basis for cross examination of Mr. Athas.)

Presented expert testimony on behalf of the Southern Environmental Law Council in Case No. PUE-2013-00088 Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to § 56-597 et seq. of the Code of Virginia

Presented expert testimony on behalf of the Nova Scotia Small Business Advocate in Matter NSPI-P-128.13 In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2014 Annual Capital Expenditure Plan

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket NO.13-033-U In the Matter of the Petition of the Southwestern Electric Power Company for a Declaratory Order Finding That Certain Renewable Wind Energy Purchase Agreements are Prudent, and Wind Energy Purchase Agreements are Energy Only Contracts Eligible for Cost Recovery Through the Energy Cost Recovery Rider

Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in NSPI-128-13 In the Matter of an Application by Nova Scotia Power Incorporated for Approval of Capital Expenditure for 2013 for South Canoe Wind Project - CI#42127 for $93,091,536

Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia NSPI-128-13 In the Matter of an Application by Nova Scotia Power Incorporated for Approval of its 2013 Annual Capital Expenditure Plan

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket NO.12-067-U In the Matter of the Application of Oklahoma Gas and Electric Company for an Oder Approving a Temporary Surcharge to Recover the Costs of a Renewable Wind Generation Facility

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket NO.12-038-U In the Matter of Entergy Arkansas, Inc.'s Request for approval of certain wholesale base load capacity to serve EAI customers and a proposed rider recovery mechanism for these and other capacity costs.

Presented expert testimony on behalf of the Citizen's Action Coalition of Indiana before the State of Indiana Utility Regulatory Commission. In the Matter of the application of Indiana Michigan Power Company requesting from the Commission, 1) A Finding that the Life Cycle Management program for the Donald C. Cooke Nuclear Plant is Reasonable and Necessary, 2) Approving of Cost and Schedule, 3) Authorizing Recovery through a periodic Rate Adjustment Mechanism, 4) Granting I&M Authority to Defer Costs and 5) Grant I&M future Rate Relief as may be Necessary and Appropriate.

Presented expert Public Service Commission regarding IRP and Existing Nuclear Capital Projects. In the Matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket NO.12-012-U In the Matter of Arkansas Electric Cooperative Corporation for Approval of the Acquisition of the Hot Spring

Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in Matter M04862 Application by Pacific West Commercial Corporation and NSPI for a Load Retention Rate

Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in Matter M04175 Proposed Amendments to Nova Scotia Power Inc.'s Load Retention Tariff

Provided expert testimony on behalf of the Small Business Advocate of Nova Scotia in Matter M04892 Main Computer Centre Upgrade

Presented expert testimony on behalf of the Arkansas Public Service Commission (ASPC) General Staff in Docket NO.11-069-U In the Matter of Entergy Arkansas, Inc.'s Request for Approval of the Acquisition of the Hot Spring Plant to Serve its Retail Customers

Presented expert testimony on behalf of the Oklahoma Attorney General before the Oklahoma Corporation Commission regarding IRP and baseload coal RFPs. (Causes Nos. PUD 200500516, 200600030, 200700012, 2006 through 2007.)

Presented expert testimony before the Connecticut Department of Public Utility Control (DPUC) for Select Energy in Connecticut regarding its retail licensing application in 2000.

Testified on customer impacts, pricing levels and utility planning during various electric industry restructuring proceedings in Connecticut and Massachusetts.

Presented expert testimony on numerous occasions before the Connecticut DPUC regarding special contract approvals.

## EMPLOYMENT HISTORY

**La Capra Associates, Inc.** Boston, MA
*Principal Consultant* *2009 - Present*
*Managing Consultant* *2006 - 2009*

**Direct Energy North America** Stamford, CT
*Independent Consultant* *2005*
*Assignment – New England Market Entry Business Plan, Channel Management Plan Development*

**Northeastern US Markets**
*Developed a business plan outlining the potential market entry for the client into the New England power market.*

**Cambridge Energy Research Associates** Cambridge, MA
*Associate Director, North American Electric Power* *2001 – Feb. 2005*

*Eastern North American Energy Service Principal*

Developed independent primary research on various aspects of power markets around the Eastern U.S. and Canada, primarily responsible for the Northeast and Midwest markets, including price outlooks for energy and "full requirements" electric power. Analyzed market structure, supply/demand balances, price caps, market clearing prices, capacity markets, and generation technologies.

**Northeast Utilities** **Berlin, CT**

*Director, Retail Business Strategy - Select Energy* *1997 – 2000*

*Managing Director, Marketing - Select Energy*

Directed market strategy, market research, product development, product management, strategic alliance development, retail electric energy supply management and pricing strategy for Northeast Utilities' unregulated retail energy service company, Select Energy, formed in 1997. Managed the activities of 31 professionals, including six managers. Negotiated a major retail supply agreement with the Massachusetts Municipal Association, which resulted in participation by 120 cities and towns.

*Director, Market Pricing & Policy* *1995 – 1997*

Directed the work in all areas of pricing for Northeast Utilities and its operating companies: CL&P, WMECo, PSNH and HWPCo, with revenues totaling over $3 billion. Three managerial units comprised the pricing organization, Cost of Service, Rates and Special Contracts. Led the development of proposals in unbundled rates prior to the restructuring of electric utility markets in Connecticut and Massachusetts. Responsible for developing utility discount rate and energy efficiency offerings for large customers in Business Retention and Economic Development circumstances, which were coordinated and packaged into state and local economic development agencies incentive packages.

*Manager, Market Analysis* *1990 – 1995*

Led market planning and market research functions in developing strategies to prepare NU for the competitive business environment, including sales force program training and development.

*Manager, Strategic Analysis & Long Term Resource Planning* *1987 – 1990*

*Held various positions within the Capacity Planning Department* *1981 – 1987*

**United Technologies Corporation** Hartford, CT

*Analytical Engineer – International Fuel Cells/Pratt & Whitney Aircraft* *1977 – 1981*

## EDUCATION

**University of Connecticut** Storrs, CT

*Masters of Business Administration* *1987*

**Rensselaer Polytechnic Institute – HGC** **Troy, NY**

*M.S., Mechanical Engineering* *1982*

**Cooper Union New York, NY**

*B.E., Mechanical Engineering* *1977*

*Elected to Pi Tau Sigma* **–** *Mechanical Engineering Honorary Fraternity*

## PROFESSIONAL ACHIEVEMENTS

Recipient, **1998 Northeast Utilities Chairman's Award** for innovation in developing offerings and negotiating with large aggregation groups

Recipient, **1996 Northeast Utilities Chairman's Award** and **1996 Retail Business Group's President's Award** for the role in leading efforts in the Retail Competition Pilot in New Hampshire

Recipient, **Northeast Utilities 1994 Retail Business Group's President's Award** for developing and successfully implementing special utility contracting efforts

Licensed **Professional Engineer** - State of Connecticut

Past appointee to the **Electric Power Research Institute (EPRI)** Industrial Business Unit Council

Participation in the Energy Committee of the Manufacturer's Alliance of Connecticut, Inc.

Participation in various **NEPOOL** Committees

Member of the **Association of Energy Engineers**

Author of the paper **'Fulfilling on the Promises of Deregulation'**

Speaking experience includes:

- 2012, Speaker at EUCI Resource Planning: *A Practitioner's Toolkit for Current Issues*
- U.S. Chamber Of Commerce Satellite Seminar Series on *Deregulation*
- Massachusetts HEFA sponsored conference on *Organizing Energy Buying Groups*
- INFOCAST Seminars on *Negotiating Power Contracts*
- Interview on a nationally syndicated news show, *First Business*, on energy deregulation