

December 23, 2015

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

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

Dear Ms. Blundon:

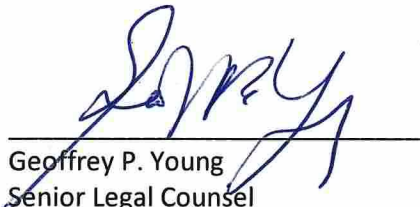
**Re: Newfoundland and Labrador Hydro – 2013 General Rate Application
Final Submission**

Enclosed please find the original plus 12 copies of Newfoundland and Labrador Hydro's final submission in relation to the above-noted matter.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



Geoffrey P. Young
Senior Legal Counsel

GPY/bs

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy - Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. - Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis

Thomas Johnson, Q.C. - Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

IN THE MATTER OF the *Electrical Power Control Act*, 1994, SNL 1994, Chapter E-5.3 (the “*EPCA*”) and the *Public Utilities Act*, 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

Newfoundland and Labrador Hydro

**2013 General Rate Application
Closing Submissions**

December 23, 2015



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1 **A. DEFINED TERMS**

2

3 The following terms appear in either the GRA Submission or the Prudence Review Submission
4 and are as defined below.

5

| Term | Definition |
|---------------------------|--|
| <i>Act</i> | <i>Public Utilities Act, SNL 1990, Chapter P-47 (as amended)</i> |
| Admin Fee | Administration Fee |
| Amended Application | Hydro's Amended Application, filed on November 10, 2014 |
| ATCO | <i>ATCO Gas and Pipelines Ltd. v. Alberta (Utilities Commission), 2015 SCC 45</i> |
| bbl | Barrel |
| BCUC | British Columbia Utilities Commission |
| Board | Public Utilities Board (NL) |
| BTU | British Thermal Unit |
| CBPP | Corner Brook Pulp and Paper |
| CDM | Conservation and Demand Management |
| CF(L) Co | Churchill Falls (Labrador) Corporation Limited |
| CIAC | Contribution in Aid of Construction |
| COS | Cost of Service |
| Cost Deferral Application | <i>Cost Deferral Application, filed by Hydro on July 10, 2015 (as subsequently amended)</i> |
| CPP | Canada Pension Plan |
| CT | Combustion Turbine |
| CT Application | <i>Application, Supply & Install of 100MW Combustion Turbine Generator, filed by Hydro on April 10, 2014</i> |

| Term | Definition |
|----------------------|--|
| Deloitte | Deloitte Canada |
| EFB | Employee Future Benefits |
| EI | Employment Insurance |
| EPC | Engineering, Procurement and Construction |
| EPCA | <i>Electrical Power Control Act, 1994, SNL 1994, Chapter E-5.1 (as amended)</i> |
| Exploits | Exploits Generation |
| FTE | Full Time Equivalent |
| GHG | Greenhouse Gas |
| Government | Government of Newfoundland and Labrador |
| GRA | <i>General Rate Application, filed by Hydro on July 30, 2013 (as subsequently amended)</i> |
| GWh | Gigawatt hours |
| HTGS | Holyrood Thermal Generating Station |
| Hydro | Newfoundland and Labrador Hydro |
| Hydro Reply Evidence | Hydro's Reply Evidence on the Prudence Review, filed by Hydro on August 7, 2015 |
| <i>Ibid.</i> | Provides a footnote reference that was cited in the preceding footnote |
| IIC | Island Industrial Customer |
| IIS | Island Interconnected System |
| IS | Information Systems |
| ITC Guidelines | Intercompany Transaction Costing Guidelines |
| KPI | Key Performance Indicators |

| Term | Definition |
|------------------------|---|
| kV | Kilovolt |
| kW | Kilowatt |
| kWh | Kilowatt Hour |
| La Capra | La Capra and Associates Inc. (currently Daymark Energy Advisors) |
| Labrador Towns | Labrador Towns, consisting of Labrador City, Wabush, Happy Valley-Goose Bay and North West River |
| Liberty | Liberty Consulting Inc. |
| Liberty Final Report | Liberty's Final Report in the Prudence Review, filed by Liberty on July 7, 2015 |
| Liberty Reply Evidence | Liberty's Reply Evidence in the Prudence Review, filed by Liberty on September 17, 2015 |
| LIS | Labrador Interconnected System |
| LOLH | Loss of Load Hours |
| MWh | Megawatt Hours |
| Nalcor | Nalcor Energy Inc. |
| NARL | North Atlantic Refinery Limited |
| NP | Newfoundland Power |
| NSP | Nova Scotia Power Inc. |
| O&M | Operating and Maintenance |
| OEB | <i>Ontario (Energy Board) v. Ontario Power Generation Inc.</i> , 2015 SCC 44 |
| OEM | Original Equipment Manufacturer |
| Outage Inquiry | <i>Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System</i> |

| Term | Definition |
|-----------------------------------|---|
| Parties | Hydro and GRA intervenors |
| PM | Preventative Maintenance |
| Prudence Review | <i>Newfoundland Labrador Hydro Prudence Review</i> |
| PSPP | Public Service Pension Plan |
| RFI | Request for Information |
| ROE | Return on Equity |
| RSP | Rate Stabilization Plan |
| RTV | Room Temperature Vulcanization |
| SEM | System Equipment Maintenance |
| Settlement Agreement | Settlement Agreement among the Parties, filed with the Board on August 14, 2015 |
| Supplemental Settlement Agreement | Supplemental Settlement Agreement among the Parties, filed with the Board on September 28, 2015 |
| Teck | Teck Resources Limited |
| TwinCo | Twin Falls Power Corporation Limited |
| UARB | Utility and Review Board |
| Vale | Vale Newfoundland and Labrador |
| WACC | Weighted Average Cost of Capital |

1 **B. BACKGROUND**

2 Hydro's last GRA was filed on August 6, 2006, resulting in a final Order issued on April 12,
3 2007.¹ Since then much has changed and much has been accomplished. In particular, Nalcor
4 was incorporated, Hydro became Nalcor's subsidiary and a number of additional Nalcor
5 subsidiaries have since been incorporated. In addition, the Muskrat Falls hydroelectric project,
6 including the Labrador-Island Link and Maritime Link, has since been sanctioned and
7 construction of these projects is well underway.

8
9 Corporate restructuring did not change the fundamental nature of Hydro's business, nor did
10 restructuring change Hydro's mandate to generate, transmit and distribute safe and reliable
11 power and energy to its customers at least cost. Instead, restructuring provided new
12 opportunities for Hydro to benefit its customers by sharing services with its affiliates. To take
13 advantage of these opportunities, Hydro adopted a matrix organizational model, resulting in
14 both savings and efficiencies in the way Hydro operates its business.

15
16 As noted by Mr. Young, counsel for Hydro, in his opening remarks:

17
18 *Hydro's duty as an electrical utility is to provide safe and reliable service to its*
19 *customers at reasonable cost. The purpose of this General Rate Application is to*
20 *provide Hydro with electricity rates that will provide the necessary revenue to*
21 *carry out that duty. Those rates must provide Hydro with sufficient revenues to*
22 *ensure its reasonable expenses can be paid and must provide Hydro with*
23 *sufficient margin so that Hydro can access debt in the marketplace on reasonable*
24 *terms.*²

¹ Order No. P.U. 8(2007).

² September 9, 2015 Transcript, pages 12-13.

1 Despite various challenges faced by Hydro in responding to the system interruptions in January
2 2013 and 2014, Hydro has accomplished much since the last GRA. This was highlighted by Mr.
3 Martin, CEO in his direct evidence:

4
5 *New generation would be required with supporting infrastructure. So throughout*
6 *the decision process, a decision was made to address this need through the*
7 *combustion turbine that was recently pushed into service and the Muskrat Falls*
8 *Labrador Island Link Project. These projects were sanctioned, and as I mentioned,*
9 *they're either in service with respect to the new combustion turbine or they're*
10 *under construction as we speak with Muskrat Falls and the Labrador Island Link.*

11
12 *We have accomplished these efforts and initiatives which are required in the*
13 *context of safety performance significantly improving over that same period of*
14 *time. Last year for the first time in Newfoundland and Labrador Hydro's history,*
15 *there was zero lost time incidents. From an environmental performance*
16 *perspective, Holyrood emissions have been significantly reduced in respect to the*
17 *sulphur dioxide NO_x and particulate. GHG is still the same issue it was in the past,*
18 *needs to be dealt with. Now in addition to that with respect to our ISO 14001*
19 *certification, we've increased our record of meeting our annual targets from an*
20 *average of 75 percent to now we are sustained meeting those targets in between*
21 *a 98 to 100 percent level each year.*

22
23 *The key reliability indicators for direct customer service have stabilized. We are*
24 *focused there on measures maintaining the ability to supply the customer. I offer,*
25 *for example, some of the key performance measures that we are tracking. With*
26 *respect to the bulk transmissions system, we're looking at the 230 kV system in*
27 *two parts. Part A, the transformer and circuit breaker performance, we are*
28 *outperforming the Canadian average, and on the 230 kV transmission system,*

1 *we're generally aligned with the CEA averages, more volatility, but over time*
2 *aligned.*³

3
4 As has been discussed in the hearing, Hydro has experienced growth in operating expenses
5 since 2007. Demand growth and the requirement for new generation, coupled with aging
6 assets requiring significant reinvestment have put pressure on Hydro's earnings. As Mr. Martin
7 testified:

8
9 *Our next step was evident. We took a step back, established the condition based*
10 *assessment for all of the assets, we developed a comprehensive 20 year outlook*
11 *for each of those assets, we prepared an initial budget and a schedule against*
12 *this plan over a 20 year period, we then stood back and resourced the plan*
13 *understanding what level of resources would be required to carry it out, we*
14 *optimized that resource levelling, and we established the plan and locked it in*
15 *place. This plan has yielded an outlook which has more than doubled our capital*
16 *expenditures for sustaining capital from 2005 of approximately 35 million. We've*
17 *more than doubled that per year and that will continue over time. It's an*
18 *absolutely [sic] requirement to maintain these assets and keep them at a point*
19 *where they offer acceptable reliability to the customer.*

20
21 *In addition to additional capital, regular annual maintenance work is increasing,*
22 *it has to increase, the assets need it. The increase in ongoing maintenance costs*
23 *will continue to increase as these assets continue to age and we seek to maintain*
24 *their reliability.*⁴

25
26 Hydro continually balances reliability and least cost in fulfilling its mandate to provide safe,
27 least cost, reliable service. Hydro respectfully submits that it has exercised due care in the

³ September 9, 2015 Transcript, pages 59-60.

⁴ September 9, 2015 Transcript, pages 58-59.

1 management of costs, but the reality of its infrastructure needs necessitates asking for the
 2 relief sought at this time.

3

4 **B.1 PROCEDURAL HISTORY**

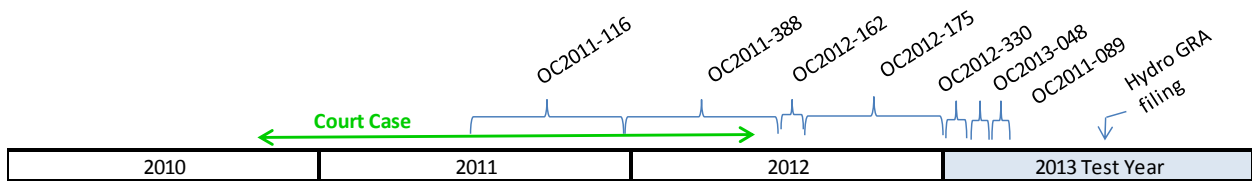
5 **B.1.1 Timing of GRA Filing**

6 Hydro’s GRA filing on July 30, 2013 resulted in a period of almost seven years since its previous
 7 filing on August 3, 2006.⁵ Hydro believes that a period of three years is an appropriate period
 8 between GRA filings.⁶ The delay in the GRA filing is recounted in Hydro’s response to NP-NLH-
 9 369⁷ and depicted graphically in Chart 1 below.

10

11

Chart 1



12

13 There were developments materially affecting Hydro’s load, costs and revenues, commencing
 14 in 2007 with the closure of a paper machine in Corner Brook and followed by the closure of the
 15 Grand Falls paper mill announced in late 2008 and carried out in 2009, that made filing a GRA
 16 in that timeframe problematic. Due to the operation of the RSP and the potential rate volatility
 17 for the IICs, on January 16, 2009, Hydro applied to the Board for an Order to extend the
 18 deadline for filing a GRA until June 30, 2009 and to continue the existing IIC rates. In response,
 19 the Board issued an order approving the continuation of the rates, rules and regulations for the
 20 IICs on an interim basis, and directing Hydro to make an application to finalize the interim rates,
 21 rules and regulations by June 30, 2009.⁸

⁵ For a more thorough account of these matters, please see Hydro’s response to NP-NLH-369.

⁶ PUB-NLH-074 and PUB-NLH-075.

⁷ NP-NLH-369, page 3, line 8 to page 5, line 10.

⁸ Order No. P.U. 6(2009).

1 Hydro filed an Application on June 30, 2009, in which it did not seek changes to the RSP rates.
2 Hydro stated "...that application of the existing RSP rules to calculate rates for Industrial
3 Customers would result in significant and unreasonable rate volatility...". Notice of the
4 Application and the hearing date were published, interventions were filed and over several
5 months, RFIs were issued and answered.

6
7 The Board held a hearing on June 14, 2010 to consider issues pertaining to the Board's
8 jurisdiction with regard to that matter. The Board found that its jurisdiction with regard to
9 some of the issues was limited.⁹ On September 17, 2010, Hydro and the Consumer Advocate
10 appealed this decision to the Court of Appeal, arguing that the Board did have jurisdiction over
11 the RSP amounts. The appeal on the matter of the Board's decision was heard in December of
12 2010; a decision on the appeal was rendered by the Court in June of 2012, reversing the Board's
13 decision.

14
15 Notwithstanding that some issues remained unresolved and were before the Court, in late
16 2010, the Board took steps to recommence and resolve the outstanding IIC rates and RSP
17 matters. These processes were underway when the Lieutenant Governor in Council directed
18 the Board to defer consideration of these matters and directing Hydro to file a GRA by
19 December 31, 2011.¹⁰ A subsequent Government directive delayed the GRA filing until June 30,
20 2012.¹¹

21
22 Following the Court of Appeal decision in June 2012, a series of Government directives further
23 changed the GRA filing date:

- 24 • OC2012-162 delayed the GRA filing until July 16, 2012;
- 25 • OC2012-175 delayed the GRA filing until December 31, 2012;
- 26 • OC2012-330 delayed the GRA filing until February 28, 2013;
- 27 • OC2013-048 delayed the GRA filing until March 31, 2013;

⁹ Order No. P.U. 25(2010).

¹⁰ OC2011-116.

¹¹ OC2011-388.

- 1 • OC2013-083 delayed the GRA filing until April 15, 2013; and
- 2 • OC2013-089, OC2013-090 and OC2013-091 dated April 4, 2013, which resulted in
- 3 Hydro's eventual GRA filing on July 30, 2013.¹²

4
5 References have been made during the GRA proceeding to Hydro's responsibility for the delay
6 in filing its GRA. Hydro points out that the initial directive, OC2011-116 dated April 19, 2011,
7 was to the Board, and directed the deferral of consideration of all matters before the Board at
8 that time pertaining to IIC rates and rate adjustments. Since the IICs are such a significant and
9 integral component of Hydro's Cost of Service study, this directive effectively delayed the GRA
10 filing.

11
12 Subsequent to the issuance of the Government directives on April 4, 2013 on the given rates
13 policy matters, Hydro filed its GRA on July 30, 2013, less than four months later. The length of
14 time between GRA filings has been cited as the dominant reason for Hydro's extended GRA
15 hearing process. These delays occurred outside of Hydro's management control, and the delays
16 therefore do not provide grounds for granting Hydro less than full cost recovery or impairing
17 Hydro's opportunity to earn a reasonable return on its rate base.

18 19 **B.1.2 Interim Applications**

20 Hydro's original GRA proposed to adjust rates effective January 1, 2014. Hydro's position at the
21 time was that delayed implementation of customer rates beyond January 1, 2014 would result
22 in a material revenue shortfall. To provide an opportunity for recovery of the forecast cost to
23 serve, Hydro filed an Interim Rates Application with the Board on November 18, 2013. The
24 Board did not approve Hydro's application stating that the "the proposals in the Interim Rates
25 Application raise complex and comprehensive issues which in the Board's view should be
26 addressed before interim rates are established".¹³

¹² For OC2012-162, OC2012-175, OC2012-330, OC2013-048, OC2013-083 and OC2013-089 refer to CA-NLH-024, Attachments 9, 10, 12, 13, 14 and 15 respectively.

¹³ Order No. P.U. 40(2013), page 3, lines 18-20.

1 To address the concerns with the Interim Rates Application, Hydro filed an amended Interim
2 Rates Application on February 11, 2014. In Order No. P.U. 13(2014), the Board denied Hydro's
3 Amended Interim Rates Application.

4
5 Throughout the current GRA process, Hydro has continued to file interim rate applications to
6 provide an opportunity to recover the cost of serving customers and limit the revenue
7 deficiencies to be required to be recovered from customers in future. These are as follows:

- 8 • Application filed May 12, 2014, denied by Order issued September 17, 2014;¹⁴
- 9 • Application filed on November 28, 2014, approved by Order issued December 24, 2014
10 (approving the 2014 revenue deficiency deferral account and segregating \$45.9 million,
11 denying other aspects of the application);¹⁵
- 12 • Application filed January 28, 2015, denied by Order issued May 8, 2015,¹⁶ but approving
13 specific portions and amounts effective July 1, 2015, as follows:
 - 14 ○ An interim increase of 8.0% in the base rate for NP;
 - 15 ○ An interim increase of 50% of the proposed increase in the rates for Government
16 Diesel customers;
 - 17 ○ An interim increase of 10.0% in the base rate for IICs;
 - 18 ○ Changes to the RSP rules to allow a transfer from the IIC RSP surplus and to
19 implement an IIC RSP rate so that there is an effective interim increase of 2.7% in
20 IIC rates, including Teck; and
 - 21 ○ Changes to the RSP rules to allow a transfer from the IIC RSP surplus to fund the
22 full amount of the 2014 year-end IIC RSP current balance.
- 23 • Application filed October 28, 2015 for approval of interim IIC electricity rates to be
24 effective January 1, 2016, which was approved.¹⁷

25
26 With respect to these various interim rates and revenue deficiency applications, Hydro states
27 that these were all made within its rights and duties to assure that it attains rates that allow it

¹⁴ Order No. P.U. 39(2014).

¹⁵ Order No. P.U. 58(2014).

¹⁶ Order No. P.U. 14(2015).

¹⁷ Order No. P.U. 35(2015).

1 to recover its costs and attain a reasonable rate of return as is required by the relevant
2 legislation. Delayed rate implementation of customer rates beyond January 1, 2014 has
3 resulted in Hydro incurring a shortfall of more than \$100 million in cost recovery.¹⁸ Hydro
4 submits these costs were prudently incurred in providing service to customers and Hydro
5 should be provided the opportunity to recover these costs, subject to the Board testing of these
6 costs.

7

8 **B.1.3 Innu Nation’s Stated case**

9 The Innu Nation and Hydro made submissions to the Board with respect to the Board’s
10 jurisdiction to grant the remedial relief requested by the Innu Nation with respect to compelling
11 Hydro to provide service to customers in Natuashish. On September 4, 2015, the Board advised
12 the parties that this matter was more appropriately dealt with in a separate proceeding and has
13 since taken steps to retain counsel with regard to stating a case to the Court of Appeal pursuant
14 to section 101 of the Act. Hydro therefore makes no further submissions on this matter at this
15 time.

16

17 **B.1.4 Approval of Settlement Agreements**

18 There are two settlement agreements before the Board in this matter, the Settlement
19 Agreement dated August 14, 2015 and the Supplemental Settlement Agreement dated
20 September 28, 2015. Most of the issues settled relate to cost of service matters. Achieving
21 these agreements enabled Hydro, the Parties, and the Board to reduce the length of the
22 hearing and to forego the *viva voce* testimony of several expert witnesses.

23

24 These agreements were reached after detailed and involved negotiations. They constitute the
25 common positions of the parties on these issues. All Parties were represented by learned and
26 competent counsel and advised by experts. Hydro wishes to note its appreciation to the parties
27 and to Board staff and external counsel whom assisted and cooperated in this matter. The
28 settlement agreements are before the Board for its consideration.

¹⁸ This reflects a \$45.9 million shortfall based on the proposed 2014 Test Year Revenue Requirement and a \$60.5 million shortfall based on the proposed 2015 Test Year revenue requirement.

1 Hydro joins the other Parties and Board external counsel in recommending their acceptance.

2

3 **C. LEGISLATIVE REQUIREMENTS**

4 **C.1. LEGISLATION AND ORDERS IN COUNCIL**

5 Hydro's Application seeks approval of rates under the Board's authority existing under sections
6 70 and 71 of the *Act*.

7

8 In carrying out its duties under the *Act*, pursuant to section 4 of the *EPCA*, the Board is required
9 to implement the power policy stated in sections of the *EPCA*.

10

11 In addition to the rate and rule setting powers of the Board that exist under sections 70 and 71,
12 the *Act* gives powers and guidance to the Board with respect to a number of determinations it
13 has to make with regard to the rate setting process. These include the setting of rate base
14 (section 78), the setting of return on rate base (section 80), and the determination and approval
15 of a number of accounting matters (e.g., sections 67, 68, and 69).

16

17 Both the *Act* and the *EPCA* (section 4.1 of the *Act* and section 5.2 of the *EPCA*) contain
18 provisions whereby the Lieutenant Governor in Council is empowered to exempt certain
19 activities of public utilities from the Board's jurisdiction. The *EPCA* contains provisions (found in
20 section 5.1) that empower the Lieutenant Governor in Council to give direction to the Board on
21 power policy and rate setting matters.

22

23 Directions have been given to the Board under this section of the *EPCA* with regard to a number
24 of rates policy issues. Attachments to CA-NLH-024 (Revision 1, March 23, 2015) provide 25
25 Orders in Council including:

- 26 • OC2003-347, with regard to the subsidization of rural rates;
- 27 • OC2009-063, with regard to Hydro's rate of return on equity;
- 28 • OC2013-089 (as amended by OC2013-207) with regard to the RSP Surplus; and

- 1 • OC2011-116, OC2011-388, OC2012-162, OC2012-175, OC2012-330, OC2013-048,
2 OC2013-083 and OC2013-108 with regard to the timing of Hydro’s GRA.

3
4 In addition, under OC2013-257 Hydro’s activities with regard to the Exploits generation assets
5 have been made exempt from the Board’s jurisdiction and the Board was directed to include in
6 Hydro’s operating account the associated energy costs.

7
8 Three Orders in Council merit separate discussion because they concern matters of central
9 relevance to the GRA.

10 11 **C.1.1 OC2003-347 - Subsidization of Rural Rates**

12 This Order in Council continues the longstanding policy of Government with respect to isolated
13 rural rates. Notably, the policy directs the Board to set rates for Hydro’s Isolated Customers
14 such that “lifeline rates” are continued for domestic residential customers, preferential rates
15 are provided to fish plants and to churches and community halls. OC2003-347 also directs that
16 the Rural Deficit be charged to NP and Hydro’s Rural Labrador Interconnected Customers.
17 Pursuant to an Order in Council that is not directly relevant to the present proceedings but
18 which was considered by the Board in Order No. P.U. 8(2007), the Board adopted a policy that
19 Government department customers be charged rates designed to recover the full cost of
20 service.

21 22 **C.1.2 OC2009-063 - Return on Equity**

23 This Order in Council directs the Board to set the same target ROE as most recently set for
24 Newfoundland Power. The ROE is used in the determination of the setting of the return on rate
25 base under section 80 of the Act.

26
27 The Lieutenant Governor in Council has directed that the Board, in calculating the return on
28 rate base for Hydro, set the same target ROE as was most recently set for NP, either through a

1 GRA or calculated through the NP Automatic Adjustment Mechanism.¹⁹ In Board Order No.
2 P.U. 13(2013), the Board determined that NP's target return on common equity in 2015 would
3 be 8.8%.²⁰

4
5 Hydro submits that, in accordance with the Government's directive, the ROE to be used in this
6 case for calculating Hydro's return on rate base is 8.8%.

7
8 In order to give effect to the spirit and intent of this directive, care must be taken to ensure that
9 Hydro's return is not eroded or encroached upon by offsetting the return with some other
10 amount or component of Hydro's costs. The Order in Council provides no authority to do so
11 and none should be inferred.

12
13 In particular, Hydro objects to the suggestion made by the Consumer Advocate in its Issues List
14 and cross-examination to the effect that the rate of return should be reduced or offset by some
15 amount so as to effect a reduction in the Rural Deficit to be recovered from customers. To fully
16 appreciate why this could clearly not be the intention of Government, a brief regulatory and
17 legislative history of the Rural Deficit is useful. To this end, reference can be made to
18 subparagraph 3(a)(iv) of the *EPCA*, which indicates that post 1999, the IICs are not required to
19 fund a portion of the Rural Deficit.

20
21 Perhaps more useful for an understanding of this issue is the antecedent legislative provision,
22 now repealed by the present *EPCA*, found in the *Electrical Power Control Act*, RSN 1990, C. E-5:

23
24 ***Forecast costs***

25 ***5. Notwithstanding the other provisions of this Act, the hydro corporation shall***
26 ***include in its forecast costs filed with the public utilities board***

27 ***(a) the amount to be allocated to retailers of the difference between the***
28 ***revenues and costs for the period April 1, 1989 to December 31, 1989 of***

¹⁹ OC-2009-063.

²⁰ Order No. P.U. 13(2013), page 37.

1 *the power distribution district related to the supply of power to its*
2 *customers except those customers served from the Labrador*
3 *interconnected electrical grid;*

4
5 *(b) the amount to be allocated to retailers of the difference between the*
6 *annual revenues and costs of the hydro corporation, excluding all costs*
7 *and revenues related to the supply of power to customers served from the*
8 *Labrador interconnected electrical grid;²¹ and*

9
10 *(c) the costs incurred after March 31, 1989, including fees or charges paid*
11 *to the Crown, which have been deferred by the hydro corporation and*
12 *which would, unless recovered from its customers, cause the hydro*
13 *corporation to recover less than the minimum margin of profit approved*
14 *by the public utilities board under subparagraph 3(c)(ii) in the year in*
15 *which the costs were incurred.*

16
17 ***Subsidies***

18 ***6. In determining the amounts to be included under paragraphs 5(a) and (b), the***
19 ***public utilities board shall take account of subsidies paid or payable by the Crown***
20 ***to the power distribution district until December 31, 1989 and to the hydro***
21 ***corporation after December 31, 1989 of \$20 million for the period April 1, 1989 to***
22 ***March 31, 1990 and \$10 million for the period April 1, 1990 to March 31, 1991.***

23
24 This legislative history provides an account of how the rural subsidy came into being as a fiat of
25 the legislature and how it was treated. Prior to 1989, the Government fully funded the Rural
26 Deficit incurred by the Power Distribution District in serving what are now Hydro's Rural
27 Customers. The Power Distribution District was wound up at that time and its operations were
28 absorbed into Hydro. Government made the above legislative change in 1989 to require that

²¹ Legislation was subsequently modified (*EPCA*, 1994) requiring the Rural Deficit to also be recovered from customers on the Labrador Interconnected System.

1 the Board set rates such that Hydro would recover the Rural Deficit not from Government, as
2 had been the case with the Power Distribution District, but from Hydro’s customers, notably
3 NP. As stated above and as can be seen from subparagraph 3(a)(iv) of the *EPCA*, until 1999
4 Hydro also recovered a portion of this deficit from the IICs.

5
6 The collection of the Rural Deficit from NP and from Hydro’s Labrador Interconnected
7 Customers, and not from Government, has been an ongoing regulatory issue. Hydro’s collection
8 of the Rural Deficit in this manner was an established and understood fact long before the
9 directive as to Hydro’s rate of return (OC-2009-063) was issued. Indeed, under paragraph (v) of
10 Order in Council OC2003-347 it is expressly stated that this manner of funding is to “continue”.

11
12 OC2009-063 is silent with regard to offsetting or reducing Hydro’s ROE with a subsidy to fund
13 the Rural Deficit (or by any other cost). The Consumer Advocate’s expert witness, Mr. D.
14 Bowman, accepts that Hydro now has what he calls a “mandated ROE” commensurate with
15 that of NP, but suggests that the Board should consider directing a portion of Hydro’s return
16 toward payment of the Rural Deficit.²² Hydro submits that the directive would be meaningless
17 and ineffective if the Board could deny Hydro the mandated ROE by taking away some or all of
18 the required return to serve other purposes.

19
20 The Consumer Advocate’s proposition that Hydro fund a contribution to the Rural Deficit out of
21 its rate of return cannot be reconciled with Government directives and the intentions implicit in
22 them. First, it would restrict Hydro’s recovery of the Rural Deficit from NP and from its Labrador
23 Interconnected Customers (which is contrary to paragraph (v) of OC2003-347). Second, it would
24 also amount to Government contributing toward the Rural Deficit since the funds would come
25 from reduced earnings to which Government is entitled as Hydro’s shareholder.

²² Pre-filed Evidence of C. Douglas Bowman dated June 1, 2015, page 33.

1 **C.1.3 OC2009-063 – Rate Base to Include Rural Assets**

2 This directive also requires that the whole of Hydro’s rate base be used for the purpose of
3 setting Hydro’s Rate of Return, including those assets deployed in the service of its rural
4 customers. This Order in Council directs that a change occur from prior Board ordered policy
5 whereby rural assets were excluded from rate base for the purpose of determining Hydro’s rate
6 of return.

7
8 **C.2 2014 AND 2015 ALLOWED RETURN**

9 OC2009-063 clearly and unambiguously states when the provisions of its direction regarding
10 Hydro’s ROE are to be implemented. The directive says that the Board shall adopt the policies
11 set out therein for all future GRAs by Hydro, commencing with the first GRA by Hydro after
12 January 1, 2009. The first GRA by Hydro after January 1, 2009 was the application in this case
13 made by Hydro on July 30, 2013, requesting new rates to become effective January 1, 2014;
14 and amended on November 10, 2014, requesting cost recovery for 2014 and new rates for
15 2015. According to the plain words of the Government directive, the Board is to adopt the
16 policies set out in OC23009-063 in this GRA. It follows that the target ROE for both 2014 and
17 2015 must be the return most recently set by NP, namely, 8.8%.

18

19 **C.3 TEST YEARS**

20 Paragraph 3(a) (ii) of the EPCA reads as follows:

21

22 *3. It is declared to be the policy of the province that*
23 *(a) the rates to be charged, either generally or under specific contracts, for the*
24 *supply of power within the province*
25 *(ii) should be established, wherever practicable, based on forecast costs for that*
26 *supply of power for 1 or more years,*

27

28 This provision provides ratemaking guidance to the Board and indicates that test years —
29 “wherever practicable” — should be forecast test years. There are two circumstances where

1 this requirement would not apply: (i) where the Board is specifically directed otherwise under
2 section 5.1 of the *EPCA*; and (ii) where the Board in applying proper ratemaking principles
3 deems that, for some reason, the use of a forecast test year is not practicable.

4
5 There were Government directives issued in the present matter as to the test year to be used.
6 The first of these was OC2013-089 (replaced by OC2013-091 but unchanged in this regard),
7 which was issued in April of 2013 and which directed that the Board use a 2013 Test Year. The
8 test year aspect of the directive was rescinded by OC2014-319.

9
10 Hydro filed its GRA on July 30, 2013 in compliance with OC2013-089, as amended. When Hydro
11 filed its GRA the Government-mandated test year was half over, so the GRA's 2013 Test Year
12 was not a completely forecast test year.

13
14 Following its 2013 filing based on the mandated 2013 Test Year, Hydro filed for interim relief
15 with the Board on several occasions as previously noted. Due to the passage of time without
16 receiving an approved rate change and due to changes with respect to a number of cost
17 elements, on June 6, 2014 Hydro advised the Board that it would be filing an amended GRA,
18 which it did on November 10, 2014. That filing used (i) a 2014 Test Year for the purpose of
19 testing the basis for Hydro's claimed 2014 revenue deficiency and (ii) a 2015 Test Year for the
20 purpose of setting rates on a going forward basis. At the time of its filing, the 2015 Test Year
21 was completely a forecast test year.

22
23 Although 2015 is now drawing to a close, this does not impair the relevancy or value of the test
24 year information before the Board. Some modifications to the capital asset forecast used in the
25 2015 Test Year are required to determine the revenue deficiency for 2015. These adjustments
26 are required to reflect the revenue requirement impact of delayed completion of some 2014
27 capital projects.²³ See Section D.1.2.3.

²³ See PUB-NLH-487.

1 For the purpose of rate setting, the 2015 Test Year remains the proper basis to be used for rate
2 setting for the coming period starting in 2016.

3

4 **C.4 PHASE IN OF INDUSTRIAL RATES**

5 OC2013-089 and OC-2013-090 require the use of the RSP Surplus to phase-in of IIC rates over a
6 three-year period. The phase-in period started September 1, 2013. The Board has used interim
7 orders to achieve the phase-in. Upon approval of final GRA rates, Hydro will propose the
8 conclusion of the rate phase-in to become effective September 1, 2016.

9

10 **D. ISSUES AND ARGUMENT**

11

12 In this section Hydro addresses:

- 13 • Issues affecting return;
- 14 • Revenue requirement issues;
- 15 • Cost of Service and Rates issues;
- 16 • Deferral and recovery mechanisms; and
- 17 • Management of the Rural Deficit.

18

19 **Section D.1: Issues Affecting Return**

20

21 **D.1.1 Settled Matters**

22 **D.1.1.1 Allowable Range of Return on Rate Base**

23 The Parties agreed the allowable range of return on rate base for Hydro will be ± 20 basis
24 points.²⁴

25

26 **D.1.2 Remaining Issues**

27 **D.1.2.1 Adjustment of Hydro's ROE**

- 28 • ***Future changes to Hydro's 8.8% ROE should be implemented in a Hydro GRA.***

²⁴ Settlement Agreement, page 2, paragraph 7.

1 It has been suggested that, at such time as the Board reaches a decision to change the target
2 ROE for NP, the Board could adopt an adjustment process to flow through the new ROE to
3 Hydro.²⁵ Hydro proposes that any future changes to its ROE be implemented in a Hydro GRA.²⁶
4 This avoids implementation of new rates solely to give effect to an ROE change and means that
5 the outcome of ROE changes can be implemented together with other impacts of a GRA
6 decision. Further, the approach of implementing any future ROE changes in a Hydro GRA is
7 consistent with the language of the Government directive, which sets out policies to be
8 adopted by the Board “for all future General Rate Applications” by Hydro.

10 **D.1.2.2 Assets in Rate Base**

- 11 • ***For purposes of determining the revenue requirement for setting rates for 2016, Hydro’s***
12 ***2015 Test Year total plant in service is reasonable and should not be adjusted.***

14 Hydro’s rate base is comprised of its investment in capital assets in use, deferred charges, fuel
15 inventory, materials and supplies inventory, and cash working capital allowances.²⁷

17 A detailed explanation of the updated 2015 capital expenditure amount has been provided in
18 Hydro’s evidence.²⁸ The increase in 2015 Test Year additions to plant in service is primarily due
19 to the carry-forward of the in-service dates for the CT and other capital assets that were
20 originally scheduled to go into service in 2014 but have now gone into service in 2015.

22 As stated in Undertaking No. 158:

24 *The forecast additions to plant in service in comparison to the cumulative 2014*
25 *and 2015 Test Years is an underspend of less than 1%. Hydro does not propose to*
26 *make the corresponding adjustment for rate setting purposes for 2016 given that*
27 *the forecast assets in service in 2015 are consistent with the 2015 Test Year, all of*

²⁵ November 16, 2015 Transcript, page 72.

²⁶ *Ibid.*

²⁷ Amended Application, Finance Evidence, Schedule I, page 5 of 11.

²⁸ *Ibid.*

1 *the 2015 additions which were tested in the Hearing and will be in service for a*
2 *full year in 2016, the planned growth in Hydro’s capital program and the impact*
3 *on return on rate base forecasted for 2016 in as outlined in PUB-NLH-487.*²⁹
4

5 The fact that the in-service dates of certain capital assets carried over from 2014 to 2015 should
6 not impact Hydro’s opportunity to begin recovering these costs in 2016. Further, Hydro
7 undertook a very significant amount of capital spending in 2014 and 2015 to place the Holyrood
8 CT and other used and useful assets into service, and Hydro should not be financially
9 disadvantaged by the exclusion of this in-service capital for the purposes of rate setting.
10

11 If the impact of the delayed capital additions is not included in the 2015 Test Year for the
12 purposes of rate setting, Hydro’s 2016 forecast return on rate base would be 6.18%, which is
13 below the lower end of the target range of return on rate base.³⁰
14

15 **D.1.2.3 Delayed In-Service Date of Capital Additions**

- 16 • ***Adjustments to the Test Year plant in service to reflect delayed in-service dates are***
17 ***required only for the determination of net income deficiency.***
18

19 Hydro’s 2014 additions to plant in service were less than expected. This difference reflected a
20 delay in the in-service date of the Holyrood CT and the carry-over of other capital projects.³¹
21 Grant Thornton identified \$148 million of capital assets that did not go into service in 2014 as
22 expected³² and \$110 million of this amount relates to the CT.³³ Hydro proposes adjusting the
23 2014 revenue deficiency to take into account the capital assets that were expected to be placed
24 in-service during 2014 but were not.³⁴ In addition, to account for additions to plant in service

²⁹ Undertaking No. 158.

³⁰ PUB-NLH-487 (Revision 1, October 5, 2015).

³¹ CA-NLH-326.

³² Grant Thornton Financial Consultants Report, June 12, 2015, page 115, Table 87.

³³ PUB-NLH-487 (Revision 1, October 5, 2015).

³⁴ Undertaking No. 148.

1 that were delayed from 2014 to 2015, Hydro proposes to adjust the return for the 2015 net
2 income deficiency by \$5.1 million, as outlined in the 2015 Cost Deferral Application.³⁵

3
4 To account for these delayed in-service dates, adjustments related to rate base should be made
5 to determine the 2014 revenue deficiency and the 2015 revenue deficiency. However, as
6 previous stated, adjustments related to rate base are not required and should not be made for
7 setting rates for 2016 and beyond.

8
9 The delay in bringing assets into service has the effect of reducing 2014 Test Year revenue
10 requirement by \$2.1 million.³⁶ Excluding these capital additions for the 2015 Test Year would
11 reduce revenue requirement by \$5.1 million.

12 13 **Section D.2: Revenue Requirement Issues**

14 15 **D.2.1 Settled Matters**

16 **D.2.1.1 Actuarial Gains/Losses in Employee Future Benefits**

17 The Parties agreed the Board should approve Hydro's proposed accounting treatment to
18 include actuarial gains and losses in EFBs in the 2015 Test Year.³⁷

19 20 **D.2.1.2 Expenses Associated with Asset Retirement Obligations**

21 The Parties agreed the Board should approve Hydro's proposal to include depreciation and
22 accretion expenses associated with asset retirement obligations with the amounts reduced
23 from \$3.1 million and \$3.2 million for the 2014 and 2015 Test Years, respectively, as proposed
24 in the Amended Application, to \$2.6 million and \$2.6 million, respectively.³⁸

³⁵ Cost Deferral Application, page 5.

³⁶ PUB-NLH-487, (Revision 1, Oct 5-15).

³⁷ Settlement Agreement, page 2, paragraph 8.

³⁸ Settlement Agreement, page 2, paragraph 9.

1 **D.2.1.3 2015 Test Year Hydroelectric Energy Production**

2 The Parties agreed to the methodology Hydro used to estimate its average annual hydroelectric
3 energy productions and agreed that the Board should approve the 2015 hydraulic production
4 calculation forecast of 4,604 GWh for all purposes, including the calculation of No. 6 fuel
5 expense for the 2015 Test Year and for the RSP.³⁹

6
7 **D.2.1.4 2015 Test Year Depreciation Expense**

8 The Parties agreed the depreciation methodology used to determine depreciation expense in
9 the 2015 Test Year is appropriate.⁴⁰ Grant Thornton's review of Hydro's Amended Application
10 included procedures to ensure that the depreciation rates used in the 2014 and 2015 Test Years
11 are in compliance with the Gannett Fleming Depreciation Study and in compliance with Board
12 Order No. P.U. 40(2012). In addition, Grant Thornton carried out other procedures, such as
13 reconciling the detailed depreciation schedule to the pre-filed evidence.⁴¹ As a result of
14 completing its procedures, Grant Thornton noted no significant discrepancies in the calculation
15 of the 2014 or 2015 Test Year depreciation forecasts.⁴²

16
17 Grant Thornton noted that certain project costs are subject to the Prudence Review.⁴³ Subject
18 to the decision of the Board with regard to the prudence of certain costs, Hydro submits that its
19 2014 and 2015 Test Year depreciation expense should be approved.⁴⁴

20
21 **D.2.1.5 CDM Cost Deferral and Recovery**

22 The Parties agreed the Board should approve Hydro's proposal to defer and amortize annual
23 customer energy conservation program costs, commencing in 2015, over a discrete seven year

³⁹ Settlement Agreement, page 2, paragraph 10.

⁴⁰ Settlement Agreement, page 2, paragraph 11.

⁴¹ Grant Thornton Financial Consultants Report, June 12, 2015, page 45.

⁴² Grant Thornton Financial Consultants Report, June 12, 2015, page 47. The 2014 Test Year depreciation expense of \$55.2 million reflects \$239 million of assets that were expected to go in service in 2014 (CA-NLH-116). The total of \$239 million for 2014 expected in-service assets includes the Holyrood CT, which actually did not go into service until early 2015. The delay in assets going into service, including the Holyrood CT, is \$0.4 million in 2014 (Grant Thornton Financial Consultants Report, 2013 Amended General Rate Application, June 12, 2015, page 46).

⁴³ Grant Thornton Financial Consultants Report, June 12, 2015, page 31.

⁴⁴ Amended Application, Finance Evidence, Schedule II, page 1 of 1, line 19.

1 period in a CDM Cost Deferral Account. In the Supplemental Settlement Agreement, the Parties
2 agreed the Board should approve Hydro's proposed CDM Cost Recovery Adjustment, which
3 provides for recovery of the costs charged annually to the CDM Cost Deferral Account.⁴⁵
4

5 **D.2.1.6 GRA Costs**

6 The Parties agreed the Board should approve Hydro's proposal to the Parties agreed the Board
7 should approve Hydro's proposal to recover GRA costs (in an amount to be determined) over a
8 three year period using straight-line amortization.
9

10 **D.2.2 Remaining Issues**

11 **D.2.2.1 Operating and Maintenance Expenses**

12 ***Salaries and Benefits***

- 13 • ***Hydro's salary and benefits expenses for the 2014 and 2015 Test Years reflect prudent***
14 ***management decisions concerning the staffing levels necessary to maintain safe and***
15 ***reliable service, and Hydro's commitment to offer the competitive compensation packages***
16 ***necessary to recruit and retain a highly skilled workforce.***

17
18 Hydro's 2014 Test Year salary and benefits expense is \$78.0 million. This amount includes a
19 number of elements, such as salaries, overtime, capital labour costs, benefits, and cost
20 recoveries. Excluding the other elements that make up the total salary and benefits amount,
21 the 2014 cost of salaries is \$73.2 million and the 2014 benefits expense is \$18.1 million. In the
22 2015 Test Year, the salary and benefits expense is \$85.8 million, the cost of salaries is \$77.9
23 million and the benefits expense is \$23.5 million.⁴⁶
24

25 Employee benefits include fringe benefits, EFBs and group insurance.⁴⁷ Fringe benefits generally
26 are CPP, EI, PSPP and Workers Compensation premiums and contributions paid by Hydro.⁴⁸
27 EFBs relate to severance payments upon retirement and health benefits provided to retirees on

⁴⁵ Supplemental Settlement Agreement, page 3, paragraph 12.

⁴⁶ Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.

⁴⁷ Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.

⁴⁸ Amended Application, Regulated Activities Evidence, pages 2.36, lines 19-21.

1 a cost-shared basis.⁴⁹ Group insurance benefits provide Hydro employees with health, dental,
2 life insurance and accidental death and dismemberment coverage.⁵⁰

3
4 The total cost of employee benefits in the 2014 Test Year is an increase of \$3.6 million over
5 2007 actual costs of \$14.5 million. The total cost of employee benefits in the 2015 Test Year is
6 an increase of \$9 million over 2007 actual costs.⁵¹ The cost of fringe benefits, in particular, was
7 driven higher in 2014 and then again in 2015 by increased premiums for EI and CPP and
8 increased contributions to the PPSP, in combination with salary increases discussed below. As
9 well, there is an additional expense of \$2.5 million in 2015 associated with PSPP changes
10 announced by the Government that result in higher employer contributions.⁵²

11
12 In the 2015 Test Year, the cost of EFBs is \$2.5 million higher than 2007 actual costs; this
13 increase includes actuarial losses of \$1.6 million.⁵³ The Settlement Agreement recommends
14 that the Board approve recognition of these costs in the 2015 Test Year.

15
16 In 2006, based on an analysis of its workforce and the external labour market, Hydro identified
17 the importance of focusing on recruitment and retention of skilled employees. The factors that
18 dictated the need for a focused recruitment and retention strategy included the following:

- 19
20
- Significant anticipated retirements during the coming five to ten years;
 - Large scale construction projects within the province and Western Canada;
 - Changing labour force demographics, specifically, an aging population and fewer
23 labour market entrants; and
 - Stable or declining participation trends in the trades and engineering occupations.⁵⁴
- 24
25

⁴⁹ Amended Application, Regulated Activities Evidence, page 2.37, lines 7-8.

⁵⁰ Amended Application, Regulated Activities Evidence, page 2.37, lines 20-21.

⁵¹ Amended Application, Regulated Activities Evidence, page 2.33, Table 2.4.

⁵² Amended Application, Regulated Activities Evidence, pages 2.36, lines 21-23 to 2.37, lines 1-4.

⁵³ Amended Application, Regulated Activities Evidence, page 2.37, lines 13-15.

⁵⁴ Amended Application, Introduction Evidence, Section 1.2.3, page 1.15, lines 14 - 19.

1 Over the period from 2007 to August 31, 2014, there were 238 retirements from Hydro and it is
2 anticipated that, between 2014 and 2022, 40% of Hydro’s current workforce will be eligible for
3 retirement.⁵⁵ The fact that employees who leave Hydro are often among the most experienced
4 and knowledgeable members of the workforce adds emphasis to Hydro’s focus on minimizing
5 voluntary turnover.⁵⁶

6
7 Hydro’s forecast costs for salary and benefits reflect a need for Hydro to offer a compensation
8 package that takes into account the labour market in the Province. As well, it has been
9 necessary for Hydro to address differentials in the wages that it offers, as compared to NP and
10 other Atlantic Canada utilities. These wage differentials arose primarily because of the
11 government’s previous wage restraints that were applied to Hydro.⁵⁷

12
13 Thus, in recent years, Hydro has made adjustments to salaries and wages that are necessary
14 and appropriate to fulfill key business purposes. First, these adjustments are necessary in order
15 to meet Hydro’s central concern to ensure it is paying fairly and competitively as an employer.
16 Ensuring that Hydro’s employees are paid fairly is a matter both of equity and of good business
17 practice.⁵⁸ Second, Hydro must be able to attract and retain the people needed to run its
18 operations effectively.⁵⁹ In order to attract and retain the employees that it needs, Hydro aims
19 to pay its employees fairly and equitably relative to their peers in the industry and, in particular,
20 the Atlantic Canada utility industry. As Mr. McDonald for Hydro noted: “[t]here’s no reason in
21 this world why anyone of our people who are highly qualified people in Hydro should be paid
22 any less or differently from a comparison perspective than anybody with any of these other
23 utilities.”⁶⁰

⁵⁵ Amended Application, Introduction Evidence, pages 1.15, lines 22 to 24.

⁵⁶ Amended Application, Introduction Evidence, pages 1.15, lines 26-28 to page 1.16, lines 1-2.

⁵⁷ Amended Application, Regulated Activities evidence, page 2.34, lines 9 - 16.

⁵⁸ September 16, 2015 Transcript, pages 169-170.

⁵⁹ September 16, 2015 Transcript, pages 169-170.

⁶⁰ September 17, 2015 Transcript, pages 76-77.

1 The labour market in the Province has experienced salary increases well beyond inflation over
2 the years from 2007 to 2015. Without even taking into account the skilled and specialized
3 employees that Hydro needs in many areas, Hydro is faced with the reality that average weekly
4 earnings in the Province have escalated by 35% over that period of time.⁶¹

5
6 In order to be able to attract and retain talented and specialized employees in these market
7 conditions, Hydro must be in a position to compete with its primary comparators on salaries
8 and wages. For comparative purposes, Hydro looks to other utilities, primarily in Atlantic
9 Canada and most notably, NP. As an example, the wage rate of a line worker at Hydro in 2015
10 is \$38.17 per hour. This compares to \$39.10 per hour at NP and the Atlantic Canada utility
11 average in 2015 of \$38.42.⁶²

12
13 In managing towards the Atlantic Canada utility average as the benchmark for employee
14 compensation, Hydro has taken a conservative approach. The evidence reveals a number of
15 areas where Hydro has been “much more conservative” than the recommendations of its
16 expert compensation consultant.⁶³

17
18 The expert consultants who collect information on employee compensation provide a range of
19 data points for particular job categories and, in utilizing this information, some companies have
20 adopted a philosophy described in the evidence as “broad-banding”. While Hydro is aware of
21 this practice, it decided to stay with, or “steward” towards, mid-points. For certain job
22 categories (“Hay 15” through “Hay 18”), Hydro’s expert consultant cast the data on a national
23 basis, but Hydro asked that the numbers be scaled back to Atlantic Canada data.⁶⁴ When the
24 expert consultant recommended that Hydro immediately take steps to address job categories
25 (“Hay 11” through “Hay 18”) in which Hydro was lagging relative to the other Atlantic Canada
26 utilities, Hydro decided to correct the lag naturally through the salary administration process.

⁶¹ September 16, 2015 Transcript, pages 143-144.

⁶² September 16, 2015 Transcript, page 145.

⁶³ September 16, 2015 Transcript, page 164.

⁶⁴ September 16, 2015 Transcript, pages 160 and 162.

1 This took on average two years, rather than the immediate correction recommended by the
2 consultant.⁶⁵ The expert consultant recommended that short term incentives be made
3 available down to a certain level of job category (“Hay 13”), but Hydro decided not to “dip
4 down that far in the organization” with incentive pay.⁶⁶ The expert consultant recommended
5 that employees be able to earn beyond the posted target amount for short-term incentives, but
6 Hydro decided to cap payouts at the stated amounts.⁶⁷

7 8 **Overtime**

- 9 • ***Hydro’s overtime costs reflect the aging of Hydro’s assets in the face of increased
10 customer and increased reliability expectations. Hydro has made a productivity
11 commitment by constraining overtime costs in the 2015 Test Year and going forward until
12 Hydro’s next GRA.***

13
14 Hydro incurs overtime costs as it carries out work to fulfill its mandate of providing least cost
15 reliable service. The need for overtime varies depending on the circumstances at any particular
16 time. Where possible, Hydro minimizes overtime through work planning and filling vacant
17 positions. Nevertheless, the drivers of overtime costs include emergencies – which may arise
18 due to weather and equipment related outages – labour shortages and capital project
19 requirements. Overtime is also required to plan outages at times which are least inconvenient
20 to customers such as weekends and early mornings. As well, overtime occurs because of
21 compensation paid to shift workers who must work on statutory holidays and it is necessary at
22 times to minimize customer outages or to minimize customer service interruption risks.⁶⁸

23
24 Hydro’s overtime costs included in the 2014 Test Year are \$12.2 million, which is \$6.0 million
25 higher than actual overtime costs in 2007. Of the 2014 Test Year overtime amount, \$5.4 million
26 is capitalized, compared to an actual amount of \$1.7 million that was capitalized in 2007. The

⁶⁵ September 16, 2015 Transcript, pages 162-163.

⁶⁶ September 16, 2015 Transcript, page 164.

⁶⁷ September 16, 2015 Transcript, page 165.

⁶⁸ Amended Application, Regulated Activities Evidence, page 2.35.

1 net impact of these variances is that operating overtime costs in the 2014 Test Year are \$2.3
2 million higher than actual 2007 costs. In 2014, higher overtime costs were driven by
3 incremental work requirements arising from the January 2014 outage as well as emergency call-
4 outs. The higher amount of capitalized overtime in 2014 is primarily due to an increase in
5 Hydro's capital program and higher salary costs during the period.⁶⁹

6
7 Hydro's overtime costs included in the 2015 Test Year are \$10.1 million, or \$2.1 million less
8 than the 2014 Test Year amount. Of the 2015 Test Year amount, \$5.2 million is capitalized,
9 which is an increase of \$3.5 million over the actual amount of \$1.7 million that was capitalized
10 in 2007. The net impact of these variances is that operating overtime costs in the 2015 Test
11 Year are only \$0.4 million higher than actual 2007 costs. As well, operating overtime costs in
12 the 2015 Test Year are \$2.1 million less than in the 2014 Test Year.⁷⁰

13
14 Hydro is experiencing pressure on its overtime costs for a number of different reasons. The
15 aging of Hydro's assets and the need to get generation back up quickly when problems arise
16 with these assets, the growth of demand on the system, the need to complete capital projects
17 within tight timelines, and the need to minimize impacts on the power system and on
18 customers, all contribute to a growing and pressing requirement for overtime.⁷¹ A more
19 specific example of these pressures on overtime costs is the Holyrood facility, where there has
20 been an increase in electrical maintenance, instrumentation and mechanical maintenance to
21 address the increasing corrective maintenance requirements that are becoming evident at the
22 plant.⁷²

23
24 Hydro has made a productivity commitment by constraining overtime costs in the 2015 Test
25 Year and going forward until Hydro's next GRA.⁷³ As already stated, operating overtime costs
26 included in the 2015 Test Year for rate-setting purposes are \$2.1 million lower than 2014

⁶⁹ *Ibid.*

⁷⁰ *Ibid.*

⁷¹ September 23, 2015 Transcript, page 168.

⁷² September 23, 2015 Transcript, page 171.

⁷³ September 23, 2015 Transcript, page 170-171.

1 operating overtime costs and only \$0.4 million more than actual costs in 2007. Hydro will limit
2 overtime costs through efforts such as improved efficiency in the planning, scheduling and
3 execution of work and the redeployment of resources in certain key areas.⁷⁴

4 5 **Vacancies**

- 6 • ***Hydro's 2014 and 2015 Test Years demonstrate an inverse relationship between the***
7 ***vacancy allowance and the amounts spent on overtime and labour; Hydro's vacancy***
8 ***allowance of 40 FTEs for the 2015 Test Year is the correct number for the long term.***

9
10 Hydro uses a number of factors to determine an appropriate vacancy allowance to apply to its
11 salary budget based on a combination of previous vacancy experience, most recent labour
12 conditions (trending on job competitions), and anticipated retirements and turnovers.⁷⁵ Hydro
13 experienced higher vacancy than anticipated in 2014. The 2014 Test Year includes a vacancy
14 adjustment of 20 FTEs as outlined in Undertaking No. 145, which is estimated to be the
15 equivalent of \$1.7 million at an average salary of \$85,000 per FTE.⁷⁶ However, with
16 consideration of extraordinary factors including Hydro's deferral of apprentice hiring and the
17 impact of work covered through contract labour and overtime, the 2014 vacancy rate would be
18 normalized to less than 40.⁷⁷ Hydro did not achieve savings relative to the 2014 Test Year due
19 to the higher 2014 vacancy allowance as a result of increased overtime and contract costs
20 incurred resulting from the higher number of vacant positions.⁷⁸

21
22 The 2015 Test Year includes an appropriate vacancy allowance of 40 FTEs or \$3.3 million.⁷⁹
23 While the company's vacancy experience is currently higher than its budgeted allowance, the
24 vacancy allowance is appropriate as Hydro has incurred additional costs again in 2015 relating
25 to managing its vacancies with the use of overtime, contract labour, etc., as outlined in

⁷⁴ September 23, 2015 Transcript, pages 170-171.

⁷⁵ CA-NLH-104 (Revision 1, Dec 18-14), page 2, lines 9-22.

⁷⁶ See CA-NLH-104, Revision 1, page 2, lines 9 – 22.

⁷⁷ September 16, 2015 Transcript, page 176-177.

⁷⁸ See Undertaking No. 146.

⁷⁹ See response to IC-NLH-005 (Revision 1, Dec 3-14).

1 Undertaking No. 146. As well, Hydro notes in testimony by Mr. McDonald that while the
2 vacancy rate is higher in 2015, it is Hydro's position that an allowance of 40 FTEs is appropriate
3 for the longer term (i.e., exclusion of extraordinary factors).⁸⁰

4
5 Hydro reviews its resource requirements and makes prudent decisions based on circumstances
6 and priorities that benefit Hydro customers. Hydro's costs include all factors affecting
7 resourcing of work and is not limited to strictly salaries and wages less vacancy allowance.
8 Hydro will continue to reallocate work where appropriate using a mix of temporary resources,
9 contract labour and overtime.

10 11 ***Intercompany Charges***

- 12 • ***Intercompany services provide significant benefits to Hydro's customers. The charges for***
13 ***these services are subject to transaction costing guidelines that have been reviewed***
14 ***favorably by Hydro's independent auditor and the Board's financial consultant.***

15
16 Since the last GRA, Hydro has become a subsidiary of Nalcor Energy, which has a number of
17 other subsidiaries. Nalcor has adopted a matrix model approach to the sharing of its services
18 and activities with its affiliates.⁸¹ To the extent that resources were based within Hydro and
19 could be effectively shared with affiliates without impeding Hydro's use of those resources,
20 Hydro has been able to recover the costs of those resources from its affiliates, thereby lowering
21 the overall cost of providing electrical service.⁸² These cost savings have come in the form of
22 increased recoveries from the Admin Fee as well as the sharing of resources.

23
24 The sharing of services is subject to ITC Guidelines.⁸³ The ITC Guidelines set parameters for the
25 sharing of services among the Nalcor lines of business through the Admin Fee as well as the
26 costs associated with the provision of services via the Corporate Services group.

⁸⁰ September 16, 2015 Transcript, page 180, lines 17-20.

⁸¹ September 9, 2015 Transcript, pages 73-76.

⁸² PUB-NLH-141.

⁸³ Amended Application, Volume II, Exhibit 8.

1 Through the shared services model, Hydro is able to benefit from the optimization and
2 efficiency of certain services being provided on a shared basis to affiliates within the Nalcor
3 organization. Provision of shared services at cost facilitates the sharing of services and supports
4 the optimal and most efficient use of resources. Accordingly, Hydro does not charge a mark-up
5 on intercompany transactions.⁸⁴

6
7 Deloitte conducted an independent review and noted that a common or shared services model
8 allows organizations such as Nalcor and its affiliates to optimize assets and resources to provide
9 efficient or specialized services at potentially lower costs than each individual entity replicating
10 the asset or service.⁸⁵ Deloitte concluded “the methodologies and practices adopted by Nalcor
11 are fair and reasonable and in line with other utilities.”⁸⁶

12
13 In the GRA, the Board retained Grant Thornton to provide a report and testimony by Mr. Rolph
14 on Hydro’s shared services model and inter-company transactions policy. Grant Thornton also
15 conducted a review of “the reasonableness of the methods used by Hydro and its affiliates to
16 determine the amounts charged by and to Hydro”.⁸⁷ Based on a survey of other Canadian
17 regulated utilities, Mr. Rolph did not identify any significant issues or problems with the
18 application of the shared services model as applied by Hydro and found that the approach used
19 provides value to Hydro and to its affiliates.⁸⁸ In its conclusions, Grant Thornton indicated that,
20 among other things, Hydro and its affiliates derive value from the corporate services rendered
21 by each other.⁸⁹

22
23 The specific findings reported by Grant Thornton as a result of its review include the following:

⁸⁴ CA-NLH-083.

⁸⁵ NP-NLH-024, Attachment 1, page 3.

⁸⁶ NP-NLH-024, Attachment 1, page 4.

⁸⁷ Grant Thornton Expert Report, June 1, 2015, page 1, section 1.3, where it is said that this Report “builds on” the previous Grant Thornton Report dated April 25, 2014.

⁸⁸ Grant Thornton Expert Report, June 1, 2015 page 59.

⁸⁹ Grant Thornton Expert Report, June 1, 2015, page 59.

1 *Common Services:*⁹⁰

- 2 • Using an indirect charge method to determine an arm's length price for the common
- 3 services Hydro renders to its affiliates is reasonable;
- 4 • Allocating the HR and safety and health related costs to be recovered using FTEs as the
- 5 allocator is reasonable;
- 6 • Allocating the IS related costs to be recovered using average number of users as the
- 7 allocator is reasonable;

8 *Common Expenses:*⁹¹

- 9 • Allocating the building rental costs using square footage occupied as the allocator is
- 10 reasonable;
- 11 • Allocating the telephone infrastructure-related cost using the average number of users
- 12 is reasonable;
- 13 • Treating these common expenses as flow through costs and charging them back without
- 14 a mark-up is reasonable;

15 *Corporate Services*⁹²

- 16 • It is reasonable for Hydro and its affiliates to use a direct charge method;
- 17 • The labour rates used to recover the costs appear to be fully burdened; and
- 18 • Unless the ultimate recipient of the corporate service is an energy project involving
- 19 private interest, not applying a mark- up to the costs of rendering corporate services to
- 20 be recovered is reasonable.⁹³

21
22 Grant Thornton noted that the common services related to the Admin Fee might not be fully
23 burdened.⁹⁴ Hydro acknowledged this point⁹⁵ and provided evidence indicating that the impact

⁹⁰ Grant Thornton Expert Report, June 1, 2015, page 2.

⁹¹ Grant Thornton Expert Report, June 1, 2015, pages 2-3.

⁹² Grant Thornton Expert Report, June 1, 2015, page 3.

⁹³ The ultimate recipients of corporate services do not include any energy projects involving "private" interests. CF(L)Co is the only recipient of corporate services that is not ultimately owned 100% by the Province (November 17, 2015 Transcript, pages 81-83). Transactions between Hydro and CF(L)Co do not include a mark-up in accordance with the contract between them (NP-NLH-214) and, in any event, the impact of any such mark-up would be \$41,000 and \$44,000 in the 2014 and 2015 Test Years, respectively (Undertaking 152).

⁹⁴ Grant Thornton Expert Report, June 1, 2015, page 2.

1 of calculating a fully burdened Admin Fee is \$105,000 in the 2014 Test Year and \$115,000 in the
2 2015 Test Year.⁹⁶

3
4 Hydro has demonstrated significant benefits to ratepayers from the Admin Fee. The amounts
5 recovered by Hydro through the Admin Fee for the provision of services to Nalcor affiliates are
6 \$5.6 million in the 2014 Test Year and \$5.7 million in the 2015 Test Year.⁹⁷ Hydro has estimated
7 a benefit of \$9.1 million from the initial transfer of staff from Hydro to Nalcor.⁹⁸ Hydro's
8 customers benefit from the sharing of services with Nalcor, rather than Hydro employing its
9 own dedicated full-time resources to provide those services.

10
11 Grant Thornton's annual review of Hydro also encompassed a review of non-regulated
12 activity.⁹⁹ No issues regarding non-regulated transactions or cost allocations have been
13 brought forward by Grant Thornton, or indeed by any party to this proceeding.

14

15 ***System Equipment Maintenance***

- 16 • ***Hydro's increased SEM costs are justified by Hydro assuming responsibility for costs***
17 ***previously incurred by TwinCo; by new demands imposed by the newly installed Holyrood***
18 ***CT; and by the increased preventative and corrective maintenance, including vegetation***
19 ***management.***

20

21 ***General***

22 Hydro's actual costs for SEM were \$7.5 million in 2007. These costs have increased by \$3.2
23 million in the 2014 Test Year and by a further \$4.1 million in the 2015 Test Year.¹⁰⁰

⁹⁵ November 16, 2015 Transcript, page 10.

⁹⁶ Undertaking No. 151.

⁹⁷ PUB-NLH-169 (Revision 4, Dec 3-15).

⁹⁸ NP-NLH-084.

⁹⁹ PUB-NLH-140, Attachment 1, pages 5-6.

¹⁰⁰ Amended Application, Regulated Activities Evidence, pages 2.45-2.46.

1 There are a number of key drivers of Hydro’s increased requirements for spending on SEM. Two
2 of the primary drivers that increase the SEM costs in the 2015 Test Year forecast are the costs
3 previously incurred by TwinCo and the costs associated with the new Holyrood CT. Other
4 drivers of higher SEM costs are initiatives focused on improving transmission and distribution
5 reliability performance, including vegetation management.

6 7 *TwinCo Assets*

8 CF(L)Co continues to operate and maintain the transmission assets previously owned by TwinCo
9 on Hydro’s behalf.¹⁰¹ The 2015 Test Year includes forecast operating and maintenance costs of
10 approximately \$2.8 million for the transmission lines and the terminal station.¹⁰² The work
11 giving rise to these costs was previously done for TwinCo by CF(L)Co and now is done for Hydro
12 by CF(L)Co. Hydro worked very closely with CF(L)Co to develop the budget amounts based on
13 CF(L)Co’s experience with the costs to maintain and operate the assets over the past number of
14 years.¹⁰³

15
16 Hydro provided detailed support for the 2015 Test Year forecast operating and maintenance
17 costs.¹⁰⁴ No issue has been raised during this proceeding about these costs.

18 19 *Holyrood CT*

20 Hydro’s SEM costs for the 2015 Test Year include costs of \$1 million associated with
21 maintenance of the new CT, as well as an additional \$1.6 million in respect of the extended
22 (two year) warranty that provides for technical oversight and coaching from the Engineering,
23 Procurement and Construction contractor related to the operation and maintenance of the
24 unit.¹⁰⁵ Hydro submits that the operating and maintenance costs applicable to the Holyrood CT
25 are reasonable for the provision of reliable service to customers.

¹⁰¹ PUB-NLH-367.

¹⁰² Amended Application, Regulated Activities Evidence, pages 2.12 and 2.46; PUB-NLH-367.

¹⁰³ September 24, 2015 Transcript, pages 38-40.

¹⁰⁴ PUB-NLH-367.

¹⁰⁵ Amended Application, Regulated Activities evidence, page 2.46.

1 *Preventative and Corrective Maintenance*

2 The cost increase to improve transmission and distribution reliability performance and
3 maintenance in 2014 is primarily related to the completion of \$1.0 million in preventative and
4 corrective maintenance backlog work associated with critical power transformers, air blast
5 circuit breakers and protection and control systems costs associated with the completion of the
6 preventive and corrective maintenance backlog for 2015 were forecast to be \$1.2 million.
7 However, as these costs are not considered to be reflective of normal operating conditions,
8 Hydro proposes a deferral of the costs over a five-year amortization period beginning in 2015
9 and the 2015 Test Year includes \$0.2 million of related amortization.¹⁰⁶

10

11 Hydro's vegetation management costs increased by \$1.4 million in the 2014 Test Year, as
12 compared to 2007; and by an additional \$0.5 million in the 2015 Test Year.¹⁰⁷ The higher costs
13 of vegetation management result from both an increase in contractor costs and a greater
14 amount of work. The contractor for Hydro's vegetation management work was selected
15 through a public tender process and the outcome of the process was a higher contract cost
16 than that which was reflected in Hydro's 2007 costs.¹⁰⁸ As well, Hydro found that additional
17 vegetation management is needed on dams and dykes and along transmission lines after a
18 number of interruptions were experienced due to tree contact:

19

20 *JOHNSON, Q.C.:*

21 *Q. Okay. As regards vegetation management, that's referenced on page 2.46,*
22 *line 21, further increase of a half million dollars related to vegetation*
23 *management. That's a fairly significant increase in the cost for vegetation*
24 *management. I think you'll agree.*

¹⁰⁶ Amended Application, Regulated Activities Evidence, pages 2.45-2.47 and 3.23.

¹⁰⁷ Amended Application, Regulated Activities Evidence, page 2.46.

¹⁰⁸ September 24, 2015 Transcript, page 37.

1 MR. HENDERSON:

2 A. It is, and it is specifically to address vegetation management requirements of
3 the company. We had experienced a number of customer interruptions due to
4 tree contact and we had a look and saw that we needed to put in some extra
5 effort there to stay ahead of what we were experiencing, which was a -- we
6 weren't staying ahead of the growth of vegetation along our transmission lines
7 and also on our dams and dikes, so we had to put in a bit more, and there was
8 also an increase in the contract costs. When we went to tender for that, the costs
9 have gone up as well.¹⁰⁹

10
11 **Professional Services**

- 12 • **Hydro's expenditures for professional services reflect ongoing increases in regulatory**
13 **activity. In addition, Hydro is incurring increased costs for asset assessments, and the**
14 **development of operations, maintenance and retirement plans tailored to Hydro's aging**
15 **asset portfolio.**

16
17 The cost of Professional Services in the 2014 Test Year is \$10.6 million, which is an increase of
18 \$6.8 million over 2007 actual costs. The 2015 Test Year cost of Professional Services declined
19 from the 2014 Test Year to \$8.4 million which is \$4.6 million higher than 2007 actual costs.¹¹⁰

20 The major causes of the increase in Professional Services expenses from 2007 to the 2014 Test
21 Year were higher consulting costs (\$5 million more than 2007) and GRA and Board related costs
22 (\$2.9 million more than 2007). Consulting costs were higher for a number of reasons, one of
23 which was the Outage Inquiry (accounting for \$2 million of consulting costs in 2014). GRA and
24 Board related costs in the 2014 Test Year were higher as a result of a marked increase in the
25 volume of applications and regulatory activity.¹¹¹

¹⁰⁹ September 24, 2015 Transcript, pages 36-37.

¹¹⁰ Amended Application, Regulated Activities Evidence, pages 2.39-2.40 and Table 2.7.

¹¹¹ Amended Application, Regulated Activities Evidence, page 2.40.

1 Consulting costs are \$3.4 million higher in the 2015 Test Year than in 2007 for reasons that
2 include regulatory studies and filings, environmental work and safety and health related
3 programs and condition assessments. GRA and Board related costs are \$1.7 million higher in
4 the 2015 Test Year compared to 2007 actual costs because of an increased volume of
5 applications and regulatory activity.¹¹²

6
7 One driver of higher consulting costs is a requirement for condition assessments of assets to
8 verify the timing of overhauls and replacements under the long term asset plan. Another driver
9 is the need to evaluate the extent to which Hydro's operating and maintenance activities
10 should be adjusted or modified to take into account the condition of assets.¹¹³

11 12 **External GRA Costs**

- 13 • ***The external GRA costs reflected in the 2014 and 2015 Test Years are reasonable and full***
14 ***cost recovery is justified in light of the level of recent regulatory activity during this period.***

15
16 Hydro's 2014 Test Year revenue requirement includes \$1 million in external GRA costs.
17 Hydro's 2015 Test Year revenue requirement includes \$333,333 in deferred rate hearing costs
18 (also known as deferred regulatory costs),¹¹⁴ reflecting the recovery of \$1 million of GRA costs
19 amortized on a straight-line basis over a three-year period.¹¹⁵ As part of their settlement
20 agreement, the Parties agreed to Hydro recovering its GRA costs evenly over a three-year
21 period.¹¹⁶ The External GRA Costs are included in the professional services costs discussed
22 above.

23
24 The amount to be recovered remains at issue. Hydro proposes that the Board approve an
25 update to the 2015 Test Year GRA costs to permit recovery of the actual costs incurred.

¹¹² *Ibid.*

¹¹³ September 22, 2015 Transcript, pages 99-100.

¹¹⁴ Amended Application, Finance Evidence, Schedule I, page 9, line 28.

¹¹⁵ Amended Application, Finance Evidence, page 3.22, lines 7 to 13; IC-NLH-053 (Revision 1).

¹¹⁶ Settlement Agreement, August 14, 2015, pages 4, paragraph 18.

1 Hydro notes the timing of Hydro's current GRA was determined primarily by the Government's
2 direction on rates policy.¹¹⁷ Moreover, it is quite likely the cost of one conducting one GRA in
3 seven years may compare favorably to the cost of conducting two GRAs either three years
4 apart:

5
6 *With regard to regulatory efficiency, Hydro believes there is a trade-off when*
7 *longer periods occur between GRAs. Because, typically, the prime reason to file a*
8 *GRA is the need to increase customer rates, the decision to take other steps*
9 *which results in fewer GRAs will usually result in fewer rate increases to*
10 *customers and lower overall regulatory costs due to the avoidance of GRAs in the*
11 *intervening years. It appears to be true that there is an increased complexity and*
12 *scope of GRAs that occur after several years have passed but, overall, Hydro*
13 *believes deferring GRAs when it is reasonable to do so reduces the regulatory*
14 *costs borne by the customer.*¹¹⁸

15
16 Hydro submits the Amended Application became necessary because of changes in its forecast
17 costs since filing the 2013 GRA. The prudent course of action was to amend the application
18 rather than concluding the GRA and filing another GRA immediately thereafter:

19
20 *MR. O'BRIEN:*

21 *Q. Okay, let me ask you sort of - I'll take you a year later then to the point where*
22 *there was a decision made at Hydro, I guess, to amend the filing for 2013 to*
23 *update it, I guess, in November of 2014. Can you give me your recollections as to*
24 *the reasons why that was done and who was involved with making that decision?*

25
26 *MR. HENDERSON:*

27 *A. That was - the people who were involved in that would have been myself, and*
28 *the CFO, Mr. Sturge, the General Manager of Finance, and the Rates and*

¹¹⁷ NP-NLH-369.

¹¹⁸ CA-NLH-002, page 2, lines 17 to 24.

1 *Regulatory Manager. It was presented to me, the financial outlook for the*
2 *coming year, we had updated some financial plan information, and given the*
3 *length of time that it had occurred with respect to the 2013, which was the test*
4 *year, versus where we were seeing things were going, with that length of time*
5 *that had transpired, we felt that in terms of Hydro's financial outlook, it looked to*
6 *be - it was most appropriate to file with additional information to update and go*
7 *forward with the 2014 and 2015 test year. If that wasn't the case, it was very*
8 *likely that we would have to turn around and have another application right after*
9 *the 2013 one, you know, with the 2013 test year, and that would have certainly*
10 *been, I'll say, inefficient in the sense of us going through the regulatory process*
11 *and we thought at that time the appropriate thing to do was to file for 2014 and*
12 *2015 test year.*¹¹⁹

13
14 Hydro has agreed with other parties that it will file its next GRA no later than March 31,
15 2017.¹²⁰ In preparation for the next GRA, Hydro has agreed that it will file a marginal cost study
16 no later than December 31, 2015; a cost of service methodology report no later than March 31,
17 2016; and a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later
18 than June 15, 2016.¹²¹ Furthermore, Hydro and the other parties have agreed that a generic
19 Cost of Service hearing will be held following the filing of these reports.¹²²

20
21 The busy regulatory calendar for 2016 supports the level of regulatory costs included in the
22 2015 Test Year as it is expected to continue at the 2015 Test Year level for 2016.

23 24 **CDM**

- 25 • ***Hydro's CDM initiatives are cost justified and consistent with the provision of least cost***
26 ***reliable service.***

¹¹⁹ September 23, 2015 Transcript, page 6, line 14 to page 7, line 21.

¹²⁰ Settlement Agreement, August 14, 2015, page 5, paragraph 23(d).

¹²¹ Settlement Agreement, August 14, 2015, page 5, paragraph 23(a) to (c).

¹²² Settlement Agreement, August 14, 2015, page 5, paragraph 23.

1 For the Island Interconnected System, Hydro delivers energy efficiency programs in a joint
2 effort with NP under the takeCHARGE initiative.¹²³ The utilities use the Total Resource Cost test
3 (a cost-benefit analysis) to evaluate the economics of the energy efficiency programs.¹²⁴

4
5 CDM Plan initiatives include activities to encourage behavioural change by customers, the
6 provision of rebates, marketplace promotions and other efforts targeted at reducing reliance
7 on electricity.¹²⁵

8
9 Under the takeCHARGE brand, Hydro also has implemented CDM programs such Isolated
10 Systems Community Energy Efficiency Program and the Isolated Systems Business Efficiency
11 Program, which target isolated diesel communities. The measures implemented by Hydro in
12 isolated communities have achieved total energy savings of 4.3 GWh from 2012 to 2014.¹²⁶
13 Hydro's CDM initiatives in isolated diesel communities help to constrain the growth of the Rural
14 Deficit.

15
16 Hydro also maintains the Industrial Energy Efficiency Program to assist in determining the
17 appropriate program design and components for an industrial customer energy efficiency
18 initiative.

19
20 Hydro's initiative to improve energy efficiency at its own facilities has been implemented at
21 many facilities across the Province and at Hydro's head office in St. John's. The internal energy
22 conservation steps taken by Hydro have resulted in an estimated 9.5 GWh of energy savings
23 from 2009 to 2014.¹²⁷

¹²³ PUB-NLH-313.

¹²⁴ The economic tests are updated annually for the programs and are included in NP's CDM reports that are filed annually with the Board.

¹²⁵ Amended Application, Introduction Evidence, page 1.14.

¹²⁶ IN-NLH-241, Attachment 1, page 6, Table 2.

¹²⁷ IN-NLH-239, page 3 of 4, Table 2.2.

1 **Other Income and Expenses**

- 2 • **Hydro should be allowed full recovery of its Other Income and Expenses, because the**
 3 **claimed Test Year amounts are within expected levels and unchallenged.**

4
 5 In this application, “other income and expense” refers to costs associated with the loss on
 6 disposal, removal cost and insurance.¹²⁸ Hydro’s 2014 Test Year and 2015 Test Year amounts
 7 for “other income and expense” are \$2.1 million and \$4.1 million respectively.¹²⁹ As can be
 8 seen from the Grant Thornton’s report, the forecast asset disposal costs of \$2.1 million and
 9 \$4.1 million for the two respective years include a number of constituent elements, such as the
 10 net book value of assets that are being retired, proceeds on disposal of assets and removal
 11 costs.¹³⁰ Hydro’s treatment of these asset disposal costs is in accordance with Board Order P.U.
 12 40(2012).

13
 14 The evidence shows that the 2014 and 2015 Test Year amounts for other income and expenses
 15 fall in line with the three-year average of the actual loss on disposal (\$3.3 million).¹³¹ Hydro’s
 16 evidence explains how the forecast costs were developed on the basis of a project-by-project
 17 assessment of work that results in the retirement of existing assets.¹³²

18
 19 No intervenor raised any issues with the other income and expense category of costs and Hydro
 20 submits that the costs as set out in its evidence¹³³ should be approved.

21
 22 **D.2.2.2 Supply Costs**

- 23 • **Supply costs for 2015 Test Year should reflect a No. 6 fuel cost of \$64.41 (Cdn) per barrel.**
 24 • **Supply costs incurred at HTGS should be based on a 2015 Test Year fuel conversion factor**
 25 **of 607 kWh/bbl.**

¹²⁸ NP-NLH-319.

¹²⁹ Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.

¹³⁰ Grant Thornton Financial Consultants Report, June 12, 2015, page 84, Table 72.

¹³¹ NP-NLH-319.

¹³² NP-NLH-318.

¹³³ Amended Application, Finance Evidence, Schedule III, page 1 of 2, line 32.

- 1 • **Hydro’s Capacity Assistance agreement costs for the 2014 and 2015 Test Years benefit**
- 2 **customers and should be approved for inclusion in Hydro’s revenue requirement.**
- 3 • **Supply Costs on the Isolated Systems and the Labrador Interconnected System are**
- 4 **reasonable.**

6 **Overview**

7 Hydro’s supply costs principally consist of purchases of No. 6 fuel for Holyrood, purchases of
 8 diesel and gas turbine fuel, and power purchases from other suppliers. Table 1 provides the
 9 proposed 2015 Test Year fuel costs that Hydro recommends for use in setting customer rates
 10 reflecting the correspondence provided to the Board on October 28, 2015.

11
 12 **Table 1 Supply Costs by Type for 2015 Test Years**
 13 **(\$ Millions)**

| Supply Cost | 2015 Test Year |
|---|----------------|
| No. 6 Fuel (net of RSP deferral) ¹³⁴ | \$169.0 |
| Diesel and gas turbine fuel ¹³⁵ | 21.4 |
| TOTAL | 190.4 |
| Fuel Supply Deferral ¹³⁶ | 2.0 |
| NET FUEL COST | 192.4 |
| Power purchases ¹³⁷ | 59.9 |
| TOTAL SUPPLY COST | 251.3 |

14
 15 The elements of Hydro’s supply costs are discussed separately below.

¹³⁴ Amended Application, Finance Evidence, Schedule III, line 23 and line 24.

¹³⁵ Amended Application, Finance Evidence, Schedule III, line 26.

¹³⁶ Amended Application, Finance Evidence, page 3.12, Table 3.3 Reflects a 5-year amortization of 2014 capacity related supply costs of \$9.65 million.

¹³⁷ Amended Application, Finance Evidence, Schedule III, line 26.

1 **Island Interconnected Supply Costs**2 **No. 6 Fuel**

3

4 Forecast production at the HTGS is a function of forecast load less Hydro’s own hydraulic
5 generation, power purchases, and standby generation as shown in Table 2.

6

7

Table 2

| Island Interconnected Supply | | |
|-------------------------------------|-------------------------------------|---------------|
| Line | | Energy |
| No. | Particulars | (GWh) |
| 1 | NLH Hydroelectric Generation | 4,604 |
| 2 | Power Purchases | |
| 3 | Nalcor Exploits and Star Lake | 776 |
| 4 | Wind | 189 |
| 5 | CBPP Cogen | 51 |
| 6 | Rattle Brook | 15 |
| 7 | Total Power Purchases | 1,031 |
| 8 | NLH standby generation | |
| 9 | GTs and CTs | 11 |
| 10 | Diesels | 0 |
| 11 | Total Standby Generation | 11 |
| 12 | Total Island Supply Requirement | 7,239 |
| 13 | Less Total Non - Holyrood | (5,646) |
| 14 | Holyrood Energy Requirement | 1,593 |

8

9 Therefore, the forecast ‘Holyrood Energy Requirement’ determines the test year quantity of
10 No. 6 fuel to be consumed. The forecast cost of No. 6 fuel is a function of forecast fuel cost,
11 volume of fuel consumed, and the fuel conversion factor.

12

13 The 2015 Test Year the price of fuel was estimated to be \$93.32 per barrel. However, the
14 forecast price of fuel has declined since the filing of the Amended Application. Hydro filed with
15 the Board on October 28, 2015 an updated fuel price projection for 2016. The revised 2015 Test
16 Year forecast No. 6 fuel cost per barrel reflecting the 2016 forecast fuel price is \$64.41 (\$Cdn).

1 This cost is based on an average of the forecast 2016 No. 6 fuel price of \$69.40 per barrel
2 (\$Cdn)¹³⁸ and the forecast 2015 year-end average inventory cost of \$55.35 per barrel (\$Cdn).
3 Hydro submits that the cost of \$69.15 per barrel of No. 6 fuel should be used by the Board
4 when setting rates that come in effect in 2016 as this price reflects Hydro's most recent
5 forecast cost.

6
7 *No. 6 Fuel: Effect of Hydrology*

8 The volume of fuel used at Holyrood is a function of the level of hydrology forecast. Hydro's
9 forecasted hydraulic production was agreed to by all parties in the Settlement Agreement.
10 Hydro proposes the Board accept this level of hydraulic production for the purpose of setting
11 rates in 2016.

12
13 *No. 6 Fuel: Conversion*

14 The forecast of Holyrood fuel consumption, and ultimately Holyrood production costs, is
15 affected by the energy conversion factor for a barrel of No. 6 fuel. The Board, in 2007, set this
16 conversion factor at 630 kWh per barrel of No. 6 fuel consumed.¹³⁹ Since that time, Hydro has
17 never achieved the fuel conversion rate of 630 kWh/bbl. In fact, during this period, with the
18 exception of 2008, Hydro has not achieved a fuel conversion factor greater than 614 kWh per
19 barrel.¹⁴⁰ To the extent that the actual fuel conversion factor has been lower than the 2007 Test
20 Year level, the additional Holyrood production costs have been borne by Hydro.

21
22 Mr. P. Bowman on page 27 of his pre-filed evidence, dated June 4, 2015 states:

23
24 *In short, by using the average station service rate from the past five years, a*
25 *period of load which is not representative of the Test Years, the station service*

¹³⁸ The forecast No. 6 fuel price of \$69.40 per barrel differs from the \$69.15 per barrel provided in the IIC RSP fuel rider calculation filed October 15, 2015 because the forecast fuel price for 2016 is based on a forecast conversion rate from \$US to \$Cdn and the fuel price in the fuel rider calculation requires the use of a historical conversion rate based on approved RSP rules.

¹³⁹ See Order No. P.U. 8(2007).

¹⁴⁰ See hydro's Amended Application, Section 2, Schedule V, Page 1 of 1.

1 estimate as a percentage is too high. It is also apparent that Hydro has not given
 2 full consideration to providing ratepayers with the benefits arising from the
 3 capital projects. On this basis, a material downward adjustment in the station
 4 service, to yield a net efficiency improvement of 15 kW.h/bbl (8 kW.h/bbl for
 5 capital investment, plus 7 kW.h per bbl for a better regression of station service
 6 projected levels), to 622 kW.h would be appropriate.

7
 8 Mr. P. Bowman has proposed two adjustments to Hydro’s proposed fuel conversion rate of 607
 9 kWh/bbl: (i) an adjustment of +7 kWh/bbl for a change in the approach for determining the
 10 level of Holyrood station service; and (ii) an adjustment of +8 kWh/bbl for the installation of
 11 new variable frequency drives on the unit forced draft fans.

12
 13 Excluding the new capital improvements, Mr. P. Bowman has proposed a conversion rate of
 14 614 kWh/bbl.¹⁴¹ Hydro submits that the historical performance of the HTGS in recent years
 15 (since 2010 in particular) has been nowhere near this level, per Table 2.21 on page 2.75 of the
 16 Amended Application:

17
 18 **Table 3**

| Holyrood Fuel Conversion Performance and Hydro Financial Impact 2009 - 2014 | | | | | | |
|--|----------------|----------------|----------------|----------------|----------------|------------------|
| | 2009 Actual | 2010 Actual | 2011 Actual | 2012 Actual | 2013 Actual | 2014 Forecast |
| Fuel Consumption ('000 bbls) | 1,534.7 | 1,363.2 | 1,469.2 | 1,428.3 | 1,611.0 | 2,334.5 |
| Actual Fuel Conversion Rate (kWh/bbl) | 612 | 589 | 603 | 599 | 594 | 588 |
| 2007 TY Fuel Conversion Rate (kWh/bbl) | 630 | 630 | 630 | 630 | 630 | 630 |
| Hydro's Financial Loss (\$ million) | 2.4 | 4.9 | 3.5 | 3.9 | 5.1 | 8.8 |

19
 20 This deterioration in performance continues in 2015, with Hydro forecasting a fuel conversion
 21 factor of 597 kWh/bbl.¹⁴² While Mr. P. Bowman has proposed a different approach for

¹⁴¹ 607 kWh/bbl + 7 kWh/bbl.

¹⁴² See Schedule 3, Appendix D of Hydro’s Amended 2015 Cost Deferral Application.

1 determining the station service factor used in calculating the net fuel conversion rate in 2015; it
2 ultimately remains another approach, and one which does not lead to a reconciliation with
3 Hydro's actual fuel conversion performance from the past seven years.

4

5 With respect to the +8 kWh/bbl that Mr. P. Bowman has forecasted for the new capital
6 improvements at the HTGS, Hydro submits that this level of improvement, in relation to the
7 average Holyrood unit loading forecast for the test year, is overstated. Mr. Goulding, for Hydro,
8 in his testimony stated:

9

10 *Yes, and although the preliminary data says this load point does indicate savings*
11 *of 7 to 8 kilowatt hours per barrel, from a test year perspective it would have to*
12 *be lower because we're going in with a higher average loading, and the analysis*
13 *that we've done, and again it's very limited at this point, is that the benefit is in*
14 *the order of 4 to 5 kilowatt hours per barrel.*¹⁴³

15

16 Hydro submits that if this improvement were to be included in the forecast fuel conversion
17 factor for 2016, a level of +4 kWh/bbl would be more appropriate than the +8 kWh/bbl as
18 suggested by Mr. Bowman.

19

20 Hydro submits that the 607 kWh/bbl proposed in the test year is appropriate for setting rates in
21 2016. While this fuel conversion rate does not take into account the +4 kWh/bbl due to the new
22 variable frequency drives, the historical conversion rate shows there is greater risk of achieving
23 a lower conversion rate than a higher one.

24

25 Hydro submits that approval of the Holyrood Conversion Deferral to capture variances in the
26 HTGS conversion factor would ensure that neither Hydro nor customers are advantaged or
27 disadvantaged by changes in the fuel conversion factor between test years. This matter is dealt
28 with in Section D.4.1.3.

¹⁴³ October 21, 2015 Transcript, pages 120, line 23 to 121, line 6.

1 *Power Purchases*

2 Hydro purchases power and energy from other suppliers to meet Hydro’s customers’
3 requirements on the Island Interconnected System. Power purchase expense included in the
4 2014 and 2015 Test Years is \$60.3 million and \$57.4 million respectively.¹⁴⁴ Included in power
5 purchase expense are costs associated with capacity assistance agreements.

6
7 The primary reason for the increase in power purchases costs relative to the 2007 Test Year is
8 due to the addition of wind and Exploits power. These power purchases have benefited
9 customers through reduced HTGS fuel requirements. Hydro submits these power purchases are
10 reasonable and the associated costs should be included in the 2015 revenue requirement.

11
12 Liberty, in its review of prudence issues dated July 5, 2015, stated that the CBPP Capacity
13 Assistance Agreement for 2014 made “...a major contribution to system reliability...” and that
14 “[t]here is therefore no reason for Liberty to challenge the prudence of that agreement”.¹⁴⁵

15
16 Hydro also entered into capacity assistance agreements with CBPP and Vale prior to the 2014-
17 15 winter season. Hydro made a total of three requests for capacity assistance during the 2014-
18 2015 Winter Period. These capacity requests helped to maintain generation reserves and, in the
19 case of the March 4, 2015 events, lessened the outage impact on customers.

20
21 Hydro submits that the Capacity Assistance agreement costs for the 2014 and 2015 Test Years
22 benefit customers and should be approved for inclusion in Hydro’s revenue requirement.

23

24 ***Gas Turbine and Diesel***

25 Hydro operates a number of gas turbines and diesel units on the Island Interconnected System,
26 which provide additional long term generation capacity and increased generation reserves. The

¹⁴⁴ Section 2, Regulated Activities, Schedule VI, Page 1 of 1.

¹⁴⁵ Liberty Consulting, Review of Prudence Issues, Dated July 6, 2015, Page 20.

1 cost of diesel and gas turbine fuel has been included in the 2014 and 2015 Test Years at \$6.4
2 million and \$3.6 million respectively.¹⁴⁶

3
4 Included in these forecast fuel costs for 2015 is the cost of operating the new Holyrood CT. In
5 contrast to forecast production levels included in the 2015 Test Year, Hydro has been running
6 the Holyrood CT at minimum output levels during peak periods of the day to provide enhanced
7 system reliability. This operational practice began in 2015 in response to enhanced reliability
8 assessments following the March 4, 2015 outage event, and has resulted in increased fuel
9 consumption at the Holyrood CT relative to the 2015 Test Year forecast. Hydro submits that the
10 cost of Island Interconnected gas turbine and diesel fuel be approved in conjunction with the
11 proposed Energy Supply Account so that Hydro has the opportunity to recover prudently
12 incurred supply costs on the island interconnected system.

13

14 ***Isolated Systems Supply Costs***

15 The primary source of power supply for Hydro's isolated systems throughout the Province is
16 diesel generation. The cost of diesel and gas turbine fuel has been included in the 2014 and
17 2015 Test Years at \$23.2 million and \$21.9 million respectively.¹⁴⁷

18

19 Hydro, in its letter to the Board dated October 28, 2015, provided an updated 2015 Test Year
20 forecast cost based on the most recent cost of diesel fuel of \$20.0 million. No issues were
21 raised by any party to the hearing with respect to these costs. Hydro submits that these items
22 should be accepted for inclusion in revenue requirement by the Board.

23

24 ***Labrador Interconnected Supply Costs***

25 The majority of all energy consumed on the Labrador Interconnected System is purchased from
26 CF(L)Co. Power purchase costs from CF(L)Co are forecast to be \$2.1 million and \$1.9 million for
27 2014 and the 2015, respectively. No issues were raised by any party to the hearing with respect

¹⁴⁶ Section 2, Regulated Activities, Schedule V, page 1 of 1.

¹⁴⁷ Section 2, Regulated Activities, Schedule VIII, page 1 of 1.

1 to these costs. Hydro submits that these items should be accepted for inclusion in revenue
2 requirement by the Board.

3

4 **D.2.2.3 Financing Costs**

- 5 • ***The debt guarantee provides substantial value to customers. The level of the debt***
6 ***guarantee fee payments are reasonable and are provided in response to a Government***
7 ***directive.***
- 8 • ***The timing of the RSP Surplus disposition in 2016 is currently uncertain. No adjustment to***
9 ***Hydro's 2015 Test Year financing cost is necessary.***

10

11 **General**

12 Hydro's 2014 Test Year interest expenses are \$89.7 million and Hydro's 2015 Test Year interest
13 expenses are \$89.2 million. The 2014 Test Year interest expense is \$13 million less than the
14 2007 Test Year; the 2015 Test Year is \$13.5 million less.¹⁴⁸

15

16 Three issues have arisen concerning Hydro's financing costs. Two concern Hydro's debt
17 guarantee fee payments to Government:

- 18 • Is Hydro obligated to pay the fee; and
- 19 • Should it be apportioned, with only part of Hydro's payments recognized for rate-setting
20 purposes.

21

22 Hydro's debt guarantee fee payments respond to a directive to Hydro from Government. The
23 obligation argument is relevant only to the extent the Board has authority over rate recovery,
24 and the Board should exercise that authority to allow recovery, as the Board has done
25 consistently, because the fee is reasonable and provides direct benefits to ratepayers.

26

27 The Board should reject apportionment consistent with the findings reached by Hydro's
28 financial advisor, Scotiabank.¹⁴⁹ The evidence promoting apportionment does not recognize

¹⁴⁸ Amended Application, Finance Evidence, page 3.17, Table 3.7, line 2.

1 the enhanced access to capital markets furnished by the guarantee and it rests on an overly
2 narrow view of the time frame for assessing benefits.

3

4 The third issue centers on the interest accruing in Hydro's RSP accounts, hypothesizing an
5 interest expense reduction Hydro might realize should the RSP accounts be paid out and the
6 disbursed funds replaced with long-term debt. Hydro submits that this issue is premature, as it
7 rests on decisions the Board has not yet been made concerning the disposition of RSP balances.

8

9 ***Debt Guarantee Fee: Basis for Payment***

10 The debt guarantee fee is an annual fee Hydro pays Government in return for Government
11 guaranteeing Hydro's debt obligations. The fee has been in effect for approximately 20 years,
12 and for most of that time the fee equaled 1% of Hydro's outstanding debt obligations.¹⁵⁰ In
13 2008, as a means of temporarily improving Hydro's net income, the Government waived
14 Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver
15 continued until 2011 when the Government issued OC2011-218, directing that the fee be
16 reinstated at a market rate of 25 basis points for short-term obligations and 50 basis points for
17 long-term obligations.¹⁵¹

18

19 Hydro has always included its debt guarantee fee payments in its revenue requirement.¹⁵² The
20 Board always has permitted rate recovery, while acknowledging the debt guarantee's
21 "fundamental importance" and "key role" in Hydro's overall financial condition and specific
22 ability to access capital markets.¹⁵³

¹⁴⁹ PUB-NLH-061, Attachment 1.

¹⁵⁰ Amended Application, Finance Evidence, page 3.31, lines 10-12.

¹⁵¹ PUB-NLH-058, Attachment 1, paragraph ii. Short-term obligations have a term to maturity of ten years or less; long-term obligations have a term to maturity longer than ten years.

¹⁵² Amended Application, Finance Evidence, page 3.31, lines 12-13.

¹⁵³ November 16, 2015 Transcript, Page 16, lines 7-23 (quoting from Order No. P.U. 7(2002-2003) page 35, and Order No. P.U. 14(2004) page 29. See also Amended Application, Finance Evidence, page 3.31, line 13.

1 Hydro pays the debt guarantee fee (and has reflected payment in the 2014 and 2015 Test
2 Years) because Government, has directed Hydro to do so.¹⁵⁴ NP questioned whether OC2011-
3 218 imposed a legal obligation to pay, since the statutory requirement to pay was not carried
4 forward when the Hydro Corporation Act, 2007¹⁵⁵ repealed and replaced the previously
5 governing, 1990 statute.¹⁵⁶

6
7 Hydro's position is that paying the debt guarantee fee is justified because doing so complies
8 with a stated Government policy — OC2011-218 — and because the fee is a fair exchange for
9 the benefits debt guarantee provides to Hydro's customers.¹⁵⁷ Mr. Pelley testified that the
10 Board should grant recovery of the debt guarantee fee because of the guarantee's continuing
11 importance to credit market access. Further, Scotiabank's independent analysis confirmed that
12 Government's new fees (fees much lower than those previously approved by the Board) were
13 reasonable.¹⁵⁸

15 ***Debt Guarantee Fee: Apportionment***

16 Grant Thornton for the Board did not take issue with how Scotiabank measured the reduction
17 in yield spread approach to measuring the value of the debt guarantee,¹⁵⁹ but criticized
18 Scotiabank for not apportioning the cost savings by comparing these spreads to the fees Hydro
19 pays to obtain them.¹⁶⁰ Scotiabank found that for short-term debt, the cost savings
20 attributable to the Government guarantee averaged between 31.7 and 33.0 basis points
21 ("bps"). According to Grant Thornton, a complete analysis would compare these savings to
22 what Hydro would have to pay Government to obtain them. Of the 31.7 to 33.0 bps reduction
23 in short-term yields, Hydro would be returning between 76 and 79 percent to Government via
24 the 25 bps debt guarantee fee. For long-term debt, the yield spread was 35.6 to 47.8 bps, so in

¹⁵⁴ In accordance with OC2011-218.

¹⁵⁵ SNL 2007, c H-17.

¹⁵⁶ Id., section 40, repealing Hydro Corporation Act, RSNL 1990, c H-16.

¹⁵⁷ NP-NLH-254.

¹⁵⁸ November 16, 2015 Transcript, pages 15, line 18 to 17, line 13; and pages 73, line 11 to 82, line 3.

¹⁵⁹ Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2105, page 19, lines 22-24.

¹⁶⁰ November 16, 2015 Transcript, page 96, lines 2 to 11; pages 175, line 12 to 176, line 25 and Grant Thornton Report on 2013 Amended General Rate Application, June 12, 2015, page 20, lines 16-18.

1 Grant Thornton's view the 50 bps debt guarantee fee would more than exceed the savings it
2 would generate.¹⁶¹

3

4 Grant Thornton's apportionment analysis does not to account for a central benefit of
5 Government's debt guarantee: market access. Government utilities across Canada benefit from
6 the creditworthiness of their respective government by either obtaining a debt guarantee
7 which is recovered through rates (Québec), or by borrowing directly from their provincial
8 governments (British Columbia, Ontario, Manitoba). These provinces either extend guarantees
9 or borrow funds on their utilities' behalf because credit markets view governments as among
10 the most creditworthy of counter parties.¹⁶² As Scotiabank observed, governments and those
11 with government guarantees can access capital markets when others cannot, and they can do
12 so on more flexible terms:

13

14 *There are two additional features of a Guarantee has that are very difficult to*
15 *value, namely; that during periods of stress in the credit markets, a guarantee*
16 *from a government entity provides for unrestricted market access and that a*
17 *guarantee allows for more flexibility as to maturity.*¹⁶³

18

19 The benefits of access may be hard to quantify, but the value of this central feature of Canadian
20 utility financing and regulation cannot be denied.

21

22 Grant Thornton inferred that for long-term debt Government's 50 bps fee is too high because
23 the basis spreads they examined were less than 50 bps for the period. This inference does not
24 recognize the value of enhanced market access and increased flexibility; it also implies the
25 period it examined captures all market conditions. As Mr. Pelley testified, yield spreads
26 fluctuate over time:

¹⁶¹ Grant Thornton Report on 2013 Amended General Rate Application, page 20, lines 7-15.

¹⁶² November 16, 2015 Transcript, pages 13, line 14 to 14, line 24; pages 82, line 4 to 90, line 22.

¹⁶³ PUB-NLH-061, Attachment 1, page 6.

1 *[O]ne thing I recognize is the basis point spreads that [Grant Thornton is] quoting*
2 *here are based on looking at the market over a certain period of time. That's not*
3 *to say that if we expanded that window, that there's not times that those*
4 *spreads are probably 70 or 80 basis points or 100. If you look at it over a long*
5 *cross-section of time, such that, you know - like, all you're trying to do is say -*
6 *you're trying to look at a period of time and say what's reasonable.*

7
8 *Okay, you know, they're quoting here 35.6 to 47.8, and all they're saying from*
9 *that is in their view, based on that, 50 is not unreasonable, but from my position,*
10 *I'm not concerned that 50 is too high for the reason I just gave. These spreads*
11 *fluctuate over time. There will be times when actually your long term, let's say,*
12 *your greater than ten year spread to your question, may be less than 50 basis*
13 *points, in which case the fee - I don't want to describe it this way, but you could*
14 *say "too high", but then there would be other periods of time where the spreads*
15 *could be 70 or 80 basis points. So you're trying to capture a concept that's*
16 *fluctuating in time with a single number. There's always going to be some*
17 *discrepancy.*¹⁶⁴

18
19 Government started imposing the debt guarantee fee approximately 20 years ago,¹⁶⁵ and the
20 Board has consistently recognized that the guarantee provides value to ratepayers.¹⁶⁶ The
21 benefits have not changed, and with the market-based fee, the cost of the guarantee has fallen
22 substantially. Hydro's 2014 Test Year includes a debt guarantee payment of \$3.7 million, \$5.3
23 million less than the fee would have been under the previous, 1% requirement. For the 2015
24 Test Year, Hydro's payment is \$4.4 million, \$7.5 million less than the previous 1%
25 requirement.¹⁶⁷ Hydro sees no reason for apportionment.

¹⁶⁴ November 16, 2015 Transcript, pages 94, line 3 to 95, line 5. See also November 19, 2015 Transcript, pages 28, line 3 to 29, line 6.

¹⁶⁵ Amended Application, Finance Evidence, page 3.31, lines 10-12.

¹⁶⁶ November 16, 2015 Transcript, page 16, line 5 to page 17, line 2.

¹⁶⁷ Amended Application, Finance Evidence, page 3.32, lines 7-11.

1 **RSP Interest**

2 Hydro's 2014 Test Year interest expenses include \$18.2 million of interest on Hydro's RSP
3 balances; the 2015 Test Year includes \$12.4 million.¹⁶⁸ Per the RSP rules, interest on RSP
4 balances accrues at Hydro's WACC. For the 2014 Test Year, Hydro's WACC, also equal to
5 Hydro's return on rate base, is 7.12%; for the 2015 Test Year, the WACC is 6.82%.¹⁶⁹

6
7 Comparing Hydro's total capital for financing rate base against the combination of sum of
8 Hydro's mid-year rate base plus capital work in progress, Mr. P. Bowman for the IICs
9 hypothesizes that the RSP balances are functioning as an additional form of capital financing for
10 Hydro, bearing interest at Hydro's WACC. Mr. P. Bowman then speculates that upon refunding
11 the RSP balances Hydro will substitute these funds with long-term borrowing at a significantly
12 lower rate,¹⁷⁰ resulting in immediate savings to Hydro.¹⁷¹

13
14 When the IICs asked Hydro how it was going to finance the refund of the NP surplus, Hydro
15 responded, "As this matter has not yet been ruled on by the Board, no decision has been made
16 with regard to financing."¹⁷² Hydro still considers the timing of the RSP Surplus disposition to
17 be uncertain.

18

19 **D.2.2.4 Productivity and Cost Management**

- 20 • ***By instituting a shared services model, Hydro has improved productivity and efficiency to***
21 ***the benefit of customers through more effective use of its employees.***
22 • ***Hydro has demonstrated a corporate culture that emphasizes cost consciousness and***
23 ***efficient operations.***

¹⁶⁸ Amended Application, Finance Evidence, schedule I, Page 10, line 2.

¹⁶⁹ Amended Application, Finance Evidence, page 3.17, line 7 (Table 3.7).

¹⁷⁰ As of November 20, 2014, Hydro estimated its marginal cost of long-term debt at 3.558%. Grant Thornton Report on 2013 Amended General Rate Application, page 17, line 18 to page 18, line 2 (referencing PUB-NLH-53 (Revision 1)).

¹⁷¹ Pre-Filed Evidence of P. Bowman and M. Najmidinov, pages 28-29; Ex. 2, pages 11-12; and September 30, 2015 Transcript page 100, lines 7-17 and pages 108, line 12 to 111, line 2.

¹⁷² IC-NLH-054, lines 7-8.

- 1 • ***A productivity allowance is not warranted because Hydro has achieved meaningful***
2 ***productivity gains. Inflation provides an implicit productivity allowance as the 2015 Test***
3 ***Year is being used to set rates for 2016.***

4
5 Since 2007, Hydro’s operating labour costs have increased by just 0.01 cents per kWh (one one-
6 hundredth of a cent) on an inflation-adjusted basis, from 0.83 cents per delivered kilowatt-hour
7 in 2007 to 0.84 cents per delivered kilowatt-hour in the 2015 Test Year.¹⁷³ This has been
8 achieved while Hydro has been forced to manage cost pressures in areas that have a significant
9 impact on Hydro’s overall costs.

10
11 Hydro’s evidence explains many specific areas where additional productivity and efficiency have
12 been achieved. The shared services model is an example of measures that have been
13 implemented to improve productivity and efficiency. As a result of the shared services model,
14 employees are utilized in the most effective manner, which works to the benefit of Hydro.
15 Another example is work planning and scheduling. Hydro identified this as an area in which
16 efficiency improvements could be made and it has implemented changes to work scheduling, as
17 well as execution, in order to be more efficient in its asset management and maintenance.¹⁷⁴

18
19 Furthermore, in the context of elaborating on actions taken by Hydro that contain the growth
20 of the Rural Deficit, Hydro provided evidence of numerous Hydro-wide cost control
21 initiatives.¹⁷⁵ While Hydro-wide “Initiatives with Rural Deficit Impacts”¹⁷⁶ do indeed limit the
22 growth of the Rural Deficit, they are measures that more generally result in cost savings and
23 tend to increase Hydro’s productivity and efficiency. As well, in addition to the initiatives that
24 were explained in the context of the Rural Deficit, Hydro’s evidence provides examples of many
25 other cost saving initiatives.¹⁷⁷

¹⁷³ CA-NLH-328, page 2.

¹⁷⁴ September 23, 2015 Transcript, pages 133-136 and 145.

¹⁷⁵ NP-NLH-098 (Revision 1, Dec 9-14).

¹⁷⁶ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.

¹⁷⁷ NP-NLH-057 (Revision 1, Mar 23-15).

1 The Consumer Advocate’s questions about some of Hydro’s specific productivity success stories
2 touched on whether the measurable financial outcomes of certain initiatives are of a relatively
3 small magnitude.¹⁷⁸ However, Hydro would be remiss if, in its efforts to find productivity gains,
4 it were to ignore potential gains that are individually of a relatively small size. Hydro focuses on
5 finding least-cost ways to provide safe and reliable service and does not dismiss potential
6 productivity gains simply because their magnitude may be perceived to be small. The
7 cumulative effect of small savings is meaningful and reduces overall costs to customers.

8
9 Hydro managers are responsible for ensuring work is being done as efficiently as possible. Each
10 manager is responsible for a budget and generally, there is a financial person to support
11 management of cost control.¹⁷⁹ As Mr. R. Henderson explained in this extended exchange with
12 the Consumer Advocate, cost control at Hydro is not something to be relegated to specified
13 individuals or directives; rather, cost control is a central element of Hydro’s culture that
14 permeates activities throughout the organization:

15
16 *JOHNSON, Q.C.:*

17 *Q. And can you explain how Hydro identifies efficiency initiatives within its*
18 *organization?*

19
20 *MR. HENDERSON:*

21 *A. What we do is through again the budgeting process, through our planning*
22 *process in which we develop our five year strategic plan as a key input, we look at*
23 *that to identify initiatives that we could undertake to make us more efficient. So*
24 *through that strategic planning process, we would be looking at what we will be*
25 *doing in terms of improvements on a continuous improvement basis, and then*
26 *through the budgeting process, we would establish that as well with monitoring*
27 *what goes forward in the budget in trying to keep costs within inflationary*
28 *pressures, to try to stay within what is expected inflation, and that’s done*

¹⁷⁸ September 23, 2015 Transcript, pages 144-145.

¹⁷⁹ September 23, 2015 Transcript, pages 135-137.

1 through the budgeting process. So through that, you drive actions to try to bring
2 out efficiencies.

3
4 *JOHNSON, Q.C.:*

5 *Q. Mr. Henderson, to your knowledge, has made, I mean, a directed effort to*
6 *identify efficiencies, or as Mr. O'Brien put it, to try to do more with less? I mean,*
7 *a directed effort to identify such efficiencies within Hydro? Are you aware of any*
8 *such directed effort?*

9
10 *MR. HENDERSON:*

11 *A. In terms of directed efforts, what we would be doing is through that budgeting*
12 *process, through our work execution, looking at our long term asset plans, is*
13 *looking for least cost solutions to everything that we do. So that would be part of*
14 *looking at each capital proposal, any efficiency gains would be sought through*
15 *that, so it's through a number of different avenues. There isn't a one subscribed*
16 *"this is an efficiency improvement program", it's expected each and every*
17 *manager is working to establish their work to be done in the most efficient*
18 *manner. That challenge occurs through the strategic planning process, it occurs*
19 *through the budgeting process, to ensure that those types of things are done.*

20
21 *One area that we've been focusing on, in particular, and I think I may have*
22 *spoken to Mr. O'Brien about that, is the work scheduling and planning area*
23 *where we feel that there is gains to be made there that we're setting out*
24 *objectives there to improve the amount of work that we complete in terms of*
25 *work execution, which is all around asset management and maintenance to get*
26 *more done, and to schedule it efficiently so that the cost to that annual*
27 *maintenance work is at the least cost.*

1 *JOHNSON, Q.C.:*

2 *Q. But, I guess, it's - what you've explained to us in terms of what you do is not*
3 *part of a directed effort, and, I guess, you would agree that what you've done*
4 *and what you've described has led to a circumstance where costs have*
5 *outstripped inflation by about 30 odd percent, right?*

6

7 *MR. HENDERSON:*

8 *A. There's a number of things that are happening within the company related to*
9 *the condition of our facilities, the aging of our assets, our capital investment*
10 *program, the environment in which we work, our employees work, all of those*
11 *items are putting upward cost pressure certainly to Hydro, and that we seek to*
12 *manage those as efficiently as we can.*

13

14 *JOHNSON, Q.C.:*

15 *Q. Well, as part of seeking to manage them as efficiently as you can, can you*
16 *explain why a directed effort has not been made? I mean, we talked about*
17 *organizational excellence and, you know, high cost controlled environment. Can*
18 *you explain why a directed effort has not been given, given the importance of*
19 *identifying efficiency initiatives?*

20

21 *MR. HENDERSON:*

22 *A. Well, we have done a number of things over the 3 years to look for those types*
23 *of things, and we continue to look for those initiatives. To establish, I'll say, a*
24 *separate initiative to pull people out of their jobs and go at that, we've opted not*
25 *to do it that way, we do it through each manager who's expected to do that in*
26 *their own work environment to ensure that they're doing it as efficiently as*
27 *possible. We, as I said, work planning and scheduling was one area that we felt*
28 *from an operations standpoint we can make improvements and are embarking*

1 *on that as a critical piece to do our work execution in terms of our asset*
2 *management and maintenance more efficiently.*

3
4 *JOHNSON, Q.C.:*

5 *Q. So you indicated that you opted not to go the route of a directed effort. When*
6 *was that decided upon?*

7
8 *MR. HENDERSON:*

9 *A. Well, I say that and it's somewhat - I'll say, it's by default, that we didn't do it.*
10 *I mean, the way we are doing it and looking after our facilities, as I said, is*
11 *through challenges to each of our managers to stay within inflation with their*
12 *operating budgets.*

13
14 *JOHNSON, Q.C.:*

15 *Q. If I could ask you to go to 229. . . . Yes, Page 7 of 19. These are the general*
16 *managers and managers who report to you, and I don't have to read them,*
17 *they're there on the screen. Is any of your managers specifically tasked in their*
18 *job description with cost control? Is there a go to manager on, you know, the cost*
19 *controls within your organization?*

20
21 *MR. HENDERSON:*

22 *A. The cost controls, there are - in terms of cost controls and cost management,*
23 *each manager has a responsibility, they have a budget that they have to*
24 *manage. They have people in their groups - I think in almost every case there is a*
25 *financial person that works alongside with them to help manage their budgets,*
26 *help them to exercise the cost control that they need by providing them reports*
27 *and data on how things are going relative to the budget, how they are managing*
28 *their expenses.¹⁸⁰*

¹⁸⁰ September 23, 2015 Transcript, page 145.

1 Hydro has also included in the 2015 Test Year a challenging reduction in overtime expenses
2 from historic levels.¹⁸¹ Hydro has constrained 2015 operating overtime expenses even though
3 it is experiencing growing and pressing requirements for overtime. Using 2013 overtime costs
4 as a point of comparison - since those costs were not affected by the January 2014 outage -
5 actual costs in 2013 were \$12.3 million, while Hydro has reduced overtime costs to \$10.1
6 million in the 2015 Test Year.¹⁸²

7
8 Hydro aims to reduce its overtime costs through redeployment of staff and recruitment
9 initiatives.¹⁸³ Because the achievement of this challenge has been assumed in the 2015 Test
10 Year, there will be a negative impact on Hydro's income to the extent that the challenge is not
11 met, while rates set on the basis of the 2015 Test Year will retain the benefit of the assumed
12 overtime reduction.¹⁸⁴

13
14 Another built-in productivity challenge relates to the timing of implementation of final rates for
15 Hydro. Final rates will be based on a 2015 Test Year, but, given the timing of a Board decision,
16 will not become effective until 2016. The lack of any adjustment to recognize the inflationary
17 impact on costs from 2015 to 2016 effectively operates a productivity allowance for Hydro.¹⁸⁵

19 **Section D.3: Cost of Service and Rates**

21 **D.3.1 Settled Matters**

22 **D.3.1.1 Future Studies**

23 There are a number of matters on cost of service and rate design to be addressed by the Board
24 prior to the implementation of customer rates reflecting the costs of the Labrador-Island
25 interconnection.¹⁸⁶ The rate-related matters include:

¹⁸¹ CA-NLH-328, page 2.

¹⁸² September 22, 2015 Transcript, page 97.

¹⁸³ September 23, 2015 Transcript, pages 165-171.

¹⁸⁴ CA-NLH-328, page 2.

¹⁸⁵ October 7, 2015 Transcript, page 106.

¹⁸⁶ Amended Application, Rates and Regulation Evidence, pages 4.4 - 4.6.

- 1 • A review of the embedded cost of service methodology;
- 2 • The completion of a marginal cost study and rate design review; and
- 3 • A review of Hydro’s regulatory mechanisms for the recovery of supply costs.

4

5 Hydro has committed to filing a number of reports to permit the Board to conduct a
6 comprehensive review of each of these items.

7

8 The Parties agreed the Board should in its Order direct Hydro to file:

- 9 (a) A marginal cost study no later than December 31, 2015;
- 10 (b) A cost of service methodology report no later than March 31, 2016;
- 11 (c) A report on the RSP and supply cost recovery mechanisms no later than June 15,
12 2016; and
- 13 (d) A GRA no later than March 31, 2017 for rate changes based on a 2018 Test Year.

14

15 The Parties also agreed a generic cost of service hearing should be held following the filing of
16 the reports outlined in (a) to (c) above.¹⁸⁷

17

18 **D.3.1.2 Cost of Service Methodology**

19 In the initial Settlement Agreement, the Parties agreed on the cost of service methodologies in
20 Exhibit 13 (2015 Test Year Cost of Service) with respect to functionalization, classification and
21 allocation, subject to nine exceptions:¹⁸⁸

- 22 (a) The treatment of the curtailable load of NP;
- 23 (b) The classification of wind energy purchases;
- 24 (c) The classification of all Holyrood fuel costs;
- 25 (d) NP's load factor;
- 26 (e) The specific assignment of the frequency converter to CBPP, the calculation of
27 that charge and any credit in the Cost of Service study associated with the
28 frequency converter;

¹⁸⁷ Settlement Agreement, paragraph 23.

¹⁸⁸ Settlement Agreement, page 3, paragraph 13.

- 1 (f) The calculation of the capacity factor for the HTGS;
2 (g) The allocation methodology for the Rural Deficit;
3 (h) The basis on which specifically assigned charges to customers is calculated; and
4 (i) The use of the forecast 2015 load for rate-setting purposes.
5

6 Items (a) through (f) were resolved in the Supplemental Settlement Agreement.¹⁸⁹ Items (g),
7 (h), and (i) were contested in the current GRA requiring those matters to be decided on by the
8 Board.
9

10 In the Supplemental Settlement Agreement, the Parties also agreed on the requirement and
11 the scope of a Cost of Service Methodology Review to be completed in 2016:
12

13 *The Cost of Service Methodology Review to be completed in 2016 will include a*
14 *review of: (i) all matters related to the functionalization, classification and*
15 *allocation of transmission and generation assets and power purchases (including*
16 *the determination whether assets are specifically assigned and the allocation of*
17 *costs to specifically assigned assets) and (ii) the approach to CDM cost allocation*
18 *and recovery.*¹⁹⁰
19

20 All Parties agreed that with respect to the new cost items in the current GRA, the Board should
21 approve that (i) wind purchases be classified as 100% energy-related and (ii) the costs
22 associated with Hydro's capacity assistance agreements with Vale and CBPP shall be treated as
23 production demand-related and allocated to each class of service based on a single coincident
24 peak allocator.¹⁹¹ With the exception of the allocation of (i) the Rural Deficit and (ii) operating

¹⁸⁹ Supplemental Settlement Agreement, page 2, paragraphs 7(a)-(e) and 8.

¹⁹⁰ Supplemental Settlement Agreement, page 3, paragraph 13. For further discussion of the cost of service examination, refer to Settlement Agreement, page 5, paragraph 23.

¹⁹¹ Settlement Agreement page 3, paragraph 14(b). This settlement provision is agreed to notwithstanding the generality of the parties' agreement with the functionalization, classification and allocation contained in Hydro's COS Study.

1 and maintenance costs to specifically assigned assets, the Parties have agreed that the existing
2 cost of service methodology be maintained consistent with the last GRA.

3 4 **D.3.1.3 Cost of Service Data for KPI Reporting**

5 The Parties also agreed Hydro should continue to report functionally oriented KPIs as required
6 by the Board in Order No. P.U. 14(2014); however, such reporting will be based on the most
7 recent Test Year Cost of Service study that is approved by the Board and not on a forecast basis.

8 ¹⁹² The agreed approach reduces the administrative requirement to complete a Cost of Service
9 study annually to support KPI reporting.

10 11 **D.3.1.4 Rates and RSP Issues**

12 The initial Settlement Agreement and the Supplemental Settlement Agreement provided
13 agreement on the following rates and RSP issues:

14 (a) The current rate design for IICs should continue to apply as Hydro proposed in the
15 Application.¹⁹³

16 (b) The rate design for NP will be determined using the following approach:

17 (i) The demand charge will equal \$4.75 per kW of billing demand;

18 (ii) The end block energy rate will be determined based on the 2015 Test Year No. 6
19 fuel price divided by the 2015 Test Year Holyrood fuel conversion factor (both to
20 be determined by the Board); and

21 (iii) The approved 2015 Test Year revenue requirement not recovered through the
22 demand charge and the end-block energy charge will be used to compute the
23 first block energy charge.¹⁹⁴

24 (c) Hydro's wholesale rate will include a curtailable load credit as proposed in its Amended
25 Application.

¹⁹² Settlement Agreement, page 4, paragraph 22.

¹⁹³ Settlement Agreement, page 3, paragraph 15.

¹⁹⁴ Supplemental Settlement Agreement, page 3, paragraph 10.

1 (d) If the load variation component is maintained as an element of the RSP, year-to-date
2 net load variations for NP and IICs shall be allocated among the customer groups based
3 upon energy ratios, with effect from the date to be determined by the Board.¹⁹⁵

4 (e) The proposed CDM Cost Recovery Adjustment should be approved to provide for
5 recovery of costs charged annually to the CDM Cost Deferral Account.¹⁹⁶

6 (f) The generation credit agreement between Hydro and CBPP, which the Board approved
7 on a pilot basis in Order No. P.U. 4 (2012), should be continued on a pilot basis at this
8 time.¹⁹⁷

9 (g) There shall continue to be an industrial wheeling rate with the specific rate to be
10 calculated in accordance with the methodology proposed by Hydro as may be modified
11 by the Board in an Order arising from the GRA.¹⁹⁸

13 **D.3.2 Remaining Cost of Service Issues**

14 **D.3.2.1 General**

15 A cost of service methodology establishes the approach to use in the allocation of costs to be
16 recovered from customers. Application of the cost of service methodology to the test year costs
17 provides the amount of costs allocated to each customer class through customer rates. The
18 current cost of service methodology was approved by the Board in 1993 subsequent to a cost of
19 service methodology hearing.

20
21 At the current GRA, Hydro proposed cost of service approaches for new cost items (i.e., wind
22 purchases and capacity assistance agreements) as well as changes to currently approved
23 methodologies due to changing circumstances (i.e., Rural deficit Allocation and Holyrood
24 capacity factor).

¹⁹⁵ Settlement Agreement, page 3, paragraph 16.

¹⁹⁶ Supplemental Settlement Agreement, page 3, paragraph 12.

¹⁹⁷ Settlement Agreement page 3, paragraph 19. The status of the agreement will be reviewed in the COS generic hearing referred to in paragraph 23 of the Settlement Agreement.

¹⁹⁸ Settlement Agreement, page 4, paragraph 20. The status of the agreement will be reviewed in the cost of service generic hearing referred to in paragraph 23 of the Settlement Agreement.

1 As stated, Hydro will be filing a cost of service methodology review in 2016 which will deal with,
2 among other items, cost of service issues arising from the Labrador-Island interconnection.

3
4 The initial Settlement Agreement and the Supplemental Settlement Agreement provided
5 agreement on most cost of service methodology issues. The cost of service methodology items
6 not agreed upon in the current GRA include the:

- 7 • Basis for the allocation of the Rural Deficit;
- 8 • Basis for the allocation of operating and maintenance costs to specifically assigned
9 assets for the use in determining specifically assigned charges to IICs; and
- 10 • IIC load forecast to be used in the 2015 Test Year.

11 12 **D.3.2.2 Rural Deficit Allocation**

- 13 • ***In the interest of fairness, the Rural Deficit should be allocated based on revenue***
14 ***requirement.***

15 16 *Background*

17 In its original Application, Hydro used the Rural Deficit allocation approach approved in
18 February 1993 as a result of the Cost of Service Methodology hearing.¹⁹⁹ In CA-NLH-166, the
19 Consumer Advocate asked Hydro to comment on the fairness of the methodology. In
20 conducting a fairness assessment, Hydro reviewed past statements of the Board with respect to
21 the treatment of the Rural Deficit.

22
23 On page 84 of the 1993 COS Methodology Report, the Board provided guidance on assessing
24 fairness for the Rural Deficit allocation when it stated:

25
26 *Fairness cannot be assessed as due to the method used but instead we must*
27 *assess fairness on the basis of the result, a shared burden among the classes of*
28 *customers that is fair to all and not discriminatory.*

¹⁹⁹ For the origins of the mini cost of service approach, refer to Amended Application, Evidence page 4.7, footnote 5.

1 In Order No. P.U. 7(1996-97) following NP's General Rate Application, the Board stated²⁰⁰:

2

3 *The matter of whether or not the transfer of the Rural Subsidy from Government*
4 *to Hydro and then on to its customers is a tax or cross-subsidy between utility*
5 *customers was debated before the Board and dealt with in its report entitled*
6 *"Referral by Newfoundland and Labrador Hydro for the Proposed Cost of Service*
7 *Methodology" in February 1993. The Board's conclusion in that Report was that*
8 *the Rural Subsidy was not a tax, but a form of cross-subsidization even though it*
9 *was in the extreme.*

10

11 In that same Order, the Board also stated:

12

13 *The Board confirms its previous opinion in the February 1993 ... that the Rural*
14 *Subsidy is a form of cross-subsidization, and must be dealt with as all other*
15 *expenses.*

16

17 No specific direction has been provided by Government on the methodology for allocation of
18 the Rural Deficit other than to exempt Industrial Customers from subsidizing Hydro's Rural
19 Customers.

20

21 This is the first GRA in which: (i) uniform rates are in place for customers on the LIS; and (ii)
22 none of the Secondary Revenue Credit is applied to reduce the revenue requirement for the
23 LIS.²⁰¹

²⁰⁰ Order No. P.U. 7(1996-97), page 89.

²⁰¹ Rates for Labrador Interconnected customers did not reflect recovery of any of the Rural Deficit until September 2002. In 2002, approximately \$5.0 million of the Rural Deficit was allocated to the LIS, but the impact of this initial allocation was largely offset by the application of a revenue credit of \$3.7 million from secondary energy sales to CFB Goose Bay. In Order No. P.U. 7(2002-2003), the Board decided that the Secondary Revenue Credit should be applied to reduce the Rural Deficit, rather than being applied as a credit against the cost of service for the LIS. Because of the potential for large customer impacts as a result of this change, the Board required Hydro to propose a plan for implementation, in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. By 2011, the phase-out of the CFB Goose Bay Secondary Revenue Credit was been completed concurrently with the phasing in of uniform rates for Labrador Interconnected

1 **Fairness Assessment**

2 Hydro’s review of the fairness of the Rural Deficit allocation methodology was based on
 3 the customer impacts of recovering the \$64.1 million forecast²⁰² 2015 Test Year Rural
 4 Deficit from customers on the LIS and from customers of NP.

5
 6 Table 4 provides a comparison of the Rural Deficit impact per customer under the
 7 existing method compared to an allocation based on revenue requirement and an
 8 allocation based on the number of customers served.²⁰³

10 **Table 4**

| Average Annual Cost per Customer Comparison²⁰⁴ | | | |
|--|-----------------|--------------------|------------------|
| | Existing | Revenue | Number of |
| | Method | Requirement | Customers |
| | Method | Method | Method |
| Labrador Interconnected | \$653.15 | \$207.60 | \$235.23 |
| Newfoundland Power | <u>\$216.64</u> | <u>\$236.46</u> | <u>\$235.23</u> |
| Difference | (\$436.51) | \$28.86 | \$ – |

11
 12 Under the existing methodology, customers on the LIS would bear average annual Rural Deficit
 13 costs of \$653.15, roughly three times more than the \$216.64 that would be borne by customers
 14 of NP.²⁰⁵

customers. See Amended Application, Rates and Regulation Evidence, page 4.14, footnote 21; NP-NLH-407 and October 5, 2015 Transcript, pages 161-164.

²⁰² Amended Application, Volume II, Exhibit 13, Schedule 1.2, Page 1 of 6, column 5, line 14.

²⁰³ Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.

²⁰⁴ Total 2015 Test Year deficit allocated divided by number of customers on LIS and number of customers served by NP.

²⁰⁵ Amended Application, Evidence, page 4.8, lines 12-18. As Hydro noted, “[t]he higher deficit allocation per customer is primarily related to the attributes of the Existing Methodology that provides for increased deficit allocation to the system with higher average energy usage.” Amended Application, Evidence, page 4.8, line 18 to Page 4.9, Line 2. For documentation of Labrador Interconnected customer’s higher average energy use, refer to Amended Application, Evidence, page 4.9, footnote 9.

1 The revenue to cost ratio for Labrador Interconnected customers in the 2015 Test Year under
2 the existing methodology is 1.42, while the revenue to cost ratio for NP customers is 1.12.²⁰⁶
3 The relatively higher allocation of the Rural Deficit to Labrador Interconnected customers than
4 to NP customers occurs under the existing methodology primarily because higher average
5 energy usage drives a greater allocation of the Rural Deficit. The higher average use for
6 customers on the LIS primarily results from living in an area of the Province where the climate is
7 colder.²⁰⁷ Hydro believes that the existing methodology does not produce a reasonable sharing
8 of the Rural Deficit between Labrador Interconnected customers and NP customers.

9
10 Fairness in rates is commonly assessed based on revenue to cost ratios. The use of revenue
11 requirement as a basis of Rural Deficit allocation results in the revenue to cost ratio in the 2015
12 Test Year Cost of Service Study for Hydro Rural Labrador Interconnected Customers being equal
13 to the revenue to cost ratio for NP (i.e., 1.13).²⁰⁸ Use of revenue requirement as the allocator
14 results in an average allocated annual cost per customer that that is slightly higher for NP
15 customers than for customers on the LIS.²⁰⁹

16
17 Hydro also evaluated the use of the number of customers as the allocator. If an allocation
18 based on the total number of customers is used, the average annual cost per customer of the
19 Rural Deficit for Labrador Interconnected and NP customers is the same.²¹⁰ While this
20 approach would eliminate the difference in average cost per customer between the customers
21 of NP and on the LIS, the use of the number of customers as an allocator would create fairness
22 concerns between classes on the same system.²¹¹ If the Rural Deficit within a system was
23 allocated on the number of customers, the vast majority of the Rural Deficit would be allocated
24 to the Domestic class within each system because Domestic customers comprise the largest
25 number of customers.

²⁰⁶ Amended Application, Rates and Regulation Evidence, page 4.9, Table 4.2.

²⁰⁷ Amended Application, Rates and Regulation Evidence, page 4.10, lines 1-4.

²⁰⁸ Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1, column 8, line 3.

²⁰⁹ Amended Application, Rates and Regulation Evidence, page 4.10, lines 16-18 and page 4.10, Table 4.3.

²¹⁰ Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.

²¹¹ Amended Application, Rates and Regulation Evidence, page 4.11 and footnote 13, page 4.11.

1 Hydro is proposing the Rural Deficit commencing January 1, 2014 be allocated by
2 system, based upon revenue requirement. Hydro’s proposed approach would allocate
3 on average an additional \$19 per year to NP’s customers. This represents an additional
4 0.7% increase for these customers.²¹²

5
6 The revenue requirement methodology proposed by Hydro gives consideration both to the
7 lower rates and higher usage of Labrador Interconnected customers, whereas the existing
8 methodology focuses more on the lower rates and thereby shifts more costs to customers on
9 the LIS.²¹³ The impact of Hydro’s proposed methodology is that the Rural Deficit will comprise
10 8% of customer charges from NP’s customers, and 12% of charges to retail customers on the
11 LIS.²¹⁴ On an absolute dollar basis, NP customers on average would pay somewhat more than
12 Labrador Interconnected customers,²¹⁵ but on the basis of percentage of revenue requirement
13 the impact would be higher for Labrador Interconnected customers. Using the revenue
14 requirement allocation method, the allocated cost per customer is \$236.46 for customers of NP
15 and \$207.60 for customers on the LIS. This difference reflects 14% higher average cost to serve
16 NP’s customers.²¹⁶ Hydro submits that this is a fair overall result and is more reasonable than
17 the outcome of the existing methodology.

18

19 ***Position of Intervenors***

20 All of the expert witnesses who gave evidence on this issue, except for Mr. Brockman on behalf
21 of NP, support a change from the existing allocation methodology. Mr. Greneman indicated
22 that fairness in the allocation of the rural deficit is most equitably apportioned on revenues,
23 which gives consideration to both of the revenue components (i.e., electricity rate and
24 customer load requirements).²¹⁷

²¹² October 9, 2015 Transcript, page 95, line 7 to page 96, line 11.

²¹³ October 5, 2015 Transcript, pages 198-199.

²¹⁴ October 5, 2015 Transcript, pages 199-200.

²¹⁵ Amended Application, Rates and Regulation Evidence, page 4.10, Table 4.3.

²¹⁶ October 6, 2015, Transcript, page 95, lines 17 - 24.

²¹⁷ NP-NLH-414.

1 Dr. Feehan for the Labrador Towns said that the current approach should be replaced by one
2 that ensures a more equal outcome and one of the alternative methods that he proposed for
3 consideration is comparable to one of the alternatives evaluated by Hydro.²¹⁸ Mr. D. Bowman
4 for the Consumer Advocate indicated that allocation of the Rural Deficit on the basis of either
5 revenue requirement or the number of customers is preferred over the current allocation
6 methodology.²¹⁹ Mr. Raphals for the Innu Nation recommended a fresh look at the
7 methodology for the allocation, as proposed by Hydro.²²⁰ Dr. Wilson for the Board stated
8 “[e]ither a revenue or per customer allocation would appear to be more equitable than the
9 existing allocation.”²²¹

10
11 Mr. Brockman for NP appeared to consider Hydro’s use of revenue to cost ratios in its fairness
12 assessment as inappropriate. He indicated Hydro’s approach was a “strange usage of revenue
13 to cost ratios”.²²² Hydro respectfully submits that Mr. Brockman’s statement is perplexing.
14 Hydro has presented the revenue to cost ratios to isolate the impact of the Rural Deficit on
15 each customer group in the same manner in each GRA since 1990. Mr. Brockman has
16 participated in most, if not all, of those proceedings.²²³

17 Mr. Brockman should recognize that the revenue to cost ratios for both NP’s customers and the
18 customers on the LIS are above 1.0 because the revenue to cost ratio for Hydro Rural
19 Customers is 0.51.²²⁴

20
21 The revenue to cost ratios show the ratio of the revenues collected based on the test year
22 forecast to the cost to provide service based on the allocation methodology approved by the
23 Board. No other experts expressed concerns with the use of revenue to cost ratios in evaluating

²¹⁸ Amended Application, Rates and Regulation Evidence, page 4.12, lines 6-11.

²¹⁹ Amended Application, Rates and Regulation Evidence, page 4.12, lines 13-19.

²²⁰ Amended Application, Rates and Regulation Evidence, page 4.12, lines 21-23.

²²¹ NLH-PUB-007.

²²² September 29, 2015 Transcript, page 202, lines 21-22.

²²³ Mr. Brockman’s witness profile states that he has presented evidence on behalf of NP, concerning cost of service, rate design and least cost planning in Hydro’s 1990, 1992, 2001, 2003 and 2006 general rate referrals, as well as in Hydro’s 1992 generic cost of service hearing, the 1995 Rural Rate Inquiry and Hydro’s 2009 and 2013 Applications concerning the RSP and Industrial Rates.

²²⁴ Amended Application, Volume II, Exhibit 13, Schedule 1.2, page 1 of 6, column 8, line 14.

1 the fairness of the existing Rural Deficit allocation methodology. Hydro submits the revenue to
2 cost ratio provides valuable information to the Board in evaluating the fairness of the Rural
3 Deficit.

4

5 Mr. Brockman believes the current allocation methodology is reasonable.²²⁵ In the allocation of
6 customer-related costs, the existing methodology effectively assumes there are more
7 customers on the LIS than the number of customers served by NP. Mr. Brockman also considers
8 this a reasonable approach.

9

10 Mr. Brockman states it is difficult to assess “fairness” in the allocation of the Rural Deficit. His
11 difficulty appears to be because the Rural Deficit is not causally related to the customers
12 responsible for funding it.²²⁶ Because of the disconnect between the customers creating the
13 costs and the customers that have to pay the costs, Mr. Brockman appears unwilling to
14 consider revenue to cost ratios and customer impacts in evaluating the fairness of the Rural
15 Deficit allocation methodology.

16

17 **Summary**

18 The Regulatory Framework provided in Appendix A of Order No. P.U. 8(2007) included the
19 fundamental principles used by the Board as a guide to rational decisions. Hydro submits that
20 fair cost apportionment and the end result are the regulatory principles that should be
21 considered by the Board in assessing the fairness of the Rural Deficit allocation methodology.

22 The Regulatory Framework provides the following description of each:

23

24 Fair Cost Apportionment

25 *Fairness of specific rates in the apportionment of total costs of service among the*
26 *different ratepayers should be such so as to avoid arbitrariness, capriciousness,*
27 *inequities or discrimination. Under this principle, customers in similar situations*
28 *should be treated equally (horizontal equity), while those in different situations*

²²⁵ NLH-NP-022.

²²⁶ NLH-NP-022.

1 *should be treated differently (vertical equity). This principle would not deny cross-*
2 *subsidization of rates among customers of equal circumstances but such*
3 *subsidization should not cause undue discrimination. The principle of horizontal*
4 *equity (i.e. equals treated equally) is set forth in Section 73(1) of the Act which*
5 *requires that “all tolls, rates and charges shall always, under substantially similar*
6 *circumstances and conditions in respect of service of the same description, be*
7 *charged equally to all persons and at the same rate, ...”. Furthermore, the aspect*
8 *of undue discrimination also has statutory reinforcement in Section 3(a)(i) of the*
9 *EPCA which declares it to be “...the policy of the province that the rates to be*
10 *chargedshould be reasonable and not unjustly discriminatory.”*

11
12 End Result

13 *In compliance with the legislation, the end result must be fair, just and reasonable*
14 *from the perspective of both the consumer and utility.*

15
16 The Regulatory Framework also states that: “[t]he Board has discretion to choose the approach
17 to setting rates as long as it observes the legislation and sound utility practices.” The Board has
18 been provided no legislative direction on the Rural Deficit allocation methodology (other than
19 the exemption of funding from the IICs). Therefore, the Board is required to adhere to sound
20 utility practice in its determination of a fair approach to the apportionment of the Rural Deficit
21 with the objective of achieving an end result which must be fair, just and reasonable from the
22 perspective of both the consumer and utility.

23
24 Hydro submits that the existing Rural Deficit allocation methodology is not fair to Hydro Rural
25 customers on the LIS. Hydro submits that the evidence before the Board in the GRA supports
26 the use of revenue requirement as a fair and reasonable basis for allocation of the Rural Deficit
27 in the cost of service methodology.

1 **D.3.2.3 Allocation of O&M Costs to Specifically Assigned Assets**

- 2 • **Hydro's O&M costs attributable to specifically assigned assets should be allocated**
3 **according to their relative value stated in constant 2015 dollars, rather than original cost.**

4
5 In the current cost of service methodology, the cost of capital assets that are used solely for the
6 provision of service to a single customer are functionalized as specifically assigned. Specifically
7 assigned costs are to be recovered from the customer for which the related assets provides
8 service. There are currently transmission assets in service that are specifically assigned to IIC's.
9 Customers are required to pay specifically assigned charges that recover the cost of return,
10 depreciation and operating and maintenance costs for specifically assigned assets. For
11 customers that paid a contribution for 100% of the capital investment, the specifically assigned
12 charge would only recover the operating and maintenance costs. The specifically assigned
13 charges are updated in each GRA Test Year.

14
15 In the 2015 COS study, direct O&M costs are classified/allocated based on the original cost of
16 the plant in service (which is accounted for in the in-service year dollars). Administrative and
17 General O&M expenses are classified/allocated based on a series of calculations using plant in
18 service and direct O&M.

19
20 Mr. Dean argued that using original cost to pro rate O&M expense assigns too much cost to
21 newer facilities, like the specifically assigned facilities constructed for Vale:

22 *The prorating of O&M costs using plant in service without accounting for the*
23 *time value of money has the potential to achieve inequitable results. This*
24 *possibility is heightened with an electrical system consisting of new and old*
25 *assets as one is comparing vastly different original costs. ... As such, the total of*
26 *Vale's plant in service measured in 2012 dollars is being prorated against plant in*
27 *service values that are based on 1960's dollars.*²²⁷

²²⁷ Pre-filed Evidence of Mr. Dean, June 4, 2015, page 10, line 16 through page 11, line 2.

1 To correct the situation, Mr. Dean argued that O&M apportionment should be based on assets
2 valued in constant dollars.²²⁸

3
4 Hydro acknowledges that the existing methodology may not be ideal in allocating O&M costs to
5 specifically assigned charges. This is because there is an inherent inverse relationship whereby
6 older plant that cost less at the time of installation, generally requires more O&M than more
7 expensive newer plant.²²⁹ An alternate approach to the allocation of the direct transmission
8 portion of O&M expense to specifically assigned charges is to use current dollars (2015 \$) as a
9 basis to reallocate the direct transmission O&M expense calculated in the 2015 Test Year COS
10 study between specifically assigned charges and common.²³⁰

11
12 Based on its 2015 Test Year COS Study, Hydro calculated how much the O&M cost allocations to
13 specifically assigned assets would change if the allocations were based on transmission assets
14 values stated in constant 2015 dollars instead of original costs. The result of the analysis
15 transferred approximately \$600,000 of O&M costs from specifically assigned costs to common
16 costs. The materiality of the customer impact of using current dollars rather than original costs
17 as the basis for O&M cost allocation to specifically assigned assets supports Mr. Dean's position
18 with respect to the concerns with the current approach.²³¹

19
20 The use of the approach proposed by Mr. Dean is comparable to the method used by NP in
21 determining the amount of O&M costs reflected in the cost factors that apply in determining
22 CIAC from customers for distribution line extensions.²³² The CIAC cost factors reflect operating
23 and maintenance costs based on a percentage of indexed asset costs.²³³ This approach was

²²⁸ Pre-filed Evidence of Mr. Dean, June 4, 2015, page 12, lines 3-5.

²²⁹ V-NLH-083 (Revision 1, June 23, 2015), page 1, lines 17-24. October 6 Transcript, pages 58, line 12 to 59, line 1.

²³⁰ See Amended Application, Volume II, Exhibit 13, Schedule 2.4A, Page 1 of 2, Col 5, Line 11 and Col 18, Line 11 for the total direct transmission O&M expense under the current COS methodology (i.e., \$5,522,963 + \$1,285,395 = \$6,808,358).

²³¹ Undertaking No. 45.1, Attachment 1 includes an updated 2015 Test Year Cost of Service model which reflects the impacts of using the revised methodology for allocating specifically assigned O&M expense proposed in V-NLH-083 (i.e., reflecting indexed plant values).

²³² Response to V-NLH-125.

²³³ The CIAC cost factors are submitted annually by NP for approval by the Board.

1 implemented following the 1997 hearing on the CIAC Policy and replaced the previous
2 approach that was based on the use of original costs.²³⁴ The contexts are different, but the
3 reason for using indexed costs to allocate O&M costs is the same and supports Board approval
4 of Vale’s position on O&M cost allocation.

5
6 Hydro provided the 2015 Test Year COS Study reflecting the use of indexed asset costs for the
7 purpose of allocation of O&M costs to specifically assigned assets. Hydro submits this approach
8 provides a fairer result and should be adopted for the cost of service methodology in the
9 current GRA. The Cost of Service Methodology review scheduled for 2016 will provide an
10 opportunity to perform a more comprehensive review the overall approach to determining
11 specifically assigned charges to the IICs.²³⁵

12 13 **D.3.2.4 IIC Load Forecast for 2015 Test Year**

- 14 • ***Hydro’s proposed IIC rates are reasonable; normalization for expected industrial load is***
15 ***unwarranted.***

16
17 Hydro’s proposed rates reflect the 2015 forecast load for the IICs in the 2015 Test Year. Mr. D.
18 Bowman, expert for the Consumer Advocate, presented evidence that the rates derived for the
19 2015 load forecast for IICs are not just and reasonable. Mr. D. Bowman recommended that the
20 Board adjust the test year to reflect loads during the 2015 to 2017 period.²³⁶

21
22 Hydro disagrees with Mr. D. Bowman’s assessment. Mr. Fagan for Hydro stated:

23
24 *The proposed firm demand rate and firm energy rate for IC, in combination*
25 *with the operation of the RSP, are reasonable for recovering the cost of*
26 *servicing the IC class for the period 2015 to 2017. As the IC load increases, the*
27 *new customers will pay increased demand cost as a result of their increased*

²³⁴ October 6, 2015, Transcript, page 62, lines 7-9.

²³⁵ October 6, 2015 Transcript, pages 78, line 15 to 79, line 22.

²³⁶ Pre-filed Evidence of Mr. D. Bowman, June 1, 2015, pages 23-24. For Mr. D. Bowman’s direct testimony on this issue, refer to September 30, 2015 Transcript, pages 21, line 25 to 24, line 16.

1 *demand requirements. The customers will also pay increased energy charges*
2 *based on the firm energy rate and the additional RSP charges to recover*
3 *increased fuel costs due to their load growth.*

4
5 *Normalization to reflect higher future loads in the allocation of the 2015 Test*
6 *Year revenue requirement will result in reflecting the future cost of serving IC*
7 *load in current rates. Allocation of a higher proportion of costs to Industrial*
8 *Customers based on the 2017 forecast will have the effect of materially*
9 *increasing the rates to be charged IIC and result in over-recovering the cost of*
10 *servicing Industrial Customers in both the test year and in future years.*

11
12 *The load forecast reflected in the 2015 Test Year includes Vale and Praxair as*
13 *high load factor customers and therefore no normalization is required.*²³⁷

14
15 The analysis provided in Undertaking No. 44 indicates that normalization to reflect higher
16 future loads in the allocation of the 2015 Test Year revenue requirement will result in reflecting
17 the future cost of serving IIC load in current rates. Allocation of a higher proportion of costs to
18 IIC based on the 2017 forecast will have the effect of materially increasing the rates to be
19 charged IIC and result in rates that over-recover the cost of serving IIC.

20
21 The presence of increased forecast load beyond 2015 for the IICs is not sufficient, in itself, to
22 warrant normalization. Normalization is warranted only when the Test Year rates are
23 anomalous and normalization will address the anomaly.

24
25 The load forecast reflected in the 2015 Test Year includes Vale and Praxair as high load factor
26 customers and therefore no normalization is required. Hydro submits that the IIC load forecast
27 used in the 2015 Test Year is appropriate for establishing reasonable rates.

²³⁷ October 5, 2015 Transcript, pages 99, line 6 to 100, line 9.

1 **D.3.3 Remaining Rates Issues**

2 **D.3.3.1 General**

3 Hydro has not proposed material changes in customer rate designs in the Amended Application.
 4 The settlement agreements reflect a continuation of current rate designs for NP and the IICs
 5 pending conclusion of the planned studies discussed in Section D.3.1.1. These studies scheduled
 6 for completion over the next 12 months will provide updated information on marginal costs,
 7 cost allocation issues, rate designs and supply cost recovery mechanisms.

8

9 The Settlement Agreement and the Supplemental Settlement Agreement provided agreement
 10 on many rates issues. The rates issues not reflected in the agreements include:

- 11 • The continuation of the load variation component in the RSP;
- 12 • The disposition of the RSP load variation component balance that accumulated for the
 13 period September 1, 2013 to December 31, 2014;
- 14 • The deferred rate increases proposed to apply to Hydro Rural customers on Isolated
 15 Systems; and
- 16 • The proposed Labrador Industrial Transmission Rate.

17

18 **D.3.3.2 RSP Load Variation Component**

- 19 • ***The load variation component of the RSP should be maintained.***

20

21 The IIC load is forecast to grow materially in 2016 and 2017 because two new IICs are in the
 22 process of becoming fully operational (250 GWH cumulative load growth over 2016 and
 23 2017).²³⁸ The generation utilized to serve the IIC load growth between Test Years will be
 24 supplied by from Holyrood.

25

26 The cost incurred to serve this additional load based on the Amended Application is
 27 approximately 15¢ per kWh.²³⁹ The additional energy revenues from IIC under the proposed
 28 rate are based on an energy rate of 5.151¢ per kWh. The load variation component in the RSP

²³⁸ Undertaking No. 45.1

²³⁹ Amended Application, Rates and Regulations Evidence, page 4.22, line 23.

1 allows Hydro to recover the net loss on sales growth to the IICs. For the period 2016 and 2017,
2 the load variation permits Hydro to recover approximately \$42 million in fuel costs that will not
3 be recovered through the IIC base rate.²⁴⁰

4
5 Mr. P Bowman has recommended elimination of the Load Variation Component in the RSP.²⁴¹
6 However, Mr. P. Bowman also states “...it is conceivable that the best time to eliminate the
7 provision is upon initiation of the Labrador infeed, in the event a lower incremental cost of
8 power is incorporated into the purchase rates”.²⁴² The Settlement Agreement provides for a
9 review of all components of the RSP in 2016 in addition to a review of the IIC rate design. Hydro
10 submits it is not appropriate to eliminate the RSP load variation component prior to the
11 implementation of a new IIC rate design that permits reasonable recovery of the marginal cost
12 to provide service to the IIC.

14 **D.3.3.3 Disposition of the Balance in the RSP Load Variation Component**

- 15 • ***The balance accumulating in the RSP load variation component that has accumulated***
16 ***since September 1, 2013, should be allocated among Hydro’s customer groups based on***
17 ***energy ratios.***

18
19 In the Settlement Agreement, all Parties agreed that if the load variation component is
20 maintained as an element of the RSP, year-to-date net load variations for NP and IICs shall be
21 allocated among the customer groups based upon energy ratios, with the effective date to be
22 determined by the Board.²⁴³

23
24 The amounts that accumulated in the RSP load variation component for the period 2007 to
25 August 31, 2013 have been transferred to the RSP surplus for disposition in accordance with the
26 Government directive. The forecast balance in the RSP load variation component as of

²⁴⁰ The forecast load growth for IIC and the forecast RSP load variation component transfers are provided in Undertaking No. 44.

²⁴¹ Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 47, lines 27 - 28.

²⁴² Pre-filed testimony of P. Bowman and H. Najmidinov, June 4, 2015, page 48, lines 19 - 21.

²⁴³ Settlement Agreement, page 3, paragraph 16.

1 December 31, 2014 is approximately a \$33 million credit to customers.²⁴⁴ Hydro is proposing to
 2 allocate this balance based on an energy ratio allocation effective September 1, 2013, which
 3 would result in an allocation of approximately \$31 million to NP and approximately \$2 million
 4 to the IICs.²⁴⁵

5
 6 Mr. D. Bowman for the Consumer Advocate recommended that “the Board order that the
 7 money that has accumulated in the load variation component of the Island Industrial Customer
 8 RSP account since September 1, 2013 be transferred to the RSP account of Newfoundland
 9 Power.”²⁴⁶

10
 11 Hydro disagrees with Mr. D. Bowman’s recommendation. The use of energy ratios for allocation
 12 of fuel savings resulting from load variation balances that accumulated for that period is
 13 consistent with the manner that RSP fuel price variations were allocated in the RSP for that
 14 same period.²⁴⁷ Therefore, Hydro submits that it is appropriate that the RSP rules related to the
 15 allocation of the load variation component be modified such that the year-to-date net load
 16 variation for both NP and IC is allocated among the customer groups based upon energy ratios
 17 effective is September 1, 2013.²⁴⁸

18
 19 **D.3.3.4 Implementation of the Deferred Rate Increase**

- 20 • ***The Board should approve the proposed above average increases in customer rates for***
 21 ***Hydro Rural non-Government Domestic and General Service customers on isolated***
 22 ***systems.***

23
 24 In the Amended Application, the proposed rate increases for Hydro Rural non-Government
 25 Domestic and General Service customers on isolated systems are higher than the average

²⁴⁴ Per Order No. P.U. 29(2013), load variation is to be segregated in a separate account within the RSP.

²⁴⁵ Load variations transfers for 2015 on an interim basis will need to be recalculated to reflect the approved 2015 Test Year rates and the 2015 Test Year fuel cost assumptions.

²⁴⁶ Pre-filed evidence of D. Bowman, June 1, 2015, page 14, lines 12-15.

²⁴⁷ Amended Application, Evidence, Section 4.71.

²⁴⁸ The amounts that accumulated in the load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP Surplus for disposition in accordance with the Government directive.

1 increase proposed for the Hydro Rural Island Interconnected customers. The proposed above
2 average increases result from the combined effect of (i) the 2015 Test Year forecast change in
3 rates for Island Interconnected customers and (ii) the increase in rates to implement the 2007
4 rate change that was deferred as a result of Government directives.

5
6 The non-lifeline portion of the Domestic energy rate²⁴⁹ and both small and large general service
7 diesel rates²⁵⁰ were proposed to increase by 15% in 2007 to reflect the increased cost of fuel
8 since the previous GRA. However, the 2007 proposed rate increase was not implemented in
9 2007 as a result of OC2006-512. Additional Government directives have been provided each
10 year, which have continued to defer the 2007 rate increases. The most recent Government
11 directive on this matter provides that in 2016 the customer rates shall be those that would have
12 come into effect but for the Government directives.

13
14 Hydro submits that approval of higher than average increases for Hydro Rural non-Government
15 Domestic and General Service customers is consistent with the Government directive on this
16 matter.

17 18 **D.3.3.5 Labrador Industrial Transmission Rate**

- 19 • ***Hydro's proposed transmission demand charge for service to Labrador Industrial***
20 ***Customers should be approved.***

21
22 Hydro has proposed a transmission demand charge to be applied to Labrador Industrial
23 Customers. The calculation of the demand charge is based on the portion of the transmission
24 revenue requirement determined in accordance with the COS functionalization, classification
25 and allocation methods previously approved by the Board.²⁵¹

²⁴⁹ For Domestic Customers, the 15% is applicable to only non-lifeline energy rates. The 2007 deferred rate increase for Domestic Customers would have resulted in an overall increase of 4%.

²⁵⁰ Prior to 2007, there was no annual RSP adjustment reflecting the rate change to the customers of NP.

²⁵¹ Amended Application, Rates and Regulations Evidence, page 48.

1 Hydro notes that the Billing Demand definition in the proposed Labrador Industrial
2 Transmission Rate does not address the treatment of Labrador Industrial interruptible load.
3 Hydro will be filing an application in January 2016 to address this matter in the terms of the
4 rate. This modification will not impact the calculation of proposed firm transmission demand
5 charge based on the 2015 Test Year costs.

6

7 Hydro submits that the Board should approve the methodology used by Hydro to compute the
8 proposed Labrador Transmission demand charge of \$1.25 per kW per month.

9

10 **D.3.3.6 Uniform Rates for Labrador Interconnected Customers**

- 11 • ***The proposed uniform rates for Labrador Interconnected System customers are***
12 ***reasonable.***

13

14 In Order No. P.U. 7(2002-2003), the Board approved that Hydro develop a plan to phase-in
15 uniform rates for customers on the LIS. The phase-in of uniform rates on the LIS was concluded
16 in 2011. Prior to 2011, different rate schedules applied to customers in Labrador East and
17 Labrador West.²⁵²

18

19 Mr. P. Raphals, the expert representing the Innu Nation, recommended that a rate rider should
20 be considered to apply to customers in Labrador West due to the magnitude of the capital costs
21 resulting from the Labrador City distribution upgrade.²⁵³ This recommendation is effectively
22 requesting the Board to reverse its decision on uniform rates that which was only recently
23 implemented.

24

25 Hydro notes that in Order No. P.U. 7(2002-2003), the Board did not approve the proposal of the
26 Labrador West customers requesting for Hydro to maintain a separate set of rates for Labrador

²⁵² Because of the potential large customer impacts of making this rate change, the Board required Hydro to propose a plan for implementation at its next rate hearing in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. The current GRA is the first hearing before the Board in which the Secondary Revenue Credit is fully credited to the Rural Deficit.

²⁵³ Pre-filed Evidence of Philip Raphals, June 23, 2015, page 37.

1 West. The application of a single set of rates on the LIS is consistent with the use of a single cost
2 of service study for the LIS, as approved by the Board. Hydro believes the evidence before the
3 Board does not demonstrate that the uniform rate schedules proposed by Hydro result in rate
4 discrimination to customers in Labrador East. Therefore, Hydro submits that Mr. Raphals'
5 recommendation for a rate rider to apply to customers in Labrador West should be denied.

7 **Section D.4: Supply Cost Rated Deferral and Recovery Mechanisms**

9 **D.4.1 Hydro's Proposed Supply Cost Related Deferrals**

- 10 • *Hydro should have a reasonable opportunity to recover supply costs prudently incurred in*
11 *providing service to customers.*
- 12 • *Receiving a government-directed ROE also does not justify denying or restricting Hydro's*
13 *use of these accounts due to decreased business risk; the Canadian utilities with supply*
14 *related deferral accounts often have target returns on equity higher than the 8.8%*
15 *directed for Hydro.*

16
17 Hydro has proposed three new supply related deferrals in the Amended 2013 GRA:

- 18 • The Isolated Systems Energy Supply Cost Variance Deferral Account (Isolated Systems
19 Deferral);
- 20 • The Energy Supply Cost Variance Deferral Account (Energy Supply Deferral); and
- 21 • The Holyrood Fuel Conversion Factor Deferral Account (Holyrood Conversion Deferral).

22
23 Recovery of supply costs through deferral mechanisms is common practice in regulatory
24 jurisdictions across Canada.²⁵⁴ Further, regulatory precedent also exists for the approval of such
25 deferral accounts in the context of a government directed return on equity. Specifically, BC
26 Hydro's return on equity has been set by a government directive and BC Hydro was
27 subsequently granted approval by the BCUC for a deferral account to capture variances in non-

²⁵⁴ PUB-NLH-388.

1 heritage supply costs.²⁵⁵ Hydro submits that these precedents are supportive of the
2 aforementioned deferral accounts proposed in the 2013 Amended GRA.

3

4 **D.4.1.1 Isolated Systems Deferral**

5 Hydro has proposed the Isolated Systems Deferral to capture variances from the 2015 Test Year
6 in the cost of supplying customers on Hydro's Isolated Systems. Hydro's cost of supplying these
7 customers is primarily based on the cost of diesel fuel.²⁵⁶ Diesel fuel is a commodity and is
8 priced based on market factors beyond Hydro's control. Since Hydro's 2007 GRA, the price of
9 diesel fuel has experienced significant price volatility, as noted in the following chart found on
10 page 3.47 of Hydro's Amended Application:

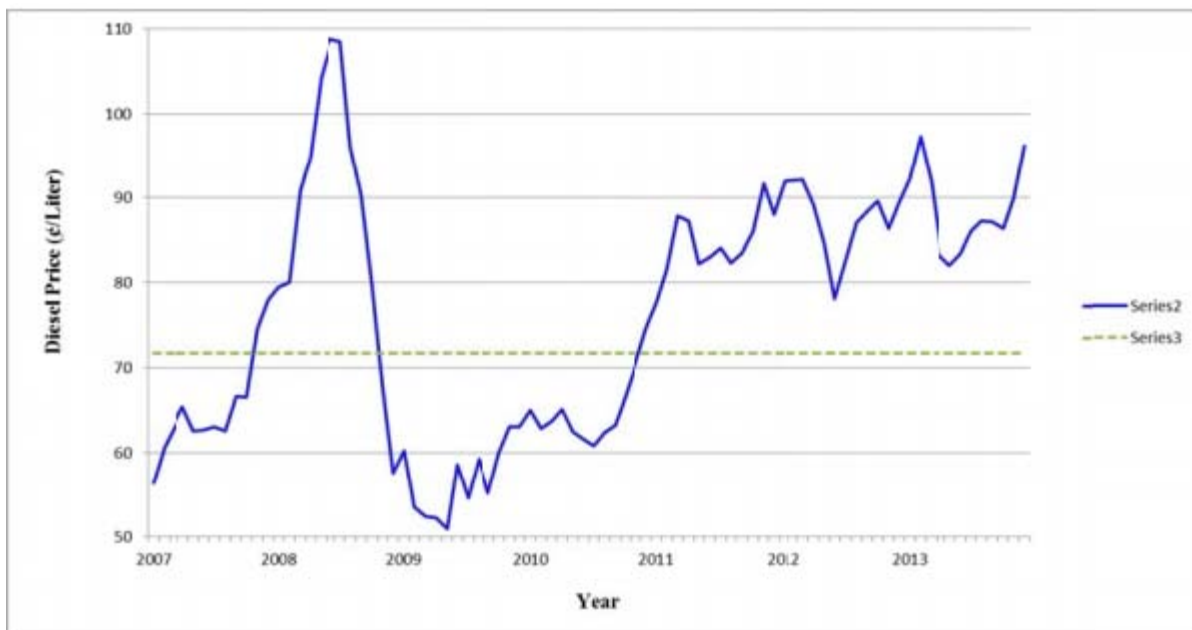
11

12

13

Chart 2

Diesel Fuel Price Variability



14

15 Chart 2 shows the level of volatility Hydro has experienced in the price of diesel fuel between
16 test years. This level of risk has been material since the 2007 Test Year, is beyond

²⁵⁵ November 18, 2015 Transcript, pages 114-120 as well as Undertaking No. 167.

²⁵⁶ The Isolated Systems Account also captures variances in supply costs on isolated systems where costs are based on the price of diesel fuel.

1 management's control, and is appropriate to be dealt with through the proposed deferral
2 account.

3

4 **D.4.1.2 Energy Supply Deferral**

5 Since Hydro's last GRA in 2007, Hydro has acquired a number of new supply sources. These new
6 supply sources, including Exploits, wind generation, and the Holyrood CT have benefited
7 customers either through increased reliability or reduced cost of service. However, variances in
8 Hydro's now more broad supply mix can have a material impact on Hydro's financial results in a
9 given year.

10

11 Without the proposed Energy Supply Account Hydro will be financially disadvantage as a result
12 of: (i) variances beyond its control; (ii) providing greater reliability of service to customers and;
13 (iii) economically optimizing the Holyrood CT in conjunction with the HTGS. These scenarios are
14 discussed in detail below. Hydro submits that approval of this account is consistent with
15 regulatory practice and in the best interest of customers and the utility.

16

17 **D.4.1.3 Holyrood Conversion Deferral**

18 Hydro has proposed a fuel conversion rate of 607 kWh/bbl for the purpose of setting base rates
19 in the 2015 Test Year, a reduction from 630 kWh/bbl approved in the 2007 Test Year. Since
20 2007, Hydro has never achieved the 2007 Test Year conversion rate. In fact, the average
21 conversion rate over this period has been 602 kWh/bbl.²⁵⁷ Table 2.21 on Page 2.75 showed the
22 financial impact to Hydro as a result of the variance in Holyrood Conversion Rate from the 2007
23 Test Year, which is shown below:

²⁵⁷ Calculated as the simple average annual rate from 2007 through 2014 per Hydro's Amended Application, Section 2, Schedule V, page 1 of 4.

1

Table 5

| Holyrood Fuel Conversion Performance and Hydro Financial Impact 2009 - 2014 | | | | | | |
|--|-----------------------|-----------------------|-----------------------|-----------------------|-----------------------|-------------------------|
| | 2009 <u>Actual</u> | 2010 <u>Actual</u> | 2011 <u>Actual</u> | 2012 <u>Actual</u> | 2013 <u>Actual</u> | 2014 <u>Forecast</u> |
| Fuel Consumption ('000 bbls) | 1,534.7 | 1,363.2 | 1,469.2 | 1,428.3 | 1,611.0 | 2,334.5 |
| Actual Fuel Conversion Rate (kWh/bbl) | 612 | 589 | 603 | 599 | 594 | 588 |
| 2007 TY Fuel Conversion Rate (kWh/bbl) | 630 | 630 | 630 | 630 | 630 | 630 |
| Hydro's Financial Loss (\$ million) | 2.4 | 4.9 | 3.5 | 3.9 | 5.1 | 8.8 |

2

3 Table 5 shows that for five of the six years Hydro incurred additional fuel costs of \$3.5 million or
4 greater as a result of the reduction in the fuel conversion rate approved in the 2007 Test Year.
5 Hydro notes that \$3.5 million represents approximately 20 basis points in the range of return
6 on rate base.²⁵⁸

7

8 The most recent estimate of Holyrood's conversion rate is 597 kWh/bbl, and the difference
9 between this estimate and the conversion rate used to calculate the 2015 Test Year results in a
10 \$2.4 million revenue shortfall to Hydro.²⁵⁹ Hydro, in the Amended Application, stated this
11 deterioration of the conversion factor was due primarily to factors beyond Hydro's control.
12 These factors include lower production requirements at Holyrood as a result of reduced system
13 loads, higher energy purchases, and higher levels of hydraulic generation.²⁶⁰ Hydro submits that
14 the utility should not be at risk for material supply cost variances that are beyond its control.

15

16 Mr. P. Bowman, in his pre-filed evidence, states the creation of this deferral would be
17 acceptable:

18

19 *In addition, however, Hydro has proposed a new Holyrood Conversion Rate*
20 *Deferral Account which means that ratepayers collectively will bear the costs of*

²⁵⁸ Transcript, October 6, page 91, line 22 to page 92, line 4.

²⁵⁹ Hydro's Amended 2015 Cost Deferral Application, page 1, Appendix D.

²⁶⁰ Amended 2013 GRA, page 2.74.

1 *whatever change in conversion factor arises in future compared to GRA levels,*
2 *positive or negative. Such an account would normally be of concern as it relates*
3 *to items reasonably within the utility’s risk profile. However, for the current*
4 *hearing given the transitional role of Holyrood, this approach may be*
5 *accepted.*²⁶¹

6
7 In addition to the factors affecting production levels at Holyrood, the BTU content of the fuel
8 affects the conversion factor and therefore Hydro’s costs. Mr. R. Henderson’s in his testimony
9 states:

10
11 *The element here of this that people should be aware of is that we, from buying*
12 *the fuel, we’re buying BTU content which is what is the real heating value of the*
13 *fuel to produce electricity. So we are paying for the BTUs. The problem for Hydro*
14 *with this is that that fuel price variability goes into the RSP to customers. It does*
15 *not come back to Hydro and Hydro suffers the consequence in a lower conversion*
16 *factor and so, the manner in which the BTU -- the kilowatt hours per barrel*
17 *number is fixed, but the BTU content varies. Hydro is taking that while it doesn’t*
18 *obtain any benefit, but the pricing improvement that you get by getting lower*
19 *BTU falls out into the price of oil which goes through the RSP and benefits*
20 *customers. So there’s a disconnect, if you like, in terms of the benefit to*
21 *customers versus the impact to Hydro.*²⁶²

22
23 Hydro has established in its No. 6 fuel supply arrangement a No. 6 fuel purchase price that can
24 vary based on the BTU content of fuel delivered. This practice ensures customers are protected
25 for changes in the BTU content of delivered fuel through the RSP. However, without the
26 proposed Holyrood Conversion Deferral Hydro will continue to be financially disadvantaged for
27 a lower BTU content as the conversion factor assumed in rates will not change with the actual
28 BTU content of the fuel being consumed at the HTGS.

²⁶¹ Pre-filed evidence of P. Bowman dated June 4, 2015, page 3.

²⁶² Testimony of R. Henderson, September 23, 2015, pages 90-91.

1 **D.4.2 Financial Incentives and System Optimization**

- 2 • ***Hydro’s proposed Energy Supply Deferral and the Holyrood Conversion Deferral foster***
3 ***system wide generation dispatching decisions that benefit customers through enhanced***
4 ***reliability.***

5
6 Hydro submits that approval of these proposed deferral accounts would provide Hydro with
7 appropriate financial incentives to operate its system on a reliable, least cost basis. Further,
8 they will ensure Hydro is not financially disadvantaged for optimizing the system for the benefit
9 of customers.

10 11 **D.4.2.1 Reliability**

12 Hydro operates its generating plants to provide reliable service to its customers, by providing
13 sufficient reserves to minimize impacts on customers for single contingency equipment
14 outages. The growth in demand in recent years has resulted in a greater reliance on
15 combustion turbines for this purpose. The addition of the Holyrood CT provides Hydro a greater
16 ability to secure reliable operation for such contingencies. Hydro is currently operating the
17 Holyrood CT to provide additional security of supply. This practice began after the events of
18 March 4, 2015 and is consistent with Liberty’s findings of the same.²⁶³ A further example of this,
19 presented to the Board during Hydro’s GRA hearing, was the required annual planned outage of
20 all units at the HTGS to complete common plant equipment maintenance. Having no units
21 operating on the Avalon Peninsula exposes customers on the Avalon Peninsula to an outage in
22 the event that a transmission line was forced out of service.

23
24 In the past, during the annual total plant outage at the HTGS, Hydro would keep the Hardwoods
25 CT available if such a contingency occurred. The Hardwoods plant does not have sufficient
26 capacity to cover completely customer load requirements, thus leaving some customers
27 exposed to an interruption during a line out contingency. With the addition of the Holyrood CT,
28 and in response to this interruption risk, Hydro has been running the Holyrood CT at minimum

²⁶³ See Liberty Consulting’s Report dated October 22, 2015, page 7, Section 2.

1 output levels during peak periods of the day to provide enhanced reliability. This operational
2 practice began in 2015 in response to enhanced reliability assessments following the March 4,
3 2015 outage event.

4
5 Without the proposed Energy Supply Account Deferral, higher costs resulting from increased
6 generation at the Holyrood CT to provide this higher standard of reliability would be borne by
7 Hydro with no opportunity to recover the additional cost from customers. This scenario creates
8 a financial disincentive for Hydro to operate the Holyrood CT in excess of the forecast test year
9 levels, regardless of whether operation of the Holyrood CT results in more reliable service to
10 customers. Hydro submits that approval of the proposed deferral accounts is consistent with
11 the provision of reliable service to customers.

13 **D.4.2.2 System Optimization**

14 There are times when Hydro has the opportunity to optimize economically the operation of the
15 Holyrood CT in conjunction with the HTGS.²⁶⁴ A scenario where a unit at the HTGS can be
16 brought offline for a week and the Holyrood CT is only used at peak times during that week can
17 result in net fuel cost savings for customers through the RSP.²⁶⁵ Without the proposed Energy
18 Supply Deferral, Hydro would be negatively impacted financially for optimizing the system in
19 this fashion, as the HTGS fuel savings would accrue inside the RSP and flow to customers while
20 all additional CT costs incurred would be borne entirely by Hydro.

21
22 Hydro currently operates the Holyrood CT and HTGS to provide the most reliable, least cost
23 service to customers. Hydro submits that approval of these supply deferrals will ensure Hydro is
24 financially incentivized to provide least cost service to customers on a system wide basis, not
25 just from specific supply sources.

²⁶⁴ GRA Transcript, October 20, pages 132-136.

²⁶⁵ GRA Transcript, September 23, 2015, page 98.

1 **D.4.3 Intervenor Evidence**

2 Two experts in their pre-filed evidence provided opinions against approval of the requested
3 deferral accounts. Mr. D. Bowman for the Consumer Advocate and Mr. Wilson for the Board
4 both opposed the creation of these deferrals in the context of Hydro’s ROE.

5

6 Mr. D, Bowman, on page 5 of his pre-filed evidence states:

7

8 *I recommend that the Board deny Hydro's proposal to establish new supply cost*
9 *variance accounts referred to as the "Isolated Systems Supply Cost Variance*
10 *Deferral Account", the "Energy Supply Cost Variance Deferral Account" and the*
11 *"Holyrood Conversion Rate Deferral Account". There is no justification for*
12 *transferring these risks to consumers when Hydro has been assured a much*
13 *higher, and uncontested, return on equity fixed by Government Directive*
14 *OC2009-063.*

15

16 Hydro submits that Mr. D. Bowman’s conclusion is inconsistent with (i) regulatory precedent in
17 Canada for utilities with government directed ROE; (ii) regulatory precedent for utilities in
18 Canada generally; and (iii) utilities in this province.

19

20 As noted previously, the BCUC in Decision G-96-04 granted approval of a deferral account,
21 which transferred the risk and benefits of supply costs variances to customers. This approval
22 was subsequent to Heritage Special Directive No. 2, which set BC Hydro’s return on equity to
23 the same levels as the most comparable investor-owned utility, grossed up for income tax.²⁶⁶

24

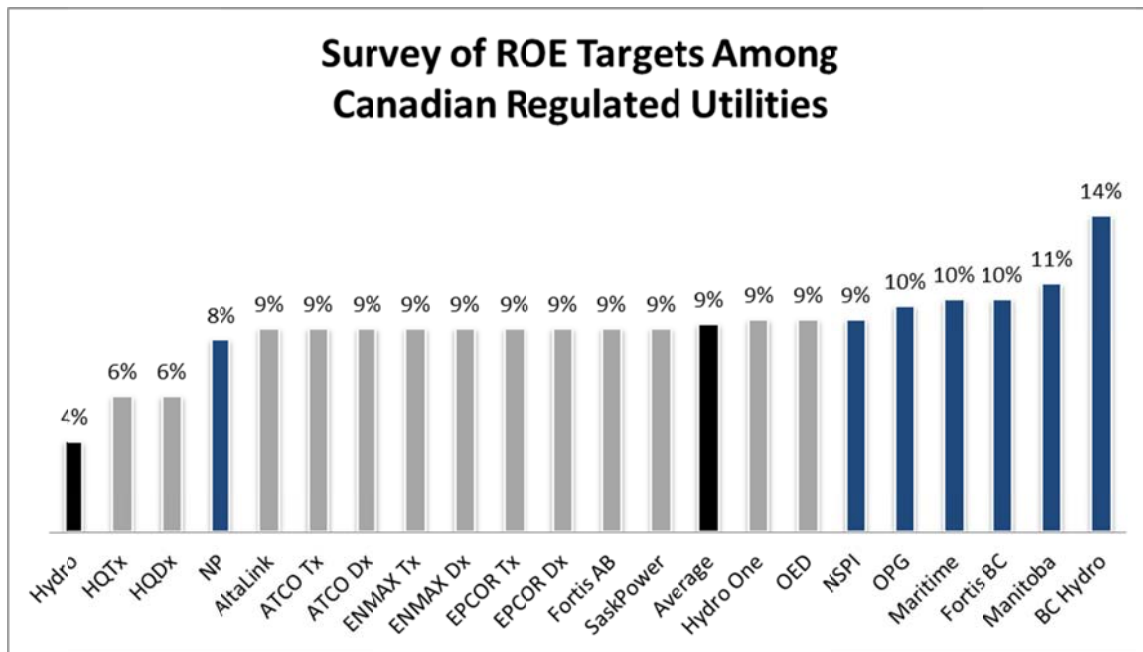
25 Hydro notes that OC2009-063 sets Hydro’s return on equity to that of NP, the only investor-
26 owned regulated utility in this jurisdiction. Hydro submits that Mr. D Bowman’s statement that
27 “there is no justification for transferring these risks to consumers when Hydro has been assured
28 a much higher, and uncontested, return on equity fixed by Government Directive OC2009-

²⁶⁶ Undertaking No. 167.

1 063”is not consistent with Canadian regulatory precedent for utilities with a government
 2 directed ROE.

3
 4 Mr. D. Bowman’s statement is also contradictory to utility practice in other jurisdictions across
 5 Canada. Mr. D. Bowman has only considered the change in Hydro’s ROE from 2007. He has not
 6 considered whether these risks existed at the time that ROE was approved nor has he
 7 considered whether these deferrals are consistent with an ROE of 8.8% when compared to
 8 other utilities across Canada. Page 3.35 of Hydro’s Amended Application provided a chart
 9 showing the ROE targets of other Canadian utilities. This chart is presented below, with utilities
 10 with approved supply deferrals per Hydro’s response to PUB-NLH-388, noted in blue:

11
 12 **Chart 3**



13
 14 Hydro submits that based on utility practice across Canada, as presented in the above noted
 15 chart, supply deferrals are in fact quite common for Canadian utilities with a higher approved
 16 ROE than Hydro has proposed in this application. This is again inconsistent with Mr. Bowman’s
 17 statement from page 16 of his pre-filed evidence:

1 *There is no justification for transferring these risks to consumers when Hydro has*
2 *been assured a higher, and uncontested, return on equity fixed by Government*
3 *Directive OC2009-063. In fact, just the opposite is true - with a higher return on*
4 *equity, Hydro should take on more risk.*

5
6 Finally, Hydro submits that Mr. Bowman's statements are not consistent with utility practice in
7 this province. The Board has historically approved supply deferrals for both Hydro and NP,
8 through the RSP and Rate Stabilization Account respectively. Hydro submits that regulatory
9 precedent exists in this province for deferral of supply costs at the same level of return on
10 equity as NP.

11
12 The evidence presented by Dr. Wilson with respect to Hydro's requested supply deferrals in
13 relation to ROE, is largely similar to that of Mr. D. Bowman. Hydro disagrees with Dr. Wilson's
14 testimony for the same reasons.

15
16 In the context of Hydro's Amended Application, Mr. D. Bowman's and Dr. Wilson's discussions
17 on Hydro's incentive to manage supply costs are incomplete. Hydro has proposed a +/-
18 \$500,000 dead band on two of the three accounts. This represents a +/- \$1,000,000 incentive,
19 each fiscal year, for Hydro to limit the supply costs incurred. Hydro submits that this level of risk
20 is sufficient incentive to manage these specific supply costs in a given year.

21 22 **Section D.5: Management of the Rural Deficit**

23 24 **D.5.1 Amount of the Rural Deficit and Controllable Costs**

- 25 • ***The Rural Deficit as a percentage of revenue requirement is stable.***

26
27 Hydro provides service to over 40 remote diesel communities.²⁶⁷ It owns and operates 21
28 diesel-generating plants serving 4,600 customers on Isolated Systems. Hydro also directly

²⁶⁷ November 23, 2015 Transcript, page 20.

1 serves 23,700 customers on the IIS. The Rural Deficit is the difference between the cost of
2 providing service to these Rural Customers and the revenues collected from those customers.

3

4 The Rural Deficit has grown from \$40.8 million in the 2007 Test Year to a forecast of \$64.1
5 million in the 2015 Test Year. The growth in the amount of the Rural Deficit has resulted
6 primarily from fuel costs, rather than from increases in costs that are controllable by Hydro.
7 Controllable costs, which are primarily operating expenses, have remained relatively consistent
8 from year to year, despite increasing wages and general inflationary pressure on material
9 supply costs and other costs.²⁶⁸ As illustrated in Chart 1 in Hydro’s March 2015 Rural Deficit
10 Annual Report, the Rural Deficit has been relatively consistent year over year when the impact
11 of fuel costs (and the ROE established by Government directive) is removed.²⁶⁹

12

13 While the absolute dollar amount of the Rural Deficit has grown since 2007, it is important to
14 put the total dollar amount into context. Evidence provided by NP makes it clear that the Rural
15 Deficit allocated to NP was greater as a percentage of NP’s total revenue requirement in 2002
16 than in either 2007 or 2015.²⁷⁰ NP’s allocation of the Rural Deficit as a percentage of its total
17 revenue requirement declined from slightly more than 15.5% in 2002 to approximately 11.5% in
18 2007.²⁷¹ Under the proposed allocation methodology, NP’s allocation of the Rural Deficit in
19 2015 falls in line with the 2007 percentage (i.e., approximately 11.8% of NP’s total 2015
20 revenue requirement).²⁷²

²⁶⁸ Amended Application, Regulated Activities Evidence, pages 2.82-2.83.

²⁶⁹ Information Exhibit #8, page 3 and Chart 1.

²⁷⁰ NLH-NP-019. See also October 7, 2015 Transcript, pages 129-130.

²⁷¹ In the response to NLH-NP-019, NP provided a bar chart showing the Rural Deficit allocated to NP as a percentage compared to NP’s “remaining revenue requirement” and it also provided the dollar amounts for NP’s total revenue requirement, including the Rural Deficit for 2002, 2007 and 2015. The actual percentages (NP’s allocation of the Rural Deficit as a percentage of NP’s total revenue requirement) for 2002 and 2007, and for 2015 under Hydro’s proposed methodology, can be calculated using the information provided in the Pre-filed Evidence and Exhibit of Mr. Brockman, pages 8-9 together with the dollar amounts in NLH-NP-019.

²⁷² October 7, 2015 Transcript, page 130.

1 D.5.2 Customer Awareness and the Rural Deficit

- 2 • ***The Board should proceed cautiously in considering the addition of a line item on***
3 ***customer bills demonstrating the impact of the Rural Deficit.***

4
5 Dr. Feehan proposed that the amounts customers contribute to the Rural Deficit should be
6 expressed on their bills because this would contribute to good public policy and, more
7 specifically, inform any future public policy debate about the continuation of the Rural Deficit
8 policy.²⁷³ In response to a question from Board Hearing Counsel, Dr. Feehan also said that he
9 saw no reason why the people receiving the subsidy should not see that on their bills just like
10 the people who are paying the subsidy.²⁷⁴

11
12 The proposal that customers be made aware of who is contributing to the Rural Deficit and who
13 is paying the cost of it gives rise to a number of implications that should be taken into account
14 before any decision is made to adopt Dr. Feehan's suggestion. A decision to communicate
15 information about which customers pay for the Rural Deficit and which customers benefit from
16 it could result in an approach to customer communications that is selective, unpopular, and,
17 potentially, provocative and even misleading. As noted by Mr. Fagan for Hydro in his
18 testimony, research with focus groups would be advisable to ensure no unforeseen
19 consequences of this action.²⁷⁵

20
21 It is also important to note that the proposed communication of information would be selective
22 because it would specifically address the cross-subsidization effect of the Rural Deficit even
23 though some element of cross-subsidization is, quite apart from the Rural Deficit, inherent in
24 rates.²⁷⁶ Of course, it is unavoidable that there will be cross-subsidization in customer rates,
25 because it is not practicable to attempt to isolate the precise costs of serving each individual
26 customer. Most people know that there are economic differences in the cost to serve different

²⁷³ October 5, 2015 Transcript, page 13.

²⁷⁴ October 5, 2015 Transcript, pages 71-72.

²⁷⁵ October 6, 2015 Transcript, page 49.

²⁷⁶ October 6, 2015 Transcript, pages 44-45.

1 customers.²⁷⁷ Presumably, under Dr. Feehan’s proposal, NP customers would be told that they
2 are paying a share of the Rural Deficit. However, if one were to do a cost of service study of
3 NP’s more rural regions, one would come up with a fairly large rural subsidy being received (not
4 paid) by rural customers on NP’s own system.²⁷⁸ Identifying Rural Customers on the IIS as a
5 subsidized group is not much different than breaking NP’s cost of service study into regions and
6 coming up with an NP rural deficit that represents cross-subsidization of NP’s rural
7 customers.²⁷⁹

8

9 When a proposal was put forward that a rural surcharge be introduced on the bills of NP in
10 1996, the proposition was opposed by all intervenors, it was a topic that received considerable
11 attention in the media and was unpopular with customers.²⁸⁰ The proposed communication
12 would potentially be provocative as well. According to Mr. Fagan’s testimony, his experience
13 from the 1995 Rural Rate Inquiry indicated that customers in some of Hydro’s rural areas are
14 offended by the notion that, although their resources have been used to support the rest of the
15 Province, there is perceived to be a need to highlight that their electricity rates are
16 subsidized.²⁸¹

17

18 The proposed communication would also potentially be confusing to customers because NP’s
19 customer would be told that they are paying the Rural Deficit when in fact it is likely that it
20 costs more to serve customers in some of NP’s rural areas than it does to serve customers in
21 some of Hydro’s rural interconnected areas.²⁸² Further, such communication has the potential
22 to pit neighbouring communities against one another: those that are being “subsidized” (e.g.,
23 Baie Verte) and those who are “subsidizing” providing of services to isolated customers (e.g.,
24 Deer Lake).²⁸³

²⁷⁷ October 6, 2015 Transcript, page 40.

²⁷⁸ October 6, 2015 Transcript, page 37.

²⁷⁹ October 6, 2015 Transcript, pages 47-48.

²⁸⁰ October 6, 2015 Transcript, page 39.

²⁸¹ October 6, 2015 Transcript, pages 38-39.

²⁸² October 6, 2015 Transcript, pages 44-45.

²⁸³ October 6, 2015 Transcript, pages 36-37.

1 It is perhaps easy to jump to a conclusion that there can be no harm in providing more
2 information to customers about the Rural Deficit. As noted above, Hydro respectfully submits
3 that Dr. Feehan’s proposal has a number of implications that should be carefully considered
4 before any decision is made to adopt that proposal. Further, if the Board decides that
5 information should be communicated about the customers who pay the Rural Deficit and the
6 customers who benefit from it, Hydro submits that consideration should be given to framing a
7 message that conveys a perception of fairness to all parties.²⁸⁴

9 **D.5.3 Conservation Measures to Control the Rural Deficit**

- 10 • ***Hydro has continued its efforts to reduce the Rural Deficit by promoting energy efficiency***
11 ***in isolated communities.***

12
13 Hydro’s Rural Deficit Annual Report of March 2015 summarizes many initiatives taken by Hydro
14 to control the overall amount of the Rural Deficit.²⁸⁵ These include a number of internal energy
15 efficiency initiatives that were completed or launched by Hydro in 2014, as well as ongoing cost
16 control measures that have been continued by Hydro. This Report also describes CDM program
17 initiatives and capital initiatives pursued by Hydro to control the Rural Deficit.

18
19 Hydro’s work on energy efficiency initiatives in isolated communities goes back as far as the
20 early 1990s.²⁸⁶ When implementation of Hydro’s takeCHARGE partnership with NP began in
21 2009, the joint effort did not include programs targeted specifically at isolated communities,
22 but the takeCHARGE programs were open to customers in isolated communities who were
23 eligible for them.²⁸⁷

24
25 Hydro partnered with the Government on a pilot project in isolated communities in 2010 to
26 2011 and then followed up by launching two programs specifically targeted at these

²⁸⁴ October 6, 2015 Transcript, pages 37-38 and 49. Hydro also suggested neutral wording, such as rate equalization policy adjustment, rather than using a work like “subsidy”. See October 6, 2015 Transcript, page 37.

²⁸⁵ Information #8.

²⁸⁶ November 24, 2015 Transcript, page 3.

²⁸⁷ November 24, 2015 Transcript, pages 2-4.

1 communities in 2012. The two initiatives are: (i) the Isolated Systems Community Energy
2 Efficiency Program and (ii) the Isolated Systems Business Efficiency Program. Hydro delivers
3 programs in isolated communities under the takeCHARGE brand, independently of its joint
4 effort with NP.²⁸⁸

5
6 The Isolated Systems Community Energy Efficiency Program includes a number of features such
7 as the provision of kits of small energy efficiency technologies to homes and businesses,
8 coupons for discounts on a number of energy efficiency products, increased incentives for
9 home insulation retrofits and work to assess the opportunity for, and challenges of, larger-scale
10 home retrofits.

11
12 The Isolated Systems Community Energy Efficiency Program is a three-year program that is
13 expected to result in total energy saving of 3.3 GWh/year and fuel cost savings of \$1.1 million
14 per year.²⁸⁹ Under this program, both residential and commercial customers are provided with
15 energy efficiency support and assistance that covers a wide range, including direct install of
16 efficiency products, education and awareness, coupons and incentives.²⁹⁰

17
18 From 2012 to 2014, Hydro was able to reach 83% of its customers in isolated communities
19 under the Isolated Systems Community Energy Efficiency Program.²⁹¹ At this point, Hydro has
20 not embarked on a “whole home approach” to CDM in these communities because changes to
21 a building envelope such as addition of insulation contribute to existing issues of water
22 infiltration, mold and condensation and because of concerns that major home renovations are
23 not within the purview of an electrical utility.²⁹²

24
25 The Isolated Systems Business Efficiency Program provides technical support and incentives to
26 commercial customers. Extensive time and effort are required to bring commercial customers

²⁸⁸ PUB-NLH-313.

²⁸⁹ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 8 of 10.

²⁹⁰ PUB-NLH-313.

²⁹¹ November 23, 2015 Transcript, page 20.

²⁹² November 24, 2015 Transcript, pages 5-7 and 171-172.

1 through the process:²⁹³ customers are given a free walk-through audit of a facility followed by
2 a report on energy saving opportunities.²⁹⁴ This is also a three-year program and an evaluation
3 is planned after the third year of the program.²⁹⁵

4
5 The Isolated Systems Business Efficiency Program is expected to result in total energy savings of
6 180 MWh. By the end of 2012, more than 40 audits had been completed with recommendation
7 reports provided to customers.²⁹⁶ To date, 58 commercial customers have been visited under
8 the Isolated Systems Business Efficiency Program.²⁹⁷

9
10 As part of its CDM efforts in isolated communities, Hydro also carries out energy efficiency
11 improvements at its own facilities. Hydro's CDM team consults with and assists the Hydro
12 Operations group in making Hydro's own operations in isolated communities more efficient.²⁹⁸

13
14 The estimated 2015 impact of Hydro's CDM initiatives on the Rural Deficit has been presented
15 in evidence.²⁹⁹ For the 2015 Test Year, savings from customer-focused energy efficiency
16 measures (including 2013 actuals) are estimated to be 9.4 GWh, or, as a dollar amount, more
17 than \$1 million. For the 2015 Test Year, savings from internally focused energy efficiency
18 measures (including 2013 actuals) are estimated to be 4.2 GWh, or more than \$600,000. Hydro
19 submits that its CDM activities have produced a successful outcome that contributes
20 significantly to its efforts to constrain the amount of the Rural Deficit.

21

22 **D.5.4 Cost Control Measures to Control the Rural Deficit**

- 23 • ***Hydro has undertaken numerous initiatives resulting in cost savings or avoided cost in***
24 ***Rural Deficit areas.***

²⁹³ PUB-NLH-313.

²⁹⁴ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.

²⁹⁵ *Ibid.*

²⁹⁶ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2, page 9 of 10.

²⁹⁷ November 23, 2015 Transcript, page 21.

²⁹⁸ November 24, 2015 Transcript, page 175.

²⁹⁹ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1, page 1 of 1.

1 Hydro has implemented many cost reduction initiatives to contain the growth of the Rural
2 Deficit. In particular, given its mandate to provide least-cost, safe and reliable power to all its
3 customers, Hydro strives to manage the costs of serving Rural Customers with a view to
4 providing reliable service while minimizing the amount of the Rural Deficit.³⁰⁰ Actions taken by
5 Hydro that contain the growth of the Rural Deficit are explained in evidence prepared
6 specifically for the purposes of this proceeding³⁰¹ and in the Rural Deficit Annual Reports, also
7 on the record of this proceeding, that Hydro files each year with the Board.³⁰²

8
9 Hydro has undertaken both dedicated efforts aimed at controlling the Rural Deficit and Hydro-
10 wide projects that result in cost savings or avoided costs in Rural Deficit areas.³⁰³ In addition to
11 the CDM program initiatives that are discussed above, efforts to control operating costs include
12 internal energy efficiency initiatives and ongoing cost control measures.³⁰⁴ Hydro has also
13 implemented capital-spending initiatives that contribute to its effort to control the Rural
14 Deficit.³⁰⁵

15
16 Examples of the numerous initiatives and programs undertaken by Hydro that result in cost
17 savings or avoided costs in Rural Deficit areas include the following:

- 18 • Capturing waste heat;
- 19 • Monitoring diesel system fuel efficiency;
- 20 • Utilizing commercial flights where practical, rather than more expensive helicopter use;
- 21 • Using a fuel-efficient mix of engines to supply load;
- 22 • Enhancing the effectiveness of planning and scheduling to minimize outages and delays;
- 23 • Carrying out life cycle cost analysis for diesel engines;
- 24 • Implementing automatic meter reading;
- 25 • Installing in-line heaters at diesel plants; and

³⁰⁰ Amended Application Regulated Activities Evidence, page 2.83.

³⁰¹ NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.

³⁰² NP-NLH-099 (Revision 2, Dec 9-14), Attachment 1; NP-NLH-098 (Revision 1, Dec 9-14), Attachment 2; and Information Exhibit #8.

³⁰³ NP-NLH-098 (Revision 1, Dec 9-14).

³⁰⁴ Information Exhibit #8, pages 3-5.

³⁰⁵ *Ibid.*, page 8.

- 1 • Implementing e-billing and in-house printing of customer bills.³⁰⁶

2
3 In the case of many of Hydro’s projects and initiatives, the reduction in the Rural Deficit by way
4 of costs saved or avoided is not quantifiable.³⁰⁷ Even so, the estimated 2015 Test Year total
5 savings (resulting from only those reductions that are quantifiable) exceed \$2 million.³⁰⁸

7 **Section D.6: Other Issues**

8 9 **D.6.1 Customer Service Strategy**

10 The Parties agreed Hydro’s “Customer Service Strategic Roadmap 2015-2017” reflects
11 appropriate customer service improvement objectives. The parties stipulated their agreement
12 did not preclude additional customer service improvements being raised during the hearing of
13 this Application or being considered by the Board.³⁰⁹

14 15 **D.6.2 Issues Raised By the Nunatsiavut Government**

16 On November 30, 2015, the Board heard testimony from two witnesses appearing on behalf of
17 the Nunatsiavut Government: Darryl Shiwak, Nunatsiavut’s Minister of Lands and Natural
18 Resources; and Chris Henderson of Lumos Energy, Nunatsiavut’s clean energy advisor,³¹⁰ who
19 was offered as Nunatsiavut’s expert on sustainable energy development in northern
20 climates.³¹¹ Minister Shiwak testified about socioeconomic conditions in Nunatsiavut’s
21 communities, particularly as regards energy affordability.³¹² Minister Shiwak also discussed
22 Nunatsiavut’s current and future energy needs, the ongoing need for improvements to the
23 diesel-generated electricity systems serving Nunatsiavut’s communities, the impact of higher
24 rates and his views on Muskrat Falls.³¹³ On cross-examination,³¹⁴ Minister Shiwak characterized

³⁰⁶ Amended Application Regulated Activities Evidence, page 2.83.

³⁰⁷ NP-NLH-098 (Revision 1, Dec 9-14).

³⁰⁸ Total of amounts shown at NP-NLH-098 (Revision 1, Dec 9-14), Attachment 1.

³⁰⁹ Settlement Agreement, page 4, paragraph 21.

³¹⁰ November 30, 2015 Transcript, pages 35, line 25 to 36, line 1.

³¹¹ November 30, 2015 Transcript, page 34, lines 1-13.

³¹² November 30, 2015 Transcript, pages 6, line 16 to 14, line 10.

³¹³ November 30, 2015 Transcript, pages 14, line 11 to 23, line 8.

1 the takeCHARGE program as “a good program, but more needs to be done to get into the
2 communities”.³¹⁵

3

4 Mr. C. Henderson’s testimony previewed a report he began two years ago to assess
5 Nunatsiavut’s energy needs and resources, and to identify opportunities to reduce energy
6 consumption and energy costs. Mr. C. Henderson advised that his report has generated a
7 Nunatsiavut energy security plan, which will be made available to the Government, the Board,
8 and interested stakeholders shortly.³¹⁶ Drawing on experience with other First Nations
9 communities in northern climates, Mr. C. Henderson advocated a “more holistic energy
10 community energy planning approach and a more holistic home energy efficiency and
11 conservation approach,”³¹⁷ which Mr. C. Henderson developed in consultation with Hydro and
12 the Board.³¹⁸ Mr. C. Henderson identified innovation opportunities for Hydro’s diesel
13 generation facilities,³¹⁹ and he elaborated on these opportunities during cross-examination.³²⁰
14 Hydro believes the Board must give consideration to its regulatory framework when
15 considering the Nunatsiavut Government’s submissions.³²¹ Hydro appreciates the intervention
16 of the Nunatsiavut Government and Minister Shiwak, and Mr. C. Henderson for the depth and
17 evenhandedness of their testimony.

18

19 **E. RATE IMPLEMENTATION**

20 **E.1 COMPLIANCE FILING**

21 Subsequent to the final Order for the GRA, Hydro will make a compliance filing reflecting the
22 Board’s decisions. The compliance filing will finalize the revenue deficiency calculations for
23 2014 and 2015 and provide recovery proposals by customer class. COS studies for each year will
24 be provided to determine the revenue deficiency by customer class.

³¹⁴ November 30, 2015 Transcript, pages 23, line 24 to 28, line 2.

³¹⁵ November 30, 2015 Transcript, page 27, lines 1 to 2.

³¹⁶ November 30, 2015 Transcript, pages 35, line 18 to 36, line 25.

³¹⁷ November 30, 2015 Transcript, pages 41, line 23 to 42, line 1.

³¹⁸ November 30, 2015 Transcript, page 37, lines 3 to 6.

³¹⁹ November 30, 2015 Transcript, pages 44, line 11 to 45, line 25.

³²⁰ November 30, 2015 Transcript, pages 57, line 11 to 67, line 16.

³²¹ Order No. P.U. 8(2007), Appendix A.

1 Delayed implementation of customer rates in 2016 will also contribute to a further revenue
2 deficiency attributable to certain customer classes. The compliance application will provide a
3 forecast 2016 revenue deficiency by customer class based on the 2015 Test Year sales forecast
4 and include a proposal for appropriate recovery.

5
6 The compliance application will include proposals that reflect the Board’s determinations in the
7 final GRA Order for the finalization of the 2015 Test Year revenue requirement and 2015 Test
8 Year rate base for use in the establishment of customer rates in 2016. This filing will include a
9 2015 Test Year COS Study reflecting the approved revenue requirements for use in establishing
10 customer rates.

11
12 The final GRA Order will also permit Hydro to update the RSP balances for 2015 reflecting the
13 updated 2015 Test Year inputs for fuel cost, hydrology, load, and customer rates. The RSP
14 balances currently being reported on an interim basis reflect the 2007 Test Year inputs.

16 **E.2 RECOVERY OF REVENUE DEFICIENCIES**

17 The rates proposed in the GRA evidence do not reflect the recovery of the revenue deficiencies
18 already incurred as the proposed rates are based upon recovery of 2015 Test Year costs.
19 Subject to the Board’s finalization of the amounts to be recovered, Hydro’s compliance
20 application will present proposals for recovery of the:

- 21 (i) 2014 Revenue Deficiency of \$45.9 million as approved for deferral in Order No. P.U.
22 58(2014) with recovery being subject to the Board’s subsequent determination;
- 23 (ii) 2015 Net Income Deficiency of \$60.5 million per Hydro’s Amended Cost Deferral
24 Application, dated November 12, 2015, with recovery being subject to the Board’s
25 subsequent determination; and
- 26 (iii) Forecast 2016 revenue deficiency resulting from delayed implementation of
27 customer rates beyond January 1, 2016.

1 One method to deal with the recovery of the revenue deficiencies to be approved by the Board
2 is to recover the deficiency through higher rates to be paid by customers in the future (i.e., as a
3 rate rider or cost recovery amortization).³²² Another method for consideration is to use the
4 material fuel savings that have accumulated and are reflected as credit balances in the RSP.
5 In the Amended Application, Hydro proposed the recovery of the 2014 deficiency through the
6 use of the credit balances in the RSP.³²³ Hydro believes using the RSP credit balances to recover
7 revenue deficiencies is consistent with intergenerational equity in that it applies funds already
8 recovered from customers to recover costs that have already been incurred to provide service
9 to those customers.³²⁴

10
11 Mr. D. Bowman agreed that the methodology for disposing of RSP balances should be reviewed
12 in light of the limited remaining operating time of the Holyrood thermal plant.³²⁵ Mr. D.
13 Bowman also recommended the use of the RSP credit balances to reduce the volatility of
14 customer rates over the period to 2017.³²⁶

15
16 Mr. Brockman agreed with the use of RSP credit balances to avoid increasing future rates for
17 costs already incurred.³²⁷ Mr. Dean also agreed; he stated:

18
19 *A recovery method that uses an existing balance is recommended over methods*
20 *such as a rate rider that would affect future years. A rate rider would worsen the*
21 *rate impact that the Industrial Customers are experiencing and would cause*
22 *intergenerational inequity due to the changing dynamics within the Industrial*
23 *Customer class.*³²⁸

³²² This is similar to the method approved by the Board in the case of NP in its 2013-2014 General Rate Application. In Order No. P.U. 13(2013), the Board approved the amortization of the forecast 2013 revenue shortfall over three years, commencing in 2013.

³²³ At year-end 2014, there was a \$35 million credit balance in the RSP load variation component and a \$43 million credit in the RSP hydraulic component.

³²⁴ October 5, 2015, Transcript, page 107, lines 10 – 25.

³²⁵ Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 14, lines 22 – 24.

³²⁶ Pre-filed evidence of C. Douglas Bowman dated June 1, 2015, page 15, lines 19 – 22.

³²⁷ September 28, 2015 Transcript, page 121, lines 1-20.

³²⁸ Pre-filed evidence of Mr. Dean, dated June 4, 2015, pages 19, line 28 to 20, line 3.

1 As indicated earlier, the final GRA Order will permit Hydro to update the RSP balances for 2015.
2 Hydro submits it is appropriate to utilize the 2015 year-end credit balances in the RSP load
3 variation component and the hydraulic variations component, where appropriate, to limit the
4 amount of revenue deficiency that will be recovered through rates from customers. Any portion
5 of the revenue deficiencies not approved for recovery through the RSP should be proposed for
6 recovery through future customer rates. This approach will likely be required for recovery of
7 revenue deficiency attributable to customers on the Labrador Interconnected System.

8

9 **F. CONCLUSION/ORDER REQUESTED**

10 In conclusion, Hydro under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and
11 80, proposes the following, effective January 1, 2016. The following is divided into two
12 sections: settled and non-settled matters.

13

14 **F.1 SETTLED ISSUES**

15 There were two settlement agreements filed with the Board in this matter. In that connection,
16 Hydro seeks the Board's approval of those agreements, and more particularly, proposes that:

17

18 (1) The allowable range of return on rate base of +/- 20 basis points be approved;³²⁹

19

20 (2) Hydro's treatment to include actuarial gains and losses on Employee Future
21 Benefits of \$1.6 million in the 2015 Test Year as part of Hydro's revenue
22 requirement be approved;³³⁰

23

24 (3) Hydro's Asset Retirement Obligations include depreciation and accretion
25 expenses of \$2.6 million and \$2.6 million, respectively for the 2014 and 2015
26 Test Years be approved;³³¹

³²⁹ Item 7 of the Settlement Agreement.

³³⁰ Item 8 of the Settlement Agreement.

³³¹ Item 9 of the Settlement Agreement.

- 1 (4) The total generation credit for NP be increased to 119,329 kW;³³²
 2
- 3 (5) Hydro's proposal to defer and amortize annual customer energy conservation
 4 program costs, commencing in 2015, over a discrete seven year period in a CDM
 5 Cost Deferral Account, be approved;³³³
 6
- 7 (6) The costs related to the Application be recovered in customer rates evenly over
 8 a three year period, commencing with the date that new rates approved in this
 9 proceeding become effective with the amount of such costs to be determined by
 10 the Board;³³⁴
 11
- 12 (7) The Service Agreement between Hydro and CBPP, which was approved on a pilot
 13 basis by the Board in Order No. P.U. 4(2012), be approved to continue on a pilot
 14 basis;³³⁵
 15
- 16 (8) An industrial wheeling rate calculated in accordance with the methodology
 17 proposed by Hydro in its Application be approved;³³⁶
 18
- 19 (9) Hydro report functionally oriented key performance indicators as required by the
 20 Board in Order No. P.U. 14(2014) based on the most recent Test Year COS Study
 21 approved by the Board rather than on a forecast basis;³³⁷
 22
- 23 (10) In preparation for the implementation of customer rates reflecting the costs of
 24 the Labrador-Island interconnection, Hydro will file with the Board the
 25 following:³³⁸

³³² Item 14(a) of the Settlement Agreement.

³³³ Item 17 of the Settlement Agreement.

³³⁴ Item 18 of the Settlement Agreement.

³³⁵ Item 19 of the Settlement Agreement.

³³⁶ Item 20 of the Settlement Agreement.

³³⁷ Item 22 of the Settlement Agreement.

³³⁸ Item 23 of the Settlement Agreement.

- 1 i. a marginal cost study no later than December 31, 2015;
- 2 ii. a cost of service methodology report no later than March 31, 2016; and
- 3 iii. a report on the Rate Stabilization Plan and supply cost recovery
- 4 mechanisms no later than June 15, 2016;
- 5 (11) A generic cost of service hearing be held following the filing of the reports
- 6 outlined in (10) above;
- 7
- 8 (12) Hydro file a GRA on or before March 30, 2017 proposing rates based on a 2018
- 9 Test Year;³³⁹
- 10
- 11 (13) the cost of service methodologies in Exhibit 13(2015 Test Year COS) be approved
- 12 with respect to:
- 13 i. the treatment of the curtailable load of Newfoundland Power;
- 14 ii. the classification of wind energy purchases as 100% energy related;
- 15 iii. the classification of all Holyrood fuel costs to energy;
- 16 iv. the use of the load forecast provided by NP; and
- 17 v. the specific assignment of the frequency converter to CBPP Limited;³⁴⁰
- 18
- 19 (14) The calculation of the capacity factor for the Holyrood Generating Plant be based
- 20 on a historical five-year period from 2010 to 2014, inclusive;³⁴¹
- 21
- 22 (15) The demand charge to NP will equal \$4.75 per kW of billing demand;³⁴²
- 23
- 24 (16) The end block energy rate to NP will be determined based on the 2015 Test Year
- 25 No. 6 fuel price divided by the 2015 Test Year Holyrood fuel conversion Factor,
- 26 both as are determined by the Board;³⁴³

³³⁹ Item 23(d) of the Settlement Agreement.

³⁴⁰ Item 7 of the Supplemental Settlement Agreement.

³⁴¹ Item 8 of the Supplemental Settlement Agreement.

³⁴² Item 10(i) of the Supplemental Settlement Agreement.

³⁴³ Item 10(ii) of the Supplemental Settlement Agreement.

- 1 (17) The approved 2015 Test Year revenue requirement that is not recovered through
2 the NP demand and end-block energy charge will be used to compute the first
3 block energy charge;³⁴⁴
4
- 5 (18) The wholesale rate charged to NP will include a curtailable load credit as
6 proposed in the Amended Application;³⁴⁵
7
- 8 (19) Hydro's proposed CDM Recovery Adjustment be approved so as to provide for
9 recovery of costs charged annually to the CDM Cost Deferral Account;³⁴⁶
10
- 11 (20) Costs associated with Hydro's capacity assistance agreements with Vale and
12 Corner Brook Pulp and Paper Limited be treated as demand related in the 2015
13 Test Year COS Study;³⁴⁷
14
- 15 (21) If the load variation component is maintained as an element of the RSP, the
16 allocation of year-to-date net load variations for NP and industrial customers
17 among the customer groups be based upon energy ratios, with effect from the
18 date to be determined by the Board (there is no settlement on the effective
19 date—Hydro proposes that the effective date be September 1, 2013);
20

21 **F.2 HYDRO'S PROPOSALS ON ISSUES NOT SETTLED**

22 On the matters that were not settled by the parties and therefore did not constitute elements
23 of either of the settlement agreements, in summary Hydro proposals are as follows.
24

25 **F.2.1 Revenue Requirement**

- 26 (1) Hydro's 2014 Test Year Revenue Requirement of \$560,755,000 be
27 approved;³⁴⁸

³⁴⁴ Item 10 of the Supplemental Settlement Agreement.

³⁴⁵ Item 11 of the Supplemental Settlement Agreement.

³⁴⁶ Item 12 of the Supplemental Settlement Agreement.

³⁴⁷ Item 14(b) of the Settlement Agreement.

- 1 (2) Hydro's adjusted 2015 Test Year Revenue Requirement of \$579,577,352
2 be approved for the purpose of determining 2015 Revenue Deficiency,³⁴⁹
3
- 4 (3) Hydro's 2015 Test Year Revenue Requirement of \$584,677,352 be
5 approved for the purpose of setting customer rates,³⁵⁰
6
- 7 (4) Hydro's forecast capital structure for the 2014 Test Year be approved with
8 a weighted average cost of capital of 7.32%;
9
- 10 (5) Hydro's forecast capital structure for the 2015 Test Year be approved with
11 a weighted average cost of capital of 6.82%;
12
- 13 (6) Pursuant to Order in Council OC2009-063, for purpose of calculating
14 Hydro's return on rate base, the return on equity last approved by Order
15 No. P.U. 13 (2013), as a result of NP's general rate application, of 8.80% be
16 approved for the 2014 Test Year and the 2015 Test Year;
17
- 18 (7) Hydro be allowed a rate of return on forecast average rate base for the
19 2014 Test Year of 7.12%;
20
- 21 (8) Hydro be allowed a rate of return on forecast average rate base for the
22 2015 Test Year of 6.82%;

³⁴⁸ Equals the \$560,855,000 proposed 2014 Test Year Revenue Requirement in the Amended Application less \$2,100,000 (i.e. the impact on 2014 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015). See PUB-NLH-487.

³⁴⁹ Equals the \$662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) \$75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of \$64.41 per barrel (ii) less \$5,100,000 (i.e. the impact on 2015 Test Year Revenue Requirement resulting from adjustments to reflect delayed in-service dates of 2014 capital projects in the 2015 rate base opening balance); (iii) less \$1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs. See PUB-NLH-487.

³⁵⁰ Equals the \$662,475,000 proposed 2015 Test Year Revenue Requirement in the Amended Application less (i) \$75,878,230 No. 6 fuel cost savings based on a Test Year No. 6 fuel cost of \$64.41 per barrel; and (ii) less \$1,919,418 Isolated supply costs savings referenced in the October 28, 2015 correspondence with the Board on projected 2016 fuel costs.

- 1 (9) The 2015 Test Year costs related to capacity assistance agreements be
2 approved for inclusion in 2015 Test Year Revenue Requirement.
3

4 **F.2.2 Deferral and Recovery Mechanisms**

- 5 (10) The proposed Isolated Systems Supply Cost Variance Deferral Account be
6 approved effective January 1, 2015;
7

- 8 (11) The proposed Energy Supply Cost Variance Deferral Account be approved
9 effective January 1, 2015;
10

- 11 (12) The proposed Holyrood Conversion Rate Account be approved effective
12 January 1, 2015.³⁵¹
13

14 **F.2.3 Amortizations**

- 15 (13) An estimated \$1.2 million (the final amount to be set after the conclusion
16 of the hearing) in external regulatory costs be deferred and recovered
17 over three years in accordance with the Settlement Agreement;³⁵²
18

- 19 (14) The regulatory treatment of Capacity Related Supply Cost Variances,
20 whereby it would be amortized over a five-year period commencing in the
21 2015 Test Year, as proposed in Hydro's application filed October 8, 2014,
22 be approved.³⁵³
23

24 **F.2.4 Rate Base**

- 25 (15) Hydro's average rate base for 2013 of \$1,548,371 be approved.³⁵⁴

³⁵¹ This account was requested, explained and described in Supplemental evidence filed by Hydro on January 14, 2015.

³⁵² Originally requested on page 3.22 of Hydro's Amended Application, updated to \$1.2 million per line 35 of Undertaking 55.

³⁵³ Pending a determination of this matter in the Prudence Review process

³⁵⁴ Finance Evidence, Schedule I, page 5 of 11, line 21.

1 (16) Hydro's forecast average rate base for the 2014 Test Year of \$1,618,867
 2 be approved for determining 2014 revenue deficiency;³⁵⁵

3
 4 (17) Hydro's forecast average rate base for the adjusted 2015 Test Year of
 5 \$1,728,324 be approved for the purpose of approving 2015 revenue
 6 deficiency;³⁵⁶

7
 8 (18) Hydro's forecast average rate base for the 2015 Test Year of \$1,802,024
 9 be approved for the purpose of approving rates;³⁵⁷

10

11 **F.2.5 Rate Stabilization Plan**

12 (19) Hydro will propose a plan for the finalization of the phase-in of IC rates to
 13 be filed with its compliance application;

14
 15 (20) As there is no further Rural Labrador Interconnected Automatic Rate
 16 Adjustment, Section 1.3(b) be removed from the RSP Rules;

17
 18 (21) The Section E – Historical Plan Balance be removed;

19
 20 (22) The load variation component be maintained as an element of the RSP;

21
 22 (23) The allocation of year-to-date net load variations for NP and industrial
 23 customers among the customer groups be based upon energy ratios, with
 24 effect from September 1, 2013;

³⁵⁵ Equals the \$1,692,567,000 proposed 2014 Test Year rate base in the Amended Application less \$73,700,000 (i.e. the impact on 2014 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).

³⁵⁶ Equals the \$1,802,024,000 proposed 2015 Test Year rate base in the Amended Application less \$73,700,000 (i.e. the impact on 2015 Test Year Rate Base resulting from adjustments to reflect delayed in-service dates of 2014 capital projects until 2015).

³⁵⁷ Equals the \$1,802,024 proposed 2015 Test Year rate base in the Amended Application.

F.2.6 Revenue Deficiency

(24) The RSP credit balance be used, where appropriate to offset the revenue deficiency that occurred due to delays in implementation of rate changes beyond January 1, 2014;

(25) The portion of the revenue deficiency not recovered using the RSP credit balance be deferred for future recovery through a rate rider or through a cost recovery amortization included in revenue requirement for determining rates.

10

F.2.7 General Rate and Cost of Service Matters

(26) The Labrador Transmission demand-related rate be set at \$1.25/kw/month;

14

(27) Commencing January 1, 2014 the Rural Deficit be allocated based on revenue requirement;

17

(28) Hydro use the indexed cost of assets in allocation of O&M costs to specifically assigned assets in the cost of service study for the 2014 and 2015 Test Years;

21

(29) The Board approve the 2015 load forecast for IIC for use in the 2015 Test Year COS Study;

24

(30) The average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service be increased to 3.47%;

26

1 (31) The Board approve the proposed above average increases in customer
2 rates for Hydro Rural non-Government Domestic and General Service
3 customers on Isolated systems; and
4

5 (32) Upon hearing this Amended Application, the Board grant such alternative,
6 additional or further relief as the Board shall consider fit and proper in the
7 circumstances.
8

9 ALL OF WHICH IS RESPECTFULLY SUBMITTED.