

October 30, 2018

Via Email & Courier

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 of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Revisions to 2018 Cost Deferral and Interim Rates Application

Enclosed with this letter please find one (1) original plus thirteen (13) copies of Newfoundland and Labrador Hydro's ("Hydro") Revised 2018 Cost Deferral and Interim Rates Application (the "Revised Application").

Following submission on Friday, October 26, 2018, Hydro became aware of a number of errors in the original 2018 Cost Deferral and Interim Rates Application (the "Original Application") and its cover letter. These errors do not impact Hydro's requested approvals as filed on October 26, 2018.

Cover Letter

Hydro's cover letter reflected incorrect information for forecast 2018. The paragraph should have read as follows:

"The evidence provided in Schedule 2 to the Application supports the approval of a 2018 cost deferral to provide Hydro an opportunity to earn a reasonable rate of return in 2018. Given the 2017 GRA process is not yet completed, Hydro anticipates that the 2017 GRA Order will not be issued until 2019. In the absence of a 2017 GRA Order in 2018, Hydro's forecast 2018 net income is \$9.9 million. This equates to a 3.13% return on equity and a 4.63% return on rate base in 2018. A 4.63% return on rate base is below the lower end of the projected return on rate base, derived pursuant to Order in Council OC2009-063, to be used in the 2017 GRA Compliance Application."

Application

Hydro's Original Application reflected incorrect net income information for forecast 2018 in paragraph 41, and incorrect rate of return on rate base for 2018 in paragraph 45.

The Revised Application and the updates to the cover letter, noted above, reflect the information as included in Hydro's October 26, 2018 filing evidence (Schedule 2, Appendix A).

In addition to the information regarding forecast 2018 described above, Hydro noted some calculation and typographical errors in the schedules to the Original Application. They are as follows:

Schedule 1 – Evidence

Hydro noted that a number of footnotes were duplicated in the process of converting its document to PDF. Hydro has reconverted the document to correct the footnote errors resulting in a change in the footnote numbers in the latter half of the document. However, there has been no change in the content of the footnotes.

Schedule 1 – Appendices F and G

In Appendix F, Hydro noted an error in the calculation of the RSP Current Plan Adjustment projection in the customer impact sheet for North Atlantic Refining Limited ("NARL"). The 2019 forecast RSP Current Plan Adjustment billings should have been \$821,808, not \$82,181 as shown. The overall customer impact for NARL is 6.1%, not 0.7%.

In Appendix G, Hydro noted an error in the presentation of the Specifically Assigned Charges for Praxair. The 2019 specifically assigned billings at existing rates should have been \$50,030, not \$199,399 as shown. This does not affect the total projected 2019 final billings for this customer; however, it changes the projected customer impact for Praxair to an increase of 1.9%, not a decrease of 47.1% as originally filed.

There is no change to the overall Island Industrial Customer impact as a result of either of these miscalculations.

Schedule 1 – Appendix H

Hydro's update to its 2017 General Rate Application ("GRA") Part B, Hydro's proposals, included a typo in paragraph 32. The date of the filing of its Cost of Service and Rate Design Methodology Review should be November 15, 2018, not November 15, 2019. In paragraph 39, the change in firm demand from \$9.95 per kW to \$10.90 per kW should be noted as an increase, not a reduction.

The nature of these errors is typographical and does not have a material impact on any of Hydro's requests in its updates to its 2017 GRA Part B, Hydro's proposals.

Summary of Changes

For ease of reference, changes to the Application have been shaded gray and revisions have been summarized in Table 1.

Table 1: Summary of Revisions – October 30, 2018

Section	Nature of Change
Cover Letter	Forecast 2018 net income, return on equity, and return on rate base
Application	Paragraph 41 – forecast 2018 net income
Application	Paragraph 45 – forecast rate of return on rate base
Schedule 1 Evidence	Footnote numbering for numbers 15 forward
Schedule 1 Appendix F	Page 5 of 6, RSP Current Plan calculation for NARL
Schedule 1 Appendix G	Page 7 of 8, Specifically Assigned charge for PRAXAIR
Schedule 1 Appendix H	Paragraph 32 – correction of date to November 15, 2018
Schedule 1 Appendix H	Paragraph 39 – change in firm demand should be noted as an increase

If you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO



Shirley Walsh
Senior Legal Counsel – Regulatory
SW/kd

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
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October 26, 2018

Via Email & Courier

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 of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: 2018 Cost Deferral and Interim Rates Application

Enclosed with this letter please find one (1) original plus thirteen (13) copies of the 2018 Cost Deferral and Interim Rates Application (the "Application").

The Application proposes:

- (i) deferral of the operating and maintenance ("O&M") costs for the Labrador Island Link ("LIL") and Labrador Transmission Assets ("LTA"), for the period prior to the full commissioning of the Muskrat Falls Project, from Hydro's 2018 and 2019 Test Year revenue requirements used in establishing 2017 GRA rates;
- (ii) updated interim customer rates for Island Industrial Customers to be implemented in concert with the Rate Stabilization Plan (RSP) rate updated required for January 1, 2019; and
- (iii) a cost deferral for 2018 to provide Hydro an opportunity to earn a reasonable rate of return in 2018.

The evidence provided in Schedule 1 to the Application provides the following:

- a proposal to defer LIL and LTA O&M costs, with the future recovery to be determined by the Board;
- a revised forecast of off-island purchases for 2018 and 2019;
- 2019 fuel costs based on the updated No. 6 fuel price forecast provided to the Board on October 15, 2018;
- a proposal to implement updated interim rates for Island Industrial Customers early in 2019;

- the projected customer rate projections for 2019 for each customer class upon implementing 2017 GRA final rates;
- and an update of Part B, Hydro proposals that was initially provided in its 2017 General Rate Application (GRA).

The evidence provided in Schedule 2 to the Application supports the approval of a 2018 cost deferral to provide Hydro an opportunity to earn a reasonable rate of return in 2018. Given the 2017 GRA process is not yet completed, Hydro anticipates that the 2017 GRA Order will not be issued until 2019. In the absence of a 2017 GRA Order in 2018, Hydro's forecast 2018 net income is \$9.9 million. This equates to a 3.13% return on equity and a 4.63% return on rate base in 2018. A 4.63% return on rate base is below the lower end of the projected return on rate base, derived pursuant to Order in Council OC2009-063, to be used in the 2017 GRA Compliance Application.

The proposed 2018 Cost Deferral Account Definition, as provided in Schedule 3 to this Application, would permit Hydro to defer the 2018 depreciation expense differential between Hydro's current depreciation expense methodology and the 2017 GRA depreciation methodology provided for in the 2017 GRA Settlement Agreement.

If you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Shirley Walsh
Senior Legal Counsel – Regulatory
SW/kd

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey
ecc: Dean Porter – Poole Althouse
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Dennis Browne, Q.C. – Brown Fitzgerald Morgan & Avis

Denis J. Fleming – Cox & Palmer
Benoît Pepin – Rio Tinto

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 and the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *Act*);

AND IN THE MATTER OF a General Rate Application by Newfoundland and Labrador Hydro (“Hydro”) filed on July 28, 2017, as revised;

AND IN THE MATTER OF an application by Hydro for approval of: (i) deferral of the operating and maintenance (“O&M”) costs required to be paid by Hydro for use of the Labrador-Island Link (“LIL”) and Labrador Transmission Assets (“LTA”) prior to full commissioning of the Muskrat Falls Project; (ii) a 2018 cost deferral account to provide Hydro the opportunity to earn a reasonable return on rate base in 2018 pursuant to Section 80 of the *Act*; and (iii) an application by Hydro, pursuant to Sections 70 and 75 of the *Act*, for the approval of Island Industrial Customer electricity rates to become effective January 1, 2019 on an interim basis (2018 Cost Deferral and Interim Rates Application).

TO: The Board of Commissioners of Public Utilities (the Board)

The 2018 Cost Deferral and Interim Rates Application of Hydro states that:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act, 2007*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.
2. Under the *Act*, the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls, and charges

for the service provided by the public utility and the rules and regulations which relate to that service.

3. Section 70 of the *Act* provides that a public utility shall not charge, demand, collect, or receive compensation for a service performed by it until the Board has approved a schedule of rates, tolls, and charges for the services provided by the public utility.
4. Section 75 of the *Act* provides that the Board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility upon the terms and conditions that it may decide.
5. Section 80 of the *Act* requires that a public utility be entitled to earn annually a just and reasonable return as determined by the Board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility.
6. In Order No. P.U. 49(2016), the Board ordered, amongst other things, that Hydro file its next General Rate Application (GRA) no later than March 31, 2017, with a 2018 Test Year. On February 20, 2017, Hydro filed an application requesting approval to file its next GRA on or before July 31, 2017, reflecting 2018 and 2019 Test Years. The Board provided its approval to Hydro's application in Order No. P.U. 8(2017).

7. On July 28, 2017, Hydro filed its 2017 GRA with the Board requesting approval of a number of proposals. One proposal was a request that the Board approve Hydro's 2018 and 2019 Test Year revenue requirements assuming no access to off-island power purchases and the continued use of thermal generation from the Holyrood Thermal Generation Station. This 2017 GRA proposal also requested that any savings resulting from access to off-island purchases be set aside in the Off-Island Purchases Deferral Account (the Deferral Account Scenario).

8. In Order No. P.U. 2(2018), the Board required Hydro to file forecast 2018 and 2019 revenue requirements and cost of service studies including the expected supply of off-island purchases, setting out the basis and support for the forecasts and assumptions used and including information related to customer rates and the updated fuel price forecast (Expected Supply Scenario).

9. Hydro provided a report on March 22, 2018 entitled "Summary Report – Additional Cost of Service Information" providing the requested information on the Expected Supply Scenario. This report provided a summary of the cost of service, revenue deficiencies and customer rates impacts using both the Deferral Account Scenario (using an updated fuel forecast) and the Expected Supply Scenario. The report also identified the changes Hydro is required to make to its deferral mechanisms in order to deal with supply cost uncertainty related to off-island purchases in the 2018 and 2019 Test Years.

10. On April 11, 2018, the Parties entered into a Settlement Agreement (the Settlement Agreement) which, in combination with a Supplemental Settlement Agreement dated July 16, 2018 (the Supplemental Settlement Agreement), resolved a number of 2017 GRA matters. The Supplemental Settlement Agreement confirmed the Parties' agreement to the use of the Expected Supply Scenario in determining Hydro's supply costs for each test year, and the use of the Revised Energy Supply Cost Variance Deferral Account to defer cost variances from the off-island purchase cost projections in the 2018 and 2019 Test Years. The definition of the Revised Energy Supply Cost Variance Deferral Account was accepted in the July 16, 2018 Supplemental Settlement Agreement.

11. A third settlement agreement on revenue requirement issues specific to the Labrador Interconnected System was filed with the Board on August 24, 2018 (the Labrador Settlement Agreement).

B. LIL and LTA Operating and Maintenance Costs

12. On July 20, 2018, Hydro filed supplemental evidence providing the customer impacts of the Settlement Agreement, Supplemental Settlement Agreement and the Labrador Settlement Agreements (the 2017 GRA Settlement Agreements). The supplemental evidence assumed that the O&M costs Hydro would incur for the use of the LIL and LTA to permit off-island purchases would be recovered through 2017 GRA customer rates to become effective in 2019.

13. On August 31, 2018, Hydro submitted an information filing on its interim Transmission Funding Agreements (interim TFAs) with the Labrador-Island Link Limited Partnership and Labrador Transmission Corporation (the asset owners of LIL and LTA). The interim TFAs require Hydro to reimburse the asset owners for their actual O&M costs which arise as a result of the assets being made available for service earlier than would otherwise be required (i.e., the LIL monopole commissioning date). The LIL monopole commissioning date is the date upon which Hydro is required to begin paying the O&M costs for the LIL and LTA under the interim TFAs.

14. Hydro entered into the interim TFAs to enable it to use the LIL and LTA to reduce costs for customers of the Island Interconnected System.

15. In addition, Nalcor Energy has provided a Minimum Performance Guarantee to Hydro that ensures that the savings realized by Hydro's use of off-island purchases will be adequate to offset any costs incurred by Hydro under the interim TFAs. Under the terms of the Minimum Performance Guarantee, Nalcor Energy will provide compensation to Hydro in the event that Hydro does not realize Net Savings as a result of entering into the interim TFAs. The Minimum Performance Guarantee was also filed with the Board on August 31, 2018.

16. The July 20, 2018 supplemental evidence stated that the basis for the 2018 and 2019 Test Year supply costs reflected a material increase in off-island purchases over the LIL beginning October 1, 2018, and a monopole commissioning date for the LIL in late October 2018.

17. On August 27, 2018, Hydro informed the Board by letter that, due to HVdc control equipment software issues, the LIL monopole commissioning date had to be revised. Hydro committed to providing updated customer rate projections at a later date.

18. In its October 1, 2018 LIL In-Service Biweekly Update, Hydro informed the Board that Hydro is taking a more conservative outlook regarding the LIL availability for 2018 and 2019. Hydro is now projecting that the LIL will be capable of transferring 110 MW at a forced outage rate of 30% for 2019.

19. Due to the ongoing uncertainty regarding the availability of reliable supply over the LIL, Hydro proposes to exclude the O&M costs for the LIL and LTA from its 2018 and 2019 Test Year revenue requirements. However, as Hydro will be required to pay these costs beginning on the LIL monopole commissioning date, for the use of the LIL and LTA to provide supply cost savings to customers, Hydro proposes to transfer to the Revised Energy Supply Cost Variance Deferral Account all LIL and LTA O&M costs paid by Hydro. The proposed transfer will occur for the period beginning with

the monopole commissioning date and concluding upon full commissioning of the Muskrat Falls Project.

20. The recovery of the balance in the Revised Energy Supply Cost Variance Deferral Account is subject to a further order of the Board.
21. Order No. P.U. 40(2003) sets out the manner by which the Rate Stabilization Plan (RSP) is calculated and applied to the rates that Hydro charges its Island Industrial Customers and Newfoundland Power. The most recent version of the RSP rules was approved in Order No. P.U. 15(2018).
22. The RSP rules require that by the 10th working day in October, Hydro shall provide to the Board, its Industrial Customers, and to Newfoundland Power an estimate of the Industrial Customer fuel rider that will become effective January 1 of the coming year. On October 15, 2018, Hydro provided the Board with its updated No. 6 fuel price forecast for the 2019 calendar year of \$92.50 per barrel, as well as the projected fuel rider.
23. On October 2, 2018, the Board directed that Hydro file, by October 26, 2018, an update reflecting both the revised forecast of off-island purchases and the updated fuel price forecast along with the revised customer rate projections for 2019 for

each customer class. The Board also directed Hydro to file a revision to its 2017 GRA to update Part B, Hydro Proposals.

24. Schedule 1 to this 2018 Cost Deferral and Interim Rates Application provides evidence on Hydro's projected customer rates reflecting the proposal to defer the LIL and LTA O&M costs during the pre-commissioning period for the Muskrat Falls Project. The Schedule also reflects Hydro's current forecast of off-island purchases (as detailed in Hydro's correspondence to the Board in the October 1, 2018 LIL In-Service Biweekly Update). The 2019 Test Year revenue requirements provided in Schedule 1 are based on the updated No. 6 fuel price forecast of \$92.50 per barrel and the 2017 GRA Settlement Agreements. Hydro has also updated its diesel and gas turbine fuel price forecast reflecting the September 2018 forecast for 2019 provided by PIRA.

25. In compliance with the Board's direction in its October 2, 2018 letter, Appendix H to Schedule 1 provides an update to Hydro's 2017 GRA Part B, Hydro Proposals reflecting the updated projected customer rates and test year revenue requirements.

C. Island Industrial Interim Rates

26. On February 9, 2018, Hydro filed an application for approval of a number of matters, including a proposed interim Island Industrial customer rates to become effective

April 1, 2018. The basis for Hydro's interim rates application was to provide Hydro an opportunity to earn a just and reasonable return during 2018.

27. The interim rates application proposed an average interim rate increase of 1.2% for Island Industrial Customers, with increases for individual customers ranging from 0.6% to 3.0%. The proposed changes included: i) interim base rates; ii) an updated RSP Fuel Rider; and iii) an updated RSP Current Plan Adjustment. The proposed interim base rates reflected an increase in the demand charge, no change in the base firm energy charge, and no changes to the specifically assigned charges. The proposed RSP rates reflected the continued operation of the RSP relative to the 2015 Test Year with a new RSP Fuel Rider to reflect the No. 6 fuel price projection for 2018, and a new RSP Current Plan Adjustment.

28. In Order No. P.U. 7(2018), the Board approved the proposed Island Industrial Customers rates on an interim basis effective April 1, 2018. The Board also ordered that Hydro establish a deferral account to track the difference between the approved specifically assigned charges and the amount that would be charged if the O&M methodology for specifically assigned charges proposed in the 2017 GRA was approved. This tracking was ordered for each Island Industrial Customer beginning on April 1, 2018.

29. The sale of the frequency converter to Corner Brook Pulp and Paper (CBPP) was approved by the Board in Order No P.U. 26(2018). The transfer of this asset to CBPP is reflected in the projected customer rates provided in Schedule 1 to this 2018 Cost Deferral and Interim Rates Application.
30. Section D. 2. of the RSP rules requires an update to the Industrial Customer RSP Current Plan Adjustment to become effective January 1 of each year to recover the balance in the Industrial Customer RSP balance at December 31 of the previous year, and the forecast financing charges to the end of the following calendar year.
31. The Industrial Customer RSP Current Plan Adjustment is currently (0.285) cents per kWh. The existing Industrial Customer RSP Current Plan Adjustment reduces customer rates as a result of a credit balance owed to customers at December 31, 2017.
32. Hydro is projecting an Industrial Customer RSP Current Plan balance owing from Industrial Customers of approximately \$1.9 million (including financing) at year-end 2018. This would require a RSP Current Plan adjustment of 0.312 cents per kWh. The 2019 Industrial Customer RSP Current Plan Adjustment update will require an increased collection of approximately \$4.4 million in 2019 relative to 2018, which equates to an approximate 11.2% average customer rate increase. Schedule 1

provides the calculation of the projected RSP Current Plan Adjustment to become effective January 1, 2019.

33. The projected 2019 Test Year base rate revenue requirement for Island Industrial Customers, as provided in Schedule 1, is approximately \$2.2 million less than the forecast 2019 revenue under existing interim rates (i.e., providing a 5.7% savings to offset the projected RSP increase). This calculation excludes the impact of the change in the specifically assigned charge methodology, which is being tracked in a deferral account.

34. The proposed change in the specifically assigned charge methodology has been accepted by the Parties to the Supplemental Settlement Agreement. Therefore, Hydro believes it is reasonable to also reflect this change in the proposed January 1, 2019 interim rates. The change in the specifically assigned charge methodology further reduces the projected 2019 Test Year base rate revenue requirement by approximately \$460,000 (i.e., an additional 1.2% savings to offset the projected RSP increase).

35. Board approval of the proposed deferral of the LIL and LTA O&M costs is also reflected in the projected test year revenue requirements presented in Schedule 1. Assuming this approval, Hydro proposes to reduce Island Industrial Customer base rates at the same time that the RSP Current Plan Adjustment is implemented.

36. The proposed Industrial Customer rates to become effective January 1, 2019 would not include an RSP fuel rider because the new 2019 forecast No. 6 fuel price of \$92.50 is reflected in the projected 2019 base rate revenue requirements provided in Schedule 1.
37. On an interim basis, Hydro proposes to (i) update the firm demand charge and the firm energy charge based on the 2019 Test Year Cost of Service Study provided in Appendix D to Schedule 1 and (ii) to revise the specifically assigned charges to reflect the specifically assigned charge methodology accepted in the Supplemental Settlement Agreement. Hydro proposes to implement these rate changes at the same time as the implementation of the updated RSP Current Plan Adjustment rate and the elimination of the RSP fuel rider, which is expected to be January 1, 2019.
38. Hydro proposes to file its revised rate sheet reflecting both the base rate change and the RSP rate changes through the RSP update application to be filed in January 2019.
39. The projected customer rate impacts for Island Industrial Customers reflecting the projected RSP Current Plan Adjustment rate and the proposed interim base rates are provided in Appendix F to Schedule 1.

D. Proposed 2018 Cost Deferral

40. The duration of the GRA process has been impacted by the uncertainty in the forecast supply costs to be used in establishing customer rates during the pre-commissioning period of the Muskrat Falls Project. Given the 2017 GRA process is not yet completed, Hydro anticipates that the 2017 GRA Order will not be issued until 2019.
41. In the absence of a 2017 GRA Order in 2018, Hydro's forecast 2018 net income is \$9.9 million. This equates to a 3.13% rate of return on equity and a 4.63% return on rate base in 2018. The projected range of rate of return on rate base for the 2018 Test Year is 5.25% - 5.65% which has been derived by applying the 8.5% rate of return on equity pursuant to Order in Council OC2009-063. A rate of return on rate base of 4.63% for 2018 is below the lower end of the projected range of rate of return on rate base for 2018 to be used in the 2017 GRA Compliance Application.
42. The Settlement Agreement included a revised approach to Hydro's depreciation methodology which would become effective for the 2018 Test Year upon issuance of the final 2017 GRA Order. If there is no 2017 GRA Order in 2018, the use of the current depreciation methodology will be required. Hydro's projected 2018 depreciation cost (including depreciation, loss on disposal, disposal proceeds, and removal costs) is projected to increase by \$15.0 million compared to the projected 2018 depreciation cost using the depreciation methodology accepted in the

Settlement Agreement. Schedule 2 provides Hydro's evidence providing the forecast financial impacts of the GRA Order being delayed until 2019.

43. Hydro proposes that the Board approve a 2018 Cost Deferral Account definition which will permit Hydro to defer for 2018 the depreciation expense differential between Hydro's current depreciation expense methodology and the 2017 GRA depreciation methodology.
44. Schedule 3 to this 2018 Cost Deferral and Interim Rates Application provides the proposed 2018 Cost Deferral Account definition.
45. Approval of the proposed 2018 Cost Deferral will provide Hydro the opportunity to earn a rate of return on rate base for 2018 of 5.28% that is within the projected range of rate of return referenced above. This is an interim measure to allow Hydro to earn a just and reasonable return while the finalization of the GRA is pending. The finalization of the return on rate base will be made by the Board pursuant to OC2009-063 at the conclusion of the 2017 GRA.
46. Hydro notes that the depreciation methodology is a settled item and the cost is prudently incurred in serving customers.

E. Application Requests

47. Therefore, Hydro requests that the Board make an Order approving:

(a) the transfer to the Revised Energy Supply Variance Deferral Account of all costs Hydro is required to pay for the use of the LIL and LTA during the period prior to full commissioning of the Muskrat Falls Project in accordance with the interim TFAs and the Minimum Performance Guarantee, less any compensation provided by Nalcor pursuant to the Minimum Performance Guarantee;

(b) revised base rates on an interim basis, effective upon the implementation of revised RSP adjustments providing: (i) an increase in firm demand charge from \$9.95 per kW to \$10.90 per kW and a decrease in the firm energy charge from 3.971 cents per kWh to 3.521 cents per kWh; and (ii) the following specifically assigned charges per year:

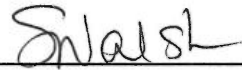
Corner Brook Pulp and Paper	\$11,458
North Atlantic Refinery Limited	\$104,051
Teck Resources Limited	\$50,030
Vale	\$144,378

(c) a 2018 Cost Deferral Account Definition, as provided in Schedule 3 to this 2018 Cost Deferral and Interim Rates Application, providing for Hydro to defer the 2018 depreciation expense differential between Hydro's current

depreciation expense methodology and the 2017 GRA depreciation methodology provided for in the Settlement Agreement.

DATED AT St. John's in the Province of Newfoundland and Labrador this 30th day of October 2018.

NEWFOUNDLAND AND LABRADOR HYDRO



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2018 Cost Deferral Evidence

October 26, 2018

A Report to the Board of Commissioners of Public Utilities



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Appendix B – 2019 Test Year Fuel Cost and Savings

Appendix C – 2018 Test Year Cost of Service Study Summary

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Appendix E – Projected 2019 Industrial Customer RSP Current Plan Adjustment

Appendix F – Projected Industrial Customer Rate Impacts – January 1, 2019

Appendix G – Projected Customer Rate Impacts – July 1, 2017

Appendix H – Revised 2017 General Rate Application Part B, Hydro’s Proposals

1 **1.0 Background**

2 On July 20, 2018, Hydro filed supplemental evidence¹ providing projected customer rate
3 impacts for 2019. The evidence reflected, among other things, the impacts of the April 11, 2018
4 Settlement Agreement (the “Settlement Agreement”) and the July 16, 2018 Supplemental
5 Settlement Agreement (the “Supplemental Settlement Agreement”), in which the Parties’
6 agreed that customer rates should be set based on the Expected Supply Scenario. On August
7 27, 2018, Hydro filed a letter with the Board of Commissioners of Public Utilities (the “Board”)
8 advising that, due to HVdc control equipment software issues, the Labrador-Island Link (LIL)
9 commissioning date required revision. Hydro committed to providing an update in customer
10 rate projections at a later date.

11
12 The basis for the 2018 and 2019 Test Year supply costs reflected in the July 20, 2018
13 supplemental evidence assumed a material ramp-up in off-island purchases over the LIL
14 beginning October 1, 2018 and a monopole commissioning date for the LIL in late October
15 2018. The LIL monopole commissioning date is the date upon which Hydro would be required
16 to begin paying the operating and maintenance (O&M) costs for the LIL and the Labrador
17 Transmission Assets (LTA).

18
19 On September 5, 2018, the Government of Newfoundland and Labrador released Terms of
20 Reference for the Board to examine options to mitigate the costs of the Muskrat Falls Project.
21 The Board has been asked to deliver an interim report by February 15, 2019 and a final report
22 by January 31, 2020. The results of the rate mitigation activities, including the impacts of
23 revenue generation activities through exports, may have a material impact on the Muskrat Falls
24 Project supply costs to be recovered through customer rates.

25
26 On October 2, 2018, the Board directed that Hydro file, by October 26, 2018, an update
27 reflecting both the revised forecast of off-island purchases and the updated fuel price forecast,

¹ Revised on August 3, 2018.

1 along with the revised customer rate projections for 2019 for each customer class. The Board
2 also directed Hydro to file a revision to its general rate application (GRA) to update Part B,
3 Hydro Proposals. The Board also indicated that if revised interim customer rates are required,
4 then this filing should include an interim rates application.

5
6 This evidence provides the required update directed by the Board and an interim rates
7 application for Island Industrial Customers. Hydro is not seeking interim rate changes for its
8 other customer classes.

9

10 **2.0 Summary of Revisions**

11 This section provides a summary of the revised assumptions used in preparing the updated
12 customer rate impacts. Hydro notes that these customer rate projections are estimates. In its
13 2017 GRA Compliance application, which is filed subsequent to the 2017 GRA Order, Hydro will
14 file updated 2018 and 2019 Test Year revenue requirements, cost of service studies, and
15 proposed rates to reflect the impact of the Settlement Agreement, Supplemental Settlement
16 Agreement, Labrador Settlement Agreement (collectively the 2017 GRA Settlement
17 Agreements), and the direction to be provided by the Board in the 2017 GRA Order.

18

19 **2.1 Availability of Off-Island Purchases Over the LIL**

20 Hydro has assumed a material increase in off-island purchases over the LIL beginning December
21 1, 2018 and a monopole commissioning date for the LIL of January 1, 2019 (assuming available
22 supply of 110 MW with a 30% forced outage rate for 2019).

23

24 **2.2 Proposed Deferral of LIL/LTA Operating and Maintenance Costs**

25 Due to the ongoing uncertainty related to availability of reliable supply over the LIL, Hydro is
26 proposing to exclude the O&M costs for the LIL and LTA from its 2018 and 2019 Test Year
27 revenue requirements. However, Hydro will be required to pay these costs beginning on the LIL
28 monopole commissioning date in order to facilitate fuel savings for its customers. Therefore,
29 Hydro is proposing to transfer all costs that it is required to pay for the use of LIL and LTA,

1 during the period prior to full commissioning of the Muskrat Falls Project, to the Revised Energy
2 Supply Variance Deferral Account.²

3

4 Under the proposed approach, the recovery of the deferred LIL and LTA O&M costs will be
5 subject to a further order of the Board.

6

7 **2.3 Timing of 2019 GRA Final Rate Implementation**

8 As a result on the ongoing delay in completing the 2017 GRA, it is unlikely that a final 2017 GRA
9 Order will be released in 2018. Therefore, Hydro believes it is probable that final rates resulting
10 from the 2017 GRA will not become effective until July 1, 2019. Hydro has continued to assume
11 the amortization periods for recovery of revenue deficiency due to delayed rate
12 implementation as detailed in the GRA Settlement Agreements. However, the projected
13 revenue deficiency now includes amounts for both 2018 and 2019.

14

15 **2.4 2019 Test Year Fuel Price**

16 The 2019 Test Year revenue requirement is based on an updated No. 6 fuel price forecast of
17 \$92.50³ per barrel compared to the \$85.55 per barrel used in the July 20, 2018 Supplemental
18 Evidence. Hydro has also updated its diesel and gas turbine fuel price forecast to reflect the
19 September 2018 forecast for fuel price in 2019.

20

21 **2.5 Corner Brook Pulp and Paper (CBPP) Frequency Converter**

22 Hydro has reflected the sale of the frequency converter to CBPP, effective August 9, 2018, in
23 the projected 2018 and 2019 Test Year revenue requirements and the proposed specifically
24 assigned charge for CBPP for 2019.

² Proposed Revised Energy Supply Cost Variance Deferral Account definition was filed in Appendix L of Hydro's March 22, 2018 Additional Cost of Service Information filing. The Parties agreed to the implementation of the proposed definition in the Supplemental Settlement Agreement.

³ As filed with the Board on October 15, 2018.

1 **2.6 Labrador Revenue and Supply Cost Forecast**

2 Hydro has updated its 2018 Test Year and 2019 Test Year load and supply cost forecasts to
3 reflect the August 24, 2018 Labrador Settlement Agreement. This update reflects current data
4 centre load projections for 2018 and 2019, including both the forecast revenue from higher
5 sales and forecast increase in supply costs (i.e., \$220,000 in interruptible costs for the winter of
6 2018-2019), and an update in the forecast 2019 Power on Order requirements for Labrador
7 Industrial Customers.

8
9 Due to the ongoing uncertainty with respect to the Tacora load requirements for 2019, the load
10 forecast for 2019 assumes only 1 MW of ongoing demand requirement for the Wabush Mines
11 facility. However, the Labrador Settlement Agreement also provides for a billing credit to be
12 made to the Iron Ore Company of Canada (IOC) in 2019 in the event that Tacora load
13 requirements are materially higher than indicated in the updated 2017 GRA forecast.

14

15 **2.7 Island Interconnected Capacity Assistance Update**

16 Hydro has updated its capacity assistance cost forecast for 2019 to reflect the additional
17 capacity assistance agreements currently being negotiated for the 2018/2019 winter season.
18 Relative to the July 20, 2018 Supplemental Evidence, this evidence includes an additional 15
19 MW of capacity assistance from CBPP,⁴ 7.6 MW of capacity assistance from Vale and 6 MW of
20 curtailable load from Vale. The additional capacity assistance is required due to the uncertainty
21 of the capacity that will be available over the LIL and is forecast to have the same cost per kW
22 as the previous agreements with CBPP and Vale.

23

24 **2.8 Interim Rates Proposal for Island Industrial Customers**

25 To manage customer impacts resulting from the update to the Rate Stabilization Plan (RSP)
26 Current Plan Adjustment for 2019, Hydro is proposing to reduce Island Industrial Customer base
27 rates at the same time that the RSP Current Plan Adjustment is implemented. The proposed

⁴ For a total of 105 MW.

1 reduction in base rates reflects the material reduction in the forecast base rate revenue
 2 requirement from Island Industrial Customers that results from Hydro's proposal to defer
 3 recovery of LIL and LTA O&M costs.

4
 5 In setting Island Industrial Customers interim rates for 2019, Hydro is also proposing to
 6 implement, on an interim basis, the proposed change in the methodology of allocation of O&M
 7 costs to specifically assigned assets. The proposed methodology change was accepted in the
 8 Supplemental Settlement Agreement.

9

10 **3.0 Off-Island Purchases**

11 **3.1 General**

12 This section provides an updated forecast of savings from off-island purchases for 2018 and
 13 2019. Under the Expected Supply Scenario, the net savings from off-island purchases will be
 14 used to reduce the revenue requirements from customers on the Island Interconnected System
 15 for the 2018 and 2019 Test Years. In this evidence, off-island purchases include recapture
 16 deliveries as well as other off-island purchases but exclude the LIL and LTA O&M costs. Other
 17 off-island purchases include short-term economic purchases, such as those which have
 18 occurred year-to-date over the Maritime Link.

19

20 **3.2 Off-Island Purchases Forecast**

21 Table 1 provides Hydro's projection of off-island purchases for 2018 and 2019.

Table 1: Expected Supply from Off-Island Purchases (GWh)⁵

Supply Source	2018	2019
Recapture Energy	69	667
Other Off-Island Purchases	83	49
Total	152	716

⁵ Assumed delivery to the Island Interconnected System at Bottom Brook for purchases over the Maritime Link and at Soldier's Pond for purchases over the LIL.

- 1 Table 2 provides Hydro's projected costs associated with off-island purchases to be recovered
2 from customer rates for 2018 and 2019.

Table 2: Projected Cost of Supply from Off-Island Purchases (\$000s)

Supply Source	2018	2019
Recapture Energy ⁶	219	1,537
Other Off-Island Purchases	7,316	4,582
LIL and LTA O&M Costs	0	0
Total	7,535	6,119

3 **3.3 Savings from Off-Island Purchases**

4 Under the Expected Supply Scenario, forecast savings from off-island purchases for 2018 and
5 2019 are used to reduce 2018 and 2019 Test Year revenue requirements. Forecast savings
6 reflect the reduction in No. 6 fuel expense,⁷ partially offset by the cost of off-island power
7 purchases.

8
9 To access off-island power purchases, Hydro entered into interim Transmission Funding
10 Agreements (interim TFAs) with the owners of the LIL and the LTA which will permit Hydro to
11 use those transmission facilities to transmit energy to the island and require Hydro to pay the
12 O&M costs associated with the use of the transmission lines.⁸ Hydro entered these interim TFAs
13 to take advantage of the opportunity use these assets earlier to reduce costs for customers on
14 the Island Interconnected System. Hydro is proposing that the O&M costs incurred to use the
15 LIL and the LTA prior to full commissioning of the Muskrat Falls Project be deferred for recovery
16 subject to a future Board Order.

⁶ Hydro has a contract in place with CF(L)Co to purchase Recapture Energy at a cost of 0.2 cents per kWh.

⁷ No. 6 fuel savings are achieved as a result of reduced fuel consumption at the Holyrood Thermal Generating Station.

⁸ On August 31, 2018, Hydro submitted an information filing on its interim TFAs with the owners of the LIL and LTA requiring Hydro to reimburse the asset owners for their actual O&M Costs which arise as a result of these assets being made available for service earlier than would otherwise be required.

1 Hydro's 2018 and 2019 Test Year costs include supply costs related to the purchase of
2 Recapture Energy and costs incurred to achieve power purchases from other jurisdictions. In its
3 2017 GRA, Hydro proposed that the RSP operate in 2018 based on the 2015 Test Year⁹ and in
4 2019 based on the 2019 Test Year. Therefore, to be consistent with the operation of the RSP, it
5 is appropriate that Hydro determine its 2018 Test Year revenue requirement for revenue
6 deficiency (or revenue excess) based on 2015 Test Year RSP fuel cost inputs (i.e., with No. 6 fuel
7 costs equal to an average of \$64.41 per barrel and a Holyrood conversion factor of 618 kWh per
8 barrel) and 2018 Test Year Load.

9

10 Savings from off-island purchases in 2018 are not recorded in the RSP but result in savings to
11 Hydro through the net effect of the reduced fuel cost (based on the approved test year fuel
12 cost) and the additional cost of purchases.

13

14 A similar approach is required for on-island gas turbine and diesel fuel costs for the 2018 Test
15 Year. Cost variances from the 2015 Test Year from these supply sources will accumulate in the
16 approved Supply Cost Variance Deferral Accounts.¹⁰ Therefore, in order to avoid duplication of
17 fuel cost recovery through 2018 revenue deficiencies and balances accumulating in the Supply
18 Cost Variance Deferral Accounts, Hydro has based the supply costs for the 2018 Test Year from
19 these sources on the 2015 Test Year inputs for computing revenue deficiency/revenue excess
20 for the 2018 Test Year.

21

22 In the Supplemental Settlement Agreement, the Parties agreed that the cost of No. 6 fuel for
23 the 2019 Test Year shall be set based on the most current fuel rider forecast (either March or
24 September) at the time of the 2017 GRA Compliance Filing. The most current fuel rider forecast
25 is \$92.50 per barrel.¹¹ While the \$92.50 may not be the fuel forecast used for the 2017 GRA
26 Compliance filing, Hydro has used this fuel price in this evidence to estimate its 2019 Test Year

⁹ Hydro's 2018 Test Year RSP reflects fuel price of \$64.41/bbl and conversion factor of 618 and 2018 Test Year load.

¹⁰ Energy Supply Cost Variance Deferral Account, Isolated Systems Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account.

¹¹ Based on September 2018 PIRA fuel forecast filed with the Board on October 15, 2018.

1 revenue requirement. Hydro has also used a No. 6 fuel price of \$92.50 per barrel to calculate
2 the savings from off-island purchases for the 2019 Test Year.¹²

3
4 In Appendix A to this evidence, Hydro has projected 2018 Test Year No. 6 fuel savings from off-
5 island purchases to be \$18.3 million. Appendix B provides projected 2019 Test Year No. 6 fuel
6 savings which are forecast to be \$113.6 million.

7
8 Table 3 provides the projected net savings from off-island purchases for the 2018 and 2019 Test
9 Years.

Table 3: Projected Net Savings from Off-Island Purchases (\$000s)

Particulars	2018	2019
No. 6 Fuel Savings	18,342	113,578
Less: Projected Costs of Off-Island Purchases	(7,535)	(6,119)
Net Savings from Off-Island Purchases	10,808	107,460

10 Hydro has reflected the forecast net savings from off-island purchases in its calculation of the
11 2018 and 2019 Test Year revenue requirements provided in this evidence.

12
13 In Appendix A to this evidence, Hydro has computed projected 2018 Test Year No. 6 fuel costs
14 to be \$147.7 million. Projected 2019 Test Year No. 6 fuel costs are expected to be \$137.9
15 million (provided in Appendix B).¹³

¹² The Supplemental Settlement Agreement signed on July 16, 2018 also provides for the use of a fuel conversion factor of 583 kWh per barrel.

¹³ Holyrood Generation (MWh)	(A)	868,954
Holyrood Conversion Factor (kWh/bbl)	(B)	583
No. 6 barrels (bbls)	(C) = (A/B) x 1,000	1,490,487
Cost per barrel (\$/bbl)	(D)	\$92.50
Total (\$000s)	(E) = (D x C)/1,000	\$137,870

1 The Supplemental Settlement Agreement also provides for variances in the forecast test year
2 net savings from off-island purchases to be transferred to a Revised Energy Supply Cost
3 Variance Deferral Account.¹⁴ Hydro is now proposing that the cost of O&M for LIL and LTA be
4 treated as a test year supply cost variance and charged to the Revised Energy Supply Cost
5 Variance Deferral Account. The disposition of the balances that accrue in this account are
6 subject to a further order of the Board.

7

8 **3.4 Revenue Requirements**

9 To estimate the impact of the settlement agreements, the revised fuel price forecast and the
10 proposed deferral of LIL and LTA O&M, Hydro has reflected these revenue requirement
11 adjustments by updating its 2018 and 2019 Test Year Cost of Service Studies.

12

13 **4.0 Cost of Service Results**

14 **4.1 General**

15 Hydro has used the cost of service methodology as described in the 2017 GRA Settlement
16 Agreements in preparing preliminary cost of service study results to determine customer rate
17 projections. Appendices C and D to this evidence provide the cost of service summary schedules
18 for the 2018 and 2019 Test Years, respectively.

19

20 The Expected Supply Scenario requires that the test year cost of service study revenue
21 requirements reflect the projected net savings from off-island purchases shown in Table 3.

22

23 Hydro has also updated its 2018 and 2019 GRA forecasts to reflect the Labrador Settlement
24 Agreement. This update reflects current data centre load projections for 2018 and 2019,
25 including both the forecast revenue from higher sales and forecast increased supply costs (i.e.,

¹⁴ The Supplemental Settlement Agreement does not define the effective date of the deferral account. To ensure the variance from the forecast Test Year savings from off-island purchases are recovered from customers, Hydro is proposing the Revised Energy Supply Cost Variance Deferral Account become effective January 1, 2018. For 2018, Hydro also proposes that the account balance be calculated based on variances from its 2018 Test Year forecast for off-island purchases valued at the 2015 Test Year cost of No. 6 fuel.

1 \$220,000 in interruptible costs for the winter of 2018-2019), and an update in the forecast 2019
2 Power on Order requirements for Labrador Industrial Customers.

3
4 The cost of service studies also assume the delayed Labrador capital project (i.e., providing the
5 Muskrat Falls to Happy Valley transmission interconnection) will be in service in December
6 2019. If this project has not been approved at the time of Hydro's filing its 2017 GRA
7 Compliance filing then Hydro will exclude the project in calculating the 2019 Test Year revenue
8 requirement. This is consistent with the Labrador Settlement Agreement.¹⁵

9
10 Hydro has used a 24-month amortization period to provide recovery of the 2018 and 2019
11 revenue deficiency from the Labrador Industrial Transmission customers and the Hydro Rural
12 Labrador Interconnected customers consistent with the Labrador Settlement Agreement.

13
14 Finally, the cost of service studies reflect the transfer of the frequency converter asset to CBPP
15 effective August 9, 2018 with no specifically assigned charge in effect for CBPP from the date of
16 the transfer until the end of calendar 2018.¹⁶

17

18 **4.2 Revenue Deficiencies**

19 Table 4 provides a derivation of Hydro's revenue deficiencies/revenue excesses for 2018 and
20 2019 based on the Expected Supply Scenario reflecting the settlement agreements.¹⁷ The
21 revenue deficiencies/revenue excesses for 2018 were determined by comparing, on a class
22 basis, the 2018 Test Year revenue requirement to the 2018 Test Year revenue forecast
23 calculated using approved base rates in effect for 2018.¹⁸ The revenue deficiency for 2019 was

¹⁵ The Labrador Settlement Agreement also assumes no depreciation costs in 2019 related to the Muskrat Falls to Happy Valley transmission project.

¹⁶ The transfer of the frequency converter to CBPP was approved by the Board in Order No. P.U. 26(2018).

¹⁷ Revenue deficiency and revenue excess are calculated by using base rates and exclude charges related to RSP and CDM adjustments.

¹⁸ The 2018 revenue forecast is calculated by using the actual approved base rates in effect during 2018 applied to the 2018 Test Year load forecast for each class.

- 1 determined following the same approach; however, base rates forecast to be in effect were
- 2 used in the calculation for forecast 2019 Test Year revenues.¹⁹

Table 4: Projected Test Year Revenue Deficiency/Excess by Customer Class (\$ millions)²⁰

Particulars	2018 Test Year			2019 Test Year		
	Revenue Forecast ²¹	Revenue Requirement ²²	Revenue Excess/ (Deficiency)	Existing Rates ²³	Revenue Requirement	Revenue Excess/ (Deficiency)
	(a)	(b)	(c)=(a)-(b)	(d)	(e)	(f)=(d)-(e)
Newfoundland Power	441.5	450.9	(9.4)	450.8	459.8	(9.0)
Island Industrial	41.2	39.1	2.1	39.1	39.1	0.0
Rural Labrador Interconnected	21.0	20.8	0.2	22.1	21.7	0.4
Labrador Industrial Transmission	4.7	4.9	(0.2)	4.8	5.6	(0.8)
Hydro Rural Government Diesel	2.1	2.1	0.0	2.1	2.4	(0.3)

- 3 Table 4 shows that, for the 2018 Test Year, Hydro will have a deficiency from Newfoundland
- 4 Power of \$9.4 million and a revenue excess of \$2.1 million from Island Industrial Customers.
- 5 Hydro will have a 2018 revenue excess of \$0.2 million from the Hydro Rural Labrador
- 6 Interconnected class and a revenue deficiency of \$0.2 million from the Labrador Industrial
- 7 Transmission class. Hydro is not projecting a revenue deficiency or a revenue excess in 2018 for
- 8 Hydro Rural Government Diesel Customers.

¹⁹ For 2019, existing rates reflect customer rates as of July 1, 2018 for all classes except Island Industrial Customers for which proposed January 1, 2019 interim rates are treated as existing rates.

²⁰ There is no revenue deficiency shown for Hydro Rural Other as the rural deficit is allocated for recovery from Newfoundland Power and Labrador Interconnected customers.

²¹ The 2018 rate revenue forecast is calculated using the base rates in effect during 2018 applied to the 2018 Test Year load forecast. Base rate revenues exclude revenues from RSP and CDM riders.

²² Revenue amounts after allocation of the Rural Deficit.

²³ Island Industrial Customers reflect January 1, 2019 interim rates.

1 The rate change required for Hydro Rural Labrador Interconnected customers is materially
2 lower than proposed in Hydro’s July 20, 2018 filing due to the increased revenues from data
3 centre loads for 2018 and 2019 exceeding the additional supply costs incurred to provide the
4 additional load.

5

6 Hydro projects a 2019 Test Year revenue deficiency from Newfoundland Power of \$9.0 million.

7 With the implementation of proposed interim rates for Island Industrial customers on January
8 1, 2019, Island Industrial Customers will have no revenue deficiency/revenue excess for 2019.

9 Hydro also projects a 2019 revenue excess of \$0.4 million from the Hydro Rural Labrador

10 Interconnected class, a revenue deficiency of \$0.8 million from the Labrador Industrial

11 Transmission class, and a \$0.3 million revenue deficiency for Hydro Rural Government Diesel
12 Customers.

13

14 In the Supplemental Settlement Agreement, the Parties agreed that the Newfoundland Power
15 credit from the Isolated Systems Deferral Account would be applied to reduce the 2018
16 Revenue Deficiency to be recovered from Newfoundland Power. For purposes of determining
17 rate increase projections for 2019, Hydro has applied this credit of approximately \$3.2 million
18 to reduce the deferred supply costs to be recovered from Newfoundland Power.

19

20 **4.3 Deferred Supply Cost Recovery**

21 The Supplemental Settlement Agreement also provides that the deferred supply costs in the
22 Energy Supply Cost Variance and Holyrood Conversion Rate Deferral Accounts of 2015, 2016
23 and 2017, as approved by the Board for recovery from customers (Approved Deferred Supply
24 Costs), will be allocated between customer classes in a manner consistent with the fuel cost
25 allocation methodology used in the RSP.²⁴

²⁴ The allocation percentage will be based on the RSP energy allocators consistent with the year in which the Approved Deferred Supply Costs were incurred.

1 The Parties agree that the Approved Deferred Supply Costs allocated to each of Newfoundland
 2 Power and the Island Industrial Customers will be recovered through rate riders determined
 3 separately for each customer class and computed reflecting a 20-month recovery period
 4 beginning with the effective date of the 2017 GRA final rates approved by the Board.
 5
 6 Table 5 provides the allocation of the Deferred Supply Costs to be recovered through the rates
 7 of Newfoundland Power and Island Industrial Customers.

Table 5: Allocation of Deferred Supply Costs (\$)

Account	Balance	Newfoundland Power	Island Industrial Customers	Labrador Allocation
Isolated Systems Deferral ²⁵	(3,293,391)	(3,150,090)	-	(143,301)
Energy Supply Cost Deferral	58,798,157	54,111,891	4,510,432	175,834
Holyrood Conversion Deferral	9,896,512	9,104,028	763,054	29,429
Total	65,401,278	60,065,830	5,273,486	61,962²⁶
Allocation Based on Historical Energy²⁷		91.8%	8.1%	0.1%

8 The Supplemental Settlement Agreement provides that the 2018 revenue deficiency/revenue
 9 excess for Newfoundland Power and Island Industrial customers be disposed of through rate
 10 riders over a 20-month period. The same approach was agreed upon for recovery of deferred
 11 supply costs. Hydro has also applied this approach for the projected 2019 revenue
 12 deficiency/revenue excess. Therefore, for the calculation of the riders to recover the deferred

²⁵ The Isolated Systems Deferral has been allocated based upon the 2015 Test Year rural deficit allocation.

²⁶ Consistent with the allocation methodology in the RSP, the portion of the costs allocated to Hydro Rural are reallocated between Newfoundland Power and Hydro Rural Interconnected customers on the same basis as the rural deficit. Also consistent with the established RSP methodology, Hydro is proposing that the Labrador Allocation of approximately \$62,000 be written off to Hydro's net income.

²⁷ Deferred Supply Costs from each of 2015, 2016, and 2017 have been allocated based upon actual energy consumption from each respective year. The allocations shown in Table 5 represent the summation of these annual allocations.

1 supply costs, a 2017 GRA Cost Recovery Rider was computed for each of Newfoundland Power
 2 and the Island Industrial Customers reflecting the total of the deferred supply costs and the
 3 2018 and 2019 revenue deficiency/revenue excess.

4
 5 Table 6 provides the derivation of the estimated monthly charge to apply to Newfoundland
 6 Power to provide recovery through the 2017 GRA Cost Recovery Rider.

Table 6: Estimated 2017 GRA Cost Recovery Rider – Newfoundland Power (\$)

Particulars	Deferred Supply Costs	2018 & 2019	Monthly Charge
	(a)	Deficiencies (b)	(c) = ((a) + (b)) / 20
Newfoundland Power	60,065,830	14,040,411	3,705,312

7 For the Island Industrial Customers, the \$5.3 million owing for the deferred supply cost is
 8 partially offset by the \$2.1 million in 2018 revenue excess. The remaining amount of \$3.2
 9 million would result in a 2017 GRA Cost Recovery Rider of 0.256¢ per kWh.²⁸ Included in its
 10 update to Part B, Hydro Proposals, included as Appendix H, is a proposal by Hydro to track the
 11 Island Industrial Customer 2017 GRA Recovery Rider by month such that any over or under
 12 recovery of this amount be charged or credited to the Island Industrial Customer RSP Current
 13 Plan balance at the conclusion of the 20-month amortization period.

14

15 **5.0 Island Industrial Customer Interim Rates Proposal**

16 **5.1 RSP Update**

17 **5.1.1 RSP Current Plan Adjustment**

18 Section D.2 of the RSP rules requires an update to the Industrial Customer RSP Current Plan
 19 Adjustment to become effective January 1 of each year to recover the balance in the Industrial

²⁸ Annual 2019 Test Year energy (A) = 743,300,000 kWh
 Average Monthly 2019 Test Year energy (B) = (A)/12 = 61,941,667 kWh/month
 Total amount owing (C) = \$3,170,016
 Monthly amount owing (D) = (C)/20 = \$158,501
 Recovery rider (E) = (D)/(B)*100 = 0.256 cents/kWh

1 Customer RSP balance at December 31 of the previous year and the forecast financing charges
2 to the end of the following calendar year.

3

4 Hydro is projecting a RSP Current Plan balance owing from Industrial Customers of
5 approximately \$1.8 million at year-end 2018 which would require a RSP Current Plan
6 adjustment of 0.312 cents per kWh.²⁹ This represents an increase of 0.597 cents per kWh from
7 the existing RSP Current Plan Adjustment of (0.285) cents per kWh. The 2019 RSP Current Plan
8 Adjustment update will require an increased collection of approximately \$4.4 million in 2019
9 relative to 2018 which equates to an approximate 11.2% average customer rate increase.

10 Appendix E provides the calculation of the projected Industrial Customer RSP Current Plan
11 adjustment for 2019.

12

13 **5.1.2 RSP Fuel Rider**

14 In accordance with the RSP rules, on October 15, 2018, Hydro provided the Board with its
15 updated No. 6 fuel price forecast for the 2019 calendar year of \$92.50 per barrel. However,
16 Hydro's proposed interim Industrial Customer rates do not include an RSP fuel rider for January
17 1, 2019 as the forecast No. 6 fuel price of \$92.50 is reflected in the proposed interim rates,
18 based upon the projected 2019 Test Year base rate revenue requirements.

19

20 **5.2 Test Year Revenue Requirement**

21 The projected 2019 Test Year base rate revenue requirement for Island Industrial Customers of
22 \$39.1 million, as provided in Table 4, is approximately \$2.7 million less than the forecast 2019
23 revenue under existing interim rates approved April 1, 2018.

24

25 Approximately \$2.2 million of the \$2.7 million revenue excess reflects the inclusion of savings
26 from off-island purchases in determining the 2019 Test Year revenue requirement. Hydro is
27 proposing to update the firm demand charge and the firm energy charge based on the 2019

²⁹ \$1.9 million amount to be recovered including financing costs in accordance with the RSP Rules.

1 Test Year Cost of Service Study, provided in Appendix D, to eliminate the forecast revenue
2 excess for 2019 and reduce the customer rate impact of updating the RSP adjustments.

3
4 Approximately \$0.5 million of the 2019 revenue excess reflects the reduction in specifically
5 assigned costs as a result of changing from the existing specifically assigned O&M cost
6 allocation methodology to the proposed 2017 GRA methodology which was accepted in the
7 Supplemental Settlement Agreement. Therefore, Hydro believes it is reasonable to reflect this
8 change in the proposed 2019 interim rates.

9
10 The overall projected average customer rate impact reflecting the combined effect of the
11 January 1, 2019 RSP update and the concurrent implementation of the proposed interim base
12 rates is an increase of 4.8%, a decrease of 6.4% relative to the impact of the Island Industrial
13 RSP update impact of 11.2%. Appendix F provides the projected customer impacts reflecting
14 the updated RSP adjustments and proposed interim base rates.

15

16 **6.0 2019 Customer Rate Projections**

17 **6.1 Projected Rate Increases**

18 As a result of the ongoing delay in the 2017 GRA process, Hydro has assumed that final GRA
19 customer rates will be implemented July 1, 2019.

20

21 Table provides the projected impacts for each customer class to become effective July 1, 2019.
22 The projected impacts include the required revisions to base rates to recover 2019 Test Year
23 costs, recovery/refund of the 2018 revenue deficiency/revenue excess and 2019 Test Year
24 revenue deficiency/revenue excess over the agreed amortization periods, and the recovery of
25 the deferred supply costs over the agreed amortization period.

**Table 7: Projected July 1, 2019 Increases in Customer Billings
(Excluding RSP Impacts)**

Customer Class	Customer Rate Impacts		Average Unit Cost cents/kWh
	\$ millions	%	
Newfoundland Power ³⁰	28.8	6.3%	8.369
Island Industrial	1.9	4.6%	5.527
Rural Labrador Interconnected	(0.6)	-2.6%	2.836
Labrador Industrial Transmission	1.0	20.2%	\$1.94/kW
Hydro Rural Government Diesel	0.4	21.4%	105.140
Hydro Rural Other ³¹	2.5	4.0%	13.367

1 Appendix G to this evidence provides the supporting calculations for the estimates of customer
2 rate impacts reflecting 2017 GRA final rates. The projected increase in rates to Newfoundland
3 Power’s retail customers is 4.0% on July 1, 2019 as a result of the 2017 GRA.

4

5 Appendix H provides an update to Part B, Hydro Proposals filed with its 2017 GRA reflecting this
6 updated evidence on customer rates.

7

8 **7.0 Conclusion**

9 This evidence provides estimated revenue requirements and projected rates reflecting the
10 following: the three settlement agreements concluded during the 2017 GRA process; the
11 updated projection of savings from off-island purchases reflecting the proposed deferral of
12 O&M costs for LIL and LTA; the updated fuel cost projection for 2019; and a July 1, 2019 GRA
13 final rate implementation date.

³⁰ Hydro notes that customer rates are also required to be updated each July 1st as a result of the operation of the RSP. The July 2019 customer rate impact of the RSP will not be known until Hydro’s filing in May 2019.

³¹ Includes Hydro Rural Isolated and Hydro Rural Interconnected, but excludes Hydro Rural Government Diesel. Hydro assumed Hydro Rural Other customers will receive the same rate increase as Newfoundland Power's retail customers, which is approximately 64% of Newfoundland Power's wholesale rate increase.

1 Hydro has also proposed to implement revised interim rates for Island Industrial Customers to
2 become effective January 1, 2019 to reduce the customer rate impacts resulting from the
3 required update to the RSP adjustments in January 2019.

4

5 The revised rate projections provide for materially lower rates in 2019 for customers on the
6 island interconnected system than the customer rates which were originally proposed in
7 Hydro's 2017 GRA Application. The lower forecast customer rates primarily reflect the provision
8 of savings from off-island purchases in the determination of rates for 2019 as required under
9 the Expected Supply Scenario and savings in depreciation as a result of the 2017 GRA
10 Settlement Agreement dated April 11, 2018.

Appendix A

2018 Test Year Fuel Cost and Savings

Table 1: Derivation of Forecast 2018 Test Year No. 6 Fuel Expense

Month	2015 Test Year No. 6 Fuel ¹ (BBLs)	Adjustment for 2018 Test Year Load (BBLs)	2018 Projected Savings from Off-Island Purchases ² (BBLs)	Net 2018 Test Year No. 6 Fuel (BBLs)	2015 Test Year Average Monthly Cost ³ (\$/BBL)	Net 2018 Forecast No. 6 Fuel Expense (\$000s)
	(a)	(b)	(c)	(d) = (a) + (b) + (c)	(e)	(f) = [(d) x (e)] / 1000
January	415,518	(3,361)	(507)	411,650	\$57.55	23,690
February	375,307	47,363	(32,379)	390,291	\$59.85	23,359
March	395,728	(123,970)	(3,311)	268,447	\$61.41	16,485
April	255,307	(16,410)	(2,813)	236,084	\$61.41	14,498
May	197,864	2,677	(15,541)	185,000	\$62.64	11,588
June	76,586	134,079	(6,393)	204,272	\$62.64	12,796
July	-	6,869	(6,869)	-	\$62.64	-
August	-	-	-	-	\$62.64	-
September	25,534	(25,534)	-	-	\$62.64	-
October	164,887	(102,740)	(22,389)	39,757	\$66.51	2,644
November	255,307	10,000	(32,298)	233,010	\$71.70	16,707
December	415,618	48,693	(123,535)	340,777	\$76.05	25,916
Total	2,577,657	(22,333)	(246,036)	2,309,288		147,684

¹ Hydro's Amended GRA Compliance Application P.U. 49(2016), Exhibit 2 - Computation of Revenue Requirements, Table 13.

² Off-Island Power Purchases (kWh)	152,050,000
2015 Test Year Conversion Rate (BBLs/kWh)	618
Reduced Barrels (BBLs)	<u>246,036</u>

³ Hydro's Amended GRA Compliance Application P.U. 49(2016), Exhibit 2 - Computation of Revenue Requirements, Table 17.

Appendix A
Page 2 of 2

Table 2: Derivation of Forecast 2018 Test Year No. 6 Fuel Savings

Month	2015 Test Year No. 6 Fuel Expense (\$000s) (a)	Net 2018 Forecast No. 6 Fuel Expense (\$000s) (b)	2018 Projected Savings from Off-Island Purchases (\$000s) (c) = (a) - (b)
January	23,913	23,690	223
February	22,462	23,359	(897)
March	24,302	16,485	7,816
April	15,678	14,498	1,181
May	12,394	11,588	806
June	4,797	12,796	(7,998)
July	-	-	-
August	-	-	-
September	1,599	-	1,599
October	10,967	2,644	8,322
November	18,306	16,707	1,599
December	31,608	25,916	5,692
Total	166,026	147,684	18,342

Appendix B

2019 Test Year Fuel Cost and Savings

Table 1: Derivation of Forecast 2019 Test Year No. 6 Fuel Expense

Month	2019 No. 6 Fuel Excluding Off-Island (BBLs)	2019 Projected Savings from Off-Island Purchases ¹ (BBLs)	Net 2019 Test Year No. 6 Fuel (BBLs)	2019 Test Year Average Monthly Cost (\$/BBL)	Net 2019 Forecast No. 6 Fuel Expense (\$000s)
	(a)	(b)	(c) = (a) + (b)	(d)	(e) = [(c) x (d)] /1000
January	480,208	(97,361)	382,847	\$92.50	35,413
February	379,420	(87,190)	292,230	\$92.50	27,031
March	294,482	(97,158)	197,324	\$92.50	18,252
April	181,390	(94,941)	86,449	\$92.50	7,997
May	148,068	(98,119)	49,949	\$92.50	4,620
June	93,773	(93,773)	-	\$92.50	-
July	97,620	(97,620)	-	\$92.50	-
August	98,220	(98,220)	-	\$92.50	-
September	94,292	(94,292)	-	\$92.50	-
October	220,833	(117,094)	103,739	\$92.50	9,596
November	293,180	(120,281)	172,899	\$92.50	15,993
December	336,875	(131,825)	205,050	\$92.50	18,967
Total	2,718,361	(1,227,874)	1,490,487		137,870

¹ Off-Island Power Purchases (kWh)	715,850,320
2019 Test Year Conversion Rate (BBLs/kWh)	583
Reduced Barrels (BBLs)	1,227,874
Cost (\$/BBL)	92.5
Total Projected 2019 Fuel Savings	113,578,310

Appendix C

2018 Test Year Cost of Service Study Summary

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Total System Revenue Requirement

Line No.	1 Description	2 Total Amount (\$)	3 Island Interconnected (\$)	4 Island Isolated (\$)	5 Labrador Isolated (\$)	6 L'Anse au Loup (\$)	7 Labrador Interconnected (\$)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	138,337,352	104,030,836	6,789,893	15,053,727	1,490,311	10,972,586	Detailed Analysis
2	Fuels - No. 6 Fuel	148,037,516	148,037,516	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	17,266,585	87,144	2,140,854	14,364,592	634,623	39,373	Detailed Analysis
4	Fuels - Gas Turbine	3,711,024	3,473,692	-	-	-	237,332	
5	Fuel Supply Deferral	-	-	-	-	-	-	
6	Power Purchases - CF(L)Co	1,395,205	-	-	-	-	1,395,205	Detailed Analysis
7	Power Purchases - Other	62,310,678	59,241,500	176,972	-	2,837,205	55,000	Detailed Analysis
8	Power Purchases - MF	-	-	-	-	-	-	
8	Power Purchases - LIL & LTA Costs	-	-	-	-	-	-	
9	Power Purchases - Off Island	7,706,759	7,706,759	-	-	-	-	
10	Depreciation	74,963,444	66,031,104	723,490	3,149,254	784,964	4,274,632	Detailed Analysis
	Expense Credits:							
11	Sundry	(456,000)	(342,916)	(22,381)	(49,621)	(4,912)	(36,169)	Total O&M Expenses
12	Building Rental Income	(15,600)	(15,600)	-	-	-	0	Detailed Analysis
13	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
14	Suppliers' Discounts	(39,600)	(29,780)	(1,944)	(4,309)	(427)	(3,141)	Total O&M Expenses
15	Pole Attachments	(1,578,275)	(1,137,383)	(23,451)	(102,027)	(67,660)	(247,754)	Detailed Analysis
16	Wheeling Revenues	-	0	-	-	-	-	Island Interconnected
17	Application Fees	(24,680)	(12,200)	(300)	(1,654)	(406)	(10,120)	Detailed Analysis
18	Meter Test Revenues	-	0	-	-	-	-	Weighted Customers
19	Total Expense Credits	(2,114,155)	(1,537,878)	(48,076)	(157,612)	(73,405)	(297,184)	
20	Subtotal Expenses	451,614,408	387,070,672	9,783,133	32,409,961	5,673,697	16,676,944	
21	Disposal Gain/Loss	-	-	-	-	-	-	Detailed Analysis
22	Subtotal Rev Req Excl Return	451,614,408	387,070,672	9,783,133	32,409,961	5,673,697	16,676,944	
23	Return on Debt	91,798,240	82,588,881	659,387	3,335,030	686,653	4,528,289	Rate Base
24	Return on Equity	35,237,955	31,702,822	253,114	1,280,195	263,581	1,738,243	Rate Base
25	Total Revenue Requirement	578,650,604	501,362,376	10,695,634	37,025,186	6,623,932	22,943,476	

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Total System
Return on Rate Base

Line No	1	2	3	4	5	6	7	8
	Total	Island Interconnected	Island Isolated	Labrador Isolated	Labrador Loup	L'Anse au Interconnected	Labrador Interconnected	Basis of Proration
	\$	\$	\$	\$	\$	\$	\$	
Rate Base:								
1	Average Net Book Value	2,054,005,042	1,844,981,477	14,918,521	74,540,490	15,707,477	103,857,077	Schedule 2.3
2	Cash Working Capital	2,162,000	1,941,986	15,703	78,460	16,533	109,318	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	57,754,996	57,754,996	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	2,994,759	102,326	357,296	2,379,253	93,027	62,856	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	4,877,967	4,652,200	-	-	-	225,767	Detailed Fuel Analysis
6	Inventory/Supplies	33,034,000	29,348,869	179,428	1,290,289	286,152	1,929,263	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Holyrood	-	-	-	-	-	-	Detailed Analysis
	Deferred Charges: Foreign Exchange Loss	-	-	-	-	-	-	
8	and Regulatory Costs	82,041,000	73,692,188	595,875	2,977,294	627,388	4,148,256	Prorated on Average Net Book Value - L. 1
9	Retired Asset Pool	7,585,989	6,814,009	55,098	275,298	58,012	383,572	Prorated on Average Net Book Value - L. 1
10	Total Rate Base	2,244,455,753	2,019,288,052	16,121,920	81,541,083	16,788,589	110,716,108	
11	Less: Rural Portion	-	-	-	-	-	-	Schedule 2.6, L. 9
12	Rate Base Available for Equity Return	2,244,455,753	2,019,288,052	16,121,920	81,541,083	16,788,589	110,716,108	
Corporate Targets:								
13	Capital Structure: Percent of Debt	77.83% ⁽¹⁾						
14	Return	<u>5.25%</u>						
15	Weighted Average Return: Debt	<u>4.09%</u>						
16	Capital Structure: Percent of Equity	18.48% ⁽¹⁾						
17	Return	<u>8.50%</u>						
18	Weighted Average Return: Equity	<u>1.57%</u>						
19	Weighted Average Cost of Capital	<u>5.66%</u>						
Return on Rate Base by System (%):								
20	Return on Rate Base - Debt Component	-	4.09%	4.09%	4.09%	4.09%	4.09%	
21	Return on Rate Base - Equity Component	-	1.57%	1.57%	1.57%	1.57%	1.57%	
Return on Rate Base (\$):								
22	Return on Debt	91,798,240	82,588,881	659,387	3,335,030	686,653	4,528,289	Schedule 2.6, L.13
23	Return on Equity	35,237,955	31,702,822	253,114	1,280,195	263,581	1,738,243	Schedule 2.6, L.14
24	Return on Rate Base (\$)	127,036,196	114,291,704	912,501	4,615,225	950,234	6,266,532	Schedule 2.6, L.15
Return on Total Rate Base (%):								
25	Return on Rate Base - Debt Component	4.09%	4.09%	4.09%	4.09%	4.09%	4.09%	L. 22 divided by L.10
26	Return on Rate Base - Equity Component	1.57%	1.57%	1.57%	1.57%	1.57%	1.57%	L. 23 divided by L.10
27	Return on Rate Base (%)	5.66%	5.66%	5.66%	5.66%	5.66%	5.66%	L. 24 divided by L.10

⁽¹⁾ Debt and equity weightings reflect a 0.62% funded ARO and 3.08% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credits (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Total System							
1	Newfoundland Power	441,522,342	392,787,557	-	58,064,862	450,852,419	
2	Subtotal Newfoundland Power	441,522,342	392,787,557	-	58,064,862	450,852,419	1.12
3	Island Industrial	41,174,619	39,071,760	-	-	39,071,760	1.05
4	Labrador Industrial	4,739,196	4,857,979	-	-	4,857,979	0.98
5	CFB - Goose Bay Secondary	-	-	-	-	-	-
6	Rural Labrador Interconnected	20,984,405	18,085,497	-	2,673,537	20,759,034	1.16
Rural Deficit Areas							
7	Island Interconnected	49,927,947	69,503,058	-	(19,575,112)	49,927,947	0.72
8	Island Isolated	1,550,692	10,695,317	-	(9,144,625)	1,550,692	0.14
9	Labrador Isolated	8,663,855	37,025,186	-	(28,361,331)	8,663,855	0.23
10	L'Anse au Loup	2,966,601	6,623,932	-	(3,657,331)	2,966,601	0.45
11	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
12	Subtotal	63,109,094	123,847,493	-	(60,738,398)	63,109,094	0.51
13	Total	571,529,656	578,650,286	-	-	578,650,286	0.99

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Interconnected							
1	Newfoundland Power	441,522,342	392,787,557	-	58,064,862	450,852,419	
2	Subtotal Newfoundland Power	441,522,342	392,787,557	-	58,064,862	450,852,419	1.12
3	Industrial - Firm	41,174,619	39,071,760	-		39,071,760	
4	Industrial - Non-Firm	-	-	-		-	
5	Subtotal Industrial	41,174,619	39,071,760	-	-	39,071,760	1.05
Rural							
6	1.1 Domestic	13,522,976	21,926,361	-	(8,403,385)	13,522,976	0.62
7	1.12 Domestic All Electric	17,034,575	24,766,176	-	(7,731,601)	17,034,575	0.69
8	1.3 Special	19,223	68,113	-	(48,890)	19,223	0.28
9	2.1 General Service 0-100 kW	9,123,833	11,483,377	-	(2,359,545)	9,123,833	0.79
10	2.3 General Service 110-1,000 kVa	5,944,059	6,581,479	-	(637,419)	5,944,059	0.90
11	2.4 General Service Over 1,000 kVa	3,289,595	3,460,580	-	(170,985)	3,289,595	0.95
12	4.1 Street and Area Lighting	993,685	1,216,973	-	(223,288)	993,685	0.82
13	Subtotal Rural	49,927,947	69,503,058	-	(19,575,112)	49,927,947	0.72
14	Total Island Interconnected	532,624,908	501,362,376	-	38,489,750	539,852,127	1.06

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Isolated							
1	1.2 Domestic Diesel	779,446	8,232,523		(7,453,077)	779,446	0.09
2	1.2G Government Domestic Diesel	-	-		-	-	-
2	1.23 Churches, Schools & Com Halls	63,100	317,210		(254,110)	63,100	0.20
3	2.1 General Service 0-10 kW	205,207	846,144		(640,938)	205,207	0.24
4	2.2 GS 10-100 kW	459,017	1,095,748		(636,732)	459,017	0.42
5	4.1 Street and Area Lighting	38,040	194,316		(156,276)	38,040	0.20
6	4.1G Gov't Street and Area Lighting	5,882	9,375		(3,493)	5,882	0.63
7	Total	1,550,692	10,695,317		(9,144,625)	1,550,692	0.14

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Isolated							
1	1.2 Domestic Diesel	3,032,845	19,925,606		(16,892,761)	3,032,845	0.15
2	1.2G Government Domestic Diesel	517,117	535,622		(18,505)	517,117	0.97
3	1.23 Churches, Schools & Com Halls	277,232	1,082,918		(805,687)	277,232	0.26
4	2.1 General Service 0-10 kW	1,241,157	3,643,401		(2,402,244)	1,241,157	0.34
5	2.2 GS 10-100 kW	3,008,584	8,558,850		(5,550,265)	3,008,584	0.35
6	2.3 GS 110-1,000 kVa	243,729	1,352,604		(1,108,875)	243,729	0.18
7	2.4 General Service Over 1,000 kVa	224,074	1,560,085		(1,336,011)	224,074	0.14
8	4.1 Street and Area Lighting	110,871	356,374		(245,503)	110,871	0.31
9	4.1G Gov't Street and Area Lighting	8,246	9,726		(1,480)	8,246	0.85
10	Total	8,663,855	37,025,186		(28,361,331)	8,663,855	0.23

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
L'Anse au Loup							
1	1.1 Domestic	550,885	1,403,020		(852,135)	550,885	0.39
2	1.12 Domestic All Electric	1,296,197	3,062,018		(1,765,821)	1,296,197	0.42
3	2.1 General Service 0-100 kW	789,492	1,579,608		(790,116)	789,492	0.50
3	2.3 General Service 110-1,000 kVa	311,102	535,974		(224,872)	311,102	0.58
4	4.1 Street and Area Lighting	18,925	43,311		(24,387)	18,925	0.44
5	Total L'Anse Au Loup	2,966,601	6,623,932		(3,657,331)	2,966,601	0.45

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/7)
Labrador Interconnected							
1	Labrador Industrial Firm	4,739,196	4,857,979	-	-	4,857,979	0.98
2	Labrador Industrial Non-Firm	-	-	-	-	-	-
3	Subtotal Industrial	4,739,196	4,857,979	-	-	4,857,979	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
Rural							
5	1.1 Domestic	101,567	204,383	-	30,213.47	234,597	0.43
6	1.1A Domestic All Electric	10,901,824	10,623,681	-	1,570,474	12,194,155	0.89
7	2.1 General Service 0-10 kW	370,747	351,378	-	51,943	403,321	0.92
8	2.2 General Service 10-100 kW	2,295,257	1,664,633	-	246,079	1,910,712	1.20
9	2.3 General Service 110-1,000 kVa	3,685,870	2,350,760	-	347,507	2,698,267	1.37
10	2.4 General Service Over 1,000 kVa	3,267,874	2,597,868	-	384,037	2,981,905	1.10
11	4.1 Street and Area Lighting	361,265	292,794	-	43,283	336,077	1.07
12	Subtotal Rural	20,984,405	18,085,497	-	2,673,537	20,759,034	
13	Total Labrador Interconnected	25,723,601	22,943,476	-	2,673,537	25,617,012	

NEWFOUNDLAND AND LABRADOR HYDRO
2018 Expected Supply Test Year Cost of Service Study - October 26, 2018 Forecast
Total System
Rural Deficit Allocation

Line No.	1	2		
		<u>Deficit Allocation</u> Allocated on Revenue Requirement (\$)		
ALLOCATION OF DEFICIT:				
1	Island Interconnected	58,064,862		
2	Labrador Interconnected	2,673,537		
3	Allocated Totals	<u><u>60,738,398</u></u>		
CUSTOMER DEFICIT ALLOCATION:				
		Amount	Revenue Requirement	Percent
Island Interconnected:				
4	Newfoundland Power	<u>58,064,862</u>	392,787,557	95.6%
Labrador Interconnected:				
5	Rural Labrador Interconnected	<u>2,673,537</u>	18,085,497	<u>4.4%</u>
6	Total	<u><u>60,738,398</u></u>		<u>100.0%</u>

Appendix D

2019 Test Year Cost of Service Study Summary

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Total System Revenue Requirement

Line No.	1 Description	2 Total Amount (\$)	3 Island Interconnected (\$)	4 Island Isolated (\$)	5 Labrador Isolated (\$)	6 L'Anse au Loup (\$)	7 Labrador Interconnected (\$)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	140,793,862	105,785,497	6,974,717	15,423,291	1,504,886	11,105,471	Detailed Analysis
2	Fuels - No. 6 Fuel	138,205,264	138,205,264	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	21,146,184	138,012	2,420,900	17,777,900	767,000	42,372	Detailed Analysis
4	Fuels - Gas Turbine	7,415,356	7,160,521	-	-	-	254,835	
5	Fuel Supply Deferral	-	-	-	-	-	-	
6	Power Purchases - CF(L)Co	1,490,325	-	-	-	-	1,490,325	Detailed Analysis
7	Power Purchases - Other	66,399,859	62,307,563	195,500	-	3,731,796	165,000	Detailed Analysis
8	Power Purchases - MF	-	-	-	-	-	-	
8	Power Purchases - LIL & LTA Costs	-	-	-	-	-	-	
9	Power Purchases - Off Island	6,373,177	6,373,177	-	-	-	-	
10	Depreciation	80,922,570	70,939,035	840,772	3,868,483	789,941	4,484,338	Detailed Analysis
	Expense Credits:							
11	Sundry	(456,000)	(342,616)	(22,590)	(49,953)	(4,874)	(35,968)	Total O&M Expenses
12	Building Rental Income	(15,600)	(15,600)	-	-	-	0	Detailed Analysis
13	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
14	Suppliers' Discounts	(39,600)	(29,753)	(1,962)	(4,338)	(423)	(3,124)	Total O&M Expenses
15	Pole Attachments	(1,598,389)	(1,151,878)	(23,750)	(103,327)	(68,522)	(250,912)	Detailed Analysis
16	Wheeling Revenues	-	0	-	-	-	-	Island Interconnected
17	Application Fees	(24,680)	(12,200)	(300)	(1,654)	(406)	(10,120)	Detailed Analysis
18	Meter Test Revenues	-	0	-	-	-	-	Weighted Customers
19	Total Expense Credits	(2,134,269)	(1,552,047)	(48,601)	(159,272)	(74,225)	(300,124)	
20	Subtotal Expenses	460,612,327	389,357,022	10,383,288	36,910,402	6,719,398	17,242,218	
21	Disposal Gain/Loss	-	-	-	-	-	-	Detailed Analysis
22	Subtotal Rev Req Excl Return	460,612,327	389,357,022	10,383,288	36,910,402	6,719,398	17,242,218	
23	Return on Debt	92,942,206	82,695,750	753,948	3,852,364	653,423	4,986,721	Rate Base
24	Return on Equity	38,297,793	34,075,636	310,672	1,587,406	269,250	2,054,830	Rate Base
25	Total Revenue Requirement	591,852,326	506,128,408	11,447,907	42,350,172	7,642,071	24,283,768	

NEWFOUNDLAND AND LABRADOR HYDRO
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Total System
Return on Rate Base

Line No	1	2	3	4	5	6	7	8
		Total	Island Interconnected	Island Isolated	Labrador Isolated	L'Anse au Loup	Labrador Interconnected	Basis of Proration
		\$	\$	\$	\$	\$	\$	
Rate Base:								
1	Average Net Book Value	2,162,232,839	1,921,725,720	17,649,807	89,303,558	15,414,005	118,139,749	Schedule 2.3
2	Cash Working Capital	1,434,000	1,274,495	11,705	59,226	10,223	78,351	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	42,899,392	42,899,392	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	3,044,251	102,326	363,540	2,420,572	94,956	62,856	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	5,068,087	4,843,004	-	-	-	225,084	Detailed Fuel Analysis
6	Inventory/Supplies	32,884,000	29,020,470	202,738	1,388,849	273,518	1,998,426	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Holyrood	-	-	-	-	-	-	Detailed Analysis
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	75,958,000	67,509,123	620,028	3,137,183	541,485	4,150,182	Prorated on Average Net Book Value - L. 1
9	Retired Asset Pool	11,710,730	10,408,135	95,592	483,671	83,483	639,849	Prorated on Average Net Book Value - L. 1
10	Total Rate Base	<u>2,335,231,298</u>	<u>2,077,782,665</u>	<u>18,943,410</u>	<u>96,793,059</u>	<u>16,417,670</u>	<u>125,294,495</u>	
11	Less: Rural Portion	-	-	-	-	-	-	Schedule 2.6, L. 9
12	Rate Base Available for Equity Return	<u>2,335,231,298</u>	<u>2,077,782,665</u>	<u>18,943,410</u>	<u>96,793,059</u>	<u>16,417,670</u>	<u>125,294,495</u>	
Corporate Targets:								
13	Capital Structure: Percent of Debt	77.08% ⁽¹⁾						
14	Return	<u>5.17%</u>						
15	Weighted Average Return: Debt	<u>3.98%</u>						
16	Capital Structure: Percent of Equity	19.25% ⁽¹⁾						
17	Return	<u>8.50%</u>						
18	Weighted Average Return: Equity	<u>1.64%</u>						
19	Weighted Average Cost of Capital	<u>5.62%</u>						
Return on Rate Base by System (%):								
20	Return on Rate Base - Debt Component	-	3.98%	3.98%	3.98%	3.98%	3.98%	
21	Return on Rate Base - Equity Component	-	1.64%	1.64%	1.64%	1.64%	1.64%	
Return on Rate Base (\$):								
22	Return on Debt	92,942,206	82,695,750	753,948	3,852,364	653,423	4,986,721	Schedule 2.6, L.12
23	Return on Equity	38,297,793	34,075,636	310,672	1,587,406	269,250	2,054,830	Schedule 2.6, L.13
24	Return on Rate Base (\$)	<u>131,239,999</u>	<u>116,771,386</u>	<u>1,064,620</u>	<u>5,439,770</u>	<u>922,673</u>	<u>7,041,551</u>	Schedule 2.6, L.14
Return on Total Rate Base (%):								
25	Return on Rate Base - Debt Component	3.98%	3.98%	3.98%	3.98%	3.98%	3.98%	L. 22 divided by L.10
26	Return on Rate Base - Equity Component	1.64%	1.64%	1.64%	1.64%	1.64%	1.64%	L. 23 divided by L.10
27	Return on Rate Base (%)	<u>5.62%</u>	<u>5.62%</u>	<u>5.62%</u>	<u>5.62%</u>	<u>5.62%</u>	<u>5.62%</u>	L. 24 divided by L.10

⁽¹⁾ Debt and equity weightings reflect a 0.58% funded ARO and 3.09% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
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Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credits (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Total System							
1	Newfoundland Power	459,777,954	396,924,408	-	62,835,316	459,759,724	
2	Subtotal Newfoundland Power	459,777,954	396,924,408	-	62,835,316	459,759,724	1.16
3	Island Industrial	39,103,710	39,105,053	-	-	39,105,053	1.00
4	Labrador Industrial	5,579,486	5,582,412	-	-	5,582,412	1.00
5	CFB - Goose Bay Secondary	-	-	-	-	-	-
6	Rural Labrador Interconnected	21,669,705	18,701,356	-	2,960,527	21,661,883	1.16
Rural Deficit Areas							
7	Island Interconnected	51,673,173	70,098,946	-	(18,425,774)	51,673,173	0.74
8	Island Isolated	1,659,717	11,447,543	-	(9,787,826)	1,659,717	0.14
9	Labrador Isolated	9,277,722	42,350,172	-	(33,072,450)	9,277,722	0.22
10	L'Anse au Loup	3,132,278	7,642,071	-	(4,509,793)	3,132,278	0.41
11	CFB Revenue Credit Applied to Deficit	-	-	-	-	-	-
12	Subtotal	65,742,889	131,538,733	-	(65,795,844)	65,742,889	0.50
13	Total	591,873,744	591,851,962	-	-	591,851,962	1.00

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Interconnected							
1	Newfoundland Power	459,777,954	396,924,408	-	62,835,316	459,759,724	
2	Subtotal Newfoundland Power	459,777,954	396,924,408	-	62,835,316	459,759,724	1.16
3	Industrial - Firm	39,103,710	39,105,053	-		39,105,053	
4	Industrial - Non-Firm	-	-	-		-	
5	Subtotal Industrial	39,103,710	39,105,053	-	-	39,105,053	1.00
Rural							
6	1.1 Domestic	14,148,092	22,336,326	-	(8,188,234)	14,148,092	0.63
7	1.12 Domestic All Electric	17,912,544	25,173,650	-	(7,261,106)	17,912,544	0.71
8	1.3 Special	19,468	69,631	-	(50,163)	19,468	0.28
9	2.1 General Service 0-100 kW	9,285,301	11,432,823	-	(2,147,522)	9,285,301	0.81
10	2.3 General Service 110-1,000 kVa	5,994,009	6,476,028	-	(482,020)	5,994,009	0.93
11	2.4 General Service Over 1,000 kVa	3,307,404	3,387,343	-	(79,939)	3,307,404	0.98
12	4.1 Street and Area Lighting	1,006,355	1,223,145	-	(216,790)	1,006,355	0.82
13	Subtotal Rural	51,673,173	70,098,946	-	(18,425,774)	51,673,173	0.74
14	Total Island Interconnected	550,554,837	506,128,408	-	44,409,543	550,537,950	1.09

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Island Isolated							
1	1.2 Domestic Diesel	814,032	8,801,149		(7,987,117)	814,032	0.09
2	1.2G Government Domestic Diesel	-	-		-	-	-
2	1.23 Churches, Schools & Com Halls	66,100	341,357		(275,257)	66,100	0.19
3	2.1 General Service 0-10 kW	224,256	912,528		(688,272)	224,256	0.25
4	2.2 GS 10-100 kW	510,480	1,172,197		(661,716)	510,480	0.44
5	4.1 Street and Area Lighting	38,525	210,466		(171,940)	38,525	0.18
6	4.1G Gov't Street and Area Lighting	6,323	9,847		(3,524)	6,323	0.64
7	Total	1,659,717	11,447,543		(9,787,826)	1,659,717	0.14

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
Labrador Isolated							
1	1.2 Domestic Diesel	3,198,936	22,740,468		(19,541,532)	3,198,936	0.14
2	1.2G Government Domestic Diesel	632,628	607,122		25,506	632,628	1.04
3	1.23 Churches, Schools & Com Halls	290,756	1,252,208		(961,453)	290,756	0.23
4	2.1 General Service 0-10 kW	1,349,414	4,189,177		(2,839,763)	1,349,414	0.32
5	2.2 GS 10-100 kW	3,203,130	9,784,539		(6,581,409)	3,203,130	0.33
6	2.3 GS 110-1,000 kVa	251,613	1,565,927		(1,314,314)	251,613	0.16
7	2.4 General Service Over 1,000 kVa	230,095	1,803,574		(1,573,479)	230,095	0.13
8	4.1 Street and Area Lighting	112,285	397,589		(285,304)	112,285	0.28
9	4.1G Gov't Street and Area Lighting	8,864	9,567		(703)	8,864	0.93
10	Total	9,277,722	42,350,172		(33,072,450)	9,277,722	0.22

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/3)
L'Anse au Loup							
1	1.1 Domestic	574,845	1,574,833		(999,988)	574,845	0.37
2	1.12 Domestic All Electric	1,386,524	3,564,171		(2,177,647)	1,386,524	0.39
3	2.1 General Service 0-100 kW	831,070	1,808,078		(977,008)	831,070	0.46
3	2.3 General Service 110-1,000 kVa	320,673	648,639		(327,966)	320,673	0.49
4	4.1 Street and Area Lighting	19,166	46,349		(27,183)	19,166	0.41
5	Total L'Anse Au Loup	3,132,278	7,642,071		(4,509,793)	3,132,278	0.41

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues (\$)	3 Cost of Service Before Deficit and Revenue Credit Allocation (\$)	4 Revenue Credit (\$)	5 Deficit Allocation (\$)	6 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5) (\$)	7 Revenue to Cost Coverage (Col.2/7)
Labrador Interconnected							
1	Labrador Industrial Firm	5,579,486	5,582,412	-	-	5,582,412	1.00
2	Labrador Industrial Non-Firm	-	-	-	-	-	-
3	Subtotal Industrial	5,579,486	5,582,412	-	-	5,582,412	
4	CFB - Goose Bay Secondary	-	-	-	-	-	-
Rural							
5	1.1 Domestic	98,006	204,808	-	32,422.18	237,230	0.41
6	1.1A Domestic All Electric	10,689,208	10,779,538	-	1,706,460	12,485,998	0.86
7	2.1 General Service 0-10 kW	364,304	355,560	-	56,287	411,847	0.88
8	2.2 General Service 10-100 kW	2,258,239	1,720,114	-	272,303	1,992,417	1.13
9	2.3 General Service 110-1,000 kVa	3,751,878	2,465,197	-	390,254	2,855,452	1.31
10	2.4 General Service Over 1,000 kVa	4,146,804	2,884,786	-	456,678	3,341,464	1.24
11	4.1 Street and Area Lighting	361,265	291,353	-	46,123	337,476	1.07
12	Subtotal Rural	21,669,705	18,701,356	-	2,960,527	21,661,883	
13	Total Labrador Interconnected	27,249,191	24,283,768	-	2,960,527	27,244,296	

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Total System
Rural Deficit Allocation

Line No.	1	2		
		<u>Deficit Allocation</u>		
		Allocated on		
		Revenue Requirement		
		(\$)		
ALLOCATION OF DEFICIT:				
1	Island Interconnected	62,835,316		
2	Labrador Interconnected	2,960,527		
3	Allocated Totals	<u><u>65,795,844</u></u>		
CUSTOMER DEFICIT ALLOCATION:				
		Amount	Revenue Requirement	Percent
Island Interconnected:				
4	Newfoundland Power	<u>62,835,316</u>	396,924,408	95.5%
Labrador Interconnected:				
5	Rural Labrador Interconnected	<u>2,960,527</u>	18,701,356	<u>4.5%</u>
6	Total	<u><u>65,795,844</u></u>		<u>100.0%</u>

NEWFOUNDLAND AND LABRADOR HYDRO
2019 Expected Supply Test Year Cost of Service Study - October 26, 2018 Update
Unit Demand, Energy & Customer Amounts

Line No.	Rate Class	Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)	Demand Demand (\$/kW)	Non-Demand (\$/kWh)	Energy (\$/kWh)	Non-Demand Demand & Energy (\$/kWh)	Customer (\$/Bill)
	Island Interconnected										
1	Newfoundland Power	12.40	-	0.03523	-	287,768.97	14.36	-	0.04081	-	333,324.38
2	Industrial - Firm	10.90	-	0.03521	-	5,165.28	10.90	-	0.03521	-	5,165.28
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	
	Rural										
4	1.1 Domestic	-	0.12133	0.03905	0.16037	40.80	-	-	-	-	
5	1.12 Domestic All Electric	-	0.10849	0.03913	0.14761	40.88	-	-	-	-	
6	1.3 Special	-	0.16173	0.03869	0.20042	40.43	-	-	-	-	
7	2.1 General Service 0-10 kW	31.02	-	0.03926	-	57.38	-	-	-	-	
8	2.2 General Service 10-100 kW	-	-	-	-	-	-	-	-	-	
9	2.3 General Service 110-1,000 kVa	23.22	-	0.03940	-	73.49	-	-	-	-	
10	2.4 General Service Over 1,000 kVa	20.51	-	0.03881	-	73.53	-	-	-	-	
11	4.1 Street and Area Lighting	-	0.12657	0.03927	0.16585	66.35	-	-	-	-	

Appendix E

Projected 2019 Industrial Customer RSP Current Plan Adjustment

**Newfoundland and Labrador Hydro
Rate Stabilization Plan Recovery Adjustment
Island Industrial Customers**

Line No	Calculation of Industrial Customer RSP Rate	Amount	Comments
	Current Plan		
1	December Balance	\$ 1,825,402	Forecast December RSP 2018 ⁽¹⁾
2	Forecast Financing Costs to December 31, 2019	\$ 64,433	Line 22
3	Total	<u>\$ 1,889,835</u>	Line 1 plus Line 2
4	12 months to date (Jan - Dec) Industrial Customer Sales (kWh) ¹	<u>605,556,124</u>	
5	Total RSP Recovery Adjustment rate (¢ per kWh)	<u>0.312</u>	Line 3/Line 4*100

**Industrial Customer Forecast Financing Charges
2019**

2015 Test Year Weighted Average Cost of Capital per annum 6.610%
Nominal Financing Rate 6.418%

	Sales 2018 kWh	Financing Costs	Adjustment	Total To Date Balance	
6	Balance Forward			1,825,402	
7	January	54,470,202	9,763	(169,947)	1,665,218
8	February	49,402,452	8,906	(154,136)	1,519,989
9	March	53,578,084	8,129	(167,164)	1,360,954
12	April	54,863,007	7,279	(171,173)	1,197,061
13	May	37,722,774	6,402	(117,695)	1,085,768
14	June	45,270,006	5,807	(141,242)	950,333
16	July	51,464,384	5,083	(160,569)	794,846
17	August	44,843,150	4,251	(139,911)	659,187
18	September	55,442,065	3,526	(172,979)	489,733
19	October	52,000,000	2,619	(162,240)	330,112
20	November	52,300,000	1,766	(163,176)	168,702
21	December	54,200,000	902	(169,104)	500
22	Total	<u>605,556,124</u>	<u>64,433</u>	<u>(1,889,335)</u>	

1 Includes forecast sales for the months of October to December

Appendix F

Projected Industrial Customer Rate Impacts – January 1, 2019

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Island Industrial Customers - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	1,158,000	\$/kW/mo	9.95	11,522,100	10.90	12,623,422		
Energy - Firm (MWh)	743,300	¢/kWh	3.971	29,516,443	3.521	26,171,714		
Spec. Assigned		\$	768,935	768,935	309,917	309,917		
Total Base Rate				41,807,478		39,105,053		-6.8%
RSP: Current Plan	743,300	¢/kWh	(0.285)	(2,118,405)	0.312	2,319,096		
RSP: Current Plan Mitigation	743,300	¢/kWh	-	-		-		
RSP: Fuel Rider	743,300	¢/kWh	(0.024)	(178,392)		-		
CDM Recovery Adjustment	743,300	¢/kWh	0.010	74,330	0.010	74,330		
Total				39,585,011	-	41,498,479	1,913,468	4.8%

¹ Based on rates proposed to be effective Jan 1, 2019.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Praxair - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	72,000	\$/kW/mo	9.95	716,400	10.90	784,876		
Energy - Firm (MWh)	50,800	¢/kWh	3.971	2,017,268	3.521	1,788,676		
Spec. Assigned		\$	-	-		-		
Total Base Rate				2,733,668		2,573,552		-6.2%
RSP: Current Plan	50,800	¢/kWh	(0.285)	(144,780)	0.312	158,496		
RSP: Current Plan Mitigation	50,800	¢/kWh	-	-	-	-		
RSP: Fuel Rider	50,800	¢/kWh	(0.024)	(12,192)	-	-		
CDM Recovery Adjustment	50,800	¢/kWh	0.010	5,080	0.010	5,080		
Total				2,581,776		2,737,128	155,352	6.0%

¹ Based on rates proposed to be effective Jan 1, 2019.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Vale - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	624,000	\$/kW/mo	9.95	6,208,800	10.90	6,802,259		
Energy - Firm (MWh)	393,800	¢/kWh	3.971	15,637,798	3.521	13,865,762		
Spec. Assigned		\$	480,243	480,243	144,378	144,378		
Total Base Rate				22,326,841		20,812,399		-7.2%
RSP: Current Plan	393,800	¢/kWh	(0.285)	(1,122,330)	0.312	1,228,656		
RSP: Current Plan Mitigation	393,800	¢/kWh	-	-	-	-		
RSP: Fuel Rider	393,800	¢/kWh	(0.024)	(94,512)	-	-		
CDM Recovery Adjustment	393,800	¢/kWh	0.010	39,380	0.010	39,380		
Total				21,149,379		22,080,435	931,056	4.4%

¹ Based on rates proposed to be effective Jan 1, 2019.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Corner Brook Pulp and Paper Limited - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	72,000	\$/kW/mo	9.95	716,400	10.90	784,876		
Energy - Firm (MWh)	34,100	¢/kWh	3.971	1,354,111	3.521	1,200,667		
Spec. Assigned		\$	-	-	11,458	11,458		
Total Base Rate				2,070,511		1,997,000		-3.7%
RSP: Current Plan	34,100	¢/kWh	(0.285)	(97,185)	0.312	106,392		
RSP: Current Plan Mitigation	34,100	¢/kWh	-	-	-	-		
RSP: Fuel Rider	34,100	¢/kWh	(0.024)	(8,184)	-	-		
CDM Recovery Adjustment	34,100	¢/kWh	0.010	3,410	0.010	3,410		
Total				1,968,552		2,106,802	138,250	7.0%

¹ Based on rates proposed to be effective Jan 1, 2019.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
North Atlantic Refinery Limited - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	384,000	\$/kW/mo	9.95	3,820,800	10.90	4,186,005		
Energy - Firm (MWh)	263,400	¢/kWh	3.971	10,459,614	3.521	9,274,357		
Spec. Assigned		\$	89,293	89,293	104,051	104,051		
Total Base Rate				14,369,707		13,564,414		-5.9%
RSP: Current Plan	263,400	¢/kWh	(0.285)	(750,690)	0.312	821,808		
RSP: Current Plan Mitigation	263,400	¢/kWh	-	-	-	-		
RSP: Fuel Rider	263,400	¢/kWh	(0.024)	(63,216)	-	-		
CDM Recovery Adjustment	263,400	¢/kWh	0.010	26,340	0.010	26,340		
Total				13,582,141		14,412,562	830,421	6.1%

¹ Based on rates proposed to be effective Jan 1, 2019.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Teck Resources - January 1, 2019 Implementation

	2019 Test Year		2018 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Interim Rates ¹	Forecast 2019 Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	6,000	\$/kW/mo	9.95	59,700	10.90	65,406		
Energy - Firm (MWh)	1,200	¢/kWh	3.971	47,652	3.521	42,252		
Spec. Assigned		\$		199,399	50,030	50,030		
Total Base Rate				306,751		157,688		-49.2%
RSP: Current Plan	1,200	¢/kWh	(0.285)	(3,420)	0.312	3,744		
RSP: Current Plan Mitigation	1,200	¢/kWh	-	-	-	-		
RSP: Fuel Rider	1,200	¢/kWh	(0.024)	(288)	-	-		
CDM Recovery Adjustment	1,200	¢/kWh	0.010	120	0.010	120		
Total				303,163		161,552	(141,611)	-46.7%

¹ Based on rates proposed to be effective Jan 1, 2019.

Appendix G

Projected Customer Rate Impacts –July 1, 2017

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Newfoundland Power - July 1, 2019 Implementation

	2019 Billing Units at 2018 First Block Size	Unit	2018 Interim Rate ⁽¹⁾	Existing Billings (\$)	2018 Interim Rate	2019TY Revenue Requirement	2018 & 2019 Deficiency ²	Recovery of Deferred Supply Costs	Forecast 2019 Billings (\$)	Change (\$)	Percent Change Utility
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i) = (f)+(g)+(h)	(j) = (i)-(d)	(k) = (j)/(d)
Demand (kW)	15,158,472	\$/kW/mo	4.75	72,002,742							
Energy (MWh)	3,000,000	¢/kWh	2.782	83,460,000							
Energy (MWh)	2,833,600	¢/kWh	10.422	295,317,792							
Total Base Rate				450,780,534		459,759,724	8,424,246	36,039,498	504,223,469	53,442,935	
RSP Recovery Adjustment-Normal	5,833,600	¢/kWh	(0.296)	(17,267,456)	(0.296)	(17,267,456)					
RSP Fuel Rider	5,833,600	¢/kWh	0.423	24,676,128		-					
CDM Recovery Adjustment	5,833,600	¢/kWh	0.022	1,283,392	0.022	1,283,392					
Total				459,472,598		443,775,660	8,424,246	36,039,498	488,239,405	28,766,807	6.3%

¹ Based on rates effective July 1, 2018.

² 2018 & 2019 Revenue Deficiency amortized over 20 months.

³ Newfoundland Power's portion of the \$65.4M in deferred supply costs amortized over 20 months.

⁴ End-consumer rate impact calculated as 64% of Utility.

End-Consumer Impact⁴ **4.0%**

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Island Industrial Customers - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	1,158,000	\$/kW/mo	10.90	12,623,422	10.90	12,622,200		
Energy - Firm (MWh)	743,300	¢/kWh	3.521	26,171,714	3.521	26,171,593		
Spec. Assigned		\$	309,917	309,917	309,917	309,917		
Recovery Rider	743,300				0.256	1,902,848		
Total Base Rate				39,105,053		41,006,558	1,901,504	4.6%
RSP: Current Plan	743,300	¢/kWh	0.312	2,319,096	0.312	2,319,096		
RSP: Current Plan Mitigation	743,300	¢/kWh	-	-	-	-		
RSP: Fuel Rider	743,300	¢/kWh		-		-		
CDM Recovery Adjustment	743,300	¢/kWh	0.010	74,330	0.010	74,330		
Total				41,498,479		43,399,984	1,901,504	4.6%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Praxair - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	72,000	\$/kW/mo	10.90	784,876	10.90	784,800		
Energy - Firm (MWh)	50,800	¢/kWh	3.521	1,788,676	3.521	1,788,668		
Spec. Assigned		\$	-	-		-		
Recovery Rider	50,800				0.256	130,048		
Total Base Rate				2,573,552		2,703,516		4.7%
RSP: Current Plan	50,800	¢/kWh	0.312	158,496	0.312	158,496		
RSP: Current Plan Mitigation	50,800	¢/kWh	-	-	-	-		
RSP: Fuel Rider	50,800	¢/kWh	-	-	-	-		
CDM Recovery Adjustment	50,800	¢/kWh	0.010	5,080	0.010	5,080		
Total				2,737,128		2,867,092	129,964	4.7%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Vale - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	624,000	\$/kW/mo	10.90	6,802,259	10.90	6,801,600		
Energy - Firm (MWh)	393,800	¢/kWh	3.521	13,865,762	3.521	13,865,698		
Spec. Assigned		\$	144,378	144,378	144,378	144,378		
Recovery Amounts	393,800				0.2560	1,008,128		
Total Base Rate				20,812,399		21,819,804		4.6%
RSP: Current Plan	393,800	¢/kWh	0.312	1,228,656	0.312	1,228,656		
RSP: Current Plan Mitigation	393,800	¢/kWh	-	-	-	-		
RSP: Fuel Rider	393,800	¢/kWh						
CDM Recovery Adjustment	393,800	¢/kWh	0.010	39,380	0.010	39,380		
Total				22,080,435		23,087,840	1,007,405	4.6%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Corner Brook Pulp and Paper - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	72,000	\$/kW/mo	10.90	784,876	10.90	784,800		
Energy - Firm (MWh)	34,100	¢/kWh	3.521	1,200,667	3.521	1,200,661		
Spec. Assigned		\$	11,458	11,458	11,458	11,458		
Recovery Amounts	34,100				0.2560	87,296		
Total Base Rate				1,997,000		2,084,215		4.1%
RSP: Current Plan	34,100	¢/kWh	0.312	106,392	0.312	106,392		
RSP: Current Plan Mitigation	34,100	¢/kWh	-	-	-	-		
RSP: Fuel Rider	34,100	¢/kWh	-	-	-	-		
CDM Recovery Adjustment	34,100	¢/kWh	0.010	3,410	0.010	3,410		
Total				2,106,802		2,194,017	87,214	4.1%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
North Atlantic Refining Limited - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	384,000	\$/kW/mo	10.90	4,186,005	10.90	4,185,600		
Energy - Firm (MWh)	263,400	¢/kWh	3.521	9,274,357	3.521	9,274,314		
Spec. Assigned		\$	104,051	104,051	104,051	104,051		
Recovery Amounts	263,400			-	0.256	674,304		
Total Base Rate				13,564,414		14,238,269		4.7%
RSP: Current Plan	263,400	¢/kWh	0.312	821,808	0.312	821,808		
RSP: Current Plan Mitigation	263,400	¢/kWh	-	-	-	-		
RSP: Fuel Rider	263,400	¢/kWh	-	-	-	-		
CDM Recovery Adjustment	263,400	¢/kWh	0.010	26,340	0.010	26,340		
Total				14,412,562		15,086,417	673,856	4.7%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings – Expected Supply Scenario
Teck Resources - July 1, 2019 Implementation

	2019 Test Year		2019 Interim Rates ¹	2019 Billings at Existing Rates (\$)	2019 Final Rates	2019 Final Billings (\$)	Change (\$)	Change (%)
	Billing Units	Unit						
Demand (kW)	6,000	\$/kW/mo	10.90	65,406	10.90	65,400		
Energy - Firm (MWh)	1,200	¢/kWh	3.521	42,252	3.521	42,252		
Spec. Assigned		\$	50,030	50,030	50,030	50,030		
Recovery Amounts	1,200				0.256	3,072		
Total Base Rate				157,688		160,754		1.9%
RSP: Current Plan	1,200	¢/kWh	0.312	3,744	0.312	3,744		
RSP: Current Plan Mitigation	1,200	¢/kWh	-	-	-	-		
RSP: Fuel Rider	1,200	¢/kWh	-	-	-	-		
CDM Recovery Adjustment	1,200	¢/kWh	0.010	120	0.010	120		
Total				161,552		164,618	3,065	1.9%

¹ Based on rates proposed to be effective Jan 1, 2019.

² 2018 Revenue Excess and Island Industrial Customer's portion of the \$65.4 M amortized over 20 months.

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Appendix G

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**Newfoundland and Labrador Hydro
2019 Required Increase in Customer Billings - Expected Supply Scenario
Remaining Classes - July 1, 2019 Implementation**

	2019 Test Year Billing Units	Unit	Existing Average Unit Cost¹	Existing Billings \$	Projected Average Unit Cost²	Revenue Requirement 2019 Cost of Service	2018 & 2019 Revenue Deficiency (12/20)⁵	Balance owing to customers in accordance with Board Order P.U. 22(2017)	\$ Change	Percent Change
Rural Labrador Interconnected	753,796,243	\$/kWh	0.029	21,937,762	0.028	21,661,883	(245,740)	(41,184)	(562,803)	-2.6%
Hydro Rural Government	2,396,960	\$/kWh	0.866	2,075,306	1.051	2,393,775	126,382	-	444,851	21.4%
Hydro Rural Other ⁴	486,719,690	\$/kWh	0.129	62,551,580	0.134	65,057,980	-	-	2,506,400	4.0%
Labrador Industrial ³	3,009,000	\$/kW	1.61	4,844,490	1.94	5,582,412	240,111	-	978,033	20.2%

¹ Average unit revenues expressed in dollars per kWh based on July 1, 2018 rates.

² Average unit revenues expressed in dollars per kWh based on 2019 Proposed Final Rates excluding the 2018 & 2019 Revenue Deficiency/(Excess).

³ Includes both Transmission and Generation Cost Recovery. The unit cost per kW is calculated based on Power on Order.

⁴ Percentage increase is 64% of Newfoundland Power's Wholesale increase.

⁵ Recovery of Rural Labrador Interconnected and Labrador Industrial forecast to occur over 24 months.

Appendix H

Revised 2017 General Rate Application Part B, Hydro's Proposals

**Newfoundland and Labrador Hydro
2017 General Rate Application
Proposals Updated to Reflect Settlement Agreements and Schedule 1, Evidence**

B. Hydro's Proposals:

1. Hydro makes this Application under the *Electrical Power Control Act, 1994* and under the *Act*, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80 of the *Act*, and requests:

Revenue Requirement

- (1) that the Board approve the Settlement Agreement dated April 11, 2018, the Supplemental Settlement Agreement dated July 16, 2018 (Supplemental Settlement Agreement), and the Labrador Settlement Agreement dated August 24, 2018.
- (2) that Hydro's proposal to have its 2018 and 2019 Test Year revenue requirements, and resulting rates, reflect the cost of the expected supply of power to the Island Interconnected System from both off-island power purchases and existing Island generation as described in the Additional Cost of Service Information filed in compliance with Board Order No. P.U. 2(2018) and agreed to in section 14 of the Supplemental Settlement Agreement dated July 16, 2018;
- (3) that a revised definition to the Energy Supply Cost Variance Deferral Account to include variances in both price and volume of off-island power purchases, as

provided in Appendix L of the Additional Cost of Service Evidence filed in compliance with Board Order No. P.U. 2(2018) and agreed to in section 18 of the Supplemental Settlement Agreement dated July 16, 2018, be approved effective January 1, 2018;

- (4) the transfer to the Revised Energy Supply Variance Deferral Account of all costs Hydro is required to pay for the use of the LIL and LTA during the period prior to full commissioning of the Muskrat Falls Project in accordance with the interim TFAs, , be approved; and
- (5) That for the purposes of calculating Hydro's 2018 Test Year, subject to change following the Board's final order and Hydro's Compliance Application:
 - a) an estimated 2018 Test Year revenue requirement of \$578,650,604 be approved;
 - b) an estimated 2018 forecast average rate base of \$2,244,455,753 be approved; and
 - c) an estimated rate of return on rate base of 5.66% in a range of 5.46% to 5.86% be approved;
- (6) that for the purposes of calculating Hydro's 2019 Test Year, subject to change following the Board's final order Hydro's Compliance Application:
 - a) An estimated 2019 Test Year revenue requirement of \$591,852,326 be approved;

- b) an estimated 2019 forecast average rate base of \$2,335,231,298 be approved; and
 - c) a rate of return on rate base of 5.62% in a range of 5.42% to 5.82% be approved;
- (7) a) that Hydro's forecast capital structure for 2018, as set out in Chapter 4 of the evidence in support of this Application, with a weighted average cost of capital of 5.66%, be approved; and
- b) that Hydro's forecast capital structure for 2019, as set out in Chapter 4 of the evidence in support of this Application, with a weighted average cost of capital of 5.62%, be approved;
- (8) that pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base for 2018 and 2019, the return on equity last approved by Order No. P.U. 18(2016) as a result of Newfoundland Power's general rate application, of 8.5 %, be approved;
- (9) that the Holyrood conversion rate of 583 kWh per barrel for the 2019 Test Year, as agreed to in section 16 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (10) that Hydro's revenue requirement include the updated costs associated with Capacity Assistance agreements for 2018 and 2019 as referenced in section 22 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

- (11) that Hydro's revenue requirements reflecting vacancies in full time equivalents of 55, as agreed to in section 10 of the Settlement Agreement dated April 11, 2018, be approved;
- (12) that Hydro's costs and expenses related to the Business Systems Transformation Project described in the Application be deferred in a separate account with recovery subject to a further order of the Board, as agreed to in section 11 of the Settlement Agreement dated April 11, 2018, be approved;
- (13) that the Debt Guarantee Fee be included in Hydro's revenue requirement in accordance with section 12 of the Settlement Agreement dated April 11, 2018, be approved;
- (14) that Hydro's 2018 Test Year fuel expense and power purchase expense reflect the 2015 Test Year inputs for the operation of: the Rate Stabilization Plan, Energy Supply Cost Variance Deferral Account, Holyrood Conversion Rate Deferral Account, and the Isolated Systems Cost Variance Deferral account including a No. 6 fuel cost of \$64.41 per barrel and a conversion rate of 618 kWh per barrel, be approved;

Regulatory Accounting

- (15) that Hydro's continued use of the working capital methodology, as agreed to in section 14 of the Settlement Agreement dated April 11, 2018, be approved;

- (16) that Hydro's proposed average rate base methodology, as agreed to in section 13 of the Settlement Agreement dated April 11, 2018, be approved;
- (17) that Hydro's proposed depreciation rates and methodology, as agreed to in section 9 of the Settlement Agreement dated April 11, 2018 and section 7 of the Labrador Settlement Agreement, be approved;
- (18) that Hydro's proposal in relation to an automatic adjustment mechanism for its target return on equity to reflect any changes to Newfoundland Power's approved target return on equity for rate setting, as agreed to in section 24 of the Settlement Agreement dated April 11, 2018, be approved;
- (19) that Hydro's proposal to amortize and recover general rate and cost of service hearing costs over a three year period commencing in 2018, as agreed to in section 22 of the Settlement Agreement dated April 11, 2018, be approved;
- (20) that, for Newfoundland Power, Island Industrial and Hydro Rural Government Diesel customers, Hydro's proposal to recover its 2018 and 2019 revenue deficiencies or revenue excesses over a 20-month period commencing on the dates 2017 GRA final rates are implemented, consistent with sections 20 and 21 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (21) that, for customers on the Labrador interconnected system, Hydro's proposal to recover its 2018 and 2019 revenue deficiencies or revenue excesses over a 24-month period commencing on the dates 2017 GRA final rates are implemented,

consistent with section 9 of the Labrador Settlement Agreement dated August 24, 2018, be approved;

- (22) that Hydro's proposal to include its 2018 and 2019 revenue deficiency or revenue excesses in rate base, as set out in Chapter 4 of the evidence in support of this Application, be approved;
- (23) that Hydro's excess earnings account definition, as agreed to in section 23 of the Settlement Agreement dated April 11, 2018, be approved;
- (24) that Hydro's proposed accounting treatment and methodology for calculation of Employee Future Benefits in the 2018 and 2019 Test Years, as agreed to in section 7 of the Settlement Agreement dated April 11, 2018, be approved;
- (25) that Hydro's proposed accounting treatment and calculation of Asset Retirement Obligations in the 2018 and 2019 Test Years, as agreed to in section 8 of the Settlement Agreement dated April 11, 2018, be approved;
- (26) that the MF-HV Capital Project will be:
 - a) excluded in Hydro's rate base in the 2018 Test Year and excluded in the calculation of depreciation expense for the 2018 Test Year;
 - b) included in Hydro's closing rate base for the 2019 Test Year, if the project approved by the Board, prior to Hydro's 2017 GRA Compliance filing, for construction to be completed by the end of 2019;
 - c) excluded for the calculation of depreciation for the 2019 test Year.

Cost of Service Methodology

- (27) that the generation credit service agreement between Hydro and Corner Brook Pulp and Paper, which was approved on a pilot basis by the Board in Order No. P.U. 4(2012), and as agreed to in section 8 of the Supplemental Settlement Agreement dated July 16, 2018, be approved to continue on a pilot basis;
- (28) that Hydro's proposal to allocate operating and maintenance expenses for specifically assigned assets by customer be based on the determination of test year transmission asset values via Handy-Whitman indexes, and as per Hydro's report dated December 21, 2017, as agreed to in section 15 of the Settlement Agreement dated April 11, 2018 and section 7(c) of Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (29) that wind energy purchases classified as 100% energy-related, as agreed to in section 7(a) of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (30) that the functionalization of TL267 as 100% demand, as agreed to in section 7(d) of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (31) that the revenue requirement method to allocate the rural deficit between Newfoundland Power and the Labrador Interconnected system approved by Order No.P.U.49 (2016), as agreed to in section 16 of the Settlement Agreement dated April 11, 2018, for use in the 2018 and 2019 Test Years, be approved;

- (32) that a filing date of no later than November 15, 2018 for Hydro's Cost of Service and Rate Design Methodology Review, as agreed to in the section 25 of the Settlement Agreement dated April 11, 2018, be approved;

2019 Rate Proposals

- (33) that, effective July 1, 2019, rates reflecting the 2017 GRA Order for all of Hydro's customers be approved on a final basis;
- (34) that, effective July 1, 2019, Newfoundland Power's rates, as agreed to in section 9 of the Supplemental Settlement Agreement dated July 16, 2018, be approved as follows:
- a) Newfoundland Power's demand charge will equal \$5.00 per kW of billing demand;
 - b) The size of Newfoundland Power's first block energy component will be determined in consultation with Newfoundland Power prior to the filing of Hydro's 2017 GRA Compliance filing;
 - c) Newfoundland Power's approved 2019 Test Year revenue requirement not recovered through the demand charge and the end-block energy charge will be used to compute the first block energy charge;
 - d) Newfoundland Power's end-block firm energy rate for use in Hydro's 2017 GRA Compliance filing will be determined based on the most current fuel rider forecast (either March or September) divided by the approved 2019

Test Year Holyrood No.6 fuel conversion rate and expressed on a cent per kWh basis;

- e) The wholesale rate will continue to include the Generation Credit and Curtailable Credit in computation of the billing demand of Newfoundland Power; and,
 - f) The Generation Credit will equal 118,054 kW for the 2018 Test Year and the 2019 Test Year;
- (35) that, effective July 1, 2019, the RSP fuel rider applicable to Newfoundland Power, as approved in Board Order No. P.U. 15(2018), be discontinued;
- (36) that for Newfoundland Power an additional 2017 GRA Recovery rider to become effective July 1, 2019 and remain in effect for 20 months to recover or refund the forecast 2018 and 2019 revenue deficiencies or revenue excess, consistent with section 20 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (37) that for the Island Industrial Customers an additional 2017 GRA Recovery rate rider to become effective July 1, 2019 and remain in effect for 20 months to recover or refund the forecast 2018 and 2019 revenue deficiencies or revenue excess, consistent with section 20 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (38) that the 2017 GRA recovery rider for the Island Industrial Customers forecast 2018 and 2019 revenue deficiencies or revenue excess be tracked by month and

any over or under recovery at the conclusion of the 20 month period be charged or credited to the Island Industrial Customer's Rate Stabilization Plan Current Plan account;

- (39) that on an interim basis for Island Industrial Customers, effective upon the implementation of revised in 2019 RSP adjustments: (i) a firm demand charge increase from \$9.95 per kW to \$10.90 per kW and the firm energy charge of 3.521 cents per kWh; and (ii) the following specifically assigned charges per year:

Corner Brook Pulp and Paper	\$11,458
North Atlantic Refinery Limited	\$104,051
Teck Resources Limited	\$50,030
Vale	\$144,378

- (40) that, effective January 1, 2019, the RSP fuel rider applicable to Island Industrial Customers approved in Board Order P.U. 7(2018), be discontinued;
- (41) that, effective January 1, 2019, a loss factor of 3.34% be approved for use in calculation of the non-firm Island Industrial energy rate, as set out in Chapter 5 and Exhibit 17 to the evidence in support of this Application, be approved on a final basis;
- (42) that the deferral of consideration of whether information on the rural deficit should be included on customers' bills for inclusion in a separate proceeding or a future Hydro general rate application, as agreed to in section 20 of the Settlement Agreement dated April 11, 2018, be approved;

- (43) that IOC is eligible for a billing credit from Hydro if actual monthly Labrador firm load requirements exceed the 2019 Test Year Load forecast by more than 10 MW. The billing credit will be calculated in accordance with section 10 of the Labrador Settlement Agreement.

Deferred Supply Costs

- (44) that Hydro's deferred supply costs be approved as prudent, specifically:
- g) 2015 Isolated Systems Supply Cost Variance Deferral Account balance of \$0.00;
 - h) 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of \$2,186,570.00;
 - i) 2017 Isolated Systems Supply Cost Variance Deferral Account credit balance of \$1,106,821.00;
 - j) 2015 Energy Supply Cost Variance Deferral Account debit balance of \$14,200,429.00;
 - k) 2016 Energy Supply Cost Variance Deferral Account debit balance of \$24,462,996.00;
 - l) 2017 Energy Supply Cost Variance Deferral Account debit balance of \$20,134,732.00;
 - m) 2015 Holyrood Conversion Rate Deferral Account debit balance of \$3,582,048.00;

- n) 2016 Holyrood Conversion Rate Deferral Account debit balance of
\$2,150,665.00;
 - o) 2017 Holyrood Conversion Rate Deferral Account debit balance of
\$4,163,799.00;
- (45) that the allocation of balances from the Isolated Systems Cost Variance Deferral Account based upon the same methodology as that which is approved for the allocation of the Rural Deficit, as agreed to in section 10 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (46) that the Labrador Interconnected System allocated portions of the Isolated Systems Cost Variance Deferral Account Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account be written off to Hydro's 2018 net income as agreed to in section 8 of the Labrador Settlement Agreement.
- (47) that the allocation of balances in the Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account computed by customer class based upon the fuel cost allocation methodology used in the Rate Stabilization Plan, and the allocation percentage be based upon the energy allocators consistent with the year in which the costs were incurred, as agreed to in section 12 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;
- (48) that balances allocated to Newfoundland Power and the Island Industrial Customers be recovered through rate riders to be determined separately for each customer class and computed reflecting a 20 month recovery period

effective July 1, 2019, as agreed to in section 13 of the Supplemental Settlement Agreement dated July 16, 2018, be approved;

- (49) that the recovery rider for the Island Industrial Customers portion of the Energy Supply Cost Variance Deferral and Holyrood Conversion Rate Deferral Account be tracked by month and any over or under recovery at the conclusion of the 20 month period be charged or credited to the Island Industrial Customer's Rate Stabilization Plan Current Plan account;

Rules and Regulations

- (50) that the calculation of the Rural Rate Alteration component to use Test Year data, as agreed to in section 18 of the Settlement Agreement dated April 11, 2018, be approved effective January 1, 2018;
- (51) that the proposed rules and regulations governing service as set out in Chapter 5 and Exhibit 17 to this evidence in support of this Application, as agreed to in section 19 of the Settlement Agreement dated April 11, 2018, be effective the date that new rates from the Application are implemented; and,
- (52) that upon hearing this Application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

2018 Cost Deferral Evidence

October 26, 2018

A Report to the Board of Commissioners of Public Utilities



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Appendix A – 2018 Forecast Financial Results

1 **1.0 Introduction**

2 On July 28, 2017, Newfoundland and Labrador Hydro (Hydro) filed its 2017 General Rate
3 Application (GRA) requesting, among other things, approval of customer rates reflecting 2018
4 and 2019 Test Year costs which reflected a proposed change in depreciation methodology. In a
5 Settlement Agreement dated April 11, 2018 (the Settlement Agreement), the Parties agreed to
6 the use of the revised depreciation methodology for the 2018 and 2019 Test Years, amongst
7 other things.¹

8
9 As a result of delays in the 2017 GRA, Hydro anticipates that its conclusion is unlikely to occur in
10 2018. In the absence of a final 2017 GRA Order in 2018, Hydro will be required to continue to
11 account for its 2018 Depreciation Expense² in accordance with its existing methodology. If
12 Hydro were to apply the existing depreciation methodology, it forecasts that it will incur an
13 additional \$15.0 million in Depreciation Expense when compared to the methodology proposed
14 in the 2017 GRA and agreed to by the Parties in the Settlement Agreement.³

15
16 This 2018 Cost Deferral and Interim Rates Application includes a proposal to establish a 2018
17 Cost Deferral Account to provide Hydro the opportunity to earn a return for 2018 which is
18 inside the projected 2018 Test Year range of return on rate for 2018.

20 **2.0 Requirement for 2018 Cost Deferral**

21 Hydro applied for, and was granted, 2018 interim rate increases for both Island Industrial
22 Customers and Newfoundland Power effective April 1 and July 1, 2018, respectively.⁴ Hydro's
23 interim rates applications were based on the expectation that a 2017 GRA Order would be
24 issued in 2018. Approval of interim rates provided recovery of a portion of Hydro's increased
25 cost of service for 2018 relative to existing rates. The recovery levels sought in these

¹ 2017 GRA, Exhibit 11, Depreciation Study.

² Depreciation Expense includes depreciation expense, loss on disposal, disposal proceeds, and removal costs.

³ Settlement Agreement dated April 16, 2018, item number 9 states "With respect to Depreciation Expense the following, which results in reductions in the 2018 and 2019 Test Years' revenue requirements of approximately \$10.1 million and \$8.9 million, respectively..."

⁴ Board Order Nos P.U. 7(2018) and P.U. 15(2018), respectively.

1 applications were based on Hydro's 2018 Test Year costs, including a decrease in Depreciation
2 Expense which was computed based on the proposed depreciation methodology from the 2017
3 GRA.

4
5 In the absence of a 2017 GRA Order in 2018, Hydro forecasts that it will be required to record
6 an additional \$15.0 million in 2018 due to depreciation methodology that was not
7 contemplated in the approval of interim rates for Newfoundland Power in 2018.⁵ Forecast
8 revenues from current rates (including the increased revenues from interim rate changes in
9 2018) will not recover enough revenue to provide Hydro the opportunity to earn a reasonable
10 return on rate base as a result of the unanticipated requirement to use the existing
11 depreciation methodology in 2018.

12
13 The 2018 cost deferral requested in this application reflects the expense differential between
14 Hydro's current Depreciation Expense methodology and the 2017 GRA depreciation
15 methodology reflected in the Settlement Agreement of April 11, 2017.

16

17 **3.0 Return on Rate Base**

18 Hydro's currently approved rate of return on rate base is 6.61% as approved in Order No. P.U.
19 22(2017) however, Hydro's 2017 GRA as filed requested approval of a 2018 Test Year return on
20 rate base of 5.73%. Due to the material reduction in return on rate base requested in the 2017
21 GRA, Hydro is proposing a cost deferral for 2018 to provide the opportunity to earn a rate of
22 return based on the reduced rate of return requirement forecast for the 2018 Test Year.

23

24 Hydro's 2018 Test Year in its original 2017 GRA filing forecast a required return on rate base of
25 5.73% based on 2018 forecast interest expense of \$94.8 million. Hydro's most recent forecast
26 of 2018 interest expense is \$90.6 million, a decrease of approximately \$4.2 million. This

⁵ The Utility interim rates application filed on April 13, 2018 reflected the approximate \$10.1 million in depreciation savings noted in the 2017 GRA Settlement Agreement signed on April 11, 2018.

1 variance is due to a number of factors including, but not limited to, change in forecast interest
2 rates, timing of debt issuances, and amount of long-term debt issued.

3 The revised forecast cost of debt for 2018 reduces Hydro's calculation of the 2018 Test Year
4 forecast rate of return on rate base. Based on the updated forecast cost of debt, Hydro projects
5 that its revised 2018 Test Year rate of return on rate base would equal approximately 5.45%.
6 Given the materiality of this change, Hydro considers it appropriate to update its rate of return
7 on rate base and average rate base calculations in its 2017 GRA Compliance Application.

8

9 **4.0 2018 Financial Projections**

10 As of the date of this filing, Hydro's forecast net income at the end of 2018 is expected to be
11 approximately \$9.9 million,⁶ with a forecast rate of return on rate base of 4.63% and a forecast
12 rate of return on equity of 3.13%. The forecast rate of return on rate base is materially below
13 the 5.25% bottom of the projected range of rate of return on rate base for the 2018 Test Year.

14

15 Should the Board approve the proposed 2018 Cost Deferral, currently forecast to be
16 approximately \$15.0 million, Hydro's forecast return on rate base would increase to 5.28%, 3
17 basis points above the bottom of the projected range of rate of return on rate base for the
18 2018 Test Year. A summary of these forecasts are provided in Table 1.

Table 1
2018 Forecast Financial Results

Particulars	Excluding 2018 Cost Deferral	Including Proposed 2018 Cost Deferral
Net Income (\$000s)	9,973	24,961
Rate of Return on Equity	3.13%	7.68%
Rate of Return on Rate Base	4.63%	5.28%
Revised Bottom of Range	5.25%	5.25%
Variance from Bottom of Range	-0.62%	0.03%

⁶ See Appendix A to this Evidence.

1 Appendix A to this evidence provides Hydro's forecast financial results for 2018.

2

3 **5.0 Conclusion**

4 Hydro's interim rates applications were based on the expectation that a 2017 GRA Order would
5 be issued in 2018. In the absence of a 2017 GRA Order by the end of 2018, Hydro will have to
6 record 2018 Depreciation Expense based on its existing approved methodology and not the
7 depreciation methodology provided for in the Settlement Agreement. The forecast impact of
8 this change in methodology is an additional \$15.0 million in Depreciation Expense for 2018.

9 Hydro projects that the additional Depreciation Expense will reduce Hydro's 2018 net income
10 such that it will not have the opportunity to earn a just and reasonable return in 2018.

11

12 The revised depreciation methodology was agreed to by the parties in the Settlement
13 Agreement. Hydro considers it reasonable that the cost differential between the existing
14 depreciation methodology and depreciation methodology reflected in the 2017 GRA Settlement
15 Agreement be approved as a cost deferral for 2018.

16

17 The proposed 2018 cost deferral is not a request for pre-approval of a change in the
18 depreciation methodology in advance of the 2017 GRA Order; rather, Hydro is proposing a 2018
19 cost deferral to be calculated as the differential between the existing and proposed
20 depreciation methodologies for 2018 yearend financial reporting purposes only, with recovery
21 subject to the Board's final GRA Order.

22

23 Approval of the requested 2018 Cost Deferral would provide Hydro the opportunity to earn a
24 2018 rate of return on rate base of 5.28% (i.e., 3 basis points above the bottom of the projected
25 range of rate of return on rate base for the 2018 Test Year). Approval of the proposed cost
26 deferral for 2018 will have no impact on customer rates, but will provide Hydro the opportunity
27 to earn a reasonable rate of return in 2018.

- 1 The actual amount of the 2018 cost deferral will be determined in preparing Hydro's 2018 year-
- 2 end financial results. The proposed 2018 Cost Deferral Account definition is included as
- 3 Schedule 3 to the 2018 Cost Deferral and Interim Rates Application.

Appendix A

2018 Forecast Financial Results

Newfoundland and Labrador Hydro
2018 Forecast Financial Results

Line No.		Existing 2018 Forecast	2018 Cost Deferral Forecast	Revised 2018 Forecast
	<u>REVENUE</u>			
1	Energy sales	557,655	-	557,655
2	Other revenue	5,831	-	5,831
3		<u>563,486</u>	<u>-</u>	<u>563,486</u>
	<u>EXPENSES</u>			
4	Operating costs	137,637	-	137,637
5	Other (income) and expense	9,155	(15,019)	(5,863)
6	Foreign Exchange	2,589	-	2,589
7	Fuels	154,779	-	154,779
8	Power purchased	73,403	-	73,403
9	Amortization	85,028	-	85,028
10	ARO Accretion	362	-	362
11	Interest	90,589	-	90,589
12		<u>553,543</u>	<u>(15,019)</u>	<u>538,524</u>
13	NET INCOME	<u>9,943</u>	<u>15,019</u>	<u>24,961</u>
14	Rate of Return on Rate Base	4.63%		5.28%
15	Projected Compliance Rate of Return Range:			
16	Upper end of the range: 5.45% + 0.20%	5.65%		5.65%
17	Lower end of the range: 5.45% - 0.20%	5.25%		5.25%
18	Financial Return on Equity	3.13%		7.68%

**Newfoundland and Labrador Hydro
2018 Cost Deferral Account Definition**

This account shall be charged based upon the following formula:

$$A = B - C$$

Where:

A = The amount to be deferred.

B = 2018 depreciation, loss on disposal, disposal proceeds, and removal costs calculated in accordance with Hydro's Board approved depreciation methodology.

C = 2018 depreciation, loss on disposal, disposal proceeds, and removal costs calculated in accordance with the depreciation methodology settled through the 2017 General Rate Application.

Disposition of any balance in this account shall be subject to a future order of the Board.

IN THE MATTER OF the *Electrical Power Control Act, 1994*, SNL 1994, Chapter E-5.1 and the *Public Utilities Act, RSNL 1990*, Chapter P-47 (the Act);

AND IN THE MATTER OF a General Rate Application by Newfoundland and Labrador Hydro ("Hydro") filed on July 28, 2017, as revised;


AND IN THE MATTER OF an application by Hydro for approval of: (i) deferral of the operating and maintenance ("O&M") costs required to be paid by Hydro for use of the Labrador-Island Link ("LIL") and Labrador Transmission Assets ("LTA") prior to full commissioning of the Muskrat Falls Project; (ii) a 2018 cost deferral account to provide Hydro the opportunity to earn a reasonable return on rate base in 2018 pursuant to Section 80 of the Act; and (iii) an application by Hydro, pursuant to Sections 70, and 75 of the Act, for the approval of Island Industrial Customer electricity rates to become effective January 1, 2019 on an interim basis (2018 Cost Deferral and Interim Rates Application).

AFFIDAVIT

I, Kevin J. Fagan, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Director, Regulatory Affairs, of Newfoundland and Labrador Hydro, the Applicant named in the attached Application.
2. I have read and understand the foregoing Application.
3. I have personal knowledge of the facts contained therein, except where otherwise indicated, and they are true to the best of my knowledge, information and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador, this 26 day of)
October 2018, before me:)



Barrister – Newfoundland and Labrador



Kevin J. Fagan