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October 11, 2017

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – Application for Recovery of the 2015 and 2016 Balances in i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; iii) the Holyrood Conversion Rate Deferral Account

Enclosed please find the original plus 12 copies of Newfoundland and Labrador Hydro's (Hydro's) Application for Recovery of the 2015 and 2016 Balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account.

An application is required annually by March 31 for the disposition of the balance in each of the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account; however, the deferral account definitions were not approved until July, 2017. As such, this application is for the recovery of the 2015 and 2016 balances in the above noted accounts.

Isolated Systems Cost Variance Deferral

In Order No. P.U. 22(2017) the Board approved the Isolated Systems Cost Variance Deferral definition. The Isolated Systems Supply Cost Variance Deferral Account provides Hydro the opportunity to recover variances in the price of supply sources on Hydro's Isolated Systems. Hydro is seeking approval of the disposition credit balances consistent with the approved definition in the amounts of $0.00 for 2015 and approximately $2.2 million for 2016.

Energy Supply Cost Variance Deferral Account

In Order No. P.U. 22(2017) the Board approved the Energy Supply Cost Variance Deferral Account definition. The Energy Supply Cost Variance Deferral Account captures variances in the cost of energy supplied to the Island Interconnected System, including variances in price and volume of Hydro's own diesel and gas turbine generation, as well as variances in the volume of power purchases of wind generation, Corner Brook Pulp and Paper cogeneration, and hydraulic generation. Hydro is seeking recovery of balances consistent with the

approved definition in the amount of approximately $14.2 million for 2015 and approximately $24.5 million for 2016.

Holyrood Conversion Rate Deferral

In Order No. P.U. 22(2017) the Board approved the Holyrood Conversion Rate Deferral definition. The Holyrood Rate Deferral Account stabilizes fuel costs related to the Holyrood Fuel Conversation Rate. Hydro is seeking recovery of balances consistent with the approved definition in the amount of approximately $3.6 million for 2015 and approximately $2.2 million for 2016.

The net amount requested for recovery from the above noted deferral accounts is approximately $42.2 million. Hydro is proposing that recovery of this net balance be administered through the Hydraulic Production Variation account in the Rate Stabilization Plan. This proposed recovery method will allow use of the current credit balance in the Hydraulic Production Variation account to mitigate customer impacts. In addition, the balance in the Hydraulic Production Variation account is amortized 25% per year, further mitigating customer rate impacts resulting from recovery of the balances.

Use of the Hydraulic Production Variation account in the Rate Stabilization Plan will allocate costs based on the preceding 12 months energy consumption from 2017. Hydro is proposing that historic supply costs be recovered from customers on the basis of their energy consumption in each respective year. As such, Hydro is also proposing a one-time transfer amongst the Rate Stabilization Plan Current Plan balances of its customers to permit the use of the existing Hydraulic Production Variation account regulations, to permit the allocation of the supply cost deferral account balances among customers based on 2015 and 2016 energy consumption.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey Pennell

Tracey L. Pennell
Senior Counsel, Regulatory

TLP/skc
Encl.

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Sheryl Nisenbaum – Praxair Canada Inc.
Dennis Browne, QC – Consumer Advocate
Dean Porter – Poole Althouse

ecc: Denis Fleming – Cox & Palmer
Larry Bartlett – Teck Resources Limited

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the recovery of the balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account, pursuant to Sections 70(1) and 80 of the *Act*.

AFFIDAVIT

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

1. I am Vice President, Production, 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 11th day of August 2017, before me:

Tracey Pennell
Barrister – Newfoundland and Labrador

Jennifer Williams

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

IN THE MATTER OF an Application by Newfoundland and Labrador Hydro for the recovery of the balances in: i) the Isolated Systems Supply Cost Variance Deferral Account; ii) the Energy Supply Cost Variance Deferral Account; and iii) the Holyrood Conversion Rate Deferral Account, pursuant to Sections 70(1) and 80 of the *Act*.

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

THE APPLICATION OF NEWFOUNDLAND AND LABRADOR HYDRO (Hydro) STATES

THAT:

A. Background

1. Hydro is a corporation continued and existing under the *Hydro Corporation Act*, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. In its 2013 Amended General Rate Application (GRA), Hydro proposed three new accounts for deferral and recovery of variances from its test year forecast of certain supply related costs. The proposed accounts included the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account.

The Isolated Systems Supply Cost Variance Deferral Account

3. The Isolated Systems Supply Cost Variance Deferral Account provides Hydro with the opportunity to recover variances in the price of supply sources on Hydro's Isolated Systems. The account is credited or charged with the difference between the approved test year price and the actual cost of fuel and purchases used to serve Hydro's customers on its Isolated Systems.

4. In Order No. P.U. 49(2016) (the GRA Order), the Board stated that it believed that the Isolated Systems Supply Cost Variance Deferral Account should be approved effective January 1, 2015, but that recovery of the balance in the account should be addressed in the annual application for disposition of the balance in the account. The Board determined that Hydro should also file with its annual application a detailed report setting out the efforts made during the year to minimize the costs on the Isolated Systems and how any variance would be collected/refunded and from which customers. As such, the Board directed Hydro to file revised language for the Isolated Systems Supply Cost Variance Deferral Account to reflect the requirement for the detailed report with the annual disposition application.

5. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22 (2017), the Board approved Hydro's revised Isolated Systems Supply Cost Variance Deferral Account definition.

The Energy Supply Cost Variance Deferral Account

6. The Energy Supply Cost Variance Deferral Account captures variances in the cost of energy supplied to the Island Interconnected System. The account applies to variances in the price and volume of Hydro's own diesel and gas turbine generation, as well as variances in the volume of power purchases from wind generation, Corner Brook Pulp and Paper cogeneration, and hydraulic generation. Further, this account also captures the energy supply costs or savings resulting from the variance in kWh supply based on the cost of generation at Holyrood Thermal Generating Station.

7. In the GRA Order, the Board stated that the proposed Energy Supply Cost Variance Deferral Account should be approved effective January 1, 2015, but required that the language of the account be revised with respect to power purchases variances to reflect variances in volume but not price. In addition, the Board found that the proposed account language was not sufficiently specific as to identify the supply sources which are to be reflected in the variances. As such, the Board directed Hydro to modify the account language to reflect these changes.

8. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22 (2017), the Board approved the revised Energy Supply Cost Variance Deferral Account definition.

The Holyrood Conversion Rate Deferral Account

9. The Holyrood Conversion Rate Deferral Account stabilizes fuel costs related to the Holyrood fuel conversion rate. The account provides for the deferral of costs incurred by Hydro resulting from variations from the test year forecast associated with the Holyrood conversion rate.

10. In the GRA Order, the Board stated that the Holyrood Conversion Rate Deferral Account should be approved in relation to variances associated with the Holyrood conversion rate, effective January 1, 2015. However, the Board determined there should be a cost variance threshold of +/- $500,000 for the Holyrood Conversion Rate Deferral Account and directed Hydro to file revised account language for the Holyrood Conversion Deferral reflecting this change.

11. On January 27, 2017, Hydro filed revised language to reflect the Board's direction. In Order No. P.U. 22 (2017), the Board approved the revised Holyrood Conversion Rate Deferral Account definition.

B. Application

Deferral Account Balances

12. Hydro is seeking approval of the approximately $42.2 million in deferred supply costs, as follows:

i. 2015 Isolated Systems Supply Cost Variance Deferral Account balance of $0.00, as detailed in Appendix B to Schedule 1;

ii. 2016 Isolated Systems Supply Cost Variance Deferral Account credit balance of $2,186,570.00, as detailed in Appendix C to Schedule 1;

iii. 2015 Energy Supply Cost Variance Deferral Account debit balance of $14,200,429.00, as detailed in Appendix G to Schedule 1;

iv. 2016 Energy Supply Cost Variance Deferral Account debit balance of $24,462,996.00, detailed in Appendix G to Schedule 1;

v. 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00, as detailed in Appendix H to Schedule 1; and

vi. 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00, as detailed in Appendix I to Schedule 1.

Allocation of Deferred Balances

13. Hydro is proposing to allocate the 2016 credit balance in the Isolated Systems Supply Cost Variance Deferral Account between Newfoundland Power and Labrador Interconnected customers based on the 2015 Test Year Rural Deficit allocation, which allocated 95.6% of the rural cost variances to Newfoundland Power. The remaining 4.4% are allocated to Labrador Interconnected customers which is absorbed by Hydro in accordance with the Rate Stabilization Plan (RSP) Rules.

14. Hydro is proposing that the 2015 and 2016 balances of the Energy Supply Cost Variance Deferral Account to be allocated on the basis of energy consumption in the years the balances accumulated which is consistent with the allocation of fuel costs in Hydro's approved cost of services methodology.

Balance Recovery

15. Due to the materiality of potential rate increases from other rate change applications currently before the Board, including but not limited to: i) Hydro's 2017 General Rate Application; ii) the discontinuance of the RSP mitigation adjustments on July 1, 2018; and iii) the normal operation of RSP adjustments in 2018, Hydro is proposing to utilize the credit balance due to customers in the RSP Hydraulic Variation Account balance to reduce the amount of deferred supply cost to be recovered from customers through increased rates.

16. The RSP Hydraulic Variation Account has a credit balance of $28,675,343.00 as of August 31, 2017. Schedule 2 provides the RSP Activity Report for August 2017.

17. Hydro is proposing to transfer the net deferred supply cost balance of approximately $42.2 million to the RSP Hydraulic Variation Account effective December 31, 2017. Current RSP rules amortize the year-end balance in the RSP Hydraulic Variation Account to be paid by customers at a rate of 25% per year. This approach would apply to any deferred supply costs which are in excess of

the credit balance resulting from the accumulation of prior years' activity in the RSP Hydraulic Variation Account.

18. Use of the RSP Hydraulic Variation Account in conjunction with existing RSP Rules will allocate the remaining deferred supply costs on 2017 energy consumption. Hydro's Application seeks to allocate 2015 and 2016 costs based on energy consumption from each respective year.

19. As such, Hydro is also proposing the Board approve a one-time transfer from Newfoundland Power's RSP Current Plan to the Island Industrial Customers' RSP Current Plan effective December 31, 2017, to occur in January 2018, to ensure that the deferred supply costs are recovered on the basis of 2015 and 2016 energy consumption.

20. Schedule 1 to the Application provides Hydro's evidence supporting its proposals.

C. Order Requested

21. Hydro hereby requests that the Board make and Order pursuant to Sections 70(1) and 80 of the *Act* approving:

    i. the 2015 Isolated System Supply Cost Variance Deferral Account balance of $0.00;

ii. the 2016 Isolated Systems Supply Cost Variance Deferral Account Credit Balance of $2,186,570.00;

iii. the 2015 Energy Supply Cost Variance Deferral Account debit balance of $14,200,429.00;

iv. the 2016 Energy Supply Cost Variance Deferral Account debit balance of $24,462,996.00;

v. the 2015 Holyrood Conversion Rate Deferral Account debit balance of $3,582,048.00;

vi. the 2016 Holyrood Conversion Rate Deferral Account debit balance of $2,150,665.00

vii. the transfer of the net deferred supply cost balance of $42,209,568.00 to the RSP Hydraulic Variation Account effective December 31, 2017;

viii. the allocation of the 2016 credit balance in the Isolated Supply Systems Cost Variance Deferral Account reflected in the net supply cost balance of $42,209,568.00 between Newfoundland Power and Labrador Interconnected Customers based on the 2015 Test Year Rural Deficit Allocation; and

ix. a one-time transfer between Newfoundland Power's RSP Current Plan balance to the Island Industrial Customers' RSP Current Plan balance, effective December 31, 2017, to ensure cost recovery of the 2015 and 2016 supply costs based on 2015 and 2016 energy consumption.

D. Reasons for Approval

22. The balances in the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account, and the Holyrood Conversion Rate Deferral Account were incurred in accordance with the definitions approved by the Board in Order No. P.U. 22 (2017).

23. Approval of the Hydro's Application provides a reasonable balance of the interests of the customers and the utility and permits Hydro to recover prudently incurred supply costs consistent with Section 70(1) of the *Act.*

DATED at St. John's, in the Province of Newfoundland and Labrador, this 11th day of October, 2017.

Tracey L. Pennell
Counsel for the Applicant
Newfoundland and Labrador Hydro
500 Columbus Drive P.O. Box 12400
St. John's, NL A1B 4K7
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SCHEDULE 1

2015 & 2016 SUPPLY COST RECOVERY APPLICATION EVIDENCE

2015 & 2016 Supply Cost Recovery Application Evidence

Table of Contents

1.0 Background

In Order No. P.U. 49(2016) (the GRA Order), the Board of Commissioners of Public Utilities (the Board) approved three new supply cost deferral accounts to become effective January 1, 2015: the Isolated Systems Supply Cost Variance Deferral Account (Isolated Systems Deferral); the Energy Supply Cost Variance Deferral Account (Energy Supply Deferral); and the Holyrood Conversion Rate Deferral Account (Holyrood Conversion Deferral). In the GRA Order, the Board also directed Hydro to file revised account definitions for each account. In Order No. P.U. 22(2017), the Board approved Hydro's revised deferral account definitions.

This evidence provides support for Hydro's proposal for the recovery of the balances in the Isolated Systems Deferral, Energy Supply Deferral, and the Holyrood Conversion Deferral accounts for 2015 and 2016. For reference, the approved deferral account definitions are included as Appendix A to this evidence.

2.0 Isolated Systems Deferral

2.1 General

Hydro purchases diesel fuel in order to supply customers on its isolated systems. Diesel fuel is a commodity and its price is set by market forces which can fluctuate greatly. This volatility and corresponding fuel price variance is beyond Hydro's control. As such, the Isolated Systems Deferral permits Hydro to defer variances from the approved test year in the price of supply costs in Hydro's isolated systems.

Hydro has three main supply sources for its isolated systems: 1) diesel fuel consumed in its diesel generation plants; 2) purchases from Hydro Quebec to serve customers on the L'Anse Au Loup system; and 3) purchases of wind energy in the community of Ramea on the south coast of the island of Newfoundland. Hydro's purchase price from Hydro Quebec and wind generation is adjusted based on the change in the price of diesel fuel.

The Isolated Systems Deferral account includes a Cost Variance Threshold (Deadband) of +/- $500,000 per calendar year. This means that Hydro is only permitted to defer annual cost variances in excess of +/- $500,000 that result from price changes relative to the Test Year cost of supply.

In the GRA Order, the Board determined that disposition of the balance in the account should be addressed in an annual application to the Board.[1]

2.2 Account Balances

Table 1 summarizes the amounts that have accumulated in the Isolated Systems Deferral for 2015 and 2016.

Table 1 – Isolated Systems Deferral Summary

Line No.	Particulars ($ 000s)	Supply Cost Variances	Deadband	Net
1	2015 Isolated Systems Deferral	163	(500)	
2	2016 Isolated Systems Deferral	(2,687)	500	(2,187)
3	**Total**			**(2,187)**

In 2015, Hydro incurred approximately $163,000 in supply costs in excess of its approved test year as a result of price variances in isolated system supply costs, primarily as a result of higher than forecast diesel fuel costs, which averaged the equivalent of 1.4 cents per kWh higher than the approved test year cost. However, as this amount is less than the approved Deadband of $500,000, this amount is not recoverable through the deferral account and the cost is borne by Hydro.

In 2016, Hydro realized isolated supply cost savings of approximately $2.7 million when compared to the approved test year. The 2016 savings were primarily a result of an average decrease in the cost of diesel fuel consumed at Hydro's generating facilities of approximately 2.7 cents per kWh and a corresponding decrease in the cost of power purchased from Hydro

[1] Order No. P.U. 49(2016), page 116, lines 1 through 5.

Quebec and in the community of Ramea. Accounting for the Deadband of $500,000, the credit balance in this deferral account is approximately $2.2 million. Detailed calculations supporting Table 1 are included in Appendices B and C to this evidence.

2.3 Cost Management in Isolated Systems

In the GRA Order, the Board directed Hydro file a report with its annual application detailing Hydro's efforts during the year to minimize costs on the Isolated Systems. Appendices D and E to this evidence contain Hydro's 2015 and 2016 Rural Deficit reports, previously filed with the Board on August 3, 2017. These reports detail the initiatives undertaken by Hydro to minimize the costs of operating the Isolated Systems in 2015 and 2016.

3.0 Energy Supply Deferral

3.1 General

From 2008 through 2015, Hydro acquired a number of new supply sources. These new supply sources, including Exploits, wind generation, and the Holyrood Gas Turbine[2] (Holyrood GT) benefit customers by providing increased system reliability and/or by reducing fuel consumption at the Holyrood Thermal Generating Station (Holyrood TGS). In the absence of the Energy Supply Deferral account, variances in Hydro's energy supply costs could materially impact Hydro's financial results in a given year.

The Holyrood GT is essential to the reliable and adequate supply of power for customers on the Island Interconnected system. Variances in both volume and price associated with the Holyrood Gas Turbine can be significant, and in the absence of a deferral mechanism, could result in a material reduction to Hydro's earnings.

Hydro's purchases from Non-Utility Generators can also vary from test year levels. These variances, primarily caused by changes in wind and hydrology, are beyond Hydro's control and

[2] Also known as the Holyrood Combustion Turbine

require Hydro to replace that energy with generation from more expensive sources, primarily the Holyrood TGS.

The Energy Supply Deferral permits Hydro to defer variances from the approved test year in the price of supply costs on Hydro's Island Interconnected System. The Energy Supply Deferral is comprised of three main sections: 1) variations in both price and volume of standby thermal generation; 2) variations in volume only from power purchases; and, 3) fuel cost variations at the Holyrood TGS as a result of variations in energy production from sources specifically covered by the Energy Supply Deferral. The Cost Variance Threshold (Deadband) for this account is +/- $500,000 per calendar year; therefore, Hydro is only permitted to defer annual cost variances in excess of the Deadband.

3.2 Account Balances

Table 2 summarizes the deferral account activity in the Energy Supply Deferral for 2015 and 2016. Detailed calculations supporting Table 2 are included in Appendices F and G to this evidence.

Table 2 – Energy Supply Deferral Summary

Line No.	Particulars ($ 000s)	Supply Cost Variances	Deadband	Net
1	2015 Energy Supply Deferral	14,700	(500)	14,200
2	2016 Energy Supply Deferral	24,963	(500)	24,463
3	**Total**			**38,663**

The account balance at the end of 2016 is a balance owing from customers of approximately $38.7 million. In accordance with the Deadband for this account, Hydro absorbed $1.0 million in additional supply costs for the two-year period that it will not recover from customers.

3.2.1 2015 Account Balance

The 2015 Energy Supply Deferral balance of $14.2 million is comprised of the costs summarized in Table 3.

Table 3 – 2015 Energy Supply Deferral Summary

Line No.	Particulars	$ 000s
1	Standby Generation Costs	11,182
2	Power Purchase Savings	(1,526)
3	Holyrood TGS Fuel Costs	5,044
4	Deadband	(500)
5	**Total**	**14,200**

For 2015, the deferral balance primarily relates to increased standby thermal generation costs of approximately $11.2 million in excess of the amount forecast in the 2015 Test Year. The largest contributor to this variance was the Holyrood GT which produced 39.5 GWh in excess of test year levels.[3]

Details of the operating hours of the Holyrood GT are shown in Table 4.

Table 4 – Holyrood Gas Turbine 2015 Operating Data

Year	GT Function	Actual Starts	Actual Operating Hours	Reference Note
2015	Support of spinning reserve	28	205.5	1
	Backup due to the loss of a major generating unit	18	201.0	2
	Planned generation outages	21	181.2	3
	Planned Avalon Peninsula transmission outages	13	154.8	4
	Testing	15	45.8	5
	Actual Totals	**95**	**788.3**	

Notes: 1. Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings to generating equipment.
2. The primary driver of operation in this area was outages to units at the HTGS and requirements for Avalon and Spinning reserves.
3. The primary driver of operation in this area was the Holyrood total plant outage in August 2015 and therefore operation for Avalon transmission support.
4. The primary driver of operation in this area was the planned outage to the transmission line TL201 in November 2015.
5. Testing of the Holyrood GT primarily occurred in the months immediately following the commissioning and in-service date of the unit.

[3] The 2015 Test Year forecast included 6.5 GWh in production from the Holyrood GT.

As Table 4 indicates, the use of the Holyrood GT in 2015 was in support of spinning reserves and to provide generation during the loss of a major generating unit, and also required to reliably facilitate planned generation and transmission outages. The increased generation from the Holyrood GT in this manner lessened the energy requirements from the Holyrood TGS, which produced savings that partially offset the increased GT costs; these savings are reflected in Part C of the Energy Supply Deferral.

With respect to power purchases, Hydro purchased 78.2 GWh less than forecast in the 2015 Test Year from the non-utility generators specifically covered by the Energy Supply Deferral. As a result, Hydro incurred approximately $1.5 million less in power purchases costs in 2015, which was credited to the Energy Supply Deferral. The largest decrease in power purchases was from Nalcor Exploits, which produced 74.0 GWh less than the 2015 Test Year forecast. The decreased power purchases from Nalcor Exploits were primarily due to operational issues experienced at Exploits in 2015. These lower power purchases resulted in increased energy requirements from the Holyrood TGS.

Finally, Hydro incurred approximately $5.0 million in higher Holyrood TGS fuel costs in 2015 as a result of lower power purchases. For the generation sources specifically included in the Energy Supply Deferral, Hydro generated or purchased 993.9 GWh in total, versus the 2015 Test Year forecast of 1,042.3 GWh. This shortfall in energy of 48.4 GWh was replaced by generation from the Holyrood TGS. As such, the cost of this energy is charged to the Energy Supply Deferral at the approved test year marginal cost of energy at the Holyrood TGS.

In total, for 2015 Hydro incurred an additional $14.7 million in additional energy supply costs on the Island Interconnected System. With the removal of the $500,000 Deadband, Hydro is proposing to recover the $14.2 million reflected in the 2015 year-end balance.

3.2.2 2016 Account Balance

The 2016 Energy Supply Deferral balance of approximately $24.5 million is comprised of the costs summarized in Table 5.

Table 5 – 2016 Energy Supply Deferral Summary

Line No.	Particulars	$ 000s
1	Standby Generation Costs	25,060
2	Power Purchase Savings	(1,780)
3	Holyrood TGS Fuel Costs	1,683
4	Deadband	(500)
5	**Total**	**24,463**

In 2016, the Energy Supply Deferral balance primarily relates to increased thermal generation costs, which were approximately $25.0 million in excess of the amount forecast in the 2015 Test Year. The largest contributor to this variance was the Holyrood GT which produced 106.4 GWh in excess of 2015 Test Year forecast levels. Details of the 2016 operating hours of the Holyrood GT are shown in Table 6.

Table 6 – Holyrood Gas Turbine 2016 Operating Data

Year	GT Function	Actual Starts	Actual Operating Hours	Reference Note
2015	Support of spinning reserve	35	238.6	1
	Backup due to the loss of a major generating unit	5	1,245.6	2
	Planned Avalon Peninsula transmission outages	1	5.9	
	Testing	3	3.2	
	Actual Totals	**44**	**1,493.3**	

Notes: 1. Operation in this area includes for Spinning and Avalon Reserves which are generally load driven and/or due to deratings to generating equipment.
2. The primary driver of operation in this area was the extended outages to HTGS Units 1 and 2 in January and February 2016 and the requirements for Avalon and Spinning reserves, as well as for reservoir support.

The Holyrood GT operating hours in 2016 were primarily due to extended outages to Units 1 and 2 at the Holyrood TGS in January and February 2016 due to boiler tube replacements. As a result of these unit outages, the production at the Holyrood GT was increased to maintain Avalon reserves as well as provide hydraulic reservoir support. Increased generation costs from the Holyrood GT in 2016 were partially offset by fuel savings resulting from lower energy production at the Holyrood TGS; these savings are reflected in Part C of the Energy Supply Deferral.

With respect to power purchases, Hydro purchased 124.1 GWh less than forecast in the 2015 Test Year from the non-utility generators specifically covered by the Energy Supply Deferral. As a result, Hydro incurred approximately $1.8 million less in power purchase costs in 2015, which were credited to the Energy Supply Deferral. The largest decrease in power purchases was from Nalcor Exploits, which produced 138.1 GWh less than the 2015 Test Year forecast. The decreased power purchases available from Nalcor Exploits were primarily due to lower reservoir levels and operational issues with the Exploits generating units. These lower power purchases result in increased energy requirements from the Holyrood TGS.

Finally, Hydro incurred approximately $1.7 million in higher Holyrood TGS fuel costs in 2016 as a result of lower power purchases. For the generation sources specifically included in the Energy Supply Deferral, Hydro generated or purchased 1,026.2 GWh in total, versus the 2015 Test Year forecast of 1,042.3 GWh. This shortfall in energy of 16.2 GWh, was replaced by more costly generation from the Holyrood TGS. As such, the cost of this energy is charged to the Energy Supply Deferral at the approved test year marginal cost of energy at the Holyrood TGS.

In 2016, Hydro incurred approximately $25.0 million in additional supply costs. With the removal of the $500,000 Deadband, Hydro is proposing to recover the approximately $24.5 million reflected in the year-end balance.

4.0 Holyrood Conversion Deferral

4.1 General

The Holyrood Conversion Deferral permits Hydro to defer costs that result from differences between the actual and Test Year No. 6 fuel conversion rate. The Holyrood TGS conversion rate can be affected by unit loading and fuel BTU content. Generally higher production at the Holyrood TGS will improve the conversion rate and result in fuel savings, and, conversely, lower production at the Holyrood TGS will reduce the conversion rate and result in higher fuel costs.

For the purpose of calculating Hydro's test year fuel costs and monthly Rate Stabilization Plan (RSP) balances, a fixed conversion rate is used for the number of kWh output for each barrel of No. 6 fuel consumed by the Holyrood TGS. Hydro's approved No. 6 conversion rate for the 2015 Test Year is 618 kWh per barrel.[4] Hydro is permitted to defer annual costs in excess of the Cost Variance Threshold (Deadband) of +/- $500,000 per calendar year.

4.2 Account Balances

Table 7 summarizes the deferral account activity in the Holyrood Conversion Deferral for both 2015 and 2016. Detailed calculations supporting Table 7 are included in Appendices H and I to this evidence.

Table 7 – Holyrood Conversion Deferral

Line No.	Particulars ($ 000s)	Supply Cost Variances	Deadband	Net
1	2015 Holyrood Conversion Deferral	4,082	(500)	3,582
2	2016 Holyrood Conversion Deferral	2,651	(500)	2,151
3	**Total**			**5,733**

The account balance at the end of 2016 is an amount owing from customers of approximately $5.7 million. In accordance with the Deadband in the approved deferral account definition,

[4] Board Order No. P.U. 49(2016), page 32, lines 25-26.

Hydro absorbed $1.0 million in additional supply costs for the two-year period that it will not recover from customers.

The 2015 actual conversion rate of 602 kWh per barrel resulted in Hydro incurring approximately $4.1 million in additional No. 6 fuel costs. The 2016 actual conversion rate of 608 kWh per barrel resulted in Hydro incurring approximately $2.7 million in additional No. 6 fuel costs.

In 2015, Hydro achieved a fuel conversion rate of 602 kWh per barrel compared to the 2015 Test Year rate of 618 kWh per barrel. In 2016, Hydro achieved a fuel conversion rate of 608 kWh per barrel compared to the 2015 Test Year rate of 618 kWh per barrel. The variances from the test year conversion rate for 2015 and 2016 were primarily due to a lower average unit loading than forecast in the test year.[5] A contributor to the lower average unit loading was operating of a Holyrood unit at minimum loads during the summer months in order to support Avalon reserves, which supports system reliability for customers.

Further, No. 6 fuel deliveries in 2015 and 2016 contained a lower average BTU content than what was forecast in the 2015 Test Year.[6] This lower BTU content contributed to the lower actual conversion rates in both 2015 and 2016. As a result of the actual BTU variance, Hydro received a discount on its purchase of No. 6 fuel which was passed on to customers through the RSP.[7] Finally, the station service factor for 2015 and 2016 was higher than what was approved in the 2015 Test Year, resulting in greater station service losses in 2015 and 2016.[8]

[5] Hydro's 2015 Test Year forecasted an average unit loading of 109.6 MW; the actual 2015 and 2016 average unit loadings were 88.9 MW and 90.8 MW respectively.
[6] 2015 Test Year average fuel heating content was 152,400 BTU/gal. Actual 2015 consumption averaged 150,581 BTU/gal. Actual 2016 consumption averaged 152,315 BTU/gal.
[7] For each delivery of No. 6 fuel, the purchase price is adjusted to reflect the BTU content of the delivered fuel.
[8] 2015 Actual station service factor was 5.81% vs. the 2015 Test Year approved factor of 5.00% (618 kWh/bbl). 2016 Actual station service factor was 5.32%.

5.0 Proposed Recovery of Supply Costs

5.1 Allocation of Deferred Balances

In total, Hydro is seeking to recover approximately $42.2 million in total deferred supply costs for the years 2015 and 2016. Table 8 provides the deferred balances for each account by year.

Table 8 – Summary of Deferred Supply Costs

Line No.	Particulars ($ 000s)	2015	2016	Total
1	Isolated Systems Deferral	-	(2,187)	(2,187)
2	Energy Supply Deferral	14,200	24,463	38,663
3	Holyrood Conversion Deferral	3,582	2,151	5,733
4	**Total**	**17,782**	**24,427**	**42,209**

5.1.1 Proposed Isolated Systems Deferral Allocation Methodology

Hydro proposes to allocate the balance of the Isolated Systems Deferral between Newfoundland Power and Labrador Interconnected customers, based on the proportion of the Rural Deficit[9] allocated to each customer class in the most recently approved Test Year.[10] Hydro proposes to credit Newfoundland Power's portion of the Isolated Systems savings of approximately $2.2 million to the Rate Stabilization Plan. Hydro considers this approach to be reasonable as it is consistent with the current treatment of No. 6 fuel cost variances related to serving Hydro's Rural Interconnected customers.

For the purpose of allocating the credit balance in the Isolated Systems Deferral as of December 31, 2016, Hydro proposes to apply the 2015 Test Year Rural Deficit allocation, which allocates

[9] The cost of serving Hydro's customers in isolated systems exceeds the revenues collected from those customers. This shortfall in rural revenue represents the Rural Deficit, which is funded by customers of Newfoundland Power and Hydro Rural customers on the Labrador Interconnected System, in accordance with OC2003-347.

[10] Amounts allocated to Labrador Interconnected are absorbed by Hydro's financial results in accordance with RSP-2, Section A.4, as there is no annual adjustment to deal with cost variances for the Labrador Interconnected system.

95.6% of the rural cost variances to Newfoundland Power. The remaining 4.4% of the rural cost are allocated to Labrador Interconnected customers.[11]

As the balance of the Isolated Systems Deferral did not exceed the $500,000 Deadband in 2015, Hydro will not recover any of the 2015 supply cost variance. For 2016, approximately $2.1 million of the approximately $2.2 million savings would be allocated to Newfoundland Power. The remaining 4.4%, or approximately $96,000, of the approximately $2.2 million savings would be allocated to the Labrador Interconnected system.

5.1.2 Proposed Allocation Methodology for the Energy Supply Deferral and Holyrood Conversion Deferral

Hydro is proposing that the 2015 and 2016 account balances be allocated on the basis of energy consumption in the years the balances accumulated. This approach, along with the proposed allocation of rural costs, is consistent with Hydro's approved Cost of Service methodology which allocates fuel costs on energy consumption. Hydro believes this approach is equitable as costs will be recovered from the classes of customers who received the benefit in that given year. Assuming this methodology, 2015 and 2016 costs would be allocated as noted in Table 9.

[11] In accordance with RSP Rules, balances allocated to Labrador Interconnected are written-off to Hydro's net income.

Table 9 – Energy Supply and Holyrood Conversion Allocation[12,13]

Line No.	Customer	2015 Energy (kWh)	2015 Energy (%)	Allocation of Rural (%)	Total (%)
1	Newfoundland Power	6,072,134,676	86.1%	6.5%	92.6%
2	Island Industrial	497,961,116	7.1%	0.0%	7.1%
3	Hydro Rural	476,600,929	6.8%	-6.5%	0.3%
4	**Total**	**7,046,696,721**	**100.0%**		**100.0%**
Line No.	**Customer**	**2016 Energy (kWh)**	**2016 Energy (%)**	**Allocation of Rural (%)**	**Total (%)**
5	Newfoundland Power	5,844,734,737	85.6%	6.7%	92.3%
6	Island Industrial	505,383,547	7.4%	0.0%	7.4%
7	Hydro Rural	476,456,642	7.0%	-6.7%	0.3%
8	**Total**	**6,826,574,926**	**100.0%**		**100.0%**

5.1.3 Allocation of Deferred Balances

Based on the methodologies proposed in sections 5.1.1 and 5.1.2, the deferred supply costs of approximately $42.2 million would be allocated as shown in Table 10.

[12] 95.6% of Rural Costs have been allocated to Newfoundland Power, consistent with the Rural Deficit allocation in the 2015 Test Year.

[13] The 0.3% allocated to Hydro Rural represents the amount allocated to Labrador Interconnected customers, based on the 2015 Test Year.

Table 10 – Allocation of Supply Cost Deferral Balances

2015 Supply Costs					
Line No.	**Particulars**	**Newfoundland Power**	**Island Industrial**	**Labrador Interconnected**	**Total**
1	Isolated Systems	-	-	-	-
2	Energy Supply	13,155	1,004	42	14,200
3	Holyrood Conversion	3,318	253	11	3,582
4	**Total**	**16,473**	**1,257**	**53**	**17,782**
2016 Supply Costs					
Line No.	**Particulars**	**Newfoundland Power**	**Island Industrial**	**Labrador Interconnected**	**Total**
5	Isolated Systems	(2,091)	-	(96)	(2,187)
6	Energy Supply	22,577	1,811	75	24,463
7	Holyrood Conversion	1,985	159	7	2,151
8	**Total**	**22,471**	**1,970**	**(14)**	**24,427**
9	**Total 2015 & 2016**	**38,944**	**3,227**	**38**	**42,209**

Table 10 shows that under this proposed methodology, Newfoundland Power and the Island Industrial Customers would be allocated approximately $38.9 million and $3.2 million of supply costs, respectively. Hydro would absorb the Labrador Interconnected allocation[14].

5.2 Balance Recovery

Hydro proposes that recovery of the approximately $42.2 million in deferred supply costs should be considered in conjunction with other rate changes currently before the Board. Hydro's 2017 General Rate Application requests customer rate increases in both 2018 and 2019. Additionally, the discontinuance of the RSP mitigation adjustments on July 1, 2018 will result in an additional potential rate increase to customers.[15] If Hydro were to recover the outstanding supply costs over a single year commencing in 2018, without use of any RSP credit

[14] The allocation provided in Table 10 reflects the allocation of the Isolated Systems Deferral based on the rural deficit allocation methodology.
[15] Directed by Order No's. P.U. 22(2017) and P.U. 26(2017).

balances, it would result in an additional rate increase of 9.4% to Newfoundland Power (approximately 6.4% end-consumer) and 8.2% to the Island Industrial Customers.[16]

Due to the materiality of the potential customer rate impacts, Hydro is proposing to utilize the credit balance due to customers in the RSP Hydraulic Variation balance to reduce the amount of deferred supply costs to be recovered from customers through increased rates.

5.2.1 Recovery through Hydraulic Variation

The RSP Hydraulic Variation Account has a credit balance of approximately $28.7 million as at August 31, 2017. A copy of the August 2017 RSP Report is included as Schedule 2 to this evidence.

Hydro is proposing to transfer the approved deferred supply cost balances of approximately $42.2 million to the RSP Hydraulic Variation Account. The proposed transfer would result in a net balance owing from customers of approximately $13.5 million. Current RSP rules amortize the balance in the RSP Hydraulic Variation Account to be paid by customers at a rate of 25% per year, allocated amongst customers based on their 12 months-to-date kWh.[17] If the proposed transfer takes place on December 31, 2017, the effective recovery of supply costs will occur on 2017 kWh, not on 2015 and 2016 kWh as presented in Tables 9 and 10. The variance in allocation of supply costs based on forecast 2017 kWh is shown in Table 11.

[16] Rate increases relative to existing customer rates and 2018 forecast load. Does not reflect potential rate increases resulting from the discontinuance of RSP mitigation adjustments on July 1, 2018.
[17] RSP Rules, Section A, Part 3 and Part 4.

Table 11 – Allocation of Supply Cost Deferral Balances on Forecast 2017 Energy

Line No.	Customer	2017 Forecast Energy (kWh)	2017 Energy (%)	Allocation of Rural (%)	Total (%)
1	Newfoundland Power	5,903,347,627	84.5	6.4	91.0
2	Island Industrial	610,918,644	8.7	0.0	8.7
3	Hydro Rural	469,891,925	6.7	-6.4	0.3
4	**Total**	**6,984,158,196**	**100.0**		**100.0**
Line No.	**Customer**	**Supply Costs at 2015 & 2016 Energy** (kWh)	**Supply Costs at 2017 Energy** ($000s)	**Variance** ($000s)	
5	Newfoundland Power	38,944	38,392	552	
6	Island Industrial	3,227	3,692	(465)	
7	Hydro Rural	38	125	(87)	
8	**Total**	**42,209**	**42,209**	**-**	

The Island Industrial Customer's load has grown in 2017, relative to 2015 and 2016. As such, the use of 2017 kWh to allocate supply costs would result in the Island Industrial Customers bearing additional supply costs of approximately $0.5 million (3.7 million vs. 3.2 million). In order to remedy this situation and still make use of the RSP Hydraulic Variation Account, Hydro is also proposing a transfer from Newfoundland Power RSP Current Plan balance to the Island Industrial Customers Current Plan balance effective December 31, 2017 of an amount to effectively allocate the determined supply cost balances based on 2015 & 2016 energy cost allocations.[18] Table 11 provides a projection of the proposed transfer based on forecast 2017 kWh. Hydro is proposing that the transfer occur at the end of 2017, based on actual 2017 kWh, consistent with the timing of the transfer of the 25% RSP Hydraulic Variation balance to the RSP Current Plan balance.

This transfer will permit the recovery of deferred supply costs through normal operation of the RSP Hydraulic Variation Account but reflect cost allocations based on 2015 and 2016 energy consumption. Under Hydro's proposal, assuming the August 31, 2017 balance in the RSP

[18] The portion relating to Labrador Interconnected Customers will be written-off to Hydro's net income at the same date.

Hydraulic Variation account remains unchanged, the remaining balance of approximately $13.5 million would be recovered at a rate of 25% per year.

Hydro considers its proposal to apply historical energy supply savings from one supply source to recover historical energy supply cost savings from another supply source to be reasonable. Hydro's proposal limits intergenerational equity concerns related to recovery of historical energy supply costs through future customer rates. In addition, Hydro's proposal is consistent with past practice of the Board as noted in Board Order No. P.U. 8(2007).[19]

5.2.3 Customer Rate Impacts

The projected customer rate impact of approval of Hydro's proposal to recover 2015 and 2016 supply costs through the RSP Hydraulic Variation Account is approximately 0.8% for Newfoundland Power (0.5% end-consumer) and , Newfoundland Power's rate would increase by approximately 0.8% (0.5% end-consumer) and 0.5% for Island Industrial customers.[20]

6.0 Conclusion

Hydro is seeking approval to recover approximately $42.2 million in deferred 2015 and 2016 supply costs from the Isolated Systems Deferral, the Energy Supply Deferral, and the Holyrood Conversion Deferral accounts through the RSP Hydraulic Variation Account. These costs were prudently incurred in the provision of reliable service to customers. Hydro's recovery proposal is consistent with the principle of intergenerational equity, reflects a fuel cost allocation approach consistent with the RSP, and provides a reasonable balance of the interest of the utility in achieving cost recovery and the interest of the customer in ensuring reasonable customer rate impacts.

[19] The Board approved a transfer from the RSP Hydraulic Production Variation balance to reduce customer cost increases that were anticipated to provide recovery of a historical RSP balance owed from customers.
[20] The customer rate impact estimate is completed based on rates effective July 1, 2017 applied to 2018 forecast load.

NEWFOUNDLAND AND LABRADOR HYDRO
ISOLATED SYSTEMS SUPPLY COST VARIANCE DEFERRAL ACCOUNT

This account shall be charged or credited with the amount by which Hydro's Isolated Systems Supply Cost Variance exceeds the Supply Cost Variance Threshold in a calendar year.

The ***Isolated Systems Supply Cost Variance*** will be determined by the following formula:

$$A \times (B-C)$$

Where:

A = Total actual supply produced and purchased (kWh) on Hydro's isolated systems.

B = (Total actual cost of No. 2 fuel used to provide energy plus the total actual cost of purchases) divided by the total of the (actual kWh production and the actual kWh purchases) in $/kWh.

C = (Total Test Year cost of No. 2 fuel used to provide energy plus the total Test Year cost of purchases) divided by the (total of the Test Year kWh production and the Test Year kWh purchases) in $/kWh.

The ***Supply Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year. This Application shall detail the proposed method of collection or refund and from which customer class(s), and the efforts made by Hydro during the year to minimize costs on the Isolated systems.

NEWFOUNDLAND AND LABRADOR HYDRO
ENERGY SUPPLY COST VARIANCE DEFERRAL ACCOUNT

This account shall be charged or credited with the Energy Supply cost variance incurred by Hydro on the Island Interconnected System that is in excess of the Cost Variance Threshold in the calendar year.

Variations resulting from both the price and volume of the following thermal generation sources shall be charged or credited to this account:

- Holyrood Combustion Turbine;
- Hardwoods Gas Turbine;
- Stephenville Gas Turbine;
- St. Anthony Diesel Plant; and
- Hawkes Bay Diesel Plant.

Variations resulting from the volume of the following power purchases shall be charged or credited to this account:

- Nalcor Exploits;
- Star Lake;
- Rattle Brook;
- CBPP Cogeneration;
- St. Lawrence wind; and
- Fermeuse wind.

Energy Supply costs will be determined by the following formula:

$$A + B + C$$

A = Test Year Thermal Generation Variances resulting from both price and volume;

Where:

A = (Actual Thermal Generation Cost – Test Year Thermal Generation Cost)

B = Test Year Power Purchase Variances resulting from volume;

Where:

B = (Actual kWh Purchases – Test Year kWh Purchases) x (Test Year Purchase Cost in $/kWh)

NEWFOUNDLAND AND LABRADOR HYDRO
ENERGY SUPPLY COST VARIANCE DEFERRAL ACCOUNT (continued)

C = Fuel costs or savings resulting from the variance in generation at the Holyrood Thermal Generating Facility (Holyrood TGS);

Where:

C = D/E x F

D = Holyrood TGS Test Year average annual fuel cost per barrel;

E = Test Year fuel conversion factor (kWh/bbl); and

F = [(Test Year kWh Thermal Generation + Test Year kWh Power Purchases) - (Actual kWh Thermal Generation + Actual kWh Power Purchases)] for all defined sources.

The ***Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year.

NEWFOUNDLAND AND LABRADOR HYDRO
HOLYROOD CONVERSION RATE DEFERRAL ACCOUNT

This account shall be charged or credited with the Conversion Rate Cost Variance incurred by Hydro on the Island Interconnected system, in excess of the Cost Variance Threshold in the calendar year, which results from variations from the Test Year fuel conversion rate at the Holyrood thermal generating station.

The ***Conversion Rate Cost Variance*** will be determined monthly by the following formula:

$$(A - B) \times C$$

A = Actual quantity of No. 6 fuel consumed (bbl);

B = Calculated quantity of No. 6 fuel consumed using the Cost of Service fuel conversion rate (bbl); and

C = Test Year Cost of Service No. 6 fuel cost ($/bbl).

Where:

$$B = D/E$$

D = Actual net Holyrood production (kWh); and

E = Test Year Cost of Service fuel conversion rate (kWh/bbl).

The ***Cost Variance Threshold*** equals ±$500,000 in a calendar year.

Disposition of any Balance in this Account
Hydro shall file an Application for the disposition of any balance in this account with the Board no later than the 31st day of March each year.

2015 Isolated Systems Supply Cost Variance Account
December 31, 2015

Particulars	**Diesel**	**HQ Purchases**	**Other [1]**	**Total**
A - 2017 Actual Supply Produced & Purchased (kWh)	51,676,533	24,578,740	646,064	76,901,337
B - 2017 Actual Cost / 2017 Actual Produced & Purchased ($/kWh) [B1 / B2]	0.31401	0.10898	0.25652	0.2480
C - 2015 Test Year Cost / 2015 Test Year Produced & Purchased ($/kWh) [C1 / C2]	0.30014	0.11341	0.25629	0.2459
Isolated Supply Costs [A x (B-C)]				163,031
Cost Variance Threshold				500,000
Isolated Systems Supply Cost Deferral Balance				-
B1 - 2017 Actual Cost of No. 2 Fuel + Purchases ($)	16,226,822	2,678,557	165,726	19,071,106
B2 - 2017 Actual Supply Produced & Purchased (kWh)	51,676,533	24,578,740	646,064	76,901,337
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	17,122,665	2,657,829	202,468	19,982,962
C2 - 2015 Test Year Supply Produced & Purchased (kWh)	57,048,141	23,435,400	790,000	81,273,541

[1] Other consists of purchases of Wind Generation at Ramea.

2016 Isolated Systems Supply Cost Variance Account
December 31, 2016

Particulars	**Diesel**	**HQ Purchases**	**Other [1]**	**Total**
A - 2017 Actual Supply Produced & Purchased (kWh)	51,276,280	26,142,980	610,667	78,029,927
B - 2017 Actual Cost / 2017 Actual Produced & Purchased ($/kWh) [B1 / B2]	0.27292	0.09054	0.22558	0.21144
C - 2015 Test Year Cost / 2015 Test Year Produced & Purchased ($/kWh) [C1 / C2]	0.30014	0.11341	0.25629	0.24587
Isolated Supply Costs [A x (B-C)]				(2,686,570)
Cost Variance Threshold				(500,000)
Isolated Systems Supply Cost Deferral Balance				**(2,186,570)**
B1 - 2017 Actual Cost of No. 2 Fuel + Purchases ($)	13,994,229	2,367,050	137,752	16,499,031
B2 - 2017 Actual Supply Produced & Purchased (kWh)	51,276,280	26,142,980	610,667	78,029,927
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	17,122,665	2,657,829	202,468	19,982,962
C2 - 2015 Test Year Supply Produced & Purchased (kWh)	57,048,141	23,435,400	790,000	81,273,541

[1] Other consists of purchases of Wind Generation at Ramea.

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
(pursuant to Order No. P.U. 14(2004))

RURAL DEFICIT ANNUAL REPORT

Summary of Specific Initiatives

NEWFOUNDLAND AND LABRADOR HYDRO

March 2016

Revised August 3, 2017

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1 Introduction

Newfoundland and Labrador Hydro (Hydro) serves approximately 38,300 Rural Customers. Electrical service is provided to the majority of these customers at an operating loss or deficit, except for the approximately 11,000 Rural Customers served on the Labrador Interconnected System who pay rates which both recover costs as well as contribute to funding a portion of the rural deficit.

While there is no cost of service available by each diesel area or community, revenues from Rural Customers, particularly diesel areas, do not fully offset fixed costs. Therefore, the incremental cost of fuel is a direct impact to the rural deficit as it is not fully recovered from revenues from sales.

Hydro's mandate to provide least-cost, safe and reliable power to all its customers remains its primary focus. One of several measures Hydro uses to control its operating expenses are internal and customer Conservation and Demand Management (CDM) initiatives. Such efforts reduce Hydro's costs and assist in reducing and/or limiting the growth of overall system fuel costs.

2 Rural Deficit Overview

Table 1 below shows the rural deficit for 2011 to 2015, excluding Labrador Interconnected. The 2014 Rural Deficit is estimated based upon the 2014 actual costs combined with a portion of the $45.9 million deferred 2014 Revenue Deficiency allocated to the rural deficit. The 2015 Rural Deficit calculation is based on the 2015 Test Year Cost of Service for 2015 Revenue Deficiency as filed in Hydro's May 18, 2017 Compliance Rates Application, updated for revenue to reflect actual revenues and operating costs. This information was filed with the Board during the Amended 2013 GRA process on May 18, 2017.

Operating expenses have increased from $40.0 million in 2011 to $53.6 million in 2015, primarily driven by increases in wages and benefits as well as increases in maintenance and material costs due to investment in aging assets.

Table 1
Hydro Rural (Excluding Labrador Interconnected)

$000,000	**Annual Amounts**					**Year over Year**			
	2011	**2012**	**2013**	**2014**	**2015**	**2012/ 2011**	**2013/ 2012**	**2014/ 2013**	**2015/ 2014**
Revenues	58.4	60.8	62.5	62.6	63.2	2.4	1.7	0.1	0.6
Costs:									
Operating Expenses	40.0	43.0	44.4	47.4	53.6	3.0	1.4	3.0	6.2
Fuel	26.1	27.6	28.9	35.7	26.8	1.5	1.2	6.8	(8.9)
Purchased Power	7.0	7.5	7.7	7.9	7.3	0.4	0.2	0.2	(0.6)
Depreciation	14.2	11.6	12.5	12.7	14.2	(2.6)	0.9	0.2	1.5
Return[1]	20.5	20.4	19.7	23.0	24.8	(0.1)	(0.7)	3.3	1.8
Total	107.8	110.1	113.1	126.7	126.7	2.3	3.1	13.5	0.0
Rural Deficit	**49.4**	**49.3**	**50.6**	**64.1**	**63.5**	**(0.1)**	**1.4**	**13.4**	**(0.6)**

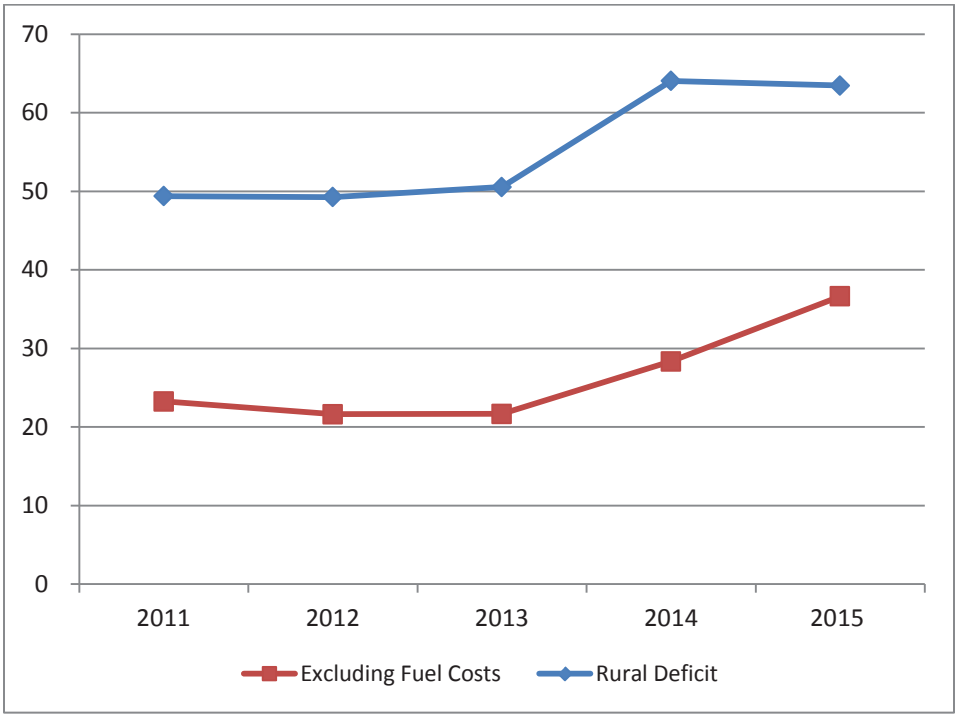
Table 1 above shows the overall rural deficit of $63.5 million in 2015 was lower than 2014 by approximately $0.6 million or 0.9%, primarily due to increased revenues. Costs were flat year-over year with a $9.5 million decrease in fuel and purchased power expenses, which were [] offset by an increase in operating expenses, depreciation, and return.

[1] Reflects return on debt only, for 2012 – 2013 inclusive.

Chart 1 below presents the rural deficit excluding and including fuel costs for the period 2011 to 2015.

Chart 1

Five-Year Rural Deficit ($ millions)



The rural deficit has been relatively consistent year over year for the period 2010 to 2013 when the impact of fuel costs is excluded. For 2014, the increased rural deficit (excluding fuel) reflects the inclusion of 8.8% return on equity proposed for rural assets. The $8.9 million decrease in the fuel expense from 2014 to 2015 reflects the increase shown when fuel costs are excluded.

3 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

In 2008, Hydro raised its focus on improving internal efficiency to reduce the internal use of energy. This ongoing activity is targeting reductions in energy usage in all facilities including diesel plants, offices, and line depots within the areas affecting the rural deficit. In 2015, Hydro completed or launched operating initiatives that are part of multi-year projects through its internal energy efficiency program. Such initiatives contribute to overall cost containment, a portion of which is allocated to Rural Customers and therefore contributes to deficit reduction. Initiatives completed in 2015 include:

- Installation of automatic temperature set-back controls for space heaters in three buildings (Whitbourne Garage, Port Saunders Line Shop, and Quartzite Control Bldg);
- Inefficient lighting at the Ramea engine hall was replaced with LED fixtures;
- Continuing to replace inefficient interior and exterior fixtures with more efficient LED fixtures at Bay d'Espoir, along with installing more efficient controls for heaters;
- The compressed air system at the Bay d'Espoir plant was re-designed, and a new efficient compressor installed to reduce energy waste and O&M costs.
- Converted exterior lighting to LED at Bishop's Falls and Post Saunders offices;
- Variable frequency drives (VFDs) were installed on Unit 2 forced-draft (FD) fan motors at Holyrood Thermal Generating Station (the FD fans supply combustion air to the steam boilers);

In addition, as previously reported, Hydro continues with its ongoing control measures which also contribute to controlling the rural deficit, as follows:

- Continuing to capture waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning diesel units' replacement sizes to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;
- Utilizing commercial air flights during regular work hours where practical, rather than more expensive helicopter use;
- Having operators choose the most fuel efficient mix of engines, where possible, to supply the community load. This is done automatically in some plants;
- More effective planning and scheduling, which includes a significant coordination effort in the upfront planning process to ensure that delays and duplicate asset outages are minimized. Planning and scheduling results in better utilization of the workforce with the planner ensuring the available weekly capacity of each crew is matched to the estimated weekly work. Overall, planning and scheduling helps Hydro perform effective maintenance activities in the most efficient manner;
- Completing a life cycle cost analysis to help ensure the overall least-cost option is chosen when analyzing tenders for the purchase of new diesel engines. This process was used when new engines were put in service in Little Bay Islands, McCallum and Francois in 2011. In the life cycle cost analysis included items such as capital cost, overhaul cost, fuel cost (based upon fuel efficiency data), routine operation, and maintenance cost were considered;
- In 2008, Hydro moved the printing of customer bills to in-house resulting in savings versus an outside printing service company;
- In 2009, mailing costs were reduced by improved sorting of customer bills to avoid multiple mail outs to single customers with multiple accounts and by eliminating return envelopes for customers not paying by mail; and

- Hydro began offering e-billing to its customers in 2010. E-billing is an electronic paperless form of sending customer bills by email. This method of billing is convenient, beneficial to the environment and offers a cost savings on postage, paper and envelopes. As of December 31, 2015 there were 5,092 customers using e-bills as their method of billing. Based on a cost of approximately $0.83 to mail a customer bill, the savings from e-bills are $4,226 per month, or $50,700 annually.

3.2 Conservation and Demand Management (CDM) Program Initiatives

The high cost of generation in isolated diesel communities and growing system load in the L'Anse au Loup system provides opportunity for Hydro to implement energy efficiency programs specific to these areas. In 2012, two programs were launched to offer incentives and technologies for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued in 2015 and further details are provided below.

Isolated System Community Energy Efficiency Program

The objective of this program is to provide outreach, education, and energy efficient products to residential and business customers in the remote diesel-system communities within Newfoundland and Labrador, free of charge. From 2012 to 2015 the program operated in 42 remote communities, installed 70,640 energy efficient products and helped customers save a total of 5.5 GWh of electricity. Overall, the program was successful and has increased local knowledge on energy efficiency and provided employment for over 48 local residents.

The program included residential and commercial direct installations with a focus on building knowledge and capacity in the communities by hiring and training local representatives. The representatives worked within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy

efficient products, including low-flow showerheads and aerators, LED lamps, compact fluorescent lamps (CFLs), smart power strips, as well as hot water tank and pipe insulation.

In addition to offering direct installs, the program included retail rebates on energy efficient products while working with local retailers to offer a greater selection of energy efficient products, such as household appliances and electronics. Mini-campaigns targeting specific community needs were also integrated into the program, including a holiday LED light string exchange, a drain water heat-recovery project, a home energy audit and draft proofing pilot, and an energy efficient products consumer survey to assess the potential for developing an online retail store to offer reasonably priced small energy efficient technology products to customers in isolated communities.

2015 Program Highlights

- Direct installations of 22,469 products for 965 residential and business customers consisting of water saving technologies and specialty bulbs for specific lighting needs including chandelier, vanity, and flood lights. Energy savings for the 2015 direct installs totaled 1,426 MWh;
- During the direct installations, information was also collected about the type of lighting, heating, and appliances in the homes and businesses which will be used for future program development.

Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. This program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro's energy efficiency team work one-on-one with customers to create a plan to address their energy efficiency needs, and provide ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. Customer incentives are based on

energy savings and to the end of 2015, more than 60 audits have been completed. This program deals primarily with small business customers and since 2012 it has produced 207 MWh of annual energy savings.

4 Capital Initiatives

Automated Meter Reading Project

The ongoing implementation of Automated Meter Reading (AMR) will reduce meter reading costs inherent in the rural deficit over the long term through reduced salary expense.

Two AMR Collectors will become operational during 2016, one in Main Brook (MBK) and the other in Roddickton (RWC). These AMRs will service the communities of Main Brook, Croque, St. Juliens. Englee, Roddickton, Bide Arm and Conche.

LED Street Light Replacement Project

During 2015, Hydro pursued a pilot LED street light replacement project for the Town of Nain. A total of 125 high pressure sodium (HPS) street light fixtures were replaced with LED fixtures. Given the location and climate of Nain, this area will help provide for a full evaluation of the performance of LED street lights on an isolated system with challenging weather conditions.

The street light retrofit in Nain is expected to yield fuel cost savings due to lower energy requirements compared to high pressure sodium (HPS) lights. Hydro estimates approximate savings of 45,000 kWh, or $10,000 in diesel fuel costs annually. LED streetlights may also result in lower operating and maintenance costs than the existing HPS lights due to the elimination of re-lamping and longer life. Hydro will continue to evaluate further implementation of LED street lighting in other communities.

Rural Deficit Annual Report

Summary of Specific Initiatives

August 3, 2017

A Report to the Board of Commissioners of Public Utilities

(pursuant to Order Nos. P.U. 14(2004) and P.U. 49(2016))

newfoundland labrador hydro
a nalcor energy company

TABLE OF CONTENTS

1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) serves approximately 38,600 Rural Customers. Electrical service is provided to the majority of these customers at an operating loss or deficit, except for the approximately 11,200 Rural Customers served on the Labrador Interconnected System who pay rates which both recover costs as well as contribute to funding a portion of the rural deficit.

While there is no cost of service available by each diesel area or community, revenues from Rural Customers, particularly diesel areas, do not fully offset fixed costs. Therefore, the incremental cost of fuel has a direct impact to the rural deficit as it is not fully recovered from revenues from sales.

Hydro's mandate to provide least-cost, safe, and reliable power to all its customers remains its primary focus. This report provides an overview of Hydro's rural deficit, as well as the operating and capital initiatives undertaken by Hydro to manage costs and mitigate the rural deficit.

2.0 Rural Deficit Overview

Table 1

Hydro Rural Deficit($ Millions)[1]

$000,000	Annual Amounts					Year over Year			
	2012	2013	2014	2015	2016	2013/ 2012	2014/ 2013	2015/ 2014	2016/ 2015
Revenues	60.8	62.5	62.6	63.7	59.8	1.7	0.1	1.1	(3.9)
Costs:									
Operating Expenses	43.0	44.4	47.4	52.3	43.8	1.4	3.0	4.9	(8.5)
Fuel	27.6	28.9	35.7	26.8	26.8	1.2	6.8	(8.9)	0.0
Purchased Power	7.5	7.7	7.9	7.3	7.3	0.2	0.2	(0.6)	0.0
Depreciation	11.6	12.5	12.7	14.2	14.2	0.9	0.2	1.5	0.0
Return[2]	20.4	19.7	23.0	24.8	25.1	(0.7)	3.3	1.8	0.3
Total	110.1	113.2	126.7	125.4	117.2	3.0	13.5	(1.3)	(8.2)
Rural Deficit	**49.3**	**50.7**	**64.1**	**61.7**	**57.4**	**1.3**	**13.5**	**(2.4)**	**(4.3)**

Table 1 shows the rural deficit for 2012 to 2016, excluding customers on the Labrador Interconnected System. The 2014 Rural Deficit is estimated based on the 2014 actual costs combined with a portion of the $45.9 million deferred 2014 revenue deficiency allocated to the rural deficit. Rural deficits for 2015 and 2016 have been estimated based on the 2015 and 2016 Cost of Service studies for revenue deficiency, as filed in Hydro's May 18, 2017 Compliance Rates Application, updated to reflect actual 2015 and 2016 revenues and operating expenses.

[1] Excluding Labrador Interconnected System.
[2] Reflects return on debt only, for 2012 – 2013 inclusive.

The overall rural deficit of $57.4 million in 2016 represents a decrease of approximately $4.3 million, or 7.0%, over that of 2015. This is due to a decrease in operating expenses, partially offset by a decrease in revenues in 2016.

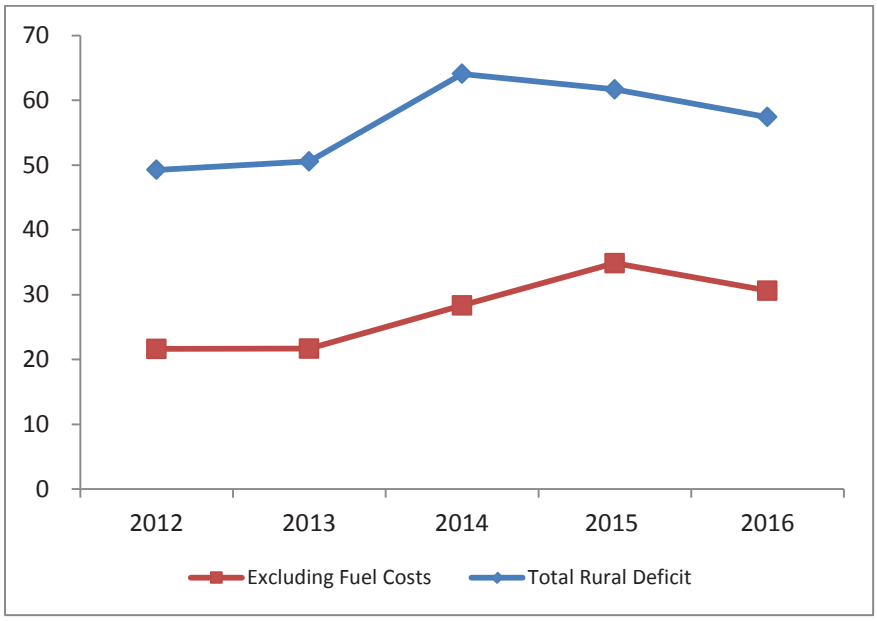


Chart 1
Five-Year Rural Deficit ($ millions)

Chart 1 shows that the rural deficit was relatively consistent between 2012 and 2013 when the impact of fuel costs is excluded. For 2014, the increased cost, excluding fuel, reflects the inclusion of 8.8% return on equity on rural assets.

3.0 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

Starting in 2008, Hydro focused on improving internal efficiency to reduce the internal use of energy. This program, which continued in 2016, targets reduction in energy usage in all facilities including diesel plants, offices, and line depots within the areas affecting the rural deficit. Throughout the year, Hydro completed or launched operating initiatives that are part of multi-year projects through its internal energy efficiency program. Such initiatives

contribute to overall cost containment, a portion of which is allocated to Rural Customers and therefore contributes to deficit reduction. Initiatives completed in 2016 include:

- Installation of energy efficient lighting at the St. Brendan's, L'Anse-Au-Loup, and Postville diesel plants;
- Replacement of existing high bay lighting with energy efficient LED fixtures in the Bishop's Falls service building carpenter shop;
- Continuing to replace inefficient interior and exterior fixtures with more efficient LED fixtures at Bay d'Espoir, along with installing more efficient controls for heaters;
- Redesign of the compressed air system at the Bay d'Espoir plant and installation of a new, efficient compressor to reduce energy waste and operating and maintenance costs.
- Installation of energy efficient high bay lighting and exterior wall packs at the Wabush line depot; and
- Installation of variable frequency drives on Unit 2 forced-draft (FD) fan motors at the Holyrood Thermal Generating Station (the FD fans supply combustion air to the steam boilers).

In addition, Hydro continues with its ongoing control measures, which also contribute to controlling the rural deficit, as follows:

- Continuing to capture waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning diesel units' replacement sizes to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;
- Utilizing commercial air flights during regular work hours where practical, rather than more expensive helicopter use; and

- Having operators choose the most fuel efficient mix of engines, where possible,[3] to supply the community load.

Hydro has also focused on effective planning and scheduling, including a significant coordination effort in the upfront planning process to ensure that delays and duplicate asset outages are minimized. Planning and scheduling results in better utilization of the workforce with the planner ensuring the available weekly capacity of each crew is matched to the estimated weekly work. Overall, planning and scheduling help Hydro to perform effective maintenance activities in the most efficient manner.

Hydro continues to perform life cycle cost analysis to help ensure the overall least-cost option is chosen when analyzing tenders for the purchase of new diesel engines. This process was used when new engines were put in service in Little Bay Islands, McCallum, and Francois in 2011. The life cycle cost analysis included items such as capital cost, overhaul cost, fuel cost (based upon fuel efficiency data), routine operation, and maintenance costs.

Since 2008, Hydro has also reduced operating and maintenance costs in the area of customer billing. In 2008, Hydro transitioned from having customer bills printed by an outside printing service to completing the work internally. Further, in 2009, mailing costs were reduced by improved sorting of customer bills to avoid multiple mail outs to single customers with multiple accounts and by eliminating return envelopes for customers not paying by mail. In order to make billing more cost efficient and environmentally friendly, Hydro began offering e-billing to its customers in 2010. E-billing is an electronic paperless form of sending customer bills by email. This method of billing is convenient, beneficial to the environment, and offers a cost savings on postage, paper, and envelopes. As of December 31, 2016, there were 6,748 customers using e-bills as their method of billing.

[3] This is done automatically in some plants.

3.2 Conservation and Demand Management Program Initiatives

The high cost of generation in isolated diesel communities and growing system load in the L'Anse au Loup system provides an opportunity for Hydro to implement energy efficiency programs specific to these areas. In 2012, two programs were launched to offer incentives and technologies for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued in 2016 and are further detailed below.

3.2.1 Isolated System Community Energy Efficiency Program

The objective of this program is to provide outreach, education, and energy efficient products to residential and business customers in the remote diesel-system communities within Newfoundland and Labrador, free of charge. From 2012 to 2016, the program operated in 42 remote communities, installed 76,000 energy efficient products, and helped customers save a total of 6.1 GWh of energy. Overall, the program was successful and has increased local knowledge on energy efficiency and provided employment for over 48 local residents.

The program included residential and commercial direct installations with a focus on building knowledge and capacity in the communities by hiring and training local representatives. The representatives worked within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy efficient products, including low-flow showerheads and aerators, LED lamps, compact fluorescent lamps, smart power strips, as well as hot water tank and pipe insulation.

In addition to offering direct installs, the program included retail rebates on energy efficient products while working with local retailers to offer a greater selection of energy efficient products, such as household appliances and electronics. Mini-campaigns targeting specific community needs were also integrated into the program, including a holiday LED light string exchange, a drain water heat-recovery project, a home energy audit and draft proofing pilot, and an energy efficient products consumer survey to assess the potential for developing an

online retail store to offer reasonably priced small energy efficient technology products to customers in isolated communities.

3.2.2 2016 Program Highlights

- Direct installations of more than 5,700 products for 345 residential and business customers, consisting of water saving technologies and specialty bulbs for specific lighting needs including chandelier, vanity, and flood lights. Energy savings for the 2016 direct installs totaled 365 MWh; and
- During the direct installations, information was also collected about the type of lighting, heating, and appliances in the homes and businesses which will be used for future program development.

3.2.3 Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. This program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro's energy efficiency team works one-on-one with customers to create a plan to address their energy efficiency needs, and provides ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. Customer incentives are based on energy savings and to the end of 2016, more than 65 audits have been completed. This program deals primarily with small business customers and since 2012 has produced 448 MWh of annual energy savings.

4.0 Capital Initiatives

4.1 Automated Meter Reading Project

The ongoing implementation of Automated Meter Reading (AMR) will reduce meter reading costs inherent in the rural deficit over the long term through reduced salary expense.

Two AMR Collectors became operational during 2016, one in Main Brook and the other in Roddickton. These AMRs service the communities of Main Brook, Croque, St. Juliens, Englee, Roddickton, Bide Arm, and Conche.

4.2 LED Street Light Replacement Project

During 2015, Hydro pursued a pilot LED street light replacement project for the Town of Nain. A total of 125 high pressure sodium (HPS) street light fixtures were replaced with LED street light fixtures. Given the location and climate of Nain, this area will help provide for a full evaluation of the performance of LED street lights in an isolated system with challenging weather conditions.

The street light retrofit in Nain will yield savings of approximately 45,000 kWh of electricity a year, which offsets approximately 12,000 litres of fuel consumption at the diesel plant. LEF streetlights may also contribute to lower operating and maintenance costs than HPS street lights due to the elimination of re-lamping requirements, and longer life. Hydro continues to evaluate the Nain project and anticipates expanding the use of LED street lights across its rural diesel systems in the near future.

5.0 Conclusion

In 2016, Hydro continued its efforts to mitigate the rural deficit by reducing operating and capital costs. Hydro's efforts include cost-reduction initiatives as well as energy conservation initiatives, as described in this report. Hydro remains committed to reducing the rural deficit and will continue to pursue opportunities to reduce costs and increase energy conservation.

Energy Supply Cost Variance Deferral Account
December 31, 2015

Line No.	Particulars	Holyrood Gas Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel	Total
1	2015 Actual Fuel Costs ($)	11,406,709	2,067,100	1,135,250	112,135	21,264	14,742,458
2	2015 Test Year Fuel Costs ($)	1,977,306	1,089,250	407,134	55,917	31,223	3,560,830
3	**A - Thermal Generation Cost Variance ($) [Line 1 - Line 2]**						**11,181,628**

	Particulars	Nalcor Exploits	Star Lake	Rattle Brook	CBPP Cogen	St. Lawrence Wind	Fermeuse Wind	Total
4	2015 Actual Power Purchases (kWh)	559,495,357	135,319,578	13,475,222	62,489,005	94,784,871	87,213,249	
5	2015 Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	51,070,000	104,800,000	84,410,000	
6	2015 Test Year Cost ($/kWh)	0.04000	0.04000	0.08358	0.20132	0.06561	0.06937	
7	**B - Power Purchase Variance ($) [(Line 4 - Line 5) x Line 6)]**	**(2,960,186)**	**(274,417)**	**(127,441)**	**2,298,874**	**(657,093)**	**194,461**	**(1,525,802)**
8	**C - Holyrood TGS Fuel Costs/(Savings) ($) [(D/E)*F]**							**5,044,603**
9	**Energy Supply Cost Variance ($) [A+B+C]**							**14,700,429**
10	**Cost Variance Threshold ($)**							**500,000**
11	**Energy Supply Cost Variance Deferral ($)**							**14,200,429**
12	D - 2015 Test Year Holyrood Average Fuel Cost (bbl)							64.41
13	E - 2015 Test Year Fuel Conversion Factor (kWh/bbl)							618
14	F - Annual kWh variance - Actual vs. Test Year (kWh) (G1-G2)							48,401,874
15	G1 - 2015 Test Year Consumption (kWh)							1,042,340,000
16	G2 - 2015 Actual Consumption (kWh)							993,938,126

Energy Supply Cost Variance Deferral Account
December 31, 2016

Line No.	Particulars	Holyrood Gas Turbine	Hardwoods Gas Turbine	Stephenville Gas Turbine	St. Anthony Diesel	Hawkes Bay Diesel	Total
1	2016 Actual Fuel Costs ($)	23,323,034	3,386,069	1,675,010	139,206	97,318	28,620,637
2	2015 Test Year Fuel Costs ($)	1,977,306	1,089,250	407,134	55,917	31,223	3,560,830
3	**A - Thermal Generation Cost Variance ($) [Line 1 - Line 2]**						**25,059,807**

	Particulars	Nalcor Exploits	Star Lake	Rattle Brook	CBPP Cogen	St. Lawrence Wind	Fermeuse Wind	Total
4	2016 Actual Power Purchases (kWh)	495,379,594	135,727,322	15,164,860	70,566,373	103,054,642	86,981,831	
5	2015 Test Year Power Purchases (kWh)	633,500,000	142,180,000	15,000,000	51,070,000	104,800,000	84,410,000	
6	2015 Test Year Cost ($/kWh)	0.04000	0.04000	0.08358	0.20132	0.06561	0.06937	
7	**B - Power Purchase Variance ($) [(Line 4 - Line 5) x Line 6)]**	**(5,524,816)**	**(258,107)**	**13,779**	**3,925,010**	**(114,513)**	**178,408**	**(1,780,239)**
8	**C - Holyrood TGS Fuel Costs/(Savings) ($) [(D/E)*F]**							**1,683,428**
9	**Energy Supply Cost Variance ($) [A+B+C]**							**24,962,996**
10	**Cost Variance Threshold ($)**							**500,000**
11	**Energy Supply Cost Variance Deferral ($)**							**24,462,996**
12	D - 2015 Test Year Holyrood Average Fuel Cost (bbl)							64.41
13	E - 2015 Test Year Fuel Conversion Factor (kWh/bbl)							618
14	F - Annual kWh variance - Actual vs. Test Year (kWh) (G1-G2)							16,152,124
15	G1 - 2015 Test Year Consumption (kWh)							1,042,340,000
16	G2 - 2016 Actual Consumption (kWh)							1,026,187,876

Holyrood Conversion Rate Deferral Account
December 31, 2015

Particulars		**Efficiency Factor (kWh/bbl)**
A - 2015 Actual quantity of No.6 fuel consumed (bbl)	2,423,336	602
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl)[1]	2,359,960	618
C - 2015 Test Year Cost of Service No. 6 fuel cost ($ per bbl)	64.41	
Holyrood Fuel Conversion Rate Variance ($) [(A - B) x C]	4,082,048	
Cost Variance Threshold ($)	500,000	
Holyrood Fuel Conversion Rate Deferral Balance ($)	**3,582,048**	

[1]Calculation of B (D/E):

D - 2015 Actual net Holyrood production (kWh)	1,458,455,118
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	618

Holyrood Conversion Rate Deferral Account
December 31, 2016

Particulars		**Efficiency Factor (kWh/bbl)**
A - 2016 Actual quantity of No.6 fuel consumed (bbl)	2,664,019	608
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl)[1]	2,622,866	618
C - 2015 Test Year Cost of Service No. 6 fuel cost ($ per bbl)	64.41	
Holyrood Fuel Conversion Rate Variance ($) [(A - B) x C]	2,650,665	
Cost Variance Threshold ($)	500,000	
Holyrood Fuel Conversion Rate Deferral Balance ($)	**2,150,665**	

[1]Calculation of B (D/E):

D - 2016 Actual net Holyrood production (kWh)	1,620,931,383
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	618

SCHEDULE 2

NEWFOUNDLAND AND LABRADOR HYDRO RATE STABILIZATION PLAN REPORT – AUGUST 31, 2017

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN REPORT
August 31, 2017

Newfoundland and Labrador Hydro

Rate Stabilization Plan Report
August 31, 2017

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003), Order No. P.U. 8 (2007) and Order No. P.U. 49 (2016), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variationss between actual results and Test Year cost of Service estimates for:

- Hydraulic production;
- No. 6 fuel cost used at Hydro's Holyrood generating station;
- Customer load (Utility and Island Industrial); and
- Rural rates.

The Test Year Cost of Service Study is based on projections of events and costs that are forecast to happen during a test year. Finance charges are calculated on the balances using the test year Weighted Average Cost of Capital which is currently 6.61% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 618 kWh/barrel regardless of the actual conversion rate experienced.

	2015 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	503,640,000	57.55	729,300,000	49,000,000
February	457,830,000	59.85	662,500,000	45,900,000
March	438,830,000	61.41	657,400,000	51,200,000
April	370,790,000	61.41	514,600,000	50,500,000
May	312,990,000	62.64	423,000,000	53,500,000
June	323,000,000	62.64	348,100,000	51,700,000
July	330,220,000	62.64	314,700,000	51,900,000
August	330,170,000	62.64	314,500,000	53,100,000
September	326,980,000	62.64	337,300,000	38,300,000
October	348,360,000	66.51	416,700,000	58,800,000
November	400,160,000	71.70	526,000,000	57,800,000
December	460,598,000	76.05	680,000,000	59,700,000
Total	4,603,568,000		5,924,100,000	621,400,000

Rate Stabilization Plan
Plan Highlights
August 31, 2017

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	3,129.8 GWh	3,067.5 GWh	62.4 GWh	$ (5,950,482)	Page 3
No 6 fuel cost - Current month	$ 67.02	$ 62.64	$ 4.38	$ 11,204,058	Page 4
Year-to-date customer load - Utility	3,992.5 GWh	3,964.1 GWh	28.4 GWh	$ (307,933)	Page 9
Year-to-date customer load - Industrial	377.9 GWh	406.8 GWh	-28.9 GWh	$ (1,647,713)	Page 10
				$ 3,297,930	
Rural rates					
Rural Rate Alteration (RRA)	$ 2,642,796				
Less : RRA to utility customer	$ 2,527,804				Page 7
RRA to Labrador interconnected	114,992				
Fuel variance to Labrador interconnected	$ 33,657				Page 5
Net Labrador interconnected	$ 148,649				
Current plan summary					
One year recovery					
Due (to) from utility customer	$ (53,291,700)				Page 7
Due (to) from Industrial customers	$ (2,577,794)				Page 8
Sub total	(55,869,494)				
Four year recovery					
Hydraulic balance	$ (28,675,343)				Page 3
Segregated Load Variation					Page 13
Utility Customer	-				
Industrial Customer	$ -				
Sub Total	-				
Utility RSP Surplus	$ (15,033,892)				Page 14
Industrial RSP Surplus	$ 1,314,217				Page 15
Total plan balance	$ (98,264,511)				

Rate Stabilization Plan
Net Hydraulic Production Variation
August 31, 2017

	A Cost of Service Net Hydraulic Production (kWh)	B Actual Net Hydraulic Production (kWh)	C Monthly Net Hydraulic Production Variance (kWh) **(A - B)**	D Cost of Service No. 6 Fuel Cost ($Can/bbl.)	E Net Hydraulic Production Variation ($) **(C / O[1] X D)**	F Financing Charges ($)	G Cumulative Variation and Financing Charges ($) **(E + F)** **(to page 16)**
Opening balance							(37,018,152)
RSP Change in Test Years [2]							15,610,907
Adjusted Opening Balance							(21,407,245)
January	503,640,000	513,587,079	(9,947,079)	57.55	(926,231)	(114,493)	(22,447,969)
February	457,830,000	466,205,211	(8,375,211)	59.85	(811,154)	(120,059)	(23,379,182)
March	438,830,000	493,847,401	(55,017,401)	61.41	(5,466,682)	(125,040)	(28,970,904)
April	370,790,000	441,109,234	(70,319,234)	61.41	(6,987,115)	(154,946)	(36,112,965)
May	312,990,000	379,810,319	(66,820,319)	62.64	(6,773,029)	(193,144)	(43,079,138)
June	323,000,000	275,454,467	47,545,533	62.64	4,819,301	(230,402)	(38,490,239)
July	330,220,000	268,819,214	61,400,786	62.64	6,223,695	(205,859)	(32,472,403)
August	330,170,000	290,996,141	39,173,859	62.64	3,970,733	(173,673)	(28,675,343)
September							
October							
November							
December							
	3,067,470,000	3,129,829,066	(62,359,066)		(5,950,482)	(1,317,616)	(28,675,343)
Hydraulic Allocation [3]							
Hydraulic variation at year end					(5,950,482)	(1,317,616)	(28,675,343)

[1] O is the Holyrood Operating Efficiency of 618 kWh/barrel (ref. Board Order No. P.U.49(2016) p.32).

[2] GRA Compliance Filing to Order No. P.U. 49(2016) January 27, 2017, Exhibit 3, p.9. approved in Board Order No. P.U.22(2017).

[3] At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers.

Rate Stabilization Plan
No. 6 Fuel Variation
August 31, 2017

	A	B	C	D	E	F	G
	Actual Quantity No. 6 Fuel	Actual Quantity No. 6 Fuel for Non-Firm Sales	Net Quantity No. 6 Fuel	Cost of Service No. 6 Fuel Cost	Actual Average No. 6 Fuel Cost	Cost Variance	No.6 Fuel Variation
	(bbl.)	(bbl.)	(bbl.) **(A - B)**	($Can/bbl.)	($Can/bbl.)	($Can/bbl.) **(E - D)**	($) **(C X F) (to page 5)**
January	375,624	-	375,624	57.55	62.79	5.24	1,969,923
February	364,336	-	364,336	59.85	67.67	7.82	2,847,505
March	330,992	-	330,992	61.41	69.22	7.81	2,586,305
April	238,004	-	238,004	61.41	68.85	7.44	1,771,655
May	178,074	-	178,074	62.64	68.03	5.39	959,532
June	111,220	-	111,220	62.64	67.46	4.82	535,904
July	78,786	-	78,786	62.64	67.39	4.75	374,107
August	36,344	-	36,344	62.64	67.02	4.38	159,127
September							
October							
November							
December							
	1,713,380	-	1,713,380				11,204,058

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
August 31, 2017

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Fuel Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**		**(G X 95.65%)**	**(G X 4.35%)**
					(to page 6)	**(to page 6)**		**(from page 4)**	**(to page 6)**	
January	5,834,707,469	502,513,639	476,656,913	6,813,878,021	1,686,840	145,279	137,804	1,969,923	131,808	5,996
February	5,861,296,315	502,837,253	477,507,277	6,841,640,845	4,127,135	354,065	336,228	4,817,428	321,598	14,630
March	5,868,946,088	511,539,463	477,768,433	6,858,253,984	6,335,739	552,225	515,769	7,403,733	493,327	22,442
April	5,890,711,235	522,901,523	478,017,217	6,891,629,975	7,842,783	696,181	636,424	9,175,388	608,732	27,692
May	5,940,218,821	534,672,467	480,315,816	6,955,207,104	8,655,909	779,109	699,902	10,134,920	669,448	30,454
June	5,926,440,577	533,757,702	479,984,623	6,940,182,902	9,112,152	820,675	737,997	10,670,824	705,885	32,112
July	5,906,121,153	544,477,652	479,997,989	6,930,596,794	9,412,278	867,706	764,947	11,044,931	731,663	33,284
August	5,902,650,591	550,599,300	478,563,855	6,931,813,746	9,540,597	889,947	773,514	11,204,058	739,857	33,657
September										
October										
November										
December										

(1) The Fuel Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the 2015 Cost of Service Study, which is 95.65% and 4.35% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss), (ref. Board Order NO. P.U.49(2016) p.105).

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
August 31, 2017

	A	B	C	D	E	F	G
	Utility					Industrial	
	Fuel Variance		Rural Allocation		Total Fuel Variance Activity for the month	Fuel Variance	
	Year-to-Date Activity	Current Month Activity [1]	Year-to-Date Activity	Current Month Activity [1]		Year-to-Date Activity	Current Month Activity [1]
	($)	($)	($)	($)	($)	($)	($)
					(B + D)		
	(from page 5)		(from page 5)		(to page 7)	(from page 5)	(to page 8)
January	1,686,840	1,686,840	131,808	131,808	1,818,648	145,279	145,279
February	4,127,135	2,440,295	321,598	189,790	2,630,085	354,065	208,786
March	6,335,739	2,208,604	493,327	171,729	2,380,333	552,225	198,160
April	7,842,783	1,507,044	608,732	115,405	1,622,449	696,181	143,956
May	8,655,909	813,126	669,448	60,716	873,842	779,109	82,928
June	9,112,152	456,243	705,885	36,437	492,680	820,675	41,566
July	9,412,278	300,126	731,663	25,778	325,904	867,706	47,031
August	9,540,597	128,319	739,857	8,194	136,513	889,947	22,241
September							
October							
November							
December							
		9,540,597		739,857	10,280,454		889,947

[1] The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

Rate Stabilization Plan
Summary of Utility Customer
August 31, 2017

	A	B	C	D	E	F	G	H
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Transfers/ Disposition [3]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)				
	(from page 12)	**(from page 6)**						**(to page 16)**
Opening Balance								(68,976,964)
RSP Change in Test Years [4]								18,312,457
Revenue Deficiency/(Sufficiency) [5]								(6,577,000)
Adjusted Opening Balance								(57,241,507)
January		1,818,648	477,649	2,296,297	(306,147)	8,951,313	-	(46,300,044)
February		2,630,085	396,561	3,026,646	(247,628)	8,175,911	-	(35,345,115)
March	-	2,380,333	364,383	2,744,716	(189,037)	8,345,233	(50,737,152)	(75,181,355)
April	(118,052)	1,622,449	341,057	1,845,454	(402,095)	6,705,626	-	(67,032,370)
May	20,265	873,842	331,100	1,225,207	(358,511)	5,710,405	-	(60,455,269)
June	(663,866)	492,680	335,661	164,475	(323,335)	4,119,678	804,000	(55,690,451)
July	107,320	325,904	226,927	660,151	(297,851)	1,091,944	-	(54,236,206)
August	(67,559)	136,513	54,466	123,420	(290,073)	1,111,160	-	(53,291,700)
September								
October								
November								
December								
Year to date		10,280,454	2,527,804	12,086,366	(2,414,677)	44,211,270	(49,933,152)	3,949,807
Hydraulic allocation								0
(from page 4)								
Total		10,280,454	2,527,804	12,086,366	(2,414,677)	44,211,270	(49,933,152)	(53,291,700)

(1) The Rural Rate Alteration is allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved 2015 Cost of Service Study, which is 95.65% and 4.35% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for Utility is 1.236 cents per kWh effective July 1, 2016 to June 30, 2017. Approved in Board Order No. P.U. 21(2016).

(3) Per Board Order No. P.U. 16(2017), the Utility Segregated Load Variation balance of $50,737,152 (refer to page 13) was transferred to the Newfoundland Power Current Plan as of March 31, 2017 to mitigate the proposed July 1, 2017 RSP Adjustment rate increase. In June, 2017 the 2017 revenue deficiency of $804,000 was removed from the plan per Board Order P.U.22(2017).

(4) GRA Compliance Filing to Order No. 49(2016) January 27, 2017, Exhibit 3 p.9. approved in Board Order No. P.U.22(2017).

(5) Cumulative revenue sufficiency credited to Utility Current Plan per Compliance Rates Application - Exhibit 3 May 2017.($35,015 (2014) - $9,998 (2015) - $31,604 (2016) = ($6,577)) Approved in Board Order No. P.U.22(2017).

Rate Stabilization Plan
Summary of Industrial Customers
August 31, 2017

	A	B	C	D	E	F	G
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment	Transfer from Load Variation Balance [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)		($)
			(A + B)				
	(from page 12)	**(from page 6)**					**(to page 16)**
Opening Balance							(2,578,000)
RSP Change in Test Years [1]							760,158
Adjusted Opening Balance							(1,817,842)
January	0	145,279	145,279	(9,722)	0	0	(1,682,285)
February	0	208,786	208,786	(8,997)	0	0	(1,482,496)
March	0	198,160	198,160	(7,929)	0	(1,546,433)	(2,838,698)
April	(11,343)	143,956	132,613	(15,182)	0	0	(2,721,267)
May	295	82,928	83,223	(14,554)	0	0	(2,652,598)
June	(55,540)	41,566	(13,974)	(14,187)	0	0	(2,680,759)
July	5,602	47,031	52,633	(14,338)	31,992	0	(2,610,472)
August	(7,622)	22,241	14,619	(13,962)	32,021	0	(2,577,794)
September							
October							
November							
December							
Year to date	(68,608)	889,947	821,339	(98,871)	64,013	(1,546,433)	(759,952)
Hydraulic allocation **(from page 3)**							0
Total	(68,608)	889,947	821,339	(98,871)	64,013	(1,546,433)	(2,577,794)

(1) GRA Compliance Filing to Order No. 49(2016) January 27, 2017, Exhibit 3 p.9. approved in Board Order No. P.U.22(2017).

(2) Per Board Order No. P.U. 24(2017), a portion of the Industrial customer segregated Load Variation balance was transferred to the Industrial Current Plan as of March 31, 2017 to mitigate the proposed July 1, 2017 RSP Adjustment rate increase. Refer to page 13 for the allocation of the segregated Load Variation balance.

Rate Stabilization Plan
Load Variation - Utility
August 31, 2017

	A	B	C	D	E	F	G	H	I	J	K
	Firm Energy						Secondary Energy				
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate[2]	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge[2]	Load Variation	Total Load Variation
	(kWh)	(kWh)	(kWh)	($Can/bbl.)	($/kWh)	($)	(kWh)	(kWh)	($/kWh)	($)	($)
			(B - A)			**C x {(D/O[1]) - E}**				**(G - H) x I**	**(F + J)**
											(to page 11)
January	729,300,000	723,432,142	(5,867,858)	57.55	0.10422	65,158	0	784,140	0.02882	(22,599)	42,559
February	662,500,000	660,922,054	(1,577,946)	59.85	0.10422	11,627	0	559,455	0.02882	(16,123)	(4,496)
March	657,400,000	674,523,311	17,123,311	61.41	0.10422	(83,172)	0	657,366	0.02882	(18,945)	(102,117)
April	514,600,000	541,811,835	27,211,835	61.41	0.10422	(132,174)	0	714,548	0.02882	(20,593)	(152,767)
May	423,000,000	460,719,663	37,719,663	62.64	0.10422	(107,810)	0	1,287,193	0.02882	(37,097)	(144,907)
June	348,100,000	332,146,387	(15,953,613)	62.64	0.10422	45,598	0	1,160,867	0.02882	(33,456)	12,142
July	314,700,000	295,148,509	(19,551,491)	62.64	0.10422	55,882	0	(823,901)	0.02882	23,745	79,627
August	314,500,000	296,390,467	(18,109,533)	62.64	0.10422	51,760	0	3,113,591	0.02882	(89,734)	(37,974)
September											
October											
November											
December											
	3,964,100,000	3,985,094,368	20,994,368			(93,131)	0	7,453,259		(214,802)	(307,933)

(1) O is the Holyrood Operating Efficiency of 618 kWh/barrel. (ref. Board Order No. P.U.49(2016) p.32)

(2) 2015 Test Year firm energy rate for Utility is 10.422 cents per kWh effective January 1, 2017 and a firming up charge of 2.882 cents per kWh effective January 1, 2017. Approved in Board Order No. P.U.22(2017).

Rate Stabilization Plan
Load Variation - Industrial
August 31, 2017

	A	B	C	D	E	F
	Cost of Service Sales	Actual Sales	Sales Variance	Cost of Service No. 6 Fuel Cost	Firm Energy Rate	Load Variation
	(kWh)	(kWh)	(kWh)	($)	($/kWh)	($)
			(B - A)			**C x {(D/O[1]) - E}**
						(to page 11)
January	49,000,000	36,580,091	(12,419,909)	57.55	0.03971	(663,296)
February	45,900,000	39,488,172	(6,411,828)	59.85	0.03971	(366,383)
March	51,200,000	50,042,258	(1,157,742)	61.41	0.03971	(69,063)
April	50,500,000	50,885,490	385,490	61.41	0.03971	22,996
May	53,500,000	56,185,178	2,685,178	62.64	0.03971	165,546
June	51,700,000	39,798,886	(11,901,114)	62.64	0.03971	(733,725)
July	51,900,000	52,445,454	545,454	62.64	0.03971	33,628
August	53,100,000	52,493,115	(606,885)	62.64	0.03971	(37,416)
September						
October						
November						
December						
	406,800,000	377,918,644	(28,881,356)			(1,647,713)

(1) O is the Holyrood Operating Efficiency of 618 kWh/barrel, (ref. Board Order No. P.U.49(2016) p.32).

Rate Stabilization Plan
Allocation of Load Variance - Year-to-Date
August 31, 2017

	A	B	C	D	E	F	G	H	I	J
	Twelve Months-to-Date				Year-to-Date Load Variance				Reallocate Rural Island Customers [1]	
	Utility	Industrial Customers	Rural Island Customers	Total	Utility	Industrial Customers	Rural Island Interconnected	Total [2]	Utility	Labrador Interconnected
	(kWh)	(kWh)	(kWh)	(kWh)	($)	($)	($)	($)	($)	($)
				(A+B+C)	**(A/D X H)**	**(B/D X H)**	**(C/D X H)**			
								(from pages 9 & 10)		
January	5,834,707,469	502,513,639	476,656,913	6,813,878,021	(531,536)	(45,778)	(43,423)	(620,737)	(41,534)	(1,889)
February	5,861,296,315	502,837,253	477,507,277	6,841,640,845	(849,527)	(72,880)	(69,209)	(991,616)	(66,198)	(3,011)
March	5,868,946,088	511,539,463	477,768,433	6,858,253,984	(995,062)	(86,730)	(81,004)	(1,162,796)	(77,479)	(3,525)
April	5,890,711,235	522,901,523	478,017,217	6,891,629,975	(1,104,839)	(98,073)	(89,655)	(1,292,567)	(85,754)	(3,901)
May	5,940,218,821	534,672,467	480,315,816	6,955,207,104	(1,086,313)	(97,778)	(87,837)	(1,271,928)	(84,015)	(3,822)
June	5,926,440,577	533,757,702	479,984,623	6,940,182,902	(1,702,322)	(153,318)	(137,871)	(1,993,511)	(131,872)	(5,999)
July	5,906,121,153	544,477,652	479,997,989	6,930,596,794	(1,602,318)	(147,716)	(130,222)	(1,880,256)	(124,556)	(5,666)
August	5,902,650,591	550,599,300	478,563,855	6,931,813,746	(1,665,292)	(155,338)	(135,016)	(1,955,646)	(129,141)	(5,875)
September										
October										
November										
December										

(1) The Load Variance initially allocated to Rural Island Interconnected is re-allocated between Utility and Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the 2015 Cost of Service Study, which is 95.65% and 4.35% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss). (ref. Board Order NO. P.U.49(2016) p.105)

(2) Total load re-allocated based on energy ratios. The total is the sum of the Load Variation - Utility (page 9) and Load Variation - Industrial (page 10).

Rate Stabilization Plan
Allocation of Load Variance - Year-to-Date
August 31, 2017

	A	B	C	D	E	F	G
	Utility					**Industrial**	
	Load Variance		Rural Allocation		Total load	Load Variance	
	Year-to-Date Activity	Current Month Activity [1]	Year-to-Date Activity	Current Month Activity [1]	Activity for the month	Year-to-Date Activity	Current Month Activity [1]
	($)	($)	($)	($)	($)	($)	($)
					(B + D) (page 7 and 13)[2]		**(page 8 and 13)**
January	(531,536)	(531,536)	(41,534)	(41,534)	(573,070)	(45,778)	(45,778)
February	(849,527)	(317,991)	(66,198)	(24,664)	(342,655)	(72,880)	(27,102)
March	(995,062)	(145,535)	(77,479)	(11,282)	(156,817)	(86,730)	(13,850)
April	(1,104,839)	(109,777)	(85,754)	(8,275)	(118,052)	(98,073)	(11,343)
May	(1,086,313)	18,526	(84,015)	1,739	20,265	(97,778)	295
June	(1,702,322)	(616,009)	(131,872)	(47,857)	(663,866)	(153,318)	(55,540)
July	(1,602,318)	100,004	(124,556)	7,316	107,320	(147,716)	5,602
August	(1,665,292)	(62,974)	(129,141)	(4,585)	(67,559)	(155,338)	(7,622)
September							
October							
November							
December							
		(1,665,292)		(129,141)	(1,794,433)		(155,338)

[1] The current month activity is calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month.

[2] From the period of January-March, 2017, the load activity was held in a separate account per Board Order P.U. 29(2013) in 'Load Variation' on page 13. Commencing April, 2017, after disposition, the load acitivity is included in 'Summary of Utility Customers' on page 7 and 'Summary of Industrial Customers' on page 8.

Rate Stabilization Plan
Load Variation
August 31, 2017

	A	B	C	D	E	F		G	H
	Utility Customer				Island Industrial Customers				
	Load Variation	Financing Charges	Transfer to Current[1]	Total To Date	Load Variation	Financing Charges	Transfers/ Disposition[2]	Total To Date	Total To Date[3]
		($)		($) (A + B + C)		($)		($) (E+ F)	($) (D + G)
	(from page 12)		**(to page 7)**		**(from page 12)**				**(to page 16)**
Opening Balance				(9,328,286)				(81,948,901)	(91,277,187)
RSP Change in Test Years[4]				(39,540,053)				78,839,381	39,299,328
Adjusted Opening Balance				(48,868,339)				(3,109,520)	(51,977,859)
January	(573,070)	(261,364)	-	(49,702,773)	(45,778)	(16,631)	-	(3,171,929)	(52,874,702)
February	(342,655)	(265,827)	-	(50,311,255)	(27,102)	(16,965)	-	(3,215,996)	(53,527,251)
March	(156,817)	(269,081)	50,737,152	-	(13,850)	(17,200)	3,247,046	-	-
April									
May									
June									
July									
August									
September									
October									
November									
December									
Total	(1,072,541)	(796,272)	50,737,152	-	(86,730)	(50,796)	3,247,046	-	-

(1) Per Board Order No. P.U. 16(2017), the Newfoundland Power segregated Load Variation balance transferred to the Newfoundland Power Current Plan to mitigate the proposed July 1, 2017 RSP Adjustment rate increase.

(2) Per Board Order No. P.U.24(2017), the Industrial Load Variation balance was used to eliminate the cumulative revenue deficiency ($1.527M), make a one-time payment to NARL Refining Limited Partnership ($0.174M) with the remaining balance transferred to the Industrial customer Current Plan ($1.546M).

(3) Per Board Order No. P.U. 29(2013), the load variation from the Industrial and Utility Customers as of September 1, 2013 be held in a separate account until its disposition.

(4) GRA Compliance Filing to Order No. P.U. 49(2016) January 27, 2017, Exhibit 3 p.9.

Rate Stabilization Plan
Utility RSP Surplus
August 31, 2017

	A	B	C	D
	Industrial Customer Adjustment	Utility Payout [1]	Financing Charges	Cumulative Balance
	($)	($)	($)	($)
				(to page 16)
Opening Balance				(143,390,469)
RSP Change in Test Years [2]				2,361,345
Adjusted Opening Balance		-		(141,029,124)
January		59,087	(754,271)	(141,724,308)
February		118,912,863	(757,989)	(23,569,434)
March		376,263	(126,057)	(23,319,228)
April		3,725,273	(124,719)	(19,718,674)
May		4,140,676	(105,462)	(15,683,460)
June		129,354	(83,880)	(15,637,986)
July		767,473	(83,637)	(14,954,151)
August		239	(79,980)	(15,033,892)
September				
October				
November				
December				
Year to date	-	128,111,227	(2,115,995)	125,995,232
Total		128,111,227	(2,115,995)	(15,033,892)

(1) Consists of a payout to Newfoundland Power for customer refunds of $118,291,149, Hydro customer refunds of $8,403,486, Hydro admin costs of $259,227 and NL Power admin costs of $1,157,365.

(2) GRA Compliance Filing to Order No. P.U. 49(2016) January 27, 2017, Exhibit 3, p.9.

Rate Stabilization Plan
Industrial RSP Surplus
August 31, 2017

	A	B	C	D	E
	Industrial Surplus	Teck Allocation [1]	Industrial Drawdown [2]	Financing Charges	Cumulative Balance
	($)	($)	($)	($)	($)
					(to page 16)
Opening Balance					(388,883)
RSP Change in Test Years [3]					97,695
Adjusted Opening Balance					(291,188)
January		4,835	222,983	(1,557)	(64,927)
February		4,257	233,053	(347)	172,037
March		4,677	268,642	920	446,276
April		3,619	283,281	2,387	735,563
May		2,851	301,902	3,934	1,044,250
June		2,751	247,686	5,585	1,300,272
July		-	-	6,954	1,307,226
August		-	-	6,991	1,314,217
September					
October					
November					
December					
Year to date	0	22,990	1,557,548	24,867	1,605,405
Total	0	22,990	1,557,548	24,867	1,314,217

(1) Per Board Order No. P.U. 29(2013), the RSP drawdown adjustment rate for Teck Resources is 1.111 cents per kWh effective September 1, 2013. Effective July 1, 2015 the RSP drawdown adjustment rate for Teck Resources is 1.141 cents per kWh.

(2) Drawdown of Industrial Customers RSP Surplus balance effective July 1, 2015 using RSP Adjustment rates for all Industrial Customers are $1.52 per kW per month and 0.294 cents per kWh as approved in Board Order No. P.U. 35(2015).

(3) GRA Compliance Filing to Order No. P.U. 49(2016) January 27, 2017, Exhibit 3, p.9.

Rate Stabilization Plan
Overall Summary
August 31, 2017

	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total To Date
	($)	($)	($)	($)	($)	($)	($)
							(A + B + C + D + E + F)
	(from page 3)	**(from page 7)**	**(from page 8)**	**(from page 13)**	**(from page 14)**	**(from page 15)**	
Opening Balance	(37,018,152)	(68,976,964)	(2,578,000)	(91,277,187)	(143,390,469)	(388,883)	(343,629,655)
RSP Change in Test Years [1]	15,610,907	18,312,457	760,158	39,299,328	2,361,345	97,695	76,441,890
Revenue Deficiency/(Sufficiency) [2]		(6,577,000)					(6,577,000)
Adjusted Opening Balance	(21,407,245)	(57,241,507)	(1,817,842)	(51,977,859)	(141,029,124)	(291,188)	(273,764,765)
January	(22,447,969)	(46,300,044)	(1,682,285)	(52,874,702)	(141,724,308)	(64,927)	(265,094,234)
February	(23,379,182)	(35,345,115)	(1,482,496)	(53,527,251)	(23,569,434)	172,037	(137,131,441)
March	(28,970,904)	(75,181,355)	(2,838,698)	-	(23,319,228)	446,276	(129,863,910)
April	(36,112,965)	(67,032,370)	(2,721,267)	-	(19,718,674)	735,563	(124,849,713)
May	(43,079,138)	(60,455,269)	(2,652,598)	-	(15,683,460)	1,044,250	(120,826,215)
June	(38,490,239)	(55,690,451)	(2,680,759)	-	(15,637,986)	1,300,272	(111,199,163)
July	(32,472,403)	(54,236,206)	(2,610,472)	-	(14,954,151)	1,307,226	(102,966,006)
August	(28,675,343)	(53,291,700)	(2,577,794)	-	(15,033,892)	1,314,217	(98,264,511)
September							
October							
November							
December							

(1) GRA Compliance Filing to Order No. P.U. 49(2016) January 27 2017, Exhibit 3 p.9. Approved in Board Order No. P.U.22(2017).

(2) Cumulative revenue sufficiency credited to Current Plan per Compliance Rates Application - May 2017, Exhibit 3, p.10. ($35,015 (2014) - $9,998