newfoundland labrador hydro
a nalcor energy company

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November 12, 2015

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

ATTENTION: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Amended 2015 Cost Deferral Application

Please find enclosed the original and 12 copies of Hydro's Amended 2015 Cost Deferral Application, amending its July 10, 2015 Application, in which Hydro now seeks the deferral of $60.5 million to reduce Hydro's forecast 2015 net income deficiency.

For ease of reference, Schedules 1 and 2 to the original Application remain unchanged. Schedule 3 has been deleted in its entirety and replaced with additional supporting evidence that is new to this filing.

The changes in the enclosed Amended 2015 Cost Deferral Application from the original Application are shown in the usual manner for amended filings of documents, that is, new text is underlined and deleted text is shown as strikethrough text.

Please note that in the Amended 2015 Cost Deferral Application, Hydro is seeking approval of:

- a cost deferral of $60.5 million to reduce Hydro's forecast 2015 net income deficiency;
- the deferral of Hydro's 2015 GRA costs for 2015 with recovery to be determined in a future order of the Board; and
- the GRA Settlement Agreement dated August 14, 2015, an on interim basis, pending a final order from the Board in relation to Hydro's GRA.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey L. Pennell
Legal Counsel

TLP/bds

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson, Q.C. – Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

IN THE MATTER OF the *Public Utilities Act*, RSN 1990, Chapter P-47 (the "Act"); and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2015; and

IN THE MATTER OF an Amended application by Newfoundland and Labrador Hydro for approval of a proposed cost deferral account to reduce Hydro's forecast net income deficiency for 2015 until the Board tests 2015 Test Year costs (the "Amended 2015 Cost Deferral Application").

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

The AMENDED 2015 COST DEFERRAL APPLICATION of Newfoundland and Labrador Hydro (the "Applicant") states that:

1. Newfoundland and Labrador Hydro (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. On January 28, 2015 Hydro filed an application with the Board (the 2015 Interim Rates Application) seeking approval of adjustments to its customer rates to provide interim rate relief effective March 1, 2015, in advance of conclusion of its General Rate Application (GRA). The evidence to the 2015 Interim Rates

Application is attached at Tab B of Schedule 1 to this ~~2015 Cost Deferral~~ Application.

3. The 2015 Interim Rates Application also requested approval for rates to be paid by Hydro's Island Industrial Customers (IIC) in compliance with Orders in Council OC2013-089 and OC2013-090, as amended, which provided direction to the Board and to Hydro, respectively, with regard to the phasing-in of rate changes to Hydro's IIC.

4. Order No. P.U. 14(2015) (the 2015 Interim Rates Order) directed Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on consumers and Hydro incorporating the findings in the 2015 Interim Rates Order.

5. On May 27, 2015, Hydro filed its Interim Rates Compliance Application proposing revised rates for July 1, 2015 and approval of a 2015 Revenue Deficiency Deferral Account prior to the conclusion of its GRA.

6. The Board provided correspondence by letter on June 3, 2015 requesting that Hydro 1) file a revised interim rates compliance application and 2) file a separate application for Hydro's deferral account proposal. ~~This 2015 Cost Deferral Application reflects the direction of the Board on this matter.~~

7. On June 5, 2015, Hydro filed a Revised Compliance Application reflecting the direction of the Board as provided in Order No. P.U. 14(2015) (the 2015 Interim Rates Order). The schedules and evidence to the Revised Compliance Application are attached at Tabs A and B of Schedule 2 to this Amended 2015 Cost Deferral Application.

8. On July 23, 2015 Hydro filed a 2015 Cost Deferral Application, requesting a cost deferral in amount of $20.0 million to reduce Hydro's forecast 2015 net income deficiency. At that time, ~~A~~approval of customer rates changes reflecting the determinations set out in Order No. P.U. 14(2015) ~~is~~ was forecast to provide a net income deficiency based upon the 2015 Test Year of $41.8 million and a forecast net loss of $8.6 million based upon the 2015 Test Year.

9. The evidence provided in the Revised Compliance Application filed on June 5, 2015, attached at Tab B of Schedule 2, ~~shows~~ showed that the Board's approval of interim rates in 2015 ~~provides~~ provided Hydro the opportunity to recover approximately 38% of the forecast net income deficiency based upon existing rates (i.e., $26 million/ $67.8 million) and ~~results~~ resulted in a forecast financial loss of $8.6 million in 2015.

10. Hydro's 2015 Interim Rates reply submission dated February 25, 2015, and attached at Tab E of Schedule 1 to this Amended 2015 Cost Deferral

Application, ~~shows~~ showed that a higher proportion of cost recovery is common in regulatory decisions on interim rates in Alberta and Manitoba.

11. As indicated in the evidence to Hydro's 2015 Interim Rates Application, attached a Tab B of Schedule 1, Hydro's proposal for implementation of interim rates on March 1, 2015 provided recovery of approximately 70% of the forecast 2015 net income deficiency. An additional $20 million in cost recovery, to that approved by the Board to be recovered through interim rates in 2015, would have provided Hydro the opportunity to recover 70% of the forecast 2015 net income deficiency.

12. Hydro's GRA hearing commenced on September 9, 2015 and is ongoing. Hydro does not expect the Board to be in a position to make final determinations on its GRA prior to the end of 2015. As such, Hydro is filing this Amended 2015 Cost Deferral Application to address the 2015 financial impacts of the delayed conclusion of Hydro's GRA beyond 2015. ~~This 2015 Cost Deferral Application requests approval of a cost deferral of $20 million to reduce Hydro's forecast 2015 net income deficiency~~. Schedule 3 shows that the updated forecast net income deficiency for Hydro in 2015 is approximately $60.5 million based on a forecast net loss of $30.8 million.

13. ~~Approval of the 2015 Cost Deferral Application would provide for a forecast net income of $11.4 million based upon the forecast 2015 Test Year. This amount is~~

~~$21.8 million less than the proposed 2015 Test Year net income of $33.2 million.~~ This Amended 2015 Cost Deferral Application requests approval of a cost deferral of $60.5 million to reduce Hydro's forecast 2015 net income deficiency.

14. Appendix F to Schedule 3 provides a proposed 2015 Net Income Deficiency Deferral Account to permit cost deferral of ~~$20 million~~ $60.5 million in 2015 to reduce Hydro's 2015 forecast net income deficiency, which has primarily resulted from: (i) ~~the~~ delayed implementation of ~~the~~ rates and the Rate Stabilization Plan (RSP) to reflect the 2015 Test Year as proposed in the Amended Application; (ii) increased supply costs beyond those reflected in the 2015 Test Year for which Hydro has proposed the implementation of supply cost recovery mechanisms in its Amended Application; and (iii) the delayed implementation of accounting proposals reflected in Hydro's Amended Application and accepted in the Settlement Agreement dated August 14, 2015 ~~proposed in its 2013 GRA~~.

15. The actual 2015 net income deficiency will be finalized upon conclusion of the GRA at which time the approved net income deficiency that has resulted from delayed implementation of customer rates for 2015 can be set aside in a deferral account for future recovery.

16. Hydro submits that implementation of the 2015 Interim Rates Order, on its own, does not provide a reasonable opportunity for Hydro to earn a fair return in 2015. Therefore, Hydro requests that the Board approve the proposed deferral account to reduce Hydro's forecast 2015 net income deficiency.

17. ~~The evidence supporting~~ Support for this 2015 Amended Cost Deferral Application is provided in 1) the record of the 2015 Interim Rates Application and attached as Schedule 1, which formed the basis for the 2015 Interim Rates Order, ~~and~~ 2) the record of the Revised Compliance Application and attached as Schedule 2, and 3) the evidence and appendices to this 2015 Amended Cost Deferral Application which is attached as Schedule 3.

Other 2015 Adjustments

18. A~~n~~ final order of the Board on Hydro's GRA is not expected before the conclusion of Hydro's 2015 financial year-end. As such, Hydro's is requesting interim approval of several items for financial reporting and planning purposes.

a) General Rate Application Costs - Hydro is forecast to incur $1.2 million in 2015 associated with external GRA hearing costs. In its GRA, Hydro has proposed that these costs be deferred and recovered over a period of three years. Hydro proposes that the Board approve the deferral of Hydro's 2015 GRA costsfor 2015, with recovery to be determined in a

future order of the Board, to permit more accurate financial reporting of Hydro's results.

b) GRA Settlement Agreement – On August 14, 2014, the Parties to Hydro's GRA entered into a settlement agreement, attached at Appendix G to Schedule 3 of this Application. This agreement, among other items, provided for: specific deliverable dates for reports from Hydro and the filing of Hydro's next general rate application, adjustments to Hydro Asset Retirement Obligation costs in the 2015 Test Year, accounting treatment for Employee Future Benefits, and deferral of Conservation Demand Management costs. Hydro is requesting interim approval of this agreement to provide for greater certainty regarding Hydro's year-end financial reporting, and agreed upon deliverable dates.

19. Hydro now makes application that the Board make an Order approving:

a) a cost deferral of $60.5 million to reduce Hydro's forecast 2015 net income deficiency;

b) the account definition for the proposed cost deferral as provided in Appendix F to the Amended 2015 Cost Deferral Application;

c) the deferral of Hydro's 2015 GRA costs for 2015 with recovery to be determined in a future order of the Board; and

d) the GRA Settlement Agreement dated August 14, 2015, an on interim basis, pending a final order from the Board in relation to Hydro's GRA.

DATED AT St. John's in the Province of Newfoundland and Labrador this ~~10th~~ 12th day of ~~July~~ November 2015.

NEWFOUNDLAND AND LABRADOR HYDRO

~~Geoffrey P. Young~~ Tracey L. Pennell
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Facsimile: (709) 737-1782

IN THE MATTER OF the *Public Utilities Act*, RSN 1990, Chapter P-47 (the "Act"); and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2015; and

IN THE MATTER OF an Amended application by Newfoundland and Labrador Hydro for approval of a proposed cost deferral account to reduce Hydro's forecast net income deficiency for 2015 until the Board tests 2015 Test Year costs (the "Amended 2015 Cost Deferral Application").

AFFIDAVIT

I, Carla L. Russell, Chartered Accountant, of St. John's, in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am General Manager Finance, of Newfoundland and Labrador Hydro the Applicant named in the attached Amended 2015 Cost Deferral Application.
2. I have read and understand the foregoing Amended 2015 Cost Deferral Application.
3. I have personal knowledge of the facts contained herein, 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 12th day of November, 2015, before me:)

Bobbi Sheppard
Commissioner for Oaths
Province of Newfoundland & Labrador
Expiry date: December 31, 2017

Carla L. Russell

Schedule 1

AMENDED 2015 COST DEFERRAL APPLICATION

NEWFOUNDLAND AND LABRADOR HYDRO

November 12, 2015

Schedule 1 – A – 2015 Interim Rates Application

Schedule 1 – B –2015 Interim Rates Application Evidence

Schedule 1 – C – 2015 Cost of Service

Schedule 1 – D – Requests for Information – Questions and Reponses by Party

Schedule 1 – E – Written Submissions by Party

Schedule 1 – F – Order No. P.U. 14(2015)

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January 28, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - 2015 Interim Rates Application

Further to the Board's letter of December 24, 2014, enclosed please find the original plus 12 copies of Hydro's Application for interim approval of customer electricity rates for implementation as of March 1, 2015. For convenience of reference, where changes have been made from the contents of similar schedules filed in the Amended General Rate Application, those changes are shown as shaded.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Senwung Luk – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn
Genevieve M. Dawson – Benson Buffett

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

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro, pursuant to Sections 70 and 75 of the *Act*, for the approval of customer electricity rates, rules and regulations on an interim basis to become effective March 1, 2015 (the "2015 Interim Rates Application").

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

THE 2015 INTERIM RATES APPLICATION of Newfoundland and Labrador Hydro (the Applicant) for an Interim Order says:

Background

1. Newfoundland and Labrador Hydro (Hydro) is a corporation continued and existing under the *Hydro Corporation Act, 2007,* is a public utility within the meaning of the Act and is subject to the provisions of the *Electrical Power Control Act, 1994*.

2. Under the Act the Board has the general supervision of public utilities and requires that a public utility submit for the approval of the Board the rates, tolls and charges for the service provided by the public utility and the rules and regulations which relate to that service.

3. In its Amended General Rates Application (the "Amended Application") filed with the Board on November 10, 2014, Hydro requested that the proposed customer rates be approved on an interim basis in advance of completing the General Rate Application (GRA). This approach would reduce the amount of 2015 costs deferred for future

recovery from customers. Hydro also proposed revised Rate Stabilization Plan (RSP) Rules to become effective on an interim basis effective January 1, 2015 to permit the continued phase-in of the Island Industrial Customer (IIC) rates.

4. Based on existing rates, Hydro would achieve a forecast return on rate base of 3.33% in 2015, which is below the bottom of the approved range of return on rate base of 7.29% established in the 2007 GRA and is also lower than the proposed 2015 return on rate base of 6.82%.

5. In Orders in Council OC2013-089 and OC2013-090, as amended, direction was given to the Board and to Hydro, respectively, with regard to the phasing-in of rate changes to Hydro's IIC. IIC base rates have not changed since 2007. In a letter from the Board dated December 24, 2014, Hydro was directed to file a comprehensive interim rates application for rates to be charged effective March 1, 2015. In accordance with that directive from the Board, this 2015 Interim Rates Application is for an Interim Order as to rates to be paid by Hydro's IIC, Newfoundland Power (NP) and Hydro's Rural Customers.

Reduced Forecast Fuel Prices

6. The forecast cost of No. 6 fuel at Holyrood has decreased materially since Hydro filed its Amended Application on November 10, 2014. Hydro's Amended Application was based upon an average No. 6 fuel cost of $93.32 per barrel. The most recent fuel forecast provided by PIRA indicates an average fuel cost for 2015 of $65.63 per barrel. Based upon the 2015 Test Year forecast of approximately 2.6 million barrels, the revised fuel cost forecast reduces the 2015 Test Year cost of service by approximately $73 million.

7. The proposal to increase customer rates in 2015 as requested in the Amended Application is no longer supported by the 2015 fuel cost forecast. Therefore, Hydro has reflected the 2015 fuel cost reduction to $65.63 per barrel in this 2015 Interim Rates

Application. The fuel cost reduction impacts the rate proposals for all customers whose rates are materially affected by fuel prices.

Utility Rate

8. While there is a base rate increase of 11.2% inherent in the proposed rate adjustment to NP, the base rate increase is more than offset by the reduced billing impact of resetting the RSP fuel rider from 1.526 ¢/kWh to zero, consistent with the inclusion of the 2015 forecast fuel cost in the proposed base rate. The result is a proposed rate decrease to NP of 9.3%. The effect of this rate reduction to NP is estimated to be a 6.3% rate reduction for its customers.

Hydro Rural Rates

Island Interconnected and L'Anse au Loup Systems

9. Hydro proposes that effective March 1, 2015, on an interim basis, that rates be reduced by 6.3% for customers served from the Island Interconnected and L'Anse au Loup systems, consistent with the estimated rate impact on NP's customers.

Non-Government Diesel Rates

10. Order in Council OC2014-372 issued on December 23, 2014 directs that the rate increase in 2015 to Hydro's Non-Government Rural Isolated Domestic and General Service customers be equal the rate increase approved for NP's customers for 2015. To comply with OC2014-372, Hydro proposes that the same percentage interim rate change apply to Hydro's diesel rates as is approved for NP's customers and for Hydro's Rural Customers on the Island Interconnected and L'Anse au Loup systems. The rate change is estimated to be a 6.3% decrease.

Government Diesel Rates

11. Government rate classes in isolated systems pay rates that recover 100% of the allocated test year costs. Similar to the forecast costs of No. 6 fuel, the forecast cost of No. 2 fuel has decreased materially for 2015 and Hydro therefore proposes rate increases for these customers that are lower than those proposed in its Amended Application.

Labrador Interconnected Rates

12. The cost of serving customers on the Labrador Interconnected System is not materially impacted by the revised fuel cost estimate for 2015. Therefore, Hydro is proposing that the rates for customers on the Labrador Interconnected System that accompanied the Amended Application, an average increase of 2.1%, be approved on an interim basis March 1, 2015.

IC Rates

13. In a submission dated December 10, 2014, the IIC submitted that the impacts of the rate proposals reflected in the Amended Application constitute "rate shock". Current IIC rates do not include a fuel rider so their rates do not recover the increased cost of Holyrood fuel since the 2007 Test Year. The proposed average base rate increase for IIC for the 2015 Test Year, based upon the fuel cost forecast used in the Amended Application and with no phase-in approach, is 39.2%. Using an updated Holyrood fuel price of $65.63 per barrel reduces the proposed base rate increase to 18.1%.

14. The 2014 year-end RSP current balance to be recovered from IIC is $6.8 million. This amount represents an additional 22% increase relative to existing rates.

15. The IC Group submission of December 18, 2014 expressed concern with the customer impacts in the Amended Application. To mitigate the customer rate impacts, the IC Group proposed that the Board consider: (i) disposition of the credit balance in the RSP

load variation component; and (ii) using a lower No. 6 fuel price in establishing revenue requirement for the purpose of establishing interim rates.

16. Pursuant to Order No. P.U. 29(2013), the RSP load variation component has been segregated with disposition between the IIC and NP to be determined in the GRA. In this 2015 Interim Rates Application, Hydro is proposing that the Board approve the disposition of the 2014 year-end load variation balance using the energy ratio allocation approach that was proposed in the Amended Application. The approval of this proposal would result in $2.1 million being allocated to the IIC, reducing the 2014 year-end IIC current balance from $6.8 million to $4.7 million. Hydro is also proposing the use of the 2014 IIC RSP Surplus balance to provide recovery of the adjusted year-end IIC current plan balance of $4.7 million.

17. In Hydro's Amended Application, Hydro proposed a two-year recovery of the IIC 2014 year-end current plan balance (the "Section E: Historical Plan Balance" in the RSP Rules). In this 2015 Interim Rates Application, the IIC current plan balance is proposed to be recovered from the IIC RSP Surplus Balance, therefore, Hydro is no longer proposing that this two-year recovery be implemented.

18. In its Amended Application, Hydro proposed to complete the phase-in of IIC rates by September 1, 2016 by limiting customer rate impacts using the IIC RSP Surplus balance. IIC base rates resulting from the 2015 Test Year Cost of Service Study were proposed to become effective for all IIC on January 1, 2015, with an offsetting RSP Surplus Credit Adjustment of 85% applied to limit the customer rate impact. The RSP Surplus Credit Adjustment was proposed to be reduced to 35% for the period September 1, 2015 to August 31, 2016, and eliminated September 1, 2016. The IIC RSP Surplus Credit at December 31, 2014 was $10.9 million.

19. Given the material reduction to the required base rate increase for the IIC caused by the use of the lower fuel cost forecast, Hydro proposes a modified approach to the phase-in of IIC rates from that proposed in the Amended Application. Hydro now proposes an RSP Surplus Credit Adjustment of 85% which would apply for the period March 1, 2015 to December 31, 2015 and a decrease to 60% for the period January 1, 2016 to August 31, 2016.

Rate Design

NP Rate Design

20. Hydro is proposing that the rate changes be implemented using the rate design approach described in the evidence to the Amended Application. For NP, Hydro is proposing that the tail block be reduced from 11.622¢ per kWh to 9.446¢, reflecting the reduced 2015 fuel cost forecast. Hydro is proposing that the other rate components remain unchanged from those proposed in the Amended Application. The proposed RSP rate reflects the removal of the fuel rider of 1.526¢ per kWh which was based upon a forecasted fuel price of $105.60/bbl ($Can) and a continuation of the current plan RSP adjustment of (0.551)¢ per kWh.

IIC Rate Design

21. For IIC, the firm energy charge has been reduced from 5.151¢ per kWh to 4.114¢ per kWh to reflect the revised 2015 fuel cost forecast. Hydro proposes that the other rate components for these customers, with the exception of Teck Resources, remain the same as they were proposed in the Amended Application. The proposed RSP adjustment for Teck is modified to provide the same 2015 rate increase proposal for Teck as is proposed for the other IIC.

July 1, 2015 RSP Update

22. The implementation of interim base rates effective March 1, 2015 to reflect an updated fuel cost for 2015 removes the RSP fuel rider that has been in effect since July 1, 2014.

Implementation of revised retail rates on March 1, 2015 that reflects both the disposition of the balance in the RSP segregated load variation component and the updated fuel forecast avoids the necessity for a July 1, 2015 rate change. Hydro sees no additional benefit to provide a further fuel cost update to become effective July 1, 2015 and proposes that the July 1, 2015 NP RSP update be suspended.

23. Hydro now makes application that the Board make:

A. an interim Order pursuant to Section 75 of the *Act*, approving

(i) the schedule of rates, tolls and charges set out in Schedule 1 to this 2015 Interim Rates Application to be effective on and after March 1, 2015, until superseded by a final order of the Board;

(ii) changes to the RSP rules to implement the phase-in of changes to the IIC rates and to remove the requirement for the RSP rate adjustment to NP scheduled for July 1, 2015, as set out in Schedule 1 of this 2015 Interim Rates Application, as follows:

(a) to provide for the allocation and disposition of the RSP load variation balance effective December 31, 2014;

(b) to provide for a one-time transfer from the IIC Surplus balance effective December 31, 2014 to provide recovery of the IIC current plan balance;

(c) to approve the proposed RSP Surplus Credit Adjustments to mitigate the rate impacts of implementing 2015 test year IIC base rates; and

(d) to suspend for 2015 the requirement for the July 1 RSP adjustment for Utility rates.

B. Such further or other matters as may appear just and reasonable in the circumstances

DATED AT St. John's in the Province of Newfoundland and Labrador this 28th day of January 2015.

Geoffrey P. Young
Counsel for the Applicant
Newfoundland and Labrador Hydro,
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Telephone: (709) 737-1277
Facsimile: (709) 737-1782

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM)

Availability:

This rate is applicable to service to Newfoundland Power (NP).

Definitions:

"Billing Demand"

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit and the Curtailable Credit, beginning in the previous December and ending in the current Month; and
(b) the Minimum Billing Demand .

In the Months of April through December, billing demand shall be the greater of:

(a) the Weather-Adjusted Native Load less the Generation Credit and the Curtailable Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.

If at the time of establishing its Maximum Native Load, NP has been requested by Hydro to reduce its Native Load by shedding curtailable load, the calculation of Billing Demand for each month shall not deduct the Curtailable Credit.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	83,142
Thermal Generation Credit	36,187
Total Generation Credit	119,329

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, Newfoundland Power will be provided an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

“Curtailable Credit” is determined based upon NP's forecast curtailable load available for the period December 1 to March 31 in accordance with the terms and conditions set forth in NP’s Curtailable Service Option. NP will notify Hydro of its available curtailable load with its forecast of annual and monthly electricity requirements.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

In order to receive the Curtailable Credit, NP must demonstrate the capability to curtail its customer load requirements to the level of the Curtailable Credit. This will be verified in a test by curtailing load at a minimum of this level for a period of one hour. The test will be carried out at a mutually agreed time in December. If the level is not sustained, the Curtailable Credit will be reduced to the level sustained. If Hydro requests NP to curtail load before a test is completed and NP demonstrates the capability to curtail to the level of the Curtailment Credit, no test will be required.

NP will be required to provide a report to Hydro not later than April 15 to demonstrate the amount of load curtailed for each request of Hydro during the previous winter season. If the load curtailed is less than forecast for either request during the winter season, the annual Curtailable Credit will be adjusted to reflect the average load curtailed for the winter season. If NP is not requested to curtail during the winter season, the Curtailment Credit will established based upon the lesser of the load reduction achieved in the test or the forecast curtailable load (as provided in the previous two paragraphs).

“Maximum Native Load” means the maximum Native Load of NP in the four-Month period beginning in December of the preceding year and ending in March of the current year.

“Minimum Billing Demand” means ninety-nine percent (99%) of:

NP’s test year Native Load less the Generation Credit and the Curtailable Credit.

The Curtailable Credit reflected in the Minimum Billing Demand will be set to equal the curtailable load used to determine the Maximum Native Load for NP for the most recently approved Test Year.

“Month” means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

“Native Load” is the sum of:

(a) the amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter;
(b) the total generation by NP averaged over the same fifteen-minute periods.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load
plus (Weather Adjustment, rounded to 3 decimal places, x 1000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

(a) the greater of:
- the Weather Adjusted Native Load less the Generation Credit and the Curtailable Credit (if applicable), times three; and
- the Minimum Billing Demand, times three; and

(b) the sum of the actual billed demands in the Months of January, February and March of the current year.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Monthly Rates:

Base Rate:

Billing Demand Charge:

Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

$5.50 per kW of billing demand

Energy Charge:

First 250,000,000 kilowatt-hours* ..... @ 3.411 ¢ per kWh
All excess kilowatt-hours* ..... @ 9.446 ¢ per kWh

Firming-up Charge:

Secondary energy supplied by
Corner Brook Pulp and Paper Limited* ..... @ 2.974 ¢ per kWh

RSP Adjustment:

Current Plan ..... @ (0.551) ¢ per kWh

Total RSP Adjustment – All kilowatt-hours ..... @ (0.551) ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses:

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering, shall be applied to the metered demand.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Weather Adjustment: This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

(a) Weather adjustment shall be undertaken for use in determining NP's Billing Demand.

(b) Weather adjustment shall be derived from Hydro's NP native peak demand model.

(c) By September 30th of each year, Hydro shall provide NP with updated weather adjustment coefficient incorporating the latest year of actuals.

(d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to weather station data for the St. John's, Gander, and Stephenville airports reported by Environment Canada. NP's regional energy sales shall be used to weight regional weather data. Hydro shall consult with NP to resolve any circumstances arising from the availability of, or revisions to, weather data from Environment Canada and/or wind chill formulation.

(e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding seven hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition on underlying weather data.

(f) Subject to the availability of weather data from Environment Canada, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of Weather-Adjusted Native Load by April 5th of each year.

General:

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach mutual agreement, the billing will be based on Hydro's best estimate.

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (INTERIM)

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Base Rate*:

Demand Charge:

The rate for Firm Power, as defined and set out in the Industrial Service Agreements, shall be $8.38 per month per kilowatt of billing demand.

Firm Energy Charge:

Base Rate**..... @ 4.114 ¢ per kWh

Specifically Assigned Charges:

The table below contains the additional specifically assigned charges for customer plant in service that is specifically assigned to the Customer.

	Annual Amount
Corner Brook Pulp and Paper Limited	$891,045
North Atlantic Refining Limited	$91,729
Teck Resources Limited	$208,600
Vale Newfoundland and Labrador Inc	$499,522

RSP Adjustment:

Current Plan ..... @ 0.000 ¢ per kWh
[ ]
Fuel Rider ..... @ 0.000 ¢ per kWh

Total RSP Adjustment – All kilowatt-hours ..... @ 0.000 ¢ per kWh

Teck Resources RSP Adjustment..... @ (1.113) ¢ per kWh

Net Teck Resources RSP Adjustment..... @ (1.113) ¢ per kWh

***Subject to RSP Surplus Credit Adjustment:**

The RSP Surplus Credit Adjustment will apply to the difference between the monthly base rate charges calculated on existing rates (based upon 2015 Test Year costs and excluding RSP adjustments) and the monthly base rate charges calculated using the base rates previously in effect (based upon 2007 Test Year costs and excluding RSP adjustments). The RSP Surplus Credit

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (INTERIM)

Adjustment will equal an 85% credit for the period March 1, 2015 to December 31, 2015 and subsequently reduce to a 60% credit effective January 1, 2016 until the conclusion of the credit August 31, 2016.

****Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL – NON-FIRM (INTERIM)

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Non-Firm Energy Charge (¢ per kWh):

Non-Firm Energy is deemed to be supplied from thermal sources. The following formula shall apply to calculate the Non-Firm Energy rate:

$$\{(A \div B) \times (1 + C) \times (1 \div (1 - D))\} \times 100$$

A = the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used

B = the conversion factor for the source used (kWh/bbl)

C = the administrative and variable operating and maintenance charge (10%)

D = the average system losses on the Island Interconnected grid for the last five years ending in 2013 (3.47%)

The energy sources and associated conversion factors are:

1. Holyrood, using No. 6 fuel with a conversion factor of 607 kWh/bbl
2. Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl
3. Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL – WHEELING (INTERIM)

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy and whose Industrial Service Agreement so provides.

Rate:

Energy Charge:

All kWh (Net of losses)* ..... @ 0.443 ¢ per kWh

* For the purpose of this Rate, losses shall be 3.47%, the average system losses on the Island Interconnected Grid for the last five years ending in 2013.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM)

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations 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 formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A: Hydraulic Production Variation

1. **Activity:**
   Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

   $$\{(A - B) \div C\} \times D$$

   Where:

   A = 2015 Test Year Cost of Service Net Hydraulic Production (kWh)
   B = Actual Net Hydraulic Production (kWh)
   C = 2015 Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
   D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)

2. **Financing:**
   Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. **Hydraulic Variation Customer Assignment:**
   Customer assignment of hydraulic variations will be performed annually as follows:

   $$(E \times 25\%) + F$$

   Where:

   E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
   F = Financing charges accumulated to December 31

   The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

4. Customer Allocation:

The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved 2015 Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. Activity

1.1 Fuel Cost Variations

This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly 2015 Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
G = Monthly Actual Average No. 6 Fuel Cost ($Can /bbl.)
H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2 Load Variations

Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the 2015 Test Year Cost of Service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

C = 2015 Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly 2015 Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
I = Actual Sales, by customer class (kWh)
J = 2015 Test Year Cost of Service Sales, by customer class (kWh)
K = Firm energy rate, by customer class

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the 2015 Test Year Cost of Service Study, in accordance with the following formula:

$$(J - I) \times L$$

Where:

I = Actual Sales (kWh)
J = 2015 Test Year Cost of Service Sales (kWh)
L = Secondary Energy Firming Up Charge

1.3 Rural Rate Alteration

(a) Newfoundland Power Rate Change Impacts:
This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

$$(M - N) \times O$$

Where:

M = 2015 Cost of Service rate [1]
N = Existing rate
O = Actual Units (kWh, bills, billing demand)

2. Monthly Customer Allocation: Load and Fuel Activity

At December 31, 2014, the cumulative load variation segregated in accordance with Order No. P.U. 29(2013) will be allocated between Newfoundland Power and the IC based on the percentages derived from 12 months-to-date kWh and transferred to the respective RSP current plan balances. [ ]

Each month, the year-to-date total for fuel price variation and the year-to-date total for the Newfoundland Power and Industrial Customer load variation will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

[1]

- Hydro's schedule of rates for its rural customers not affected by the December 6th, 2006 Government directive.
- For customers affected by the December 6th, 2006 Government directive, the Cost of Service rate equals the phased-in 2007 Forecast Cost of Service Rates for diesel rate classes 1.2D, 2.1D and 2.2D.
- No Rural Rate Alternation will arise from the phase-in of 2007 Forecast Cost of Service rates for the customers affected by the December 6th, 2006 Government directive.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

The year-to-date portion of the fuel price variation and load variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved 2015 Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

3. **Monthly Customer Allocation: Rural Rate Alteration Activity**
   Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved 2015 Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. **Plan Balances**
   Separate plan balances for Newfoundland Power and the Island Industrial Customer class will be maintained. The allocation of the segregated load variation will be maintained in a separate account until a further Order of the Board approving the method of disposition. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year, for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. **Industrial Fuel Price Projection:**
   In October each year, a fuel price projection for the following January to December shall be made to estimate a change from the 2015 Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

   $$[\{(S - T) \times U\} - V] \times W$$

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December
T = Hydro's average 2015 Test Year contract discount (US $/bbl)
U = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of September
V = average 2015 Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)
W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

2. Newfoundland Power Fuel Price Projection:

In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(X - T) \times Y\} - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US $/bbl)
V = average 2015 Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)
W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the 2015 Test Year.
X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for July to December of the current year and for the January to June period of the subsequent year.
Y = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of March.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power

1.1 As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance

less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values.

Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

1.2 Notwithstanding paragraph 1.1, the RSP rate adjustment scheduled for July 1, 2015 is suspended until a further Order of the Board.

2. Island Industrial Customers

As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

This calculation will exclude the Industrial Historical Plan Balance in Section E.

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values. Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

[ ]

Section E: RSP Surplus:

1. August 31, 2013 Balance:

The net load variation for Newfoundland Power and the Industrial Customers from January 1, 2007 to August 31, 2013, including financing (the RSP Surplus), will be removed from the respective customer class balance, and allocated based upon direction provided by Government in Orders in Council OC2013-089 and OC2013-207. The balances which remain after this amount is removed will form the adjusted August 31, 2013 current plan balances for each customer class.

1.1 Industrial Customer RSP Surplus:

OC2013-089 states that the remaining IC RSP Surplus is to be used to fund a three-year phase-in of rate increases for Island Industrial customers.

Transfer of Industrial Customer Current Plan Balance

Effective December 31, 2014, a one-time transfer from the Industrial Customer RSP Surplus will be applied to the Industrial Customer RSP current plan balance to reduce the adjusted December 31, 2014 balance to zero.

Industrial Customer RSP Surplus Credit Adjustment:

Using funds from the RSP Surplus, the RSP Surplus Credit Adjustment will apply to the difference between the monthly base rate charges, excluding RSP adjustments, calculated using the proposed 2015 Test Year base rates and the approved 2007 Test Year base rates. The RSP Surplus Credit Adjustment will equal an 85% credit for the period March 1, 2015 to December 31, 2015 and subsequently reduce to a 60% credit effective January 1, 2016 until the conclusion of the credit August 31, 2016.

The monthly adjustments and financing will be applied to the RSP Surplus balance each month. At the end of the phase-in period, any remaining balance will be added to the current Industrial Customer plan balance.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Teck Resources

The Teck Resources RSP Adjustment rate will be (1.113) ¢ per kWh effective March 1, 2015.

As per Board Order No. P.U. 29(2013), the Teck Resources RSP Adjustment rate will continue to be segregated from the other components of the Industrial Customer RSP to permit the phase-in of Industrial Customer rates in accordance with OC2013-089 until a further order of the Board to discontinue the Teck Resources RSP Adjustment rate.

1.2 Newfoundland Power RSP Surplus:

The Newfoundland Power allocated amount of the RSP Surplus will be segregated held until such time as its disposition occurs in accordance with an Order of the Board of Commissioners of Public Utilities through a refund in accordance with Order in Council OC2013-089.

2. Plan Balances

Separate plan balances for Newfoundland Power and the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

NEWFOUNDLAND AND LABRADOR HYDRO

CONSERVATION AND DEMAND MANAGEMENT COST RECOVERY

(INTERIM)

The CDM Cost Recovery Adjustment, expressed in cents per kWh, will be calculated to provide for the recovery of costs charged annually to the Conservation and Demand Management Cost Deferral Account (the "CDM Cost Deferral Account") over a seven-year period.

For the initial year of calculating the CDM Cost Recovery Adjustment, the CDM Cost Recovery Adjustment will be calculated to recover 1/7th of the CDM Cost Deferral Account balance at December 31 of the previous year. For each subsequent year, the CDM Cost Recovery Adjustment will be calculated to recover the sum of individual amounts representing 1/7th of the transfer to the CDM Deferral Account for the previous year and the amortizations carried forward from prior years.

There will be different CDM Cost Recovery Adjustments for Island Industrial Customers and Newfoundland Power. The CDM Cost Recovery Adjustment for Island Industrial Customers will be calculated based upon the Island Interconnected Recoverable Amount allocated for recovery from Island Industrial Customers. The CDM Cost Recovery Adjustment for Newfoundland Power will be calculated based upon the allocated Island Interconnected Recoverable Amount to Newfoundland Power (including the allocated Island Interconnected Hydro Rural Amount) plus the allocated Hydro Rural Isolated System amount to Newfoundland Power.

Assignment of Customer Balance for Recovery

The Island Interconnected Recoverable Amount will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages of previous calendar year sales for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the Island Interconnected Recoverable Amount which is initially allocated to Rural Island Interconnected will be added to the Hydro Rural Isolated System Recoverable Amount, and then re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Labrador Interconnected Recoverable Amount shall be written off to Hydro's net income (loss).

NEWFOUNDLAND AND LABRADOR HYDRO

CONSERVATION AND DEMAND MANAGEMENT COST RECOVERY

(INTERIM)

CDM Cost Recovery Adjustment

Newfoundland Power:

The adjustment rate for each year will be determined as follows:

$$B = (C \div D)$$

Where:

B = adjustment rate (¢ per kWh) for the 12-month period commencing the following July 1.
C = Recoverable Amount assigned to Newfoundland Power from previous calendar year.
D = energy sales (kWh) (firm and firmed-up secondary) to Newfoundland Power for the previous calendar year.

Island Industrial Customers:

The adjustment rate for each year will be determined as follows:

$$E = (F \div H)$$

Where:

E = adjustment rate (¢ per kWh) for the 12-month period commencing the following July 1.
F = Recoverable Amount assigned to Industrial Customers from previous calendar year.
H = firm energy sales (kWh) to Industrial Customers for the previous calendar year.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM)

APPLICABILITY:

These general Rules and Regulations apply to all Hydro Rural Customers.

1. INTERPRETATION:

(a) In these Rates and Rules the following definitions shall apply:

(i) "***Act***" means The Public Utilities Act, R.S.N. 1990, c.P-47 as amended from time to time.

(ii) "***Applicant***" means any person who applies for Service.

(iii) ***"Board"*** means the Board of Commissioners of Public Utilities of Newfoundland and Labrador.

(iv) "***Hydro***" means Newfoundland and Labrador Hydro.

(v) "***Hydro rural customers***" means regulated customers served by Hydro other than industrial customers and Newfoundland Power.

(vi) "***Customer***" means any person who accepts or agrees to accept Service.

(vii) "***Disconnected***" or "***Disconnect***" in reference to a Service means the physical interruption of the supply of electricity thereto.

(viii) "***Discontinued***" or "***Discontinue***" in reference to a Service means to terminate the Customer's on-going responsibility with respect to the Service.

(ix) "***Domestic Unit***" means a house, apartment or other similar residential unit which is normally occupied by one family, or by a family and no more than four other persons who are not members of that family, or which is normally occupied by no more than six unrelated persons.

(x) ***"Service"*** means any service(s) provided by Hydro pursuant to these Regulations.

(xi) "***Serviced premises***" means the premises at which Service is delivered to the Customer.

(xii) *"**Government Departments**"* means electric service accounts of Provincial or Federal government departments, agencies, boards, commissions, and crown corporations but excludes hospitals, fish plants, churches, schools, community halls, municipal buildings and like facilities.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(b) Unless the context requires otherwise these Rates and Rules shall be interpreted such that:

(i) words imparting male persons include female persons and corporations.

(ii) words imparting the singular include the plural and vice versa.

2. CLASSES OF SERVICE:

(a) Hydro shall provide the following classes of Service:

ISLAND INTERCONNECTED AREA

1.1	Domestic
1.1S	Domestic Seasonal
1.3	Burgeo School and Library
2.1	General Service, 0-100 kW
2.3	General Service, 110 kVA (100 kW) - 1000 kVA
2.4	General Service, 1000 kVA and Over
4.1	Street and Area Lighting Service

ISLAND AND LABRADOR DIESEL AREA

1.2D	Domestic Diesel - Non-Government
1.2DS	Domestic Seasonal Diesel – Non-Government
2.1D	General Service Diesel - Non-Government, 0-10 kW
2.2D	General Service Diesel - Non-Government, 10 kW and Over
4.1D	Street and Area Lighting Service Diesel - Non-Government
1.2G	Domestic Diesel - Government Departments
2.1G	General Service Diesel - Government Departments, 0-10kW
2.2G	General Service Diesel - Government Departments, 10kW and Over
4.1G	Street and Area Lighting Service Diesel - Government Departments

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

LABRADOR INTERCONNECTED AREA

1.1L	Domestic
2.1L	General Service, 0-10 kW
2.2L	General Service, 10-100 kW (110 kVA)
2.3L	General Service, 110 kVA (100 kW) - 1000 kVA
2.4L	General Service, 1000 kVA and Over
4.1L	Street and Area Lighting Service
4.11L	Street and Area Lighting Service Labrador - Installed as of Sept. 1, 2002
4.12L	Street and Area Lighting Service Labrador– Customer Owned
5.1L	Secondary Energy

(b) The terms and conditions relating to each class of Service shall be those approved by the Board from time to time.

(c) Service, other than Street and Area Lighting Service, shall be metered except where the energy consumption is relatively low and constant and in the opinion of Hydro can be readily determined without metering.

(d) The Customer shall use the Service on the Serviced Premises only. The Customer shall not resell the Service in whole or in part except that the Customer may include the cost of Service in charges for the lease of space or as part of the cost of other services provided by the Customer.

3. APPLICATION FOR SERVICE:

(a) An Applicant, when required by Hydro, shall complete a written Electrical Service Contract.

(b) An application for Service, when accepted by Hydro, constitutes a binding contract between the Applicant and Hydro which cannot be assigned.

(c) The person who signs an application for Service shall be personally liable for Service provided pursuant thereto, unless that person has authority to act for another Person denoted as the Applicant on the application for Service.

(d) Hydro may in its discretion refuse to provide Service to an Applicant where:

(i) the Applicant fails or refuses to complete an application for Service.

(ii) the Applicant provides false or misleading information on the application for Service.

(iii) the Applicant or the Owner or an Occupant of the Serviced Premises has a bill for any Service which is not paid in full 30 days or more after issuance.

(iv) the Applicant fails to provide the security or guarantee required under Regulation 4.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(v) the Applicant is not the owner or an occupant of the Serviced Premises.

(vi) the Service requested is already supplied to the Serviced Premises for another Customer who does not consent to having his Service Discontinued.

(vii) the Applicant does not pay a charge described in Regulation 9 (b), (c) or (d).

(viii) the Applicant otherwise fails to comply with these Regulations.

(e) A Customer who has not completed an application for Service shall do so within 5 days of a request having been made by Hydro in writing.

4. SECURITY FOR PAYMENT:

(a) An Applicant or a Customer shall give such reasonable security for the payment of charges as may be required by Hydro. When the Customer has established two consecutive years of good credit history, the security deposit will be refunded with simple interest calculated at a Rate equivalent to the Rate paid from time to time by the chartered banks on over-the-counter withdrawal savings accounts.

(b) Hydro may in its discretion require special guarantees from an Applicant or Customer whose location or load characteristics would require abnormal investment in facilities or who requires Service of a special nature.

5. SERVICE STANDARDS - METERED SERVICES:

(a) Service shall normally be provided at one of the following nominal standard secondary voltages depending upon the requirements of the load to be served and the availability of a three phase supply:

Single phase, 3-Wire	-	120/240 volts
Three phase, 4-Wire	-	120/208 volts wye
Three phase, 4-Wire	-	347/600 volts wye

Service at any other supply voltage may be provided in special cases at the discretion of Hydro.

(b) Service shall be supplied at single-phase 120/240 volts where the maximum demand is estimated by Hydro to be less than 75 kW. Where the maximum demand is estimated to be 75kW or greater, service shall normally be supplied at one of the standard three-phase voltages.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

Hydro may, if requested by the Customer, provide a three-phase supply where the maximum demand is estimated to be less than 75 kW, if a contribution in aid of construction is paid to Hydro to cover the cost of transformers, equipment and any line extensions or upgrades required to provide the three-phase service.

To determine the contribution required, the cost to provide three-phase service will be reduced by the value of any single-phase plant supported by the projected revenue from the Customer, as calculated in accordance with Hydro's distribution line contribution in aid of construction policy applicable to General Service Customers. Where the necessary equipment and transformer capacity already exist at the location in question, no contribution in aid of construction will be required to provide the three-phase service.

(c) Hydro shall determine the point at which power and energy is delivered from Hydro's facilities to the Customer's electrical system.

(d) Service entrances shall be in a location satisfactory to Hydro and, except as otherwise approved by Hydro, shall be wired for outdoor meters.

(e) Where Hydro has reason to believe that Service to a Customer has or will have load characteristics which may cause undue interference with Service to another Customer, the Customer shall upon written notice by Hydro provide and install, at his expense and within a reasonable period of time, the equipment necessary to eliminate or prevent such interference.

(f) (i) Any Customer having a connected load or a normal operating demand of more than 25 kilowatts, in areas where space limitations or aesthetic reasons make it impractical to use a pole mounted transformer bank, shall, on request of Hydro, install and maintain a padmount transformer and all associated underground wiring, or provide at his expense a suitable vault or enclosure on the Serviced Premises for exclusive use by Hydro for its equipment necessary to supply and maintain service to the Customer.

(ii) Where either the service requirements of a Customer or changes to a Customer's electrical system necessitate the installation of additional equipment to Hydro's system which cannot be accommodated in Hydro's existing vaults or structures, the Customer shall, on request of Hydro, provide at the Customer's expense such additional space in its vault or enclosure as Hydro shall require to accommodate the additional equipment.

(g) The Customer shall not use a Service for across the line starting of motors rated over 10 horsepower except where specifically approved by Hydro.

(h) For Services having rates based on kilowatt demand, the average power factor shall not be less than 90%. Hydro, in its discretion, may make continuous tests of power factor or may test the Customer's power factor from time to time. If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at his expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(i) Hydro shall provide transformation for Service up to 500 kVA where the required service voltage is one of Hydro's standard service voltages and installation is in accordance with Hydro's standards. In other circumstances, Hydro, on such conditions as it deems acceptable, may provide the transformation.

(j) All Customer wiring and installations shall be in compliance with all statutory and regulatory requirements including the Canadian Electrical Code, Part 1 and, where applicable, in accordance with Hydro's specifications. However, the provision of Service shall not in any way be construed as acceptance by Hydro of the Customer's electrical system.

(k) The Customer shall provide such protective devices as may be necessary to protect his property and equipment from any disturbance beyond the reasonable control of Hydro.

6. SERVICE STANDARDS - STREET AND AREA LIGHTING SERVICE:

(a) For Street and Area Lighting Service Hydro shall use its best efforts to provide illumination during the hours of darkness for a total of approximately 4200 hours per year. Hydro shall, subject to Regulation 9 (i) make all repairs necessary to maintain service.

(b) Hydro shall supply the energy required and shall provide and maintain the illuminating fixtures and lamps together with necessary overhead conductors, control equipment and other devices.

(c) Hydro shall not be required to provide Street and Area Lighting Service where, in the opinion of Hydro, the normal Service is unsuitable for the task or where the nature of the activities carried out in the area would likely result in damage to the poles, wiring or fixtures.

(d) Hydro shall provide a range of fixture sizes utilizing an efficient lighting source in accordance with current standards in the industry and shall consult with the Customer regarding the most appropriate use of such fixtures for any specific installation.

(e) The location of fixtures for Street and Area Lighting Service shall be determined by Hydro in consultation with the Customer. After poles and fixtures have been installed they shall not be relocated except at the expense of the Customer.

(f) Hydro does not guarantee that fixtures used for Street and Area Lighting Service will illuminate any specific area.

(g) Where the installation of fixtures is required in a location where there are no existing distribution poles the Customer shall pay any contribution in aid of construction as may be determined under Hydro's policy for the pole line extension required to supply electric service to the location of the fixtures.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(h) Hydro shall not be required to provide additional Street and Area Lighting Service to a Customer where on at least two occasions in the preceding twelve months, his bill for such Service has been in arrears for more than 30 days.

7. METERING:

(a) Service to each building shall be metered separately except as provided in Regulation 7(b).

(b) Service to buildings and facilities on the same Serviced Premises which are occupied by the same Customer may, subject to Regulation 7(c), be metered together provided the Customer supplies and maintains all distribution facilities beyond the point of supply.

(c) Except as provided in Regulation 7(d) Service to each new Domestic Unit shall be metered separately.

(d) Where an existing Domestic Unit is subdivided into two or more new Domestic Units, Service to the new Domestic Units may, in the discretion of Hydro, be metered together.

(e) Where four or more Domestic Units are metered together, the Basic Customer Charge shall be multiplied by the number of Domestic Units.

(f) Where the Service to a Domestic Unit has a connected load for commercial or nondomestic purposes exceeding 3000 watts, exclusive of space heating, the Service shall not qualify for the Domestic Service Rate.

(g) Hydro shall not be required to provide more than one meter per Service, however, sub-metering by the Customer for any purpose not inconsistent with these Regulations is permitted.

(h) Subject to Regulations 7(c) and 7(g) Service to different units of a building may, at the request of the Customer, be combined on one meter or be metered separately.

(i) Maximum demand for billing purposes shall be determined by demand meter or, at the option of Hydro, may be based on:

(i) 80% of the connected load, where the demand does not exceed 100 kW, or

(ii) the smallest size transformer(s) required to serve the load if it is intermittent in nature such as X-Ray, welding machines or motors that operate for periods of less than thirty minutes, or

(iii) the kilowatt-hour consumption divided by an appropriate number of hours use where the demand is less than 10 kW.

(j) When charges are based on maximum demand the metering shall normally be in kVA if the applicable Rate is in kVA and in kW if the applicable Rate is in kW.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

If the demand is recorded on a kVA meter but the applicable Rate is based on a kW demand, the recorded demand may be decreased by ten percent (10%) and the result shall be treated as the kW demand for billing purposes.

If the demand is recorded on a kW meter but the applicable Rate is based on a kVA demand, the recorded demand may be increased by ten percent (10%) and the result shall be treated as the kVA demand for billing purposes.

(k) The Customer shall ensure that meters and related equipment are visible and readily accessible to Hydro's personnel and are suitably protected. Unless otherwise approved by Hydro, meters shall be located outdoors and shall not subsequently be enclosed.

(l) If a meter is located indoors and Hydro employees are unable to obtain access to read the meter at the normal reading time for three consecutive months, the Customer shall upon written notice given by Hydro, provide for the installation of an outdoor meter at his expense.

(m) In the event that a dispute arises regarding the accuracy of a meter, and Hydro is unable to resolve the matter with the Customer then either the Customer or Hydro shall have the right to request an accuracy test in accordance with the requirements of the Electricity Inspection Act of Canada. Should the test indicate that the meter accuracy is not within the allowable limits, the Customer's bill shall be adjusted in accordance with the provisions of the said Act and all costs involved in the removal and testing of the meter shall be borne by Hydro. Should the test confirm the accuracy of the meter, the costs involved shall be borne by the party requesting the test. Hydro may require a Customer to deposit with Hydro in advance of testing, an amount sufficient to cover the costs involved.

(n) Metering shall normally be at secondary distribution voltage level but may at the option of Hydro be at the primary distribution level. When metering is at the primary distribution voltage (4-25KV) the monthly demand and energy consumption shall be reduced by 1.5%.

8. METER READING:

(a) Where reasonably possible Hydro shall read meters monthly provided that Hydro may, at its discretion, read meters at some other interval and estimate the reading for the intervening month(s). Areas which consist primarily of cottages will have their meters read four times per year and Hydro will estimate the readings for all other months.

(b) If Hydro is unable to obtain a meter reading due to circumstances beyond its reasonable control, Hydro may estimate the reading.

(c) If due to any cause a meter has not correctly recorded energy consumption or demand, then the probable consumption or demand shall be estimated in accordance with the best data available and used to determine the relevant charge.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

9. CHARGES:

(a) Every Customer shall pay Hydro the charges approved by the Board from time to time for the Service(s) provided to the Customer or provided to the Serviced Premises at the Customer's request.

(b) Where a Customer requires Service for a period of less than three (3) years, the Customer shall pay Hydro in advance a "Temporary Connection Fee". The Temporary Connection Fee is calculated as the estimated labour cost of installing and removing lines and equipment necessary for the Service plus the estimated cost of non-salvageable material.

(c) Where special facilities are required or requested by the Customer or any facility is relocated at the request of the Customer, the Customer shall pay Hydro in advance the estimated additional cost of providing the special facilities and the estimated cost of the relocation less any betterment.

(d) The Customer shall pay Hydro in advance or on such other terms approved by the Board from time to time any contribution in aid of construction as may be determined by the methods prescribed by the Board.

(e) The Customer shall pay Hydro the amount set forth in the Rate for all poles required for Street and Area Lighting Service which are in addition to those installed by Hydro for the distribution of electricity. This charge shall not apply to Hydro poles and communications poles used jointly for Street and Area Lighting Service and communications attachments.

(f) Where a service is Disconnected pursuant to Regulation 12(a), b(ii), (c), or (d) and the Customer subsequently requests that the service be reconnected, the Customer shall pay a reconnection fee. Where a Service is Disconnected pursuant to Regulation 12(g) and an Applicant subsequently requests that the service be reconnected, the Applicant shall pay a reconnection fee. Applicants that pay the reconnection fee will not be required to pay the application fee. The reconnection fee shall be $20.00 where the reconnection is done during Hydro's normal office hours or $40.00 if it is done at other times.

(g) Where a Service, other than a Street and Area Lighting Service, is Discontinued pursuant to Regulation 11(a), or Disconnected pursuant to Regulations 12(a), b(ii), (c) or (d) and the Customer subsequently requests that the Service be restored within 12 months, the Customer shall pay, in advance, the minimum monthly charges that would have been incurred over the period if the Service had not been Discontinued or Disconnected.

(h) (i) Where a Street and Area Lighting Service is Discontinued pursuant to Regulation 11(a), (b), or (c), or 9(i), or when a Customer requests removal of existing fixtures, and/or poles, the Customer shall pay at the time of removal an amount equal to the unrecovered capital cost, plus the cost of removal less any salvage value of only the poles to be Discontinued or removed.

(ii) If a Customer requests the subsequent replacement of the fixture, either immediately or at any time within 12 months by another, whether or not of the same type or size, the Customer shall pay, in advance, an amount equal to the

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

unrecovered capital cost of the fixture removed, plus the cost of removal, less any non-luminaire salvage, as well as the monthly charges that would have been incurred over the period if the Service had not been Discontinued.

(iii) Where a Street and Area Lighting Service is Discontinued, any pole dedicated solely to the Street and Area Lighting Service may, at the Customer's request, remain in place for up to 24 months from the date of removal of the fixture, during which time the Customer shall continue to pay the prescribed monthly charge for the pole.

(i) Where street and area lighting fixtures or lamps are wantonly, wilfilly, or negligently damaged or destroyed (other than through the negligence of Hydro), Hydro, at its option and after notifying the Customer by letter, shall remove the fixtures and the monthly charges for these fixtures will cease thirty days after the date of the letter. However, if the customer contacts Hydro within thirty days of the date of the letter and agrees to pay the repair costs in advance and all future repair costs, Hydro will replace the fixture and rental charges will recommence. If any future repair costs are not paid within three months of the date invoiced, Hydro, after further notifying the Customer by letter, may remove the fixtures. In all such cases the fixtures shall not be replaced unless the Customer pays to Hydro in advance all amounts owing prior to removal plus the cost of removing the old fixtures and installing the new fixtures.

(j) Where a Service other than Street and Area Lighting Service is not provided to the Customer for the full monthly billing period or where Street and Area Lighting Service is not provided for more than seven (7) days during the monthly billing period, the relevant charge to the Customer for the Service for that period may be prorated except where the failure to provide the Service is due to the Customer or to circumstances beyond the reasonable control of Hydro.

(k) Where a Customer's Service is at primary distribution or transmission voltage and the Customer provides his own transformation and all other facilities beyond the designated point of supply the monthly demand charge shall, subject to the minimum monthly charge, be reduced as follows:

For the Island Interconnected, L'Anse au Loup and Isolated service areas:

(i) for supply at 4 KV to 25 KV..... $0.40 per kVA

(ii) for supply at 33 KV to 138 KV..... $0.90 per kVA

For the Labrador Interconnected service area:

(iii) for supply at 4 KV to 25 KV..... $0.25 per kVA

(iv) for supply at 33 KV to 138 KV..... $0.60 per kVA

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(l) Where a Customer's monthly demand has been permanently reduced because of the installation of peak load controls, power factor correction, or by rendering sufficient equipment inoperable, by any means satisfactory to Hydro, the monthly demands recorded prior to the effective date of such reduction may be adjusted when determining the Customer's demand for billing purposes thereafter. Should the Customer's demand increase above the adjusted demands in the following 12 months, the Customer will be billed for the charges that would have been incurred over the period if the demand had not been adjusted.

(m) Charges may be based on estimated readings or costs where such estimates are authorized by these Regulations.

(n) An application fee of $8.00 will be charged for all requests for Customer name changes and connection of new Serviced Premises. Landlords will be exempted from the application fee for name changes at Serviced Premises for which a landlord agreement pursuant to Regulation 11(f) is in effect.

10. BILLING:

(a) Hydro shall bill the Customer monthly for charges for Service. However, when a Service is disconnected or a bill is revised, Hydro may issue an additional bill.

(b) The charges for Street and Area Lighting Service may be included as a separate item on a bill for any other Service.

(c) Bills are due and payable when issued. Payment shall be made at such place(s) as Hydro may designate from time to time. Where a bill is not paid in full by the date that a subsequent bill is issued and the amount outstanding is $50.00 or more, Hydro will charge interest at a rate equal to the prime rate charged by chartered banks on the last day of the previous month plus five percent.

(d) Where a Customer's cheque or automated payment is not honoured by their financial institution, a charge of $16.00 may be applied to the Customer's bill.

(e) Where a Customer is billed on the basis of an estimated charge, an adjustment shall be made in a subsequent bill should such estimate prove to be inaccurate.

(f) Where between normal meter reading dates, one Customer assumes from another Customer the responsibility for a metered Service or a Service is Discontinued, Hydro may base the billing on an estimate of the reading as of the date of change.

(g) Where a Customer has been under billed due to an error on the part of Hydro or due to an act or omission by a third party, the Customer may, at the discretion of Hydro, be relieved of the responsibility for all or any part of the amount of the under billing.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

11. DISCONTINUANCE OF SERVICE:

(a) A Service may be Discontinued by the Customer at any time upon prior notice to Hydro provided that Hydro may require 10 days prior notice in writing.

(b) A Service may be Discontinued by Hydro upon 10 days prior notice in writing to the Customer if the Customer:

(i) provided false or misleading information on the application for the Service

(ii) fails to provide security or guarantee for the Service required under Regulation 4.

(c) A Service may be Discontinued by Hydro without notice if the Service was Disconnected pursuant to Rule 12 and has remained Disconnected for over 30 consecutive days.

(d) When Hydro accepts an application for Service, any prior contract for the same Service shall be Discontinued except where an agreement for that Service is signed by a landlord under Regulation 11(f).

(e) Where a Service has been Discontinued, the Service may, at the option of Hydro and subject to Rule 12(a), remain connected.

(f) A landlord may sign an agreement with Hydro to accept charges for Service provided to a rental premise for all periods when Hydro does not have a contract for Service with a tenant for that premise.

12. DISCONNECTION OF SERVICE:

(a) Hydro shall Disconnect a Service within 10 days of receipt of a written request from the Customer.

(b) Hydro may Disconnect a Service without notice to the Customer:

(i) where the Service has been Discontinued.

(ii) on account of or to prevent fraud or abuse.

(iii) where in the opinion of Hydro the Customer's electrical system is defective and represents a danger to life or property.

(iv) where the Customer's electrical system has been modified without compliance with the Electrical Regulations.

(v) where the Customer has a building or structure under Hydro's wires which is within the minimum clearances recommended by the Canadian Standards Association.

(vi) when ordered to do so by any authority having the legal right to issue such order.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

(c) Hydro may, in accordance with its Collection Policies, Disconnect a Service upon prior notice to the Customer if the Customer has a bill for any Service which is not paid in full 30 *days or more after issuance.*

(d) Hydro may Disconnect a Service upon 10 days prior notice to the Customer if the Customer is in violation of any provision of these Regulations.

(e) Hydro may refuse to reconnect a Service if the Customer is in violation of any provisions of these Rules or if the Customer has a bill for any Service which is unpaid.

(f) Hydro may disconnect a service to make repairs or alterations. Where reasonable and practical, Hydro shall give prior notice to the Customer.

(g) Hydro may disconnect the Service to a rental premises where the landlord has an agreement with Hydro authorizing Hydro to disconnect the Service for periods when Hydro does not have a contract for Service with a tenant of that premises.

13. PROPERTY RIGHTS:

(a) The Customer shall provide Hydro with space and cleared rights-of-way on private property for the line(s) and facilities required to serve the Customer.

(b) Hydro shall have the right to install, remove or replace such of its property as it deems necessary.

(c) The Customer shall provide Hydro with access to the Serviced Premises at all reasonable hours for purposes of reading a meter or installing, replacing, removing or testing its equipment, and measuring or checking the connected load.

(d) All equipment and facilities provided by Hydro shall remain the property of Hydro unless otherwise agreed in writing.

(e) The Customer shall not unreasonably interfere with Hydro's access to its property.

(f) The Customer shall not attach wire, cables, clotheslines or any other fixtures to Hydro's poles or other property except by prior written permission of Hydro.

(g) The Customer shall allow Hydro to trim all trees in close proximity to service lines in order to maintain such lines in a safe manner.

(h) The Customer shall not erect any buildings or obstructions on any of Hydro's easement lands or alter the grade of such easements by more than 20 centimetres, without the prior approval of Hydro.

NEWFOUNDLAND AND LABRADOR HYDRO

RULES AND REGULATIONS (INTERIM) (Continued)

14. HYDRO LIABILITY:

Hydro shall not be liable for any failure to supply Service for any cause beyond its reasonable control, nor shall it be liable for any loss, damage or injury caused by the use of Services or resulting from any cause beyond its reasonable control.

15. GENERAL:

(a) No employee, representative or agent of Hydro has authority to make any promise, agreement or representation, whether verbal or otherwise, which is inconsistent with these Regulations and no such promise, agreement or representation shall be binding on Hydro.

(b) Any notice under these Regulations will be considered to have been given to the Customer on the date it is received by the Customer or three days following the date it was delivered or mailed by Hydro to the Customer's last known address, whichever is sooner.

16. POLICIES FOR AUTOMATIC RATE CHANGES

(a) Island Interconnected System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(b) L'Anse au Loup System:

(i) As Newfoundland Power changes its rates, Hydro will automatically adjust all rates such that these customers pay the same rates as Newfoundland Power customers.

(c) Isolated Systems:

(i) Isolated Rural Domestic customers, excluding Government departments, pay the same rates as Newfoundland Power for the basic customer charge and First Block consumption (outlined in Rate 1.2D). Rates charged for consumption above this block will be automatically adjusted by the average rate of change granted Newfoundland Power from time to time.

(ii) Rates for Isolated Rural General Service customers, excluding Government departments, will increase or decrease by the average rate of change granted Newfoundland Power from time to time.

(iii) As Newfoundland Power changes its rates, Hydro will automatically adjust Rural Isolated street and area lighting rates, excluding those for Government departments, such that these rates are the same as charged Newfoundland Power customers.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.2G

DOMESTIC DIESEL

GOVERNMENT DEPARTMENTS (INTERIM)

Availability:

For Service to Government Departments throughout the Island and Labrador diesel service areas of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge ..... $58.03 per month

Energy Charge:
All kilowatt-hours ..... @ 88.360 ¢ per kWh

Minimum Monthly Charge $58.03

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1G

GENERAL SERVICE DIESEL 0-10 kW

GOVERNMENT DEPARTMENTS (INTERIM) (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge ..... $62.22 per month

Energy Charge:
All kilowatt-hours ..... @ 80.272¢ per kWh

Minimum Monthly Charge..... $62.22

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 2.2G

GENERAL SERVICE DIESEL OVER 10 KW

GOVERNMENT DEPARTMENTS (INTERIM) (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: ..... $76.64 per month

Demand Charge:
The maximum demand registered on the meter in the current month..... @ $62.25 per kW

Energy Charge:
All kilowatt-hours..... @ 58.135 ¢ per kWh

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 4.1G

STREET AND AREA LIGHTING SERVICE DIESEL

GOVERNMENT DEPARTMENTS (INTERIM) (Continued)

Availability:

For Street and Area Lighting Service to Government Departments throughout the Island and Labrador Diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$89.67
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	60.22
150W (14,400 lumens)	89.67

[1] Only High Pressure Sodium fixtures are available for all new installations and replacements.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.1L

DOMESTIC (INTERIM)

Availability:

For Service throughout the Labrador Interconnected service area of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge: ..... $7.29 per month

Energy Charge:
All kilowatt-hours ..... @ 3.341 ¢ per kWh

Minimum Monthly Charge..... $7.29

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations**.**
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1L

GENERAL SERVICE 0 - 10 kW (INTERIM)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: ..... $10.65 per month

Energy Charge:
All kilowatt-hours ..... @ 5.339 ¢ per kWh

Minimum Monthly Charge: Single Phase..... $10.65
Three Phase..... $20.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.2L

GENERAL SERVICE 10 - 100 kW (110 kVA) (INTERIM)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month..... @ $2.24 per kW

Energy Charge:
All kilowatt-hours..... @ 2.480 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kW of maximum demand occurring in the 12 months ending with the current month, but not less than $20.00 for a three phase service**.**

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.3L

GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA (INTERIM)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month .... @ $2.04 per kVA

Energy Charge:
All kilowatt-hours..... @ 2.142 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations**.** **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.4L

GENERAL SERVICE 1000 kVA AND OVER (INTERIM)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate:

Billing Demand Charge:
The maximum demand registered on the meter in the current month.... @ $1.79 per kVA

Energy Charge:
All kilowatt-hours..... @ 1.763 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.1L

STREET AND AREA LIGHTING SERVICE (INTERIM)

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR[1]	
250W (9,400 lumens)	$ 15.86
HIGH PRESSURE SODIUM [2]	
100W (8,600 lumens)	11.75
150W (14,400 lumens)	15.86
250W (23,200 lumens)	20.92
400W (45,000 lumens)	27.03

[1] Fixtures previously owned by the Town of Wabush as of September 1, 1985, and transferred to Hydro in 1987.

[2] Only High Pressure Sodium fixtures are available for all new installations and replacements installed after September 1, 2002.

Special poles used exclusively for lighting service

Wood ..... $ 4.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.11L

STREET AND AREA LIGHTING SERVICE (INTERIM)

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro existing as of September 1, 2002.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM[1]	
100W (8,600 lumens)	$ 7.93

[1] Any new fixtures added will be at the rates set out in Rate 4.1L.

Closed

Special poles used exclusively for lighting service

Wood ..... $ 4.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.12L

STREET AND AREA LIGHTING SERVICE (INTERIM)

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by the customer.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM	
100W (8,600 lumens)	$ 4.82

Special poles used exclusively for lighting service

Wood ..... $ 4.00

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 5.1L

SECONDARY ENERGY

Availability:

For Service to Customers on the Labrador Interconnected grid engaged in fuel switching who purchase a minimum of 1 MW load and a maximum of 24 MW, who provide their own transformer and, who are delivered power at primary voltages. Hydro shall supply Secondary Energy to the Customer at such times and to the extent that Hydro has Churchill Falls electricity available in excess of the amount it requires for its own use, and to meet its commitments and sales opportunities, present and future, for firm energy. Moreover, Hydro may interrupt or reduce the supply of Secondary Energy at its sole discretion for any cause whatsoever. The energy delivered shall be used solely for the operation of the equipment engaged in fuel switching.

Energy Charge:

The energy charge shall be calculated monthly based on:

EITHER:

A. The Customer's cost of fuel (cents per litre) most recently delivered to the Customer including fuel additives, if any, in accordance with the following formula:

Secondary Energy Rate = Constant Factor x Fuel Cost/Litre x 90%

$$\text{Constant Factor} = \frac{3413\ \text{BTU/kWh} \times A \times B}{C \times D}$$

Where:

A = Customer's Electric Boiler Efficiency

B = Transformer and Losses Adjustment Factor

C = BTU/Litre of the Customer's fuel

D = Customer's Oil-fired Boiler Efficiency

OR:

B. One (1) cent less than the New York Mercantile Exchange (NYMEX) settlement price for New York Independent System Operator (NYISO) Zone A Swap Peak electricity after the end of trading on the 19th day of the previous month, converted to Canadian dollars using the exchange rate at the closing of the same day.

WHICHEVER IS GREATER

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 5.1L

SECONDARY ENERGY

Prior to the commencement of service, the Customer will provide to Hydro the rate component values for insertion in the pricing formula for Secondary Energy. If subsequent changes to any of these rate components are required, the Customer will provide them to Hydro as soon as practicable. Hydro may require that these rate component values be verified.

Communications

The Customer and Hydro shall each designate a position within their respective staffs to be responsible for communications as to changes in the cost of the fuel delivered to the Customer. Hydro will contact the Customer's designate on or before the second working day of each month at which time the Customer's designate will inform Hydro of the fuel cost. If this information is unavailable to Hydro for any reason, Hydro will use the previous month's fuel cost and other inputs and make the adjustment to the correct values in the following month's billing.

Hydro will inform the Customer of the value of part B of the energy charge calculation on the first business day following the 21st day of the month preceding the month for which the rate is being set.

Power Factor

If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at the Customer's expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

General:

Insofar as they are not inconsistent with the forgoing, the conditions of service provided in the Rules and Regulations shall apply to Customers in this rate class.

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

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

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro, pursuant to Sections 70 and 75 of the *Act*, for the approval of customer electricity rates, rules and regulations on an interim basis to become effective March 1, 2015 (the "2015 Interim Rates Application").

AFFIDAVIT

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

1. I am Manager, Rates and Regulation, 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 28th day of January 2015, before me:

Barrister – Newfoundland and Labrador

Kevin J. Fagan

2015 Interim Rates Application Evidence

Newfoundland and Labrador Hydro

January 2015

newfoundland labrador hydro
a nalcor energy company

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1.0 BACKGROUND

The Amended Application, filed on November 10, 2014, is based on a 2015 Test Year for the purpose of setting new base rates for customers to become effective in 2015. Based on existing rates, Newfoundland and Labrador Hydro (Hydro) would achieve a return on rate base of 3.33% in 2015, which is below the bottom of the approved range of return on rate base of 7.29% established in the 2007 General Rate Application (GRA).[1] The 2015 forecast return on rate base under existing rates of 3.33% is also lower than the proposed 2015 return on rate base of 6.82%. Hydro's forecast income statement under existing rates shows a net loss of $34.6 million for 2015.[2]

In its Amended Application, Hydro requested that the proposed customer rates be approved on an interim basis in advance of completing the GRA. This approach would reduce the amount of 2015 costs deferred for future recovery from customers. Hydro also proposed revised Rate Stabilization Plan (RSP) Rules to become effective on an interim basis effective January 1, 2015 to permit the continued phase-in of the Island Industrial Customer (IC) rates and to ensure the forecast fuel costs reflected in the proposed interim rates were consistent with the forecast fuel costs used in the operation of the RSP.

The Island IC Group presented the position that the impacts of the rate proposals reflected in the Amended Application constitute "rate shock".[3] The IC Group presented a submission in response to Hydro's Amended Application providing alternatives for the Board of Commissioners of Public Utilities (the Board) to consider to reduce the customer rate impacts in implementing interim Island IC rates for 2015.[4] Newfoundland

[1] As shown in Schedule II, line 43, Finance evidence in the Amended Application.
[2] See Schedule II, Finance evidence in the Amended Application.
[3] See letter of IC Group filed December 10, 2014.
[4] See letter of IC Group filed December 18, 2014.

Power (NP) also made a submission which indicated uncertainty on the potential impacts on NP's customers with respect to the implementation of revised RSP rules effective January 1, 2015.[5]

In a letter to Hydro, dated December 24, 2014, the Board advised that it was unable to make a determination with respect to the proposed revised interim Island IC rates prior to January 1, 2015. The Board also expressed the view that the proposed interim rates for Island IC should be considered at the same time as the proposed interim rates for NP. The Board directed Hydro to file a comprehensive and complete application setting out proposals for interim rates for NP and the Island IC to be effective March 1, 2015, and setting out the implications of these proposals for Hydro Rural Customers.

This evidence provides the required information to support Hydro's application requesting approval of Hydro's interim rate proposals for NP, Island IC and Hydro Rural Customers. The evidence will also address the submission of the Island IC Group with respect to "rate shock" and also provides clarity with respect to the RSP implications for retail customers.

2.0 ISLAND INDUSTRIAL CUSTOMER RATES

2.1 Background

As directed by Government, IC rates are to be phased in over a three-year period, with funding for this phase-in to be drawn from the IC RSP Surplus.[6] The phase-in started in September 2013 with a change in the RSP credit adjustment for Teck and the removal of the RSP adjustment for the other Island IC. The rate impacts of the September 1, 2013

[5] See letter of December 11, 2014 in which NP requested the Board to require Hydro to: (i) specify the revisions to the RSP rules which are required to permit the phase-in of Island IC rates beginning January 1, 2015; and (ii) provide information with respect to the implications for NP's customers of the proposed interim revisions.

[6] OC2013-089 and OC2013-090 dated April 4, 2013.

rate change were 22.4% increase for Teck and a 19.1% average increase for the other Island IC.

The Island IC rates do not currently include a fuel rider and, as a result, their rates do not recover the increased cost of Holyrood fuel since the 2007 Test Year. The proposed average base rate increase for Island IC for the 2015 Test Year is 39.2% with no phase-in approach.[7] The proposed 39.2% base rate increase does not include the customer rate impact of recovering the 2014 year-end RSP current balance of $6.8 million from Island IC.[8]

2.2 Amended Application – IC Phase-in Proposals

The Amended Application proposed to complete the phase-in of IC rates by September 1, 2016 by limiting customer impacts through the use of the IC RSP Surplus balance. The IC RSP Surplus balance at December 31, 2014 was $10.9 million.[9] Appendix A to this evidence provides the RSP report for December 2014.

Base rates resulting from the 2015 Test Year Cost of Service Study were proposed to become effective for all Island IC on January 1, 2015, with an offsetting RSP Surplus Credit Adjustment equal to 85% of the base rate increase to limit the customer rate impact.[10] The proposed RSP Surplus Credit Adjustment would be reduced to 35% for the period September 1, 2015 to August 31, 2016 and eliminated on September 1, 2016.

[7] Source: Table 4.15 on page 4.50 of evidence to the Amended Application.

[8] The $6.8 million is lower than the forecast 2014 year-end balance of $8.3 million reflected in the Amended Application primarily due to the credit transfer from the RSP Hydraulic Variation Account at December 31, 2014. In the Amended Application, Hydro proposed the 2014 year-end balance in the RSP Hydraulic Variation Account be applied to recover Hydro's 2014 Test Year forecast Revenue Deficiency. This proposal has not yet been approved by the Board.

[9] The Amended Application was based upon a forecast $11.0 million IC RSP Surplus balance.

[10] The RSP Surplus Credit Adjustment would be calculated on a monthly basis based upon a percentage of the change in rates between 2007 Test Year base rates and 2015 Test Year base rates. This means that 85% of the customer's monthly bill impact of implementation of new base rates will be recovered from the RSP Surplus.

To reduce the customer rate impacts of recovery of the RSP balance concurrent with the phase-in of IC base rates, the Amended Application proposed to recover the $6.8 million year-end 2014 current RSP balance over a two-year period rather than the normal 12-month period.

Table 1 provides the forecast annualized customer impacts of the phase-in proposals included in the Amended Application updated for RSP balances at December 31, 2014.[11] These impacts reflect the combined effect of the base rate phase-in and the recovery of the 2014 year-end RSP balance over a two-year period.

Table 1
Amended Application - IC rate impacts

	March 1, 2015	**September 1, 2015**	**September 1, 2016**
Island IC [12]	17.9%	16.7%	10.0%

2.3 Hydro's Response to IC Group Submission

The IC Group submission of December 18, 2014 expressed concern with the customer impacts and proposed that the Board: (i) consider disposition of the credit balance in the RSP load variation component; and (ii) consider using a lower No. 6 fuel cost in establishing revenue requirement for the purpose of establishing interim rates.

2.3.1 Hydro's Proposal on RSP Load Variation Component

The 2014 year-end credit balance in the RSP load variation component is approximately $35.5 million.[13] Per Order P.U. 29(2013), this balance is currently segregated.[14]

[11] Table 1 assumes the next stage of the phase-in occurs on March 1, 2015 rather than January 1, 2015 as proposed in the Amended Application.
[12] Teck Resources is scheduled to close in 2015.
[13] See page 12 of the December 2014 RSP Report provided as Appendix A.
[14] Per Order No. P.U. 29(2013), load variation is to be segregated in a separate account within the RSP. This balance will remain segregated until a further Order of the Board providing for the disposition of the balance.

The Amended Application proposes that the RSP rules related to the allocation of the load variation component be modified such that the year-to-date net load variation for both NP and IC is allocated among the customer groups based upon energy ratios.[15] The proposed effective date for the proposed RSP change is September 1, 2013.[16]

Disposition of the RSP load variation component based upon an energy ratio allocation would result in a credit of $2.1 million to the IC RSP current balance. The Amended Application provided no recommendation on the timing of the disposition of the 2014 year-end balance of the RSP load variation component. Hydro believes it is reasonable to apply the $2.1 million IC portion of the segregated credit balance in the RSP load variation component to reduce the customer rate impact of recovering the $6.8 million RSP current balance due from IC.[17] The 2015 Interim Rates Application reflects this proposal.

Board approval of the proposed disposition of the segregated RSP load variation component effective December 31, 2014, would reduce the IC RSP current balance to $4.7 million due from customers (i.e., $6.8 million less $2.1 million). The remainder of the $35.5 million segregated RSP load variation balance would flow through the RSP for disposition to retail customers.[18]

[15] The proposed method will allocate the net cost effect of load variation on a basis consistent with the manner that fuel cost variation is currently allocated in the RSP. The proposed method is also consistent with the cost allocation effects of changes in load in a Test Year Cost of Service Study.
[16] The amounts that accumulated in the load variation component for the period 2007 to August 31, 2013 have been transferred to the RSP Surplus for disposition in accordance with the Government directive.
[17] The $2.1 million assumes Board approval of the proposed allocation methodology for the balance in the RSP segregated load variation component effective December 31, 2014 (i.e., based on energy ratios).
[18] Under the proposed 2015 Test Year Cost of Service forecast, approximately 4.3% or $100,000 of the balance would be credited to the Labrador Interconnected System. The disposition of this balance normally accrues to Hydro's net income. However, given 2014 is a test year, it would be appropriate for this balance to be applied to reduce cost recovery related to the net income deficiency from customers on the Labrador Interconnected System.

The proposed disposition reduces customer rate impacts and partially addresses fairness concerns related to the recovery of historic fuel costs through a future IC RSP recovery factor which would apply to all customers including new customers that were not operating at the time these costs were incurred. If these costs were recovered through a future RSP recovery factor, the fuel costs deferred for recovery through the RSP would be recovered from Island IC based upon their future energy use. These RSP fuel costs were incurred prior to the two new Island IC, Vale and Praxair, entering into full operations. As these customers increase their energy requirements and become fully operational, the portion of the current RSP balance recovered from them will increase accordingly.

Hydro believes it is reasonable to recover the remaining $4.7 million in the 2014 year-end RSP current balance costs from the IC RSP Surplus of $10.9 million which also accumulated prior to the new customers becoming fully operational.[19] This treatment of the IC RSP Surplus would facilitate the phase-in of IC rates in that lower rate increases are required of Island IC for 2015 and 2016 during the base rate phase-in period. The 2015 Interim Rates Application includes this proposal as an element of the phase-in of Island IC rates.

2.3.2 Hydro's Proposal on 2015 Test Year Holyrood Fuel Cost

Since Hydro filed its Amended Application on November 10, 2014, the forecast cost of No. 6 fuel at Holyrood has decreased materially. Hydro's Amended Application was based upon an average No. 6 fuel cost of $93.32 per barrel. Based upon the most recent fuel forecast provided by PIRA, the average fuel cost for 2015 is forecast to be $65.63 per barrel.[20] Based upon the 2015 Test Year forecast of approximately 2.6 million

[19] This approach is consistent with the use of approximately $38.1 million of the initial $49 million IC RSP Surplus to provide recovery of the fuel costs allocated to IC that accumulated in the RSP over the period January 1, 2007 to August 31, 2013, as approved in Order No. P.U. 26(2013).

[20] PIRA Energy Group, World oil market forecast update, January 5, 2015, No. 6 fuel 12-month average price of $64.30 (Can/bbl). The average fuel cost for 2015 includes the effect of average inventory cost.

barrels, the revised fuel cost forecast reduces the 2015 Test Year Cost of Service by approximately $73 million (total 2015 Test Year No. 6 fuel cost of $245 million in Amended Application less $172 million based upon $65.63 per barrel). [21] This reduction is equal to approximately 11.8% of the 2015 Test Year revenue requirement for the Island Interconnected System provided in the Amended Application.[22]

Revising the rate increase proposals provided in the Amended Application to adjust for the lower 2015 forecast fuel cost materially reduces the customer impacts for the phase-in period. The base rate increase for the Island IC required to recover the 2015 Test Year costs reflected in the Amended Application is 39.2%. Modifying the revenue requirement to reflect an updated Holyrood fuel cost of $65.63 per barrel reduces the proposed base rate increase to 18.1%.

Hydro believes it is appropriate to reflect a more current 2015 No. 6 fuel cost forecast in establishing March 1, 2015 interim rates. The 2015 Interim Rates Application proposes rates that reflect the updated forecast 2015 fuel cost of $65.63 per barrel.

For the purpose of establishing interim rates, an adjusted revenue requirement for NP and the Island IC was determined to reflect the reduced No. 6 fuel cost forecast for 2015. The computation of the adjusted revenue requirement did not require the completion of a revised 2015 Test Year Cost of Service Study. Appendix B to this evidence provides the calculation of a 2015 Test Year adjusted revenue requirement to be used for the purpose of establishing interim rates for 2015.[23]

[21] ($93.32/bbl - $65.63/bbl) x 2,624,371 bbls = $72,668,833 or $73 million.

[22] 11.8% =$73 million/$621 million. The $621 million is provided in Schedule 1.2, page 2 of 8 in the 2015 Test Year Cost of Service Study (Exhibit 13 to the Amended Application).

[23] The customer allocation of the fuel cost reduction for the 2015 Test Year provided in Appendix B for the purpose of establishing revenue requirement for determining 2015 interim rates is based upon the 2015 Test Year Cost of Service production energy allocation ratios on the Island Interconnected System. See Schedule 3.1A, page 1 of 2 of the 2015 Test Year Cost of Service Study, Exhibit 13.

A 2015 Test Year Cost of Service Study reflecting the updated fuel cost forecast will be provided to the Board for the purpose of establishing final rates.

2.4 Proposed Phase-in of Island IC Rates

The material reduction in the proposed 2015 base rate increase for Island IC from that proposed in the Amended Application requires a modified phase-in approach.[24]

Hydro considered two alternatives to the modified phase-in approach. Under the first alternative, an RSP Surplus Credit Adjustment offsetting 85% of the base rate increase would apply for the period March 1, 2015 to December 31, 2015, decrease to 60% for the period January 1, 2016 to August 31, 2016 and be eliminated on September 1, 2016. A second alternative would be the use of a 73% RSP Surplus Credit Adjustment for the period March 1, 2015 to August 31, 2016.

The calculations assume the $10.9 million balance in the IC RSP Surplus at December 31, 2014 is used to recover the $4.7 million 2014 year-end RSP balance.[25] The $6.2 million remaining IC RSP Surplus balance is proposed to be used to phase-in the Island IC base rates over the period March 1, 2015 to August 31, 2016.

Table 2 provides the Island IC rate impacts under each alternative. Appendix C provides the detail supporting the calculations in Table 2. Under both alternatives the annual RSP Adjustment for the Island IC would occur on January 1, 2016.

[24] The RSP Surplus Credit Adjustment percentages and the timing of the IC rate changes proposed in the Amended Application were developed giving consideration to both the customer impacts of the phase-in of base rates and the recovery of the 2014 forecast year-end current balance in the RSP.

[25] The $4.7 million 2014 year-end RSP balance is the adjusted balance that reflects the load variation credit of $2.1 million applied against the $6.8 million IC RSP current plan balance provided in Appendix A.

Table 2 **Interim Rates Application - IC Rate Impacts** [26]			
	March 1, 2015	**January 1, 2016**	**September 1, 2016**
Alternative 1	2.7%	4.4%	10.2%
Alternative 2	4.9%	-	12.7%

The use of the 73% RSP Surplus Credit Adjustment for the remainder of the phase-in period eliminates the requirement for an additional base rate adjustment on January 1, 2016. However, the use of two RSP Surplus Adjustments providing three rate changes to complete the base rate phase-in limits the maximum impact of any single base rate change to approximately 10%. Hydro is proposing Alternative 1 for this reason.

Table 3 provides the IC RSP Surplus balances under each alternative. Appendix D provides the supporting calculations for Table 3.

Table 3 **Forecast IC RSP Surplus Drawdown Balances ($millions)**			
	March 1, 2015[27]	**January 1, 2016**	**September 1, 2016**
Alternative 1	6.3	2.6	0.1
Alternative 2	6.3	3.1	0.2

2.5 Island IC Rate Design

Hydro has followed the same rate design approach as described in the Amended Application in deriving the proposed 2015 interim rates for the Island IC.

For Island IC, the energy charge has been reduced from 5.151¢ per kWh to 4.114¢ per kWh to reflect the revised 2015 fuel cost forecast. The proposed price for the other rate

[26] Teck Resources is scheduled to close operations in 2015.

[27] Assumes Board approval of disposition of the 2014 RSP segregated load variation balance based upon energy ratios effective December 31, 2014 and the IC RSP Surplus balance of $10.9 million is used to provide recovery of the adjusted 2014 year-end IC current RSP balance of $4.7 million (i.e., $6.8 million 2014 year-end IC RSP current balance in Appendix B less $2.1 million allocated load variation balance).

components are the same as included in the Amended Application. The proposed Island IC rate is provided below. Rate components that have been revised from those filed in the Amended Application have been shaded.

Island IC Base Rate:

Demand Charge:

$8.38 per kW of billing demand per month

Firm Energy Charge: @ 4.114 ¢ per kWh

Specifically Assigned Charges as follows:

	Annual Amount
Corner Brook Pulp and Paper Limited	$891,045
North Atlantic Refining Limited	$91,729
Teck Resources Limited	$208,600
Vale Newfoundland and Labrador Inc.	$499,522

The average system losses used in the calculation of the energy charge for non-firm service to Island IC is 3.47%. The proposed Island Industrial wheeling rate is 0.443¢ per kWh.

There is currently no RSP recovery rate in effect for Island IC. It is proposed that Teck Resources will continue to have an RSP Adjustment rate to manage customer impacts consistent with Government directives. The proposed Teck RSP rate effective March 1, 2015 is (1.113)¢ per kWh.[28] Hydro proposes the revised RSP rate for Teck be approved to provide the same rate increase to Teck as is proposed for the other Island IC.

[28] The Teck RSP Adjustment rate is currently (1.111)¢ per kWh as approved in Order No. P.U. 29(2013).

3.0 UTILITY RATE

3.1 Proposed Rate Change

In the Amended Application, the proposed base rate provided an increase of 26.5% in base rate revenue from NP. This material increase primarily resulted from increased recovery of fuel costs reflected in the proposed base rate; these fuel costs are currently being recovered through the RSP fuel rider. The RSP fuel rider is proposed to be set to zero upon implementation of the new base rate. As a result, the billing impact of the base rate increase is materially offset by the elimination of the RSP fuel rider. The overall billing impact of the proposed base rate and RSP rate change reflected in the Amended Application is 4.1%.[29]

The RSP fuel rider of 1.526¢ per kWh in the existing rate to NP provides for the recovery of approximately $90 million of fuel costs if maintained for all of 2015.[30] This amount is not recorded as revenue by Hydro as the amounts are credited to the RSP (i.e., a deferral account on the balance sheet).

The proposed rate for NP to become effective March 1, 2015 on an interim basis reflects an increase in the billing demand charge and an increase in the base rate energy charges (see Section 3.2). The proposed base rate increase to NP reflecting the lower forecast fuel costs for 2015 is 11.2%. See Table 4.

[29] See Table 4.15 on page 4.50 of the evidence to the Amended Application.
[30] See Table 4.15 on page 4.50 of the evidence in the Amended Application and Table 4 in this evidence.

Table 4 **NP - 2015 Forecast Revenues and RSP Charges ($millions)**				
	Existing Rates	**Proposed Rates – March 1, 2015**	**Change**	
Forecast Revenue	415.4	461.7	46.3	11.2%
RSP Fuel Rider Charges	90.4	-	(90.4)	
RSP Recovery Rider Charges[31]	(32.6)	(32.6)	-	
Total Forecast Billings	473.2	429.1	(44.1)	-9.3%

Table 4 shows that while the 2015 Interim Rates Application proposes a revenue increase to Hydro from NP of 11.2%, the billing impact would be a rate decrease to NP of 9.3%.

3.2 NP Rate Design

Hydro has followed the same rate design approach as described in the Amended Application in deriving the proposed interim rate for NP to become effective March 1, 2015. The tail block energy charge has been reduced from 11.622¢ per kWh to 9.448¢ per kWh to reflect the revised 2015 fuel cost forecast.[32] The proposed price for the other rate components are the same as included in the Amended Application.

The proposed March 1, 2015 rate for NP is provided below. Rate components that have been revised from those filed in the Amended Application have been shaded.

NP Base Rate:

Demand Charge:

$5.50 per kW of billing demand per month

[31] Based upon RSP recovery adjustment of (0.551)¢ per kWh effective July 1, 2014.

[32] As shown in Appendix B, there is also an adjustment to revenue requirement to reflect the estimated impact of the rural deficit for 2015.

Energy Charge:

First 250,000,000 kilowatt-hours	@	3.411	¢ per kWh
All excess kilowatt-hours	@	9.446	¢ per kWh
Firming-up Charge:	@	2.974	¢ per kWh

NP RSP Rate

The proposed RSP rate of (0.551)¢ per kWh reflects the removal of the fuel rider of 1.526¢ per kWh which was based upon a forecasted fuel cost of $105.60/bbl (Can). The proposed RSP recovery adjustment reflects the continuation of the existing RSP recovery adjustment.

3.3 July 1 2015 RSP Update

There are two RSP adjustments updated each July 1. The RSP fuel rider is updated to reflect forecast fuel costs for the following 12 months and the RSP recovery adjustment is updated to reflect balances that have accumulated as a result of variances from forecast fuel costs and RSP recovery over the previous 12 months.[33]

The implementation of interim base rates effective March 1, 2015 to reflect an updated fuel cost for 2015 removes the RSP fuel rider that has been in effect since July 1, 2014. Hydro sees no additional benefit to provide a further fuel cost update to become effective July 1, 2015. If upon the conclusion of the GRA, a more recent forecast indicates an adjustment to the fuel cost reflected in the 2015 Test Year fuel cost is required, the Board can implement a fuel cost adjustment at that time.

The current RSP recovery adjustment effective July 1, 2014 of (0.551)¢ per kWh provides forecast reduced billings for 2015 of $32 million.[34] This credit is scheduled to expire on July 1, 2015. However, approval of the proposed disposition of the balance in the RSP

[33] The RSP recovery adjustment also flows through transfers from the RSP Hydraulic Variation Account.
[34] See Table 4.15 on page 4.50 of the evidence in the Amended Application.

segregated load variation balance effective December 31, 2014 would result in a credit of approximately $33 million to the NP RSP current balance. An additional credit balance transfer of $33 million effective year-end 2014 would permit the existing RSP recovery adjustment to continue until the end of June 2016 without resulting in a large RSP balance owing from customers.

Implementation of revised retail rates on March 1, 2015 that reflect both the disposition of the balance in the RSP segregated load variation component and the updated fuel forecast avoids the requirement for a July 1, 2015 rate change. The 2015 Interim Rates Application is proposing there be no RSP rate adjustment for 2015.

4.0 RETAIL RATES

This section provides the impacts on retail rates if the Board approves the 2015 Interim Rates Application.

4.1 Rates on the Island Interconnected and L'Anse au Loup Systems

Approval of the proposed interim rates effective March 1, 2015 results in a rate reduction of 6.3% to retail customers on both the Island Interconnected System and the L'Anse au Loup System. This compares with the 2.8% increase proposed in the Amended Application.

4.2 Hydro Diesel Rates

Non-Government Diesel Rates

On December 23, 2014 Government issued Order in Council (OC) 2014-372. This OC requires that the rate increase in 2015 to Hydro's Non-Government Rural Isolated Domestic and General Service customers be equal to the rate increase approved for NP's customers. To comply with OC2014-372, the 2015 Interim Rates Application proposes the same percentage rate change apply to non-government customers on

Hydro's Diesel Systems as is proposed for NP's customers and Hydro's Rural Customers on the Island Interconnected and L'Anse au Loup systems. In the Amended Application, Hydro proposed above average rate increases to these customers. See Table 5 provided in Section 5.

OC2014-372 is provided as Appendix E to this evidence.

Government Diesel Rates

Government rate classes in isolated systems pay rates that recover 100% of the allocated test year costs. Similar to the forecast costs of No. 6 fuel, the forecast cost of No. 2 fuel has decreased materially for 2015.[35]

To address this 2015 fuel cost reduction, Hydro is proposing lower rate increases for these customers in the 2015 Interim Rates Application than proposed in the Amended Application. See Table 5 provided in Section 5.

4.3 Labrador Interconnected Rates

The average increase proposed for Hydro Rural Customers on the Labrador Interconnected System in the Amended Application is 2.1%. The cost of serving customers on the Labrador Interconnected System is not impacted by the updated fuel cost estimate for the 2015 Test Year. Therefore, Hydro is proposing the rates included in the Amended Application be approved on an interim basis March 1, 2015.[36]

[35] No. 2 fuel is used in generating electricity on Hydro's Isolated Diesel Systems. The 2015 forecast cost has reduced by $3.2 million to $15.6 million compared to the forecast of $18.8 million reflected in the Amended Application.

[36] The reduced revenue requirement for Newfoundland Power as a result of lower fuel costs will result in a higher rural deficit allocation to the Labrador Interconnected System. Hydro has not reflected this adjustment in the 2015 Interim Rates Application.

5.0 CUSTOMER RATE IMPACTS

Table 5 provides a comparison of the average customer impacts under both the Amended Application and the Interim Rates Application.

Table 5
2015 Proposed Customer Rate Impacts[37]

	Amended Application	2015 Interim Application
Island Interconnected System		
Newfoundland Power – Wholesale rate	4.1%	(9.3%)
Estimated end consumers rate impact	2.8%	(6.3%)
Estimated rural consumers rate impact	2.8%	(6.3%)
Industrial Customers	39.2%	18.1%
Island Isolated systems		
Domestic	7.1%	(6.3%)
General Service 0-10	18.5%	(6.3%)
General Service Over 10 kW	19.2%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)
Island Isolated - Government Departments		
General Service 0-10	24.7%	16.6%
General Service Over 10 kW	25.4%	16.9%
Street and Area Lighting	27.5	27.5%
Labrador Interconnected System		
Domestic	1.9%	1.9%
General Service 0 - 10	1.9%	1.9%
General Service 10 - 100 kW	1.9%	1.9%
General Service 110 - 1000 kVA	1.9%	1.9%
General Service 1000 kVA and Over	1.9%	1.9%
Street and Area Lighting	17.5%	17.5%
Labrador Isolated Systems		
Domestic	7.1%	(6.3%)
General Service 0-10	18.5%	(6.3%)
General Service Over 10 kW	19.2%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)
Labrador Isolated - Government Departments		
Domestic	21.5%	14.0%
General Service 0-10	24.7%	16.6%
General Service Over 10 kW	25.4%	16.9%
Street and Area Lighting	27.5%	27.5%
L'Anse Au Loup System		
Domestic	2.8%	(6.3%)
General Service 0-10	2.8%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)

[37] Exclude the effects of the Northern Strategic Plan which applies to customers on isolated systems in Labrador.

6.0 2015 NET INCOME DEFICIENCY

As shown in Section 3, even though the 2015 Interim Rates Application proposes a billing decrease to NP of 9.3%, the proposed base rate increase provides a revenue increase to Hydro from NP of 11.2%. As a result, the delayed implementation of a new Utility rate beyond January 1, 2015 will result in a 2015 net income shortfall for Hydro.

The 2015 Interim Rates Application also proposes base rate increases to Island IC, Government customers on Diesel Systems and customers on the Labrador Interconnected System. A delay in implementation of new rates beyond January 1, 2015 will also result in a 2015 net income shortfall for Hydro from these customer groups.

Approval of the proposed interim rates effective March 1, 2015 does not provide recovery of the financial impact of delayed rate implementation beyond January 1, 2015. The net income shortfall resulting from the delayed rate implementation is approximately $20 million.[38] The Amended Application proposed that the revenue shortfall associated with delayed implementation of 2015 rates be recovered through a rate rider to be implemented upon the establishment of final customer rates.

Table 6 provides the estimated 2015 net income deficiency by customer group. The net income deficiency by customer group was determined based upon the proportion of the forecast revenue shortfall for January and February for each customer class.

[38] The actual 2015 net income shortfall will be finalized upon the Board's determination of final 2015 Test Year revenue requirement and customer rates.

Table 6 **Forecast Allocation of 2015 Net Income Shortfall**	
Customer Group	**Shortfall ($millions)**
NP and Hydro Rural (excl. Lab. Interconnected)	18.39
Island IC	1.37
Hydro Rural – Isolated Systems Government	0.10
Hydro Rural – Labrador Interconnected	0.16
Total	20.02

Recovery of the 2014 and 2015 net income shortfall is not reflected in the rates proposed in the 2015 Interim Rates Application. In the Amended Application, Hydro proposed the credit balance in the RSP Hydraulic Variation Account be used to provide recovery of the 2014 Revenue Deficiency. Hydro still considers this proposal to be appropriate.[39] However, the approach to recovery of the 2014 and 2015 net income shortfall can be dealt with by the Board at the conclusion of testing Hydro's costs for 2014 and 2015.

7.0 APPROVALS REQUIRED FOR IMPLEMENTATION

The proposed rate schedules reflecting the proposals provided in this evidence are included in Schedule 1 to the 2015 Interim Rates Application. All rate schedules with the exception of the rate schedules for customers on the Labrador Interconnected System have changed relative to those filed in the Amended Application. All changes from that filed in the Amended Application have been shaded.

The RSP rules in the rate schedules reflect the following proposals:

[39] The credit balance in the RSP Hydraulic Variation Account at year-end 2014 is $43.4 million. See Appendix A.

- The Board is requested to approve removal of Section B (1.3(b)) as there is no further Rural Labrador Interconnected Automatic Rate Adjustment. References to the December 6, 2006 Government directive have also been removed. This proposal is consistent with the Amended Application;
- The RSP rules related to the allocation of the load variation component are modified such that the year-to-date net load variation for both NP and IC is allocated among the customer groups based upon energy ratios. The proposed effective date for the RSP change is September 1, 2013. This proposal is consistent with the Amended Application. See Section B(2);
- The RSP rules are modified to provide for disposition of the 2014 year-end RSP segregated load variation balance of $35.5 million to the respective current RSP plan balances based upon 2014 energy ratios effective December 31, 2014. See Section B(2). This is a new proposal;
- The RSP rules include a new clause which suspends the NP RSP rate adjustment scheduled for July 1, 2015 until a further Order of the Board. See Section D (1.2). This is a new proposal;
- The Board is requested to approve the removal of Section D (2.2), by which the IC RSP Adjustment was suspended effective January 1, 2014. This proposal is consistent with the Amended Application;
- In the Amended Application, Hydro proposed a new Section E: Historical Balance. This section is no longer required under the 2015 Interim Rates Application.
- The Board is requested to approve a one-time transfer from the IC RSP Surplus balance effective December 31, 2014 to provide recovery of the IC current plan balance. See revised Section E (1.1). This is a new proposal;
- The Board is requested to approve implementation of an RSP Surplus Credit Adjustment described in Section 4.6.5 of the Amended Application evidence in which the IC RSP Surplus balance will be used to phase-in Island IC base rates. The RSP Surplus Credit Adjustment is proposed to be 85% for the period March 1, 2015

to December 31, 2015, decreased to 60% for the period January 1, 2016 to August 31, 2016 and eliminated September 1, 2016. See revised Section E (1.1). This is a modification to the RSP Surplus Credit Adjustment proposed in the Amended Application; and

- The Board is requested to approve implementation of an updated Teck Resources RSP Adjustment rate necessary to comply with Government direction. See revised Section E(1.1). This is a modification of the RSP Adjustment for Teck proposed in the Amended Application.

APPENDIX A

December 2014 Rate Stabilization Plan Report

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN REPORT
December 31, 2014
PRELIMINARY

Newfoundland and Labrador Hydro

Rate Stabilization Plan Report
December 31, 2014

Summary of Key Facts

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro), as amended by Board Order No. P.U. 40 (2003) and Order No. P.U. 8 (2007), is established for Hydro's utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations 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 was approved by Board Order No. P.U. 8 (2007) and 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 7.529% per annum. Holyrood's operating efficiency is set, for RSP purposes, at 630 kWh/barrel regardless of the actual conversion rate experienced.

	2007 Test Year Cost of Service			
	Net Hydraulic Production	No. 6 Fuel Cost	Utility Load	Industrial Load
	(kWh)	($Can/bbl.)	(kWh)	(kWh)
January	427,100,000	54.17	574,800,000	78,300,000
February	388,680,000	54.73	518,600,000	70,900,000
March	415,080,000	55.46	524,700,000	76,600,000
April	355,520,000	55.46	429,200,000	75,600,000
May	324,240,000	55.46	358,700,000	69,500,000
June	328,500,000	54.49	298,400,000	73,800,000
July	386,790,000	54.49	293,400,000	77,500,000
August	379,140,000	54.49	287,000,000	77,900,000
September	363,560,000	54.49	297,700,000	73,000,000
October	340,510,000	54.56	360,200,000	74,400,000
November	364,390,000	54.56	439,300,000	74,100,000
December	398,560,000	58.98	543,800,000	72,700,000
Total	4,472,070,000		4,925,800,000	894,300,000

Rate Stabilization Plan
Plan Highlights
December 31, 2014

	Actual	Cost of Service	Variance	Year-to-Date Due (To) From customers	Reference
Hydraulic production year-to-date	4,670.7 GWh	4,472.1 GWh	198.7 GWh	$ (18,010,509)	Page 4
No 6 fuel cost - Current month	$ 93.50	$ 58.98	$ 34.52	$ 119,653,898	Page 5
Year-to-date customer load - Utility	5,852.1 GWh	4,925.8 GWh	926.3 GWh	$ (296,453)	Page 8
Year-to-date customer load - Industrial	392. GWh	894.3 GWh	-502.3 GWh	$ (25,416,148)	Page 9
				$ 75,930,788	
Rural rates					
Rural Rate Alteration (RRA) [1]	$ (10,078,761)				
Less : RRA to utility customer	$ (8,076,216)				Page 10
RRA to Labrador interconnected	(2,002,545)				
Fuel variance to Labrador interconnected	$ 901,193				Page 6
Net Labrador interconnected	$ (1,101,352)				
Current plan summary					
One year recovery					
Due (to) from utility customer	$ (39,004,557)				Page 10
Due (to) from Industrial customers	$ 6,774,833				Page 11
Sub total	(32,229,724)				
Four year recovery					
Hydraulic balance	$ (43,358,639)				Page 4
Segregated Load Variation					Page 12
Utility Customer	$ 519,908				
Industrial Customer	$ (35,979,573)				
Sub Total	$ (35,459,665)				
Utility RSP Surplus	$ (124,013,626)				Page 13
Industrial RSP Surplus	$ (10,892,683)				Page 14
Total plan balance	$ (245,954,337)				

[1] Beginning January 2011, the RRA includes a monthly credit of $98,295. This amount relates to the phase in of the application of the credit from secondary energy sales to CFB Goose Bay to the Rural deficit as stated in Section B, Clause 1.3(b) of the approved Rate Stabilization Plan Regulations which received final approval in Order No. P.U. 33 (2010) issued December 15, 2010.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Net Hydraulic Production Variation
December 31, 2014

	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 12)**
Opening balance							(39,801,010)
January	427,100,000	536,781,236	(109,681,236)	54.17	(9,430,845)	(241,493)	(49,473,348)
February	388,680,000	491,548,118	(102,868,118)	54.73	(8,936,464)	(300,180)	(58,709,992)
March	415,080,000	522,832,527	(107,752,527)	55.46	(9,485,643)	(356,223)	(68,551,858)
April	355,520,000	426,489,174	(70,969,174)	55.46	(6,247,540)	(415,938)	(75,215,336)
May	324,240,000	369,954,774	(45,714,774)	55.46	(4,024,351)	(456,369)	(79,696,056)
June	328,500,000	281,279,242	47,220,758	54.49	4,084,221	(483,556)	(76,095,391)
July	386,790,000	266,269,167	120,520,833	54.49	10,424,096	(461,709)	(66,133,004)
August	379,140,000	255,957,693	123,182,307	54.49	10,654,292	(401,262)	(55,879,974)
September	363,560,000	266,357,259	97,202,741	54.49	8,407,266	(339,052)	(47,811,760)
October	340,510,000	372,963,387	(32,453,387)	54.56	(2,810,566)	(290,098)	(50,912,424)
November	364,390,000	412,913,649	(48,523,649)	54.56	(4,202,302)	(308,911)	(55,423,637)
December	398,560,000	467,377,970	(68,817,970)	58.98	(6,442,673)	(336,283)	(62,202,593)
	4,472,070,000	4,670,724,196	(198,654,196)		(18,010,509)	(4,391,074)	(62,202,593)
Hydraulic Allocation [2]					14,452,880	4,391,074	18,843,954
Hydraulic variation at year end					(3,557,629)	-	(43,358,639)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

(2) At year end 25% of the hydraulic variation balance and 100% of the annual financing charges are allocated to customers as follows:.

	(from page 6) 12 month kWh	% of kWh to total	Allocation	Reallocate Rural	**(to pages 11 & 12)** Net
Utility	5,852,126,368	87.2%	16,440,596	1,160,150	17,600,746
Industrial	392,007,676	5.8%	1,101,282		1,101,282
Rural	463,481,626	7.0%	1,302,076	(1,302,076)	-
Total	6,707,615,671	100.0%	18,843,954	(141,926)	18,702,028
Labrador Inteconnected (write-off to income)				141,926	141,926
				-	18,843,954

Newfoundland and Labrador Hydro

Rate Stabilization Plan
No. 6 Fuel Variation
December 31, 2014

	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 6)**
January	311,974	0	311,974	54.17	104.55	50.38	15,717,272
February	330,404	0	330,404	54.73	114.37	59.64	19,705,279
March	336,807	0	336,807	55.46	115.08	59.62	20,080,440
April	204,611	0	204,611	55.46	116.57	61.11	12,503,798
May	140,687	0	140,687	55.46	114.61	59.15	8,321,658
June	69,714	0	69,714	54.49	114.52	60.03	4,184,930
July	74,127	0	74,127	54.49	111.72	57.23	4,242,300
August	86,200	0	86,200	54.49	111.71	57.22	4,932,364
September	90,658	0	90,658	54.49	110.44	55.95	5,072,337
October	108,693	0	108,693	54.56	105.37	50.81	5,522,686
November	195,443	0	195,443	54.56	100.35	45.79	8,949,357
December	301,905	8	301,897	58.98	93.50	34.52	10,421,477
	2,251,225	8	2,251,217	55.47	108.54	53.07	119,653,898

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Allocation of Fuel Variance - Year-to-Date
December 31, 2014

	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 89.10%)**	**(G X 10.90%)**
					(to page 7)			**(from page 5)**	**(to page 7)**	
January	5,603,728,914	348,666,137	459,258,079	6,411,653,130	13,736,759	854,706	1,125,807	15,717,272	1,003,094	122,713
February	5,664,560,418	354,489,796	462,266,852	6,481,317,066	30,958,705	1,937,405	2,526,441	35,422,551	2,251,059	275,382
March	5,796,147,497	357,155,092	469,518,334	6,622,820,923	48,574,999	2,993,162	3,934,830	55,502,991	3,505,934	428,896
April	5,845,354,684	356,096,276	472,164,936	6,673,615,896	59,566,479	3,628,762	4,811,548	68,006,789	4,287,089	524,459
May	5,915,517,955	356,357,967	469,720,965	6,741,596,887	66,975,571	4,034,690	5,318,186	76,328,447	4,738,504	579,682
June	5,906,422,350	355,287,469	469,523,829	6,731,233,649	70,647,675	4,249,651	5,616,051	80,513,377	5,003,901	612,150
July	5,911,372,726	367,726,532	470,095,183	6,749,194,442	74,234,400	4,617,871	5,903,406	84,755,677	5,259,935	643,471
August	5,917,093,062	372,247,993	467,803,919	6,757,144,975	78,537,975	4,940,873	6,209,193	89,688,041	5,532,391	676,802
September	5,938,483,840	363,899,898	465,261,574	6,767,645,313	83,150,483	5,095,316	6,514,579	94,760,378	5,804,490	710,089
October	5,934,948,611	379,486,735	463,001,233	6,777,436,580	87,817,101	5,615,116	6,850,847	100,283,064	6,104,105	746,742
November	5,944,900,314	387,781,146	463,758,836	6,796,440,297	95,546,466	6,232,420	7,453,535	109,232,421	6,641,100	812,435
December	5,852,126,368	392,007,676	463,481,626	6,707,615,671	104,393,240	6,992,835	8,267,823	119,653,898	7,366,630	901,193

(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 approved Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Allocation of Fuel Variance - Monthly
December 31, 2014

	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 6)		(from page 6)		(to page 10)	(from page 6)	(to page 11)
January	13,736,759	13,736,759	1,003,094	1,003,094	14,739,853	854,706	854,706
February	30,958,705	17,221,946	2,251,059	1,247,965	18,469,911	1,937,405	1,082,699
March	48,574,999	17,616,294	3,505,934	1,254,875	18,871,169	2,993,162	1,055,757
April	59,566,479	10,991,480	4,287,089	781,155	11,772,635	3,628,762	635,600
May	66,975,571	7,409,092	4,738,504	451,415	7,860,507	4,034,690	405,928
June	70,647,675	3,672,104	5,003,901	265,397	3,937,501	4,249,651	214,961
July	74,234,400	3,586,725	5,259,935	256,034	3,842,759	4,617,871	368,220
August	78,537,975	4,303,575	5,532,391	272,456	4,576,031	4,940,873	323,002
September	83,150,483	4,612,508	5,804,490	272,099	4,884,607	5,095,316	154,443
October	87,817,101	4,666,618	6,104,105	299,615	4,966,233	5,615,116	519,800
November	95,546,466	7,729,365	6,641,100	536,995	8,266,360	6,232,420	617,304
December	104,393,240	8,846,774	7,366,630	725,530	9,572,304	6,992,835	760,415
		104,393,240		7,366,630	111,759,870		6,992,835

(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.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Load Variation - Utility
December 31, 2014

	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	Load Variation	Cost of Service Sales	Actual Sales	Firming Up Charge	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 10)
January	574,800,000	701,822,280	127,022,280	54.17	0.08805	(262,412)	0	0	0.00841	0	(262,412)
February	518,600,000	668,138,074	149,538,074	54.73	0.08805	(176,004)	0	0	0.00841	0	(176,004)
March	524,700,000	704,231,084	179,531,084	55.46	0.08805	(3,277)	0	0	0.00841	0	(3,277)
April	429,200,000	543,018,070	113,818,070	55.46	0.08805	(2,078)	0	0	0.00841	0	(2,078)
May	358,700,000	458,076,079	99,376,079	55.46	0.08805	(1,814)	0	0	0.00841	0	(1,814)
June	298,400,000	328,626,921	30,226,921	54.49	0.08805	(47,092)	0	0	0.00841	0	(47,092)
July	293,400,000	303,396,872	9,996,872	54.49	0.08805	(15,574)	0	0	0.00841	0	(15,574)
August	287,000,000	300,426,340	13,426,340	54.49	0.08805	(20,917)	0	0	0.00841	0	(20,917)
September	297,700,000	315,235,972	17,535,972	54.49	0.08805	(27,320)	0	0	0.00841	0	(27,320)
October	360,200,000	401,788,711	41,588,711	54.56	0.08805	(60,172)	0	0	0.00841	0	(60,172)
November	439,300,000	508,174,745	68,874,745	54.56	0.08805	(99,650)	0	0	0.00841	0	(99,650)
December	543,800,000	619,191,220	75,391,220	58.98	0.08805	419,857	0	0	0.00841	0	419,857
	4,925,800,000	5,852,126,368	926,326,368			(296,453)	0	0		0	(296,453)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Summary of Utility Customer
December 31, 2014

	A	B	C	D	E	F	H
	Load Variation	Allocation Fuel Variance	Allocation Rural Rate Alteration [1]	Subtotal Monthly Variances	Financing Charges	Adjustment [2]	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)	($)
				(A + B + C)			
	(from page 8)	**(from page 7)**					**(to page 12)**
Opening Balance							(80,173,930)
January		14,739,853	(1,016,527)	13,723,326	(486,455)	(3,740,713)	(70,677,772)
February		18,469,911	(1,030,686)	17,439,225	(428,837)	(3,561,176)	(57,228,560)
March		18,871,169	(923,118)	17,948,051	(347,234)	(3,753,552)	(43,381,295)
April		11,772,635	(841,706)	10,930,929	(263,216)	(2,894,286)	(35,607,868)
May		7,860,507	(697,990)	7,162,517	(216,051)	(2,441,546)	(31,102,948)
June		3,937,501	(563,085)	3,374,416	(188,717)	(1,751,581)	(29,668,830)
July		3,842,759	(626,858)	3,215,901	(180,016)	(2,957,733)	(29,590,678)
August		4,576,031	(619,867)	3,956,164	(179,541)	(2,929,157)	(28,743,212)
September		4,884,607	(531,034)	4,353,573	(174,399)	(3,073,551)	(27,637,589)
October		4,966,233	(668,733)	4,297,500	(167,691)	(3,917,440)	(27,425,220)
November		8,266,360	(665,811)	7,600,549	(166,403)	(4,954,704)	(24,945,778)
December		9,572,304	109,199	9,681,503	(102,422)	(6,037,114)	(21,403,811)
Year to date	0	111,759,870	(8,076,216)	103,683,654	(2,900,982)	(42,012,553)	58,770,119
Hydraulic allocation **(from page 4)**							(17,600,746)
Total	0	111,759,870	(8,076,216)	103,683,654	(2,900,982)	(42,012,553)	(39,004,557)

(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 Cost of Service Study, which is 89.10% and 10.90% respectively. The Labrador Interconnected amount is then removed from the plan and written off to net income (loss).

(2) The RSP adjustment rate for the Utility was 0.533 cents per kwh effective July 1,2013 to June 30, 2014 and is 0.975 cents per kwh effective July 1, 2014 to June 30, 2015.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Load Variation - Industrial
December 31, 2014

	A	B	C	D	E	F
	Cost of Service Sales (kWh)	Actual Sales (kWh)	Sales Variance (kWh) **(B - A)**	Cost of Service No. 6 Fuel Cost ($)	Firm Energy Rate ($/kWh)	Load Variation ($) **C x {(D/O[1]) - E} (to page 11)**
January	78,300,000	28,925,453	(49,374,547)	54.17	0.03676	(2,430,419)
February	70,900,000	31,688,409	(39,211,591)	54.73	0.03676	(1,965,011)
March	76,600,000	33,620,893	(42,979,107)	55.46	0.03676	(2,203,614)
April	75,600,000	31,139,219	(44,460,781)	55.46	0.03676	(2,279,582)
May	69,500,000	31,983,361	(37,516,639)	55.46	0.03676	(1,923,544)
June	73,800,000	26,476,656	(47,323,344)	54.49	0.03676	(2,353,488)
July	77,500,000	33,771,940	(43,728,060)	54.49	0.03676	(2,174,687)
August	77,900,000	33,808,084	(44,091,916)	54.49	0.03676	(2,192,782)
September	73,000,000	20,247,328	(52,752,672)	54.49	0.03676	(2,623,499)
October	74,400,000	40,386,121	(34,013,879)	54.56	0.03676	(1,695,360)
November	74,100,000	41,846,773	(32,253,227)	54.56	0.03676	(1,607,603)
December	72,700,000	38,113,439	(34,586,561)	58.98	0.03676	(1,966,559)
	894,300,000	392,007,676	(502,292,324)			(25,416,148)

(1) O is the Holyrood Operating Efficiency of 630 kWh/barrel.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Summary of Industrial Customers
December 31, 2014

	A	B	C	D	E	F
	Load Variation	Allocation Fuel Variance	Subtotal Monthly Variances	Financing Charges	Adjustment	Cumulative Net Balance
	($)	($)	($)	($)	($)	($)
			(A + B)			
	(from page 9)	**(from page 7)**				**(to page 12)**
Opening Balance						566,125
January		854,706	854,706	3,435	0	1,424,266
February		1,082,699	1,082,699	8,642	0	2,515,607
March		1,055,757	1,055,757	15,263	0	3,586,627
April		635,600	635,600	21,762	0	4,243,989
May		405,928	405,928	25,750	0	4,675,667
June		214,961	214,961	28,370	0	4,918,998
July		368,220	368,220	29,846	0	5,317,064
August		323,002	323,002	32,261	0	5,672,327
September		154,443	154,443	34,417	0	5,861,187
October		519,800	519,800	35,563	0	6,416,550
November		617,304	617,304	38,932	0	7,072,786
December		760,415	760,415	42,914	0	7,876,115
Year to date		6,992,835	6,992,835	317,155	0	7,309,990
Hydraulic allocation **(from page 4)**						(1,101,282)
Total		6,992,835	6,992,835	317,155	0	6,774,833

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Load Variation January - December 2014
December 31, 2014

	A	B	C	D	E	F	G
	Utility Customer			Island Industrial Customers			
	Load Variation	Financing Charges	Total To Date	Load Variation	Financing Charges	Total To Date	Total To Date [1]
		($)	($) (A + B)		($)	($) (D+ E)	($) (C +F)
	(from page 8)			**(from page 9)**			**(to page 15)**
Opening Balance			790,787			(8,991,282)	(8,200,495)
January	(262,412)	4,798	533,173	(2,430,419)	(54,555)	(11,476,256)	(10,943,083)
February	(176,004)	3,235	360,404	(1,965,011)	(69,632)	(13,510,899)	(13,150,495)
March	(3,277)	2,187	359,314	(2,203,614)	(81,977)	(15,796,490)	(15,437,176)
April	(2,078)	2,180	359,416	(2,279,582)	(95,845)	(18,171,917)	(17,812,501)
May	(1,814)	2,181	359,783	(1,923,544)	(110,258)	(20,205,719)	(19,845,936)
June	(47,092)	2,183	314,874	(2,353,488)	(122,598)	(22,681,805)	(22,366,931)
July	(15,574)	1,910	301,210	(2,174,687)	(137,622)	(24,994,114)	(24,692,904)
August	(20,917)	1,828	282,121	(2,192,782)	(151,652)	(27,338,548)	(27,056,427)
September	(27,320)	1,712	256,513	(2,623,499)	(165,877)	(30,127,924)	(29,871,411)
October	(60,172)	1,556	197,897	(1,695,360)	(182,801)	(32,006,085)	(31,808,188)
November	(99,650)	1,201	99,448	(1,607,603)	(194,197)	(33,807,885)	(33,708,437)
December	419,857	603	519,908	(1,966,559)	(205,129)	(35,979,573)	(35,459,665)
Total	(296,453)	25,574	519,908	(25,416,148)	(1,572,143)	(35,979,573)	(35,459,665)

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

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Utility RSP Surplus
December 31, 2014

	A	B	C	D
	Industrial Customer Adjustment	Utility Payout	Financing Charges	Cumulative Balance
	($)	($)	($)	($)
	(from page 10)			**(to page 15)**
Opening Balance				(115,330,446)
January			(699,767)	(116,030,213)
February			(704,013)	(116,734,226)
March			(708,285)	(117,442,511)
April			(712,582)	(118,155,093)
May			(716,906)	(118,871,999)
June			(721,256)	(119,593,255)
July			(725,632)	(120,318,887)
August			(730,035)	(121,048,922)
September			(734,464)	(121,783,386)
October			(738,921)	(122,522,307)
November			(743,404)	(123,265,711)
December			(747,915)	(124,013,626)
Year to date	-	-	(8,683,180)	(8,683,180)
Total			(8,683,180)	(124,013,626)

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Industrial RSP Surplus
December 31, 2014

	A	B	C	D	E
	Industrial Surplus	Teck Allocation [1]	Industrial Drawdown	Financing Charges	Cumulative Balance
	($)	($)	($)	($)	($)
	(from page 11)		**(from page 11)**		**(to page 15)**
Opening Balance					(10,858,146)
January		66,308		(65,882)	(10,857,720)
February		62,040		(65,879)	(10,861,559)
March		69,269		(65,903)	(10,858,193)
April		66,730		(65,882)	(10,857,345)
May		64,063		(65,877)	(10,859,159)
June		59,650		(65,888)	(10,865,397)
July		60,902		(65,926)	(10,870,421)
August		59,299		(65,956)	(10,877,078)
September		60,783		(65,997)	(10,882,292)
October		60,410		(66,028)	(10,887,910)
November		63,329		(66,062)	(10,890,643)
December		64,039		(66,079)	(10,892,683)
Year to date	0	756,822	0	(791,359)	(34,537)
Total	0	756,822	0	(791,359)	(10,892,683)

(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.

Newfoundland and Labrador Hydro

Rate Stabilization Plan
Overall Summary
December 31, 2014

	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 4)	**(from page 10)**	**(from page 11)**	**(from page 12)**	**(from page 13)**	**(from page 14)**	
Opening Balance	(39,801,010)	(80,173,930)	566,125	(8,200,495)	(115,330,446)	(10,858,146)	(253,797,902)
January	(49,473,348)	(70,677,772)	1,424,266	(10,943,083)	(116,030,213)	(10,857,720)	(256,557,870)
February	(58,709,992)	(57,228,560)	2,515,607	(13,150,495)	(116,734,226)	(10,861,559)	(254,169,225)
March	(68,551,858)	(43,381,295)	3,586,627	(15,437,176)	(117,442,511)	(10,858,193)	(252,084,406)
April	(75,215,336)	(35,607,868)	4,243,989	(17,812,501)	(118,155,093)	(10,857,345)	(253,404,154)
May	(79,696,056)	(31,102,948)	4,675,667	(19,845,936)	(118,871,999)	(10,859,159)	(255,700,431)
June	(76,095,391)	(29,668,830)	4,918,998	(22,366,931)	(119,593,255)	(10,865,397)	(253,670,806)
July	(66,133,004)	(29,590,678)	5,317,064	(24,692,904)	(120,318,887)	(10,870,421)	(246,288,830)
August	(55,879,974)	(28,743,212)	5,672,327	(27,056,427)	(121,048,922)	(10,877,078)	(237,933,286)
September	(47,811,760)	(27,637,589)	5,861,187	(29,871,411)	(121,783,386)	(10,882,292)	(232,125,251)
October	(50,912,424)	(27,425,220)	6,416,550	(31,808,188)	(122,522,307)	(10,887,910)	(237,139,499)
November	(55,423,637)	(24,945,778)	7,072,786	(33,708,437)	(123,265,711)	(10,890,643)	(241,161,420)
December	(43,358,639)	(39,004,557)	6,774,833	(35,459,665)	(124,013,626)	(10,892,683)	(245,954,337)

APPENDIX B

Calculation of Adjusted 2015 Test Year Revenue Requirement

2015 Test Year Adjusted Revenue Requirements for NP and Island IC

Line No.		A Newfoundland Power	B Island Industrial	Reference
1	Total Revenue as Filed	525,340,174	42,517,934	Amended Application, Section 4, Table 4.15, Page 4.50
2	No. 6 Fuel Cost Variance	(61,417,518)	(6,442,092)	Line 7 and 8, Col B
3	Adjusted Revenue before Rural Deficit Impact	463,922,656	36,075,842	Line 1 + Line 2
4	Rural Deficit Impact[1]	(2,173,595)	0	
5	Net Adjusted Revenue	461,749,061	36,075,842	Line 3 + Line 4

		MWh @ Gen[2]	Amount ($)	
6	No. 6 Fuel Cost Variance		72,668,833	2,624,371 bbls x ($93.32/bbl - $65.63/bbl)
	Allocation by Customer Class:			
7	Newfoundland Power	84.517%	61,417,518	Line 6, Col B x Line 7, Col A
8	Island Industrial	8.865%	6,442,092	Line 6, Col B x Line 8, Col A
9	Hydro Rural	6.618%	4,809,223	Line 6, Col B x Line 9, Col A
		100.00%	72,668,833	

[1] Rural deficit attributable to NP decreases by $2.2M as a net result of lower No. 6 fuel costs ($4.8M) and diesel costs ($3.2M). These costs reductions are materially offset by the reduced revenue resulting from the proposed 6.3% decrease in Hydro Rural rates in the 2015 Interim Rates Application ($5.8M).

[2] Source: 2015 Test Year Cost of Service Study, Exhibit 13 in Amended Application, Schedule 3.1A, page 1 of 2.

APPENDIX C

IC Rate Phase-in Alternatives

Newfoundland and Labrador Hydro
Calculation of IC Phase-in Annualized Rate Impacts[1]
Alternative 1[2]
($millions)

Line No.		A	B	C	D
	IC Billings (excluding Teck)				
		Existing Rates	**1-Mar-15**	**1-Jan-16**	**1-Sep-16**
1	Base Rates Billing	29.42	34.78	34.78	34.78
2	RSP Phase-In	-	-	-	-
3	Total Revenue and RSP	29.42	34.78	34.78	34.78
4	RSP Surplus Credit	-	(4.55)	(3.21)	-
5	Total Billing	29.42	30.23	31.57	34.78
6	Annualized Rate Increase		2.7%	4.4%	10.2%
	Teck Billings[3]				
		Existing Rates	**1-Mar-15**	**1-Jan-16**	**1-Sep-16**
7	Base Rates Billing	1.22	1.40	-	-
8	RSP Phase-In	-	-	-	-
9	Total Revenue and RSP	1.22	1.40	-	-
10	RSP Surplus Credit	-	(0.16)	-	-
11	RSP Teck Adjustment[4]	(0.23)	(0.23)		
12	Total Billing	0.99	1.02	-	-
13	Annualized Rate Increase		2.7%	-	-

[1] Calculations are based upon 2015 billing determinants.
[2] Alternative 1 assumes an RSP Surplus Credit using 85% of the proposed base rate increase for Mar 1, 2015 to Dec 31, 2015 and 60% for Jan 1, 2016 to Aug 31, 2016.
[3] Teck Resources is forecast to close operations in 2015.
[4] Current RSP rate for Teck effective Sept 1, 2013 of (1.111) cents/kWh adjusted to (1.113) cents/kWh effective Mar 1, 2015.

Newfoundland and Labrador Hydro
Calculation of IC Phase-in Annualized Rate Impacts[1]
Alternative 2[2]
($millions)

		A	B	C	D
	IC Billings (excluding Teck)				
Line No.		**Existing Rates**	**1-Mar-15**	**1-Jan-16**	**1-Sep-16**
1	Base Rates Billing	29.42	34.78	34.78	34.78
2	RSP Phase-In	-	-	-	-
3	Total Revenue and RSP	29.42	34.78	34.78	34.78
4	RSP Surplus Credit	-	(3.91)	(3.91)	-
5	Total Billing	29.42	30.87	30.87	34.78
6	Annualized Rate Increase		4.9%	0.0%	12.7%
	Teck Billings[3]				
		Existing Rates	**1-Mar-15**	**1-Jan-16**	**1-Sep-16**
7	Base Rates Billing	1.22	1.40	-	-
8	RSP Phase-In	-	-	-	-
9	Total Revenue and RSP	1.22	1.40	-	-
10	RSP Surplus Credit	-	(0.13)	-	-
11	RSP Teck Adjustment[4]	(0.23)	(0.23)		
12	Total Billing	0.99	1.04	-	-
13	Annualized Rate Increase		4.9%	-	-

[1] Calculations are based upon 2015 billing determinants.
[2] Alternative 2 assumes an RSP Surplus Credit using 73% of the proposed base rate increase for Mar 1, 2015 to Aug 31, 2016.
[3] Teck Resources is forecast to close operations in 2015.
[4] Current RSP rate for Teck effective Sept 1, 2013 of (1.111) cents/kWh adjusted to (1.116) cents/kWh effective Mar 1, 2015.

APPENDIX D

Calculation of Drawdown of IC RSP Surplus Balance

Newfoundland and Labrador Hydro
Forecast IC RSP Surplus drawdown summary for Mar 1, 2015 to Aug 31, 2016
Alternative 1[1]

Line No			A Total IC Allocation	B Finance Charge[2]	C Cumulative Net Balance[3]	
1		Opening balance			(6,190,197)	
2	2015	January	0	(34,113)	(6,224,310)	
3		February	0	(34,301)	(6,258,611)	
4		March	385,400	(34,490)	(5,907,701)	
5		April	385,686	(32,556)	(5,554,571)	
6		May	399,743	(30,610)	(5,185,438)	
7		June	395,966	(28,576)	(4,818,049)	
8		July	387,927	(26,551)	(4,456,673)	
9		August	395,284	(24,560)	(4,085,948)	
10		September	343,074	(22,517)	(3,765,391)	
11		October	422,286	(20,750)	(3,363,856)	
12		November	420,586	(18,538)	(2,961,808)	
13		December	427,659	(16,322)	(2,550,471)	
14		Y-T-D	3,963,610	(323,884)	3,639,726	
15		Balance			(2,550,471)	
16	2016	January	305,674	(14,055)	(2,258,852)	
17		February	292,503	(12,448)	(1,978,797)	
18		March	310,197	(10,905)	(1,679,505)	
19		April	306,604	(9,255)	(1,382,156)	
20		May	315,186	(7,617)	(1,074,587)	
21		June	311,696	(5,922)	(768,813)	
22		July	318,615	(4,237)	(454,436)	
23		August	332,285	(2,504)	(124,655)	
24		Y-T-D	2,492,759	(66,943)	2,425,816	(124,655)
25		Balance			(124,655)	

[1] Reflects Alternative 1 for phase-in which is 85% RSP Surplus Credit Adjustment effective for Mar 1, 2015 to Dec 31, 2015 and 60% for Jan 1, 2016 to Aug 31, 2016.

[2] 2015 Test Year proposed monthly financing rate of 6.613%.

[3] Dec 31, 2014 closing IC RSP Surplus balance of $10.9M adjusted for one-time transfer to recover IC current RSP plan balance as at Dec 31, 2014 of $4.7M. $4.7M is the adjusted Dec 31, 2014 closing IC current RSP Plan balance of $6.8M reduced by the $2.1 million IC share of the $35.5M Dec 31, 2014 segregated load variation balance.

Newfoundland and Labrador Hydro
Forecast IC RSP Surplus drawdown summary for Mar 1, 2015 to Aug 31, 2016
Alternative 2[1]

Line No			A Total IC Allocation	B Finance Charge[2]	C Cumulative Net Balance[3]
1		Opening balance			(6,190,197)
2	2015	January	0	(34,113)	(6,224,310)
3		February	0	(34,301)	(6,258,611)
4		March	330,907	(34,490)	(5,962,194)
5		April	331,155	(32,857)	(5,663,896)
6		May	343,225	(31,213)	(5,351,883)
7		June	340,025	(29,493)	(5,041,351)
8		July	333,161	(27,782)	(4,735,972)
9		August	339,480	(26,099)	(4,422,592)
10		September	294,640	(24,372)	(4,152,324)
11		October	362,669	(22,883)	(3,812,538)
12		November	361,209	(21,010)	(3,472,339)
13		December	367,284	(19,135)	(3,124,190)
14		Y-T-D	3,403,755	(337,748)	3,066,007
15		Balance			(3,124,190)
16	2016	January	371,903	(17,217)	(2,769,504)
17		February	355,878	(15,262)	(2,428,888)
18		March	377,406	(13,385)	(2,064,866)
19		April	373,035	(11,379)	(1,703,211)
20		May	383,477	(9,386)	(1,329,120)
21		June	379,230	(7,325)	(957,215)
22		July	387,648	(5,275)	(574,842)
23		August	404,280	(3,168)	(173,730)
24		Y-T-D	3,032,857	(82,397)	2,950,460
25		Balance			(173,730)

[1] Reflects Alternative 2 for phase-in which is 73% RSP Surplus Credit Adjustment effective for Mar 1, 2015 to Aug 31, 2016.

[2] 2015 Test Year proposed monthly financing rate of 6.613%.

[3] Dec 31, 2014 closing IC RSP Surplus balance of $10.9M adjusted for one-time transfer to recover IC current RSP plan balance as at Dec 31, 2014 of $4.7M. $4.7M is the adjusted Dec 31, 2014 closing IC current RSP Plan balance of $6.8M reduced by the $2.1 million IC share of the $35.5M Dec 31, 2014 segregated load variation balance.

APPENDIX E

Order in Council OC2014-372

Executive Council

Newfoundland and Labrador

Certified to be a true copy of a Minute of a Meeting of the Committee of the Executive Council of Newfoundland and Labrador approved by His Honour the Lieutenant-Governor on

2014/12/23

OC2014-372

NR/DM
E Martin/Nalcor
A Wells/PUB
TB/Secretary
FIN/DM
Deputy Clerk
File

MC2014-0585. XX2014-140.

Under the authority of section 5.1 of the Electrical Control Power Act, 1994, the Lieutenant Governor in Council is pleased to direct the Board of Commissioners of Public Utilities to adopt a policy for Non-Government Rural Isolated Domestic and General Service customers of Newfoundland and Labrador Hydro that:

i) any changes in rates charged to these customers shall be equal to changes approved for equivalent rate classes of Newfoundland Power customers on or after January 1, 2007;

ii) notwithstanding (i), commencing January 1, 2016 rates for these customers shall be those that would have come into effect but for this directive and directives OC2006-512, OC2008-365, OC2009-390, OC2010-322 and OC2012-329; and

iii) the provisions of this directive do not apply to rates to be established for these customers following December 31, 2015.

Julia Mullaley
Clerk of the Executive Council

newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
Canada A1B 4K7
t. 709.737.1400 f. 709.737.1800
www.nlh.nl.ca

February 4, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - 2015 Interim Rates Application

In its Amended Application filed with the Board of Commissioners of Public Utilities (the Board) on November 10, 2014, Newfoundland and Labrador Hydro (Hydro) requested that the proposed customer rates be approved on an interim basis in advance of completing the General Rate Application. This approach would reduce the amount of 2015 costs deferred for future recovery from customers.

In a letter from the Board dated December 24, 2014, the Board stated it was "unable to make a determination on the differing proposals and complex issues raised with respect to the proposed revised interim Industrial Customer rates prior to January 1, 2015." The Board also believed that interim rates for Newfoundland Power and the Island Industrial Customers should be considered at the same time. Hydro was directed by the Board to file a comprehensive interim rates application for rates to be charged effective March 1, 2015. Hydro complied with the Board directive and filed the 2015 Interim Rates Application on January 28, 2015.

Hydro is supportive of the compressed schedule provided by the Board to deal with the 2015 Interim Rates Application in an effort to achieve the target date for new customer rates to become effective March 1, 2015. To further aid the Board in reviewing the 2015 Interim Rates Application, Hydro has enclosed an updated 2015 Test Year Cost of Service Study to reflect the revised fuel costs used in the 2015 Interim Rates Application.[1]

At the counsel meeting of January 30, 2015, Newfoundland Power stated that it did not support the 2015 Interim Rates Application. Without Newfoundland Power's support for the application, implementation of the proposed 6.3% rate decrease to the customers of Newfoundland Power may not be attainable effective March 1, 2015. Following the counsel meeting, Hydro requested a meeting with Newfoundland Power to try and facilitate implementation of reduced customer rates effective March 1, 2015. This meeting is tentatively scheduled for Friday, February 6.

[1] Any differences in revenue requirements for Newfoundland Power and Industrial Customers from those provided in Appendix B to the 2015 Interim Rates Application are related to rounding.

Hydro is actively working to progress the 2015 Interim Rates Application in an expedient manner to ensure reduced customer rates, consistent with Hydro's application, are implemented as soon as possible.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey L. Pennell
Legal Counsel

TLP/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Senwung Luk – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn
Genevieve M. Dawson – Benson Buffett

2015 TEST YEAR COST OF SERVICE

Updated to reflect the revised fuel costs

in Hydro's 2015 Interim Rates Application

dated January 28, 2015

January 29, 2015

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Island Interconnected ($)	4 Island Isolated ($)	5 Labrador Isolated ($)	6 L'Anse au Loup ($)	7 Labrador Interconnected ($)	8 Basis of Proration
	Revenue Requirement							
	Expenses							
1	Operating, Maintenance and Admin.	139,566,670	106,052,783	5,871,802	14,032,074	1,633,449	11,976,563	Detailed Analysis
2	Fuels - No. 6 Fuel	172,737,329	172,737,329	-	-	-	-	Detailed Analysis
3	Fuels - Diesel	15,649,393	87,140	1,916,489	13,063,614	507,629	74,521	Detailed Analysis
4	Fuels - Gas Turbine	3,672,993	3,473,690	-	-	-	199,303	
5	Fuel Supply Deferral	1,991,280	1,991,280					
6	Power Purchases -CF(L)Co	1,856,851	-	-	-	-	1,856,851	Detailed Analysis
7	Power Purchases - Other	61,396,916	58,109,820	232,400	-	3,054,696	-	Detailed Analysis
9	Depreciation	64,339,518	57,258,885	538,967	2,620,505	435,327	3,485,835	Detailed Analysis
	Expense Credits:							
10	Sundry	(664,680)	(505,072)	(27,964)	(66,827)	(7,779)	(57,038)	Total O&M Expenses
11	Building Rental Income	(17,472)	(17,472)	-	-	-	0	Detailed Analysis
12	Tax Refunds	-	-	-	-	-	-	Total O&M Expenses
13	Suppliers' Discounts	(103,548)	(78,683)	(4,356)	(10,411)	(1,212)	(8,886)	Total O&M Expenses
14	Pole Attachments	(1,718,482)	(1,263,389)	(24,203)	(105,320)	(69,837)	(255,733)	Detailed Analysis
15	Secondary Energy Revenues	-	-	-	-	-	-	Island Interconnected
16	Wheeling Revenues	-	0	-	-	-	-	Island Interconnected
17	Application Fees	(26,544)	(11,476)	(168)	(1,472)	(412)	(13,016)	Detailed Analysis
18	Meter Test Revenues	(3,400)	(2,075)	(57)	(215)	(110)	(943)	Weighted Customers
19	**Total Expense Credits**	**(2,534,126)**	**(1,878,167)**	**(56,749)**	**(184,245)**	**(79,350)**	**(335,615)**	
20	**Subtotal Expenses**	**458,676,824**	**397,832,760**	**8,502,910**	**29,531,948**	**5,551,750**	**17,257,457**	
21	Disposal Gain/Loss	4,074,381	3,555,647	133,059	273,138	70,800	41,737	Detailed Analysis
22	**Subtotal Rev Reqt Excl Return**	**462,751,205**	**401,388,407**	**8,635,969**	**29,805,086**	**5,622,550**	**17,299,194**	
23	Return on Debt	88,982,245	80,364,761	609,802	2,915,201	560,525	4,531,956	Rate Base
24	Return on Equity	33,867,524	30,587,624	232,097	1,109,554	213,341	1,724,907	Rate Base
25	**Total Revenue Requirement**	**585,600,973**	**512,340,792**	**9,477,867**	**33,829,840**	**6,396,417**	**23,556,057**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Return on Rate Base

Line No	1	2 Total $	3 Island Interconnected $	4 Island Isolated $	5 Labrador Isolated $	6 L'Anse au Loup $	7 Labrador Interconnected $	8 Basis of Proration
	Rate Base:							
1	Average Net Book Value	1,623,460,914	1,463,835,765	11,343,054	52,258,240	10,540,414	85,483,442	Schedule 2.3
2	Cash Working Capital	7,037,000	6,345,094	49,167	226,517	45,688	370,534	Prorated on Average Net Book Value - L. 1
3	Fuel Inventory - No. 6 Fuel	58,916,050	58,916,050	-	-	-	-	Specifically Assigned - Holyrood
4	Fuel Inventory - Diesel	3,518,344	186,223	165,549	3,084,574	44,283	37,715	Detailed Fuel Analysis
5	Fuel Inventory - Gas Turbine	4,198,498	3,992,487	-	-	-	206,011	Detailed Fuel Analysis
6	Inventory/Supplies	27,402,000	24,359,458	250,202	973,460	217,976	1,600,905	Prorated on Total Plant in Service, Schedule 2.2
7	Deferred Charges: Holyrood	-	-					Detailed Analysis
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	77,491,000	69,871,776	541,426	2,494,389	503,115	4,080,294	Prorated on Average Net Book Value - L. 1
9	Total Rate Base	**1,802,023,806**	**1,627,506,853**	**12,349,399**	**59,037,180**	**11,351,476**	**91,778,900**	
10	Less: Rural Portion	-	-	-	-	-	-	Schedule 2.6, L. 9
11	Rate Base Available for Equity Return	**1,802,023,806**	**1,627,506,853**	**12,349,399**	**59,037,180**	**11,351,476**	**91,778,900**	
	Corporate Targets:							
12	Capital Structure: Percent of Debt	74.076% (1)						
13	Return	6.666%						
14	Weighted Average Return: Debt	**4.938%**						
15	Capital Structure: Percent of Equity	21.357% (1)						
16	Return	8.800%						
17	Weighted Average Return: Equity	**1.879%**						
18	Weighted Average Cost of Capital	**6.817%**						
	Return on Rate Base by System (%):							
19	Return on Rate Base - Debt Component	-	4.938%	4.938%	4.938%	4.938%	4.938%	
20	Return on Rate Base - Equity Component	-	1.879%	1.879%	1.879%	1.879%	1.879%	
	Return on Rate Base ($):							
21	Return on Debt	88,982,245	80,364,761	609,802	2,915,201	560,525	4,531,956	Schedule 2.6, L.12
22	Return on Equity	33,867,524	30,587,624	232,097	1,109,554	213,341	1,724,907	Schedule 2.6, L.13
23	Return on Rate Base ($)	**122,849,768**	**110,952,385**	**841,898**	**4,024,755**	**773,867**	**6,256,863**	Schedule 2.6, L.14
	Return on Total Rate Base (%):							
24	Return on Rate Base - Debt Component	4.938%	4.938%	4.938%	4.938%	4.938%	4.938%	L. 21 divided by L.9
25	Return on Rate Base - Equity Component	1.879%	1.879%	1.879%	1.879%	1.879%	1.879%	L. 22 divided by L.9
26	Return on Rate Base (%)	**6.817%**	**6.817%**	**6.817%**	**6.817%**	**6.817%**	**6.817%**	L. 23 divided by L.9

(1) Debt and equity weightings reflect a 0.667% funded ARO and 3.9% component for Employee Future Benefits at 0% cost.

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credits ($)	5 Deficit ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	Total System							
1	Newfoundland Power	461,711,758	402,222,213	-	59,488,702	-	461,710,914	
2	RSP Activity	-	-	-	-	-	-	
3	Subtotal Newfoundland Power	**461,711,758**	**402,222,213**	**-**	**59,488,702**	**-**	**461,710,914**	**1.15**
4	Island Industrial	36,074,016	36,177,072	-	-		36,177,072	1.00
5	Unallocated RSP Hydraulic Variation	-	-	-	-		-	-
6	Labrador Industrial	5,437,390	5,429,118	-	-		5,429,118	1.00
7	CFB - Goose Bay Secondary	932,221	19,653	912,568	-		932,221	47.43
8	Rural Labrador Interconnected	20,520,143	18,107,285	-	2,678,069		20,785,354	1.13
	Rural Deficit Areas							
9	Island Interconnected	48,399,154	73,941,500	-	(25,542,347)		48,399,154	0.65
10	Island Isolated	1,554,779	9,477,867	-	(7,923,088)		1,554,779	0.16
11	Labrador Isolated	7,912,462	33,829,840	-	(25,917,378)		7,912,462	0.23
12	L'Anse au Loup	2,699,891	6,396,417	-	(3,696,526)		2,699,891	0.42
13	CFB Revenue Credit Applied to Deficit	-	-	(912,568)	912,568		-	-
14	**Subtotal**	**60,566,287**	**123,645,625**	**(912,568)**	**(62,166,771)**	**-**	**60,566,287**	**0.49**
15	**Total**	**585,241,815**	**585,600,967**	**-**	**-**	**-**	**585,600,967**	**1.00**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit Allocation ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	Island Interconnected							
1	Newfoundland Power	461,711,758	402,222,213	-	59,488,702	-	461,710,914	
2	NLP RSP Activity	-					-	
3	**Subtotal Newfoundland Power**	**461,711,758**	**402,222,213**	**-**	**59,488,702**	**-**	**461,710,914**	**1.15**
4	Industrial - Firm	36,074,016	36,177,072	-			36,177,072	
5	Industrial - Non-Firm	-	-	-			-	
6	Industrial RSP Activity	-					-	
7	**Subtotal Industrial**	**36,074,016**	**36,177,072**	**-**	**-**		**36,177,072**	**1.00**
	Rural							
8	1.1 Domestic	13,412,813	21,825,972	-	(8,413,159)		13,412,813	0.61
9	1.12 Domestic All Electric	16,034,854	25,206,406	-	(9,171,552)		16,034,854	0.64
10	1.3 Special	18,012	62,394	-	(44,382)		18,012	0.29
11	2.1 General Service 0-10 kW							
12	2.2 General Service 10-100 kW	8,731,299	12,400,318	-	(3,669,019)		8,731,299	0.70
13	2.3 General Service 110-1,000 kVa	5,996,982	8,592,816	-	(2,595,834)		5,996,982	0.70
14	2.4 General Service Over 1,000 kVa	3,286,618	4,547,734	-	(1,261,117)		3,286,618	0.72
15	4.1 Street and Area Lighting	918,576	1,305,861	-	(387,285)		918,576	0.70
16	**Subtotal Rural**	**48,399,154**	**73,941,500**	**-**	**(25,542,347)**		**48,399,154**	**0.65**
17	**Total Island Interconnected**	**546,184,928**	**512,340,785**	**-**	**33,946,355**		**546,287,140**	**1.07**

Note1:
Calculation of Island Industrial Non-Firm Revenue Credit

Island Industrial Non-Firm Revenues, Ln 5, Col 2	-
Island Industrial Non-Firm Allocated Cost of Service, Ln 5, Col 3	-
Credit to be allocated to Island Interconnected Firm Customers	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	Island Isolated							
1	1.2 Domestic Diesel	752,263	7,172,233		(6,419,970)		752,263	0.10
2	1.2G Government Domestic Diesel	0	0		0		0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0		0	0.00
4	2.1 General Service 0-10 kW	208,134	914,227		(706,092)		208,134	0.23
5	2.2 GS 10-100 kW	555,599	763,491		(207,892)		555,599	0.73
6	2.3 GS 110-1,000 kVa	0	446,270		(446,270)		0	0.00
7	2.4 General Service Over 1,000 kVa	0	0		0		0	0.00
8	2.5 GS Diesel	0	0		0		0	0.00
9	2.5G Gov't General Service Diesel	0	0		0		0	0.00
10	4.1 Street and Area Lighting	38,783	181,646		(142,863)		38,783	0.21
11	4.1G Gov't Street and Area Lighting	0	0		0		0	0.00
12	**Total**	**1,554,779**	**9,477,867**		**(7,923,088)**		**1,554,779**	**0.16**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	Labrador Isolated							
1	1.2 Domestic Diesel	3,216,171	17,963,510		(14,747,339)		3,216,171	0.18
2	1.2G Government Domestic Diesel	0	0		0		0	0.00
3	1.23 Churches, Schools & Com Halls	0	0		0		0	0.00
4	2.1 General Service 0-10 kW	1,148,283	3,441,081		(2,292,799)		1,148,283	0.33
5	2.2 GS 10-100 kW	2,863,808	8,787,428		(5,923,620)		2,863,808	0.33
6	2.3 GS 110-1,000 kVa	341,452	1,791,102		(1,449,650)		341,452	0.19
7	2.4 General Service Over 1,000 kVa	231,518	1,499,779		(1,268,261)		231,518	0.15
8	2.5 GS Diesel	0	0		0		0	0.00
9	2.5G Gov't General Service Diesel	0	0		0		0	0.00
10	4.1 Street and Area Lighting	111,231	346,941		(235,710)		111,231	0.32
11	4.1G Gov't Street and Area Lighting	0	0		0		0	0.00
12	**Total**	**7,912,462**	**33,829,840**		**(25,917,378)**		**7,912,462**	**0.23**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	L'Anse au Loup							
1	1.1 Domestic	499,503	1,319,666		(820,163)		499,503	0.38
2	1.12 Domestic All Electric	1,165,835	2,920,813		(1,754,978)		1,165,835	0.40
3	2.1 General Service 0-10 kW	0	0		0		0	0.00
4	2.2 General Service 10-100 kW	783,425	1,691,583		(908,158)		783,425	0.46
5	2.3 General Service 110-1,000 kVa	205,494	396,823		(191,330)		205,494	0.52
6	4.1 Street and Area Lighting	45,634	67,532		(21,897)		45,634	0.68
7	**Total L'Anse Au Loup**	**2,699,891**	**6,396,417**		**(3,696,526)**		**2,699,891**	**0.42**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Comparison of Revenue & Allocated Revenue Requirement

Line No.	1 Rate Class	2 Revenues ($)	3 Cost of Service Before Deficit and Revenue Credit Allocation ($)	4 Revenue Credit ($)	5 Deficit Allocation ($)	6 RSP Activity ($)	7 Revenue Requirement After Deficit and Revenue Credit Allocation (Col.3+4+5+6) ($)	8 Revenue to Cost Coverage (Col.2/3)
	Labrador Interconnected							
1	Industrial IOCC Firm	5,437,390	5,429,118		-		5,429,118	1.00
2	Industrial IOCC Non-Firm	-	-		-		-	0.00
3	**Subtotal Industrial**	**5,437,390**	**5,429,118**	**-**	**-**		**5,429,118**	**1.00**
4	**CFB - Goose Bay Secondary**	932,221	19,653	912,568	-		932,221	47.43
	Rural							
5	1.1 Domestic	103,203	214,932	-	31,788.42		246,720	0.48
6	1.1A Domestic All Electric	11,255,906	10,904,394	-	1,612,761		12,517,155	1.03
7	2.1 General Service 0-10 kW	417,993	371,215	-	54,903		426,118	1.13
8	2.2 General Service 10-100 kW	2,386,562	1,852,925	-	274,048		2,126,973	1.29
9	2.3 General Service 110-1,000 kVa	3,129,052	2,322,913	-	343,559		2,666,473	1.35
10	2.4 General Service Over 1,000 kVa	2,860,240	2,116,892	-	313,088		2,429,980	1.35
11	4.1 Street and Area Lighting	367,187	324,013	-	47,922		371,935	1.13
12	**Subtotal Rural**	**20,520,143**	**18,107,285**	**-**	**2,678,069**		**20,785,354**	**1.13**
13	**Total Labrador Interconnected**	**26,889,754**	**23,556,057**	**912,568**	**2,678,069**		**27,146,694**	**1.14**

Note1:
Calculation of CFB - Goose Bay Secondary Revenue Credit

CFB - Goose Bay Secondary Revenues, Ln 4, Col 2		932,221
CFB - Goose Bay Secondary Allocated Cost of Service, Ln 4, Col 3		(19,653)
CFB - Goose Bay Secondary Allocated Deficit, Ln 4, Col 5		-
Revenue Credit		912,568
Revenue Credit Applied to Deficit	**100.0%**	912,568
Revenue Credit Applied to Firm Regulated Labrador Interconnected Customers		-
		912,568

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Rural Deficit Allocation

Line No.	1 Rate Class	2 Allocated Revenue Reqt ($)	3 Demand ($)	4 Energy ($)	5 Customer ($)	6 Source
		Before Deficit and Revenue Credit Allocation				
	CLASSIFICATION TO DEMAND, ENERGY, CUSTOMERS:					
1	Newfoundland Power	402,222,213	153,942,024	243,948,426	4,331,763	Schedule 1.3.1, p. 1
2	Rural Labrador Interconnected	18,107,285	11,073,770	1,332,693	5,700,823	Schedule 1.3.1, p. 3
3	**Total**	**420,329,498**	**165,015,794**	**245,281,118**	**10,032,586**	
4	Deficit Classified	62,166,770.78	24,405,851	36,277,100	1,483,820	Prorated on Line 3

* Specifically assigned costs are converted to equivalent unweighted customers by dividing the assigned cost by the allocated customer cost per unweighted customer.

Rural Customer Costs per Rural Customer:

Island Interconnected:	$540.00
Labrador Interconnected:	$491.46

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Rural Deficit Allocation

Line No.	1	2
	Rate Class	Deficit Allocation Allocated 100% on Revenue Reqt ($)
	ALLOCATION OF DEFICIT:	
1	Island Interconnected	59,488,701.65
2	Labrador Interconnected	2,678,069.13
3	**Allocated Totals**	**62,166,771**

CUSTOMER DEFICIT ALLOCATION:

		Amount	Percent
	Island Interconnected:		
4	Newfoundland Power	59,488,702	95.7%
5	Sub-Total Island Interconnected	59,488,702	
	Labrador Interconnected:		
6	Rural Labrador Interconnected	2,678,069	4.3%
7	Subtotal Labrador Interconnected	2,678,069	
8	**Total**	**62,166,771**	100.0%

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

Line No.	1 Rate Class	2	3	4	5	6	7	8	9	10	11
		Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Island Interconnected										
1	Newfoundland Power	10.18	-	0.04118	-	360,980.26	11.69	-	0.04727	-	414,369.27
2	Industrial - Firm	8.38	-	0.04114	-	28,184.17	8.38	-	0.04114	-	28,184.17
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-
	Rural							-	-		
4	1.1 Domestic	-	0.10111	0.04569	0.14680	41.29	-	-	-	-	-
5	1.12 Domestic All Electric	-	0.10454	0.04576	0.15030	41.35	-	-	-	-	-
6	1.3 Special	-	0.13414	0.04529	0.17943	40.92	-	-	-	-	-
7	2.1 General Service 0-10 kW	-	-	-	-	-	-	-	-	-	-
8	2.2 General Service 10-100 kW	54.36	-	0.04588	-	60.18	-	-	-	-	-
9	2.3 General Service 110-1,000 kVa	32.17	-	0.04582	-	78.21	-	-	-	-	-
10	2.4 General Service Over 1,000 kVa	26.23	-	0.04514	-	78.23	-	-	-	-	-
11	4.1 Street and Area Lighting	-	0.12907	0.04591	0.17498	71.80	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

Line No.	1 Rate Class	2	3	4	5	6	7	8	9	10	11
		Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	Isolated Systems:										
1	1.2 Domestic Diesel	-	0.28222	0.60139	0.88360	58.03					
2	2.1 General Service 0-10 kW	-	0.20676	0.59595	0.80272	62.22					
3	2.2 GS 10-100 kW	62.25	-	0.58135	-	76.64					
4	2.3 GS 110-1,000 kVa	22.55	-	0.58644	-	102.41					
5	2.4 General Service Over 1,000 kVa	14.74	-	0.57179	-	93.42					
6	**Subtotal Metered Demand Classes**	46.66	-	0.58095	-	77.89					
7	4.1 Street and Area Lighting	-	0.33993	0.61039	0.95032	101.85					
	Island Isolated										
8	1.2 Domestic Diesel	-	0.49909	0.71631	1.21540	79.68	-	-	-	-	-
9	2.1 General Service 0-10 kW	-	0.37562	0.71860	1.09422	89.21	-	-	-	-	-
10	2.2 GS 10-100 kW	177.17	-	0.72542	-	120.90	-	-	-	-	-
11	2.3 GS 110-1,000 kVa	147.09	-	0.71409	-	157.31	-	-	-	-	-
12	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-
13	4.1 Street and Area Lighting	-	0.55479	0.71867	1.27346	120.20	-	-	-	-	-
	Labrador Isolated										
14	1.2 Domestic Diesel	-	0.22672	0.57198	0.79869	50.72	-	-	-	-	-
15	2.1 General Service 0-10 kW	-	0.17700	0.57434	0.75134	56.01	-	-	-	-	-
16	2.2 GS 10-100 kW	57.74	-	0.57280	-	72.54	-	-	-	-	-
17	2.3 GS 110-1,000 kVa	10.78	-	0.57082	-	93.26	-	-	-	-	-
18	2.4 General Service Over 1,000 kVa	14.74	-	0.57179	-	93.42	-	-	-	-	-
19	4.1 Street and Area Lighting	-	0.26883	0.57456	0.84339	93.46	-	-	-	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Unit Demand, Energy & Customer Amounts

Line No.	1 Rate Class	2	3	4	5	6	7	8	9	10	11
		Before Deficit and Revenue Credit Allocation					After Deficit and Revenue Credit Allocation				
		Demand			Non-Demand		Demand			Non-Demand	
		Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)	Demand ($/kW)	Non-Demand ($/kWh)	Energy ($/kWh)	Demand & Energy ($/kWh)	Customer ($/Bill)
	L'Anse au Loup										
1	1.1 Domestic	-	0.10857	0.15547	0.26404	46.87	-	-	-	-	-
2	1.12 Domestic All Electric	-	0.10042	0.15526	0.25567	46.81	-	-	-	-	-
3	2.1 General Service 0-10 kW	-	-	-	-	0.00	-	-	-	-	-
4	2.2 General Service 10-100 kW	29.96	-	0.15541	-	64.04	-	-	-	-	-
5	2.3 General Service 110-1,000 kVa	11.80	-	0.15659	-	81.29	-	-	-	-	-
6	4.1 Street and Area Lighting	-	0.10088	0.15652	0.25740	83.40	-	-	-	-	-
	Labrador Interconnected										
7	Industrial - IOCC Firm	1.68	-	-	-	6.04	1.68	-	-	-	6.04
8	Industrial - IOCC Non-Firm	-	-	-	-	0.00	-	-	-	-	0.00
9	CFB - Goose Bay Secondary	-	-	0.00193	0.00193	0.00	-	-	0.00193	0.00193	0.00
	Rural							-	-		
10	1.1 Domestic	-	0.02112	0.00201	0.02312	38.10	-	0.02424	0.00230	0.02655	43.73
11	1.1A Domestic All Electric	-	0.01871	0.00203	0.02074	38.58	-	0.02147	0.00233	0.02381	44.29
12	**Subtotal Domestic**	-	0.01872	0.00203	0.02075	38.56	-	0.02149	0.00233	0.02382	44.27
								-	-		
13	2.1 General Service 0-10 kW	-	0.01436	0.00204	0.01640	42.38	-	0.01649	0.00234	0.01883	48.65
14	2.2 General Service 10-100 kW	4.98	-	0.00205	-	54.54	5.71	-	0.00235	-	62.61
15	2.3 General Service 110-1,000 kVa	5.69	-	0.00205	-	69.93	6.53	-	0.00235	-	80.27
16	2.4 General Service Over 1,000 kVa	6.19	-	0.00201	-	69.17	7.10	-	0.00231	-	79.40
17	4.1 Street and Area Lighting	-	0.02049	0.00203	0.02252	61.42	0.00	0.02352	0.00233	0.02585	70.51

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

Line No.	1 Rate Class	2 Before Deficit and Revenue Credit Allocation Total ($)	3 Demand ($)	4 Energy ($)	5 Customer ($)	6 After Deficit and Revenue Credit Allocation Total ($)	7 Demand ($)	8 Energy ($)	9 Customer ($)
	Island Interconnected								
1	Newfoundland Power	402,222,213	153,942,024	243,948,426	4,331,763	461,710,914	176,710,063	280,028,420	4,972,431
2	Industrial - Firm	36,177,072	8,920,854	25,565,167	1,691,050	36,177,072	8,920,854	25,565,167	1,691,050
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-
	Rural								
4	1.1 Domestic	21,825,972	11,095,014	5,014,192	5,716,766	-	-	-	-
5	1.12 Domestic All Electric	25,206,406	14,689,525	6,430,096	4,086,785	-	-	-	-
6	1.3 Special	62,394	46,280	15,623	491	-	-	-	-
7	2.1 General Service 0-10 kW								
8	2.2 General Service 10-100 kW	12,400,318	6,828,007	3,472,360	2,099,951	-	-	-	-
9	2.3 General Service 110-1,000 kVa	8,592,816	5,748,210	2,758,305	86,301	-	-	-	-
10	2.4 General Service Over 1,000 kVa	4,547,734	2,909,653	1,630,571	7,510	-	-	-	-
11	4.1 Street and Area Lighting	1,305,861	361,408	128,536	815,917	-	-	-	-
12	**Subtotal Rural**	**73,941,500**	**41,678,097**	**19,449,683**	**12,813,721**				
13	**Total Island Interconnected**	**512,340,785**	**204,540,975**	**288,963,276**	**18,836,534**				

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	Isolated Systems:								
1	1.2 Domestic Diesel	25,135,743	7,412,598	15,795,681	1,927,463				
2	2.1 General Service 0-10 kW	4,355,308	1,023,387	2,949,736	382,186				
3	2.2 GS 10-100 kW	9,550,919	2,283,231	7,127,444	140,243				
4	2.3 GS 110-1,000 kVa	2,237,372	345,186	1,883,583	8,602				
5	2.4 General Service Over 1,000 kVa	1,499,779	93,949	1,404,709	1,121				
6	**Subtotal Metered Demand Classes**	13,288,069	2,722,366	10,415,736	149,967				
7	4.1 Street and Area Lighting	528,587	136,174	244,522	147,891				
8	**Total Isolated Systems**	**43,307,707**	**11,294,526**	**29,405,675**	**2,607,507**				
	Island Isolated								
9	1.2 Domestic Diesel	7,172,233	2,671,139	3,833,664	667,429	-	-	-	-
10	2.1 General Service 0-10 kW	914,227	278,558	532,903	102,766	-	-	-	-
11	2.2 GS 10-100 kW	763,491	246,342	498,289	18,860	-	-	-	-
12	2.3 GS 110-1,000 kVa	446,270	194,453	249,930	1,888	-	-	-	-
13	2.4 General Service Over 1,000 kVa	-	-	-	-	-	-	-	-
14	4.1 Street and Area Lighting	181,646	55,257	71,580	54,809	-	-	-	-
15	**Total Island Isolated**	**9,477,867**	**3,445,750**	**5,186,366**	**845,751**				
	Labrador Isolated								
16	1.2 Domestic Diesel	17,963,510	4,741,459	11,962,017	1,260,034	-	-	-	-
17	2.1 General Service 0-10 kW	3,441,081	744,828	2,416,833	279,420	-	-	-	-
18	2.2 GS 10-100 kW	8,787,428	2,036,889	6,629,155	121,384	-	-	-	-
19	2.3 GS 110-1,000 kVa	1,791,102	150,734	1,633,653	6,715	-	-	-	-
20	2.4 General Service Over 1,000 kVa	1,499,779	93,949	1,404,709	1,121	-	-	-	-
21	4.1 Street and Area Lighting	346,941	80,917	172,942	93,081	-	-	-	-
22	**Total Labrador Isolated**	**33,829,840**	**7,848,776**	**24,219,309**	**1,761,755**				

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Total Demand, Energy & Customer Amounts

	1	2	3	4	5	6	7	8	9
Line No.	Rate Class	Before Deficit and Revenue Credit Allocation				After Deficit and Revenue Credit Allocation			
		Total ($)	Demand ($)	Energy ($)	Customer ($)	Total ($)	Demand ($)	Energy ($)	Customer ($)
	L'Anse au Loup								
1	1.1 Domestic	1,319,666	448,517	642,232	228,917	-	-	-	-
2	1.12 Domestic All Electric	2,920,813	1,061,997	1,642,002	216,814	-	-	-	-
3	2.1 General Service 0-10 kW	-	-	-	-	-	-	-	-
4	2.2 General Service 10-100 kW	1,691,583	527,308	1,003,651	160,624	-	-	-	-
5	2.3 General Service 110-1,000 kVa	396,823	92,551	299,395	4,878	-	-	-	-
6	4.1 Street and Area Lighting	67,532	13,719	21,287	32,525	-	-	-	-
7	**Total L'Anse au Loup**	**6,396,417**	**2,144,093**	**3,608,567**	**643,757**				
	Labrador Interconnected								
8	Industrial - IOCC Firm	5,429,118	5,429,046	-	72	5,429,118	5,429,046	-	72
9	Industrial - IOCC Non-Firm	-	-	-	-	-	-	-	-
10	CFB - Goose Bay Secondary	19,653	-	19,653	-	19,653	-	19,653	-
	Rural								
11	1.1 Domestic	214,932	45,977	4,365	164,589	246,720	52,778	5,011	188,932
12	1.1A Domestic All Electric	10,904,394	5,893,132	639,697	4,371,566	12,517,155	6,764,727	734,308	5,018,120
13	**Subtotal Domestic**	**11,119,326**	**5,939,110**	**644,062**	**4,536,154**	**12,763,876**	**6,817,505**	**739,319**	**5,207,052**
14	2.1 General Service 0-10 kW	371,215	95,690	13,589	261,936	426,118	109,842	15,599	300,677
15	2.2 General Service 10-100 kW	1,852,925	1,224,783	151,994	476,149	2,126,973	1,405,928	174,474	546,571
16	2.3 General Service 110-1,000 kVa	2,322,913	1,949,770	235,315	137,828	2,666,473	2,238,142	270,118	158,213
17	2.4 General Service Over 1,000 kVa	2,116,892	1,827,806	284,106	4,980	2,429,980	2,098,138	326,125	5,717
18	4.1 Street and Area Lighting	324,013	36,612	3,627	283,775	371,935	42,026	4,163	325,745
19	**Subtotal Rural**	**18,107,285**	**11,073,770**	**1,332,693**	**5,700,823**	**20,785,354**	**12,711,581**	**1,529,798**	**6,543,975**
20	**Total Labrador Interconnected**	**23,556,057**	**16,502,816**	**1,352,346**	**5,700,895**	**26,234,126**	**18,140,627**	**1,549,452**	**6,544,047**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Demands, Sales, & Number of Bills

476

	1	2	3	4	5
		Units			
Line No.	Rate Class	Billing Demands (kW)	Sales (MWh)	Customers	Bills (Total No)
	Island Interconnected				
1	Newfoundland Power	15,122,049	5,924,100	1	12
2	Industrial - Firm	1,064,800	621,400	5	60
3	Industrial - Non-Firm	1,000	-	-	-
	Rural				
4	1.1 Domestic	-	109,735	11,538	138,450
5	1.12 Domestic All Electric	-	140,519	8,236	98,832
6	1.3 Special	-	345	1	12
7	2.1 General Service 0-10 kW	-	-	-	-
8	2.2 General Service 10-100 kW	125,618	75,684	2,908	34,894
9	2.3 General Service 110-1,000 kVa	178,664	60,203	92	1,103
10	2.4 General Service Over 1,000 kVa	110,944	36,122	8	96
11	4.1 Street and Area Lighting	-	2,800	947	11,364
12	**Subtotal Rural**	**415,225**	**425,409**	**23,729**	**284,751**
13	**Total Island Interconnected**	**16,603,074**	**6,970,909**	**23,735**	**284,823**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Demands, Sales, & Number of Bills

Line No.	1 Rate Class	2 Billing Demands (kW)	3 Sales (MWh)	4 Customers	5 Bills (Total No)
		Units			
	Isolated Systems:				
1	1.2 Domestic Diesel	-	26,265	2,768	33,217
2	2.1 General Service 0-10 kW	-	4,950	512	6,141
3	2.2 GS 10-100 kW	36,668	12,260	152	1,829
4	2.3 GS 110-1,000 kVa	15,307	3,212	7	84
5	2.4 General Service Over 1,000 kVa	6,372	2,457	1	12
6	**Subtotal Metered Demand Classes**	58,347	17,929	160	1,925
7	4.1 Street and Area Lighting	-	401	121	1,452
8	**Total Isolated Systems**	**58,347**	**49,545**	**3,561**	**42,735**
	Island Isolated				
9	1.2 Domestic Diesel	-	5,352	698	8,376
10	2.1 General Service 0-10 kW	-	742	96	1,152
11	2.2 GS 10-100 kW	1,390	687	13	156
12	2.3 GS 110-1,000 kVa	1,322	350	1	12
13	2.4 General Service Over 1,000 kVa	-	-	-	-
14	4.1 Street and Area Lighting	-	100	38	456
15	**Total Island Isolated**	**2,712**	**7,230**	**846**	**10,152**
	Labrador Isolated				
16	1.2 Domestic Diesel	-	20,913	2,070	24,841
17	2.1 General Service 0-10 kW	-	4,208	416	4,989
18	2.2 GS 10-100 kW	35,277	11,573	139	1,673
19	2.3 GS 110-1,000 kVa	13,985	2,862	6	72
20	2.4 General Service Over 1,000 kVa	6,372	2,457	1	12
21	4.1 Street and Area Lighting	-	301	83	996
22	**Total Labrador Isolated**	**55,634**	**42,314**	**2,715**	**32,583**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Demands, Sales, & Number of Bills

Line No.	1 Rate Class	2 Units: Billing Demands (kW)	3 Units: Sales (MWh)	4 Units: Customers	5 Units: Bills (Total No)
	L'Anse au Loup				
1	1.1 Domestic	-	4,131	407	4,884
2	1.12 Domestic All Electric	-	10,576	386	4,632
3	2.1 General Service 0-10 kW	-	-	-	-
4	2.2 General Service 10-100 kW	17,600	6,458	209	2,508
5	2.3 General Service 110-1,000 kVa	7,844	1,912	5	60
6	4.1 Street and Area Lighting	-	136	33	390
7	**Total L'Anse au Loup**	**25,444**	**23,213**	**1,040**	**12,474**
	Labrador Interconnected				
8	Industrial - IOCC Firm	3,240,000	1,790,000	1	12
9	Industrial - IOCC Non-Firm	-	-		
10	CFB - Goose Bay Secondary	-	10,200	-	-
	Rural				
11	1.1 Domestic	-	2,177	360	4,320
12	1.1A Domestic All Electric	-	315,013	9,442	113,304
13	**Subtotal Domestic**	-	**317,190**	**9,802**	**117,624**
14	2.1 General Service 0-10 kW	-	6,663	515	6,180
15	2.2 General Service 10-100 kW	246,126	74,304	728	8,730
16	2.3 General Service 110-1,000 kVa	342,935	114,720	164	1,971
17	2.4 General Service Over 1,000 kVa	295,333	141,252	6	72
18	4.1 Street and Area Lighting	-	1,787	385	4,620
19	**Subtotal Rural**	**884,393**	**655,916**	**11,600**	**139,197**
20	**Total Labrador Interconnected**	**4,124,393**	**2,456,116**	**11,601**	**139,209**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Cost Calculations for Newfoundland Power

Line No.	1 Description	2 Amount	3 Source
	Newfoundland Power:		
	Demand:		
1	**Cost ($/kW/mo.)**	**5.50**	
2	Billing Units (kW)	15,122,049	Sch 1.3.2, pg 1, Ln 1, Col 2
3	Demand Revenue	$83,171,270	Ln 1 * Ln 2
	Energy (First Block):		
4	Total Revenue Requirement	$461,710,914	Sch 1.2, pg 1, Ln 1, Col 7
5	Less: Demand Revenue	83,171,270	Ln 2 * Ln 3
6	Revenue Requirement to be Recovered Through Energy Rates	$ 378,539,645	Ln 4 - Ln 5
	Non-Fuel Energy Costs:		
7	Energy Revenue Requirement	243,948,426	Sch 1.3.1, pg 1, Ln 1, Col 4
	Less Allocated Holyrood Fuel Costs		
8	Total Holyrood Fuel Costs	172,737,329	Sch 1.1, pg 1, Ln 2, Col 3
9	Newfoundland Power Trans. Energy Allocation Ratio	0.8452	Sch 3.1A, pg 1, Ln 14, Col 4
10	Allocated Holyrood Fuel Costs	145,991,547	Ln 8 * Ln 9
11	**Non-Fuel Energy Costs:**	$ 97,956,879	Ln 7 - Ln 10
12	**Customer Costs**	$ 4,331,763	Sch 1.3.1, pg 1, Ln 1, Col 5
13	First Block Energy Consumed (MWh)	3,000,000	
14	**Cost (Mills/kWh)**	**34.11**	Ln 11 + Ln 12 / Ln 13
	Energy (Second Block):		
15	Total Revenue Requirement	$461,710,914	Sch 1.2, pg 1, Ln 1, Col 7
16	Less: Demand Revenue	83,171,270	Ln 2 * Ln 3
17	Less: First Block Revenue	102,330,000	Ln 13 * Ln 14
18	Second Block Energy Revenue	$276,209,645	
19	Second Block Energy Consumed (MWh)	2,924,100	
20	**Cost (Mills/kWh)**	**94.46**	Ln 18 / Ln 19
21	Average No. 6 Fuel Cost per Barrel	$65.63	
22	Efficiency Factor (kWh per Barrel)	607	
23	**Cost (Mills/kWh)**	**108.11**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Value of Newfoundland Power Thermal Generation Credit

Line No.	Description	1 Amount	2 Source
1	Island Interconnected System:		
2	Generation demand costs ($)	142,374,585	Sch 2.1A, C. 3, Ln 24
3	Coincident peak (kW)	1,464,218	Sch 3.1A, C. 3, Ln 13
4	Generation demand costs ($/kW)	97.24	Ln 2 / Ln 3
5	NP thermal generation capacity credit (kW)	36,187	(1)
6	Gross value of credit to NP ($)	3,518,824	Ln 4 x Ln 5
7	Less NP's cost share:		
8	Percentage	88.85%	Sch 3.1A, C. 5, Ln 14
9	Amount ($)	(3,126,620)	Ln 6 x Ln 8
10	Net value of credit to NP ($)	392,204	Ln 6 - Ln 9

(1)	NP gas turbine and diesel generation capacity (kW)	41,000
	÷ System reserve	1.13
	NP thermal generation capacity credit (kW)	36,187

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Calculation of Firming Up Charge

Line No.	Description	1 Total	2 Gas Turbine	3 Transmission & Terminals
1	Operating & Maintenance	11,846,986	6,324,023	5,522,963
2	O&M Overhead	10,248,435	5,009,775	5,238,660
3	Depreciation	11,608,505	4,982,221	6,626,284
4	Return	23,600,053	10,314,575	13,285,478
5	**Total**	**57,303,980**	**26,630,595**	**30,673,385**
6	Capacity (kW)		223,500	1,742,100
7	Cost ($/kW)	$136.76	$119.15	$17.61
8	Rate ($/kWh)	$0.02974		

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Calculation of Transmission Wheeling Charge

Line No.	Description	1	2
1	Island Interconnected Transmission Revenue Requirement		31,054,507
2	Transmission Energy Output (MWh)		7,009,400
3	Rate ($/kWh)		$0.00443

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Distribution Primary Lines Customer ($)	10 Distribution Line Transformers Demand ($)	11 Distribution Line Transformers Customer ($)	12 Distribution Secondary Lines Demand ($)	13 Distribution Secondary Lines Customer ($)	14 Distribution Services Customer ($)	15 Distribution Meters Customer ($)	16 Distribution Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Expenses																	
1	Operating & Maintenance	106,052,783	45,833,894	23,503,430	10,761,623	3,960,467	1,392,610	6,908,508	1,791,974	433,311	766,997	1,028,119	1,122,841	464,757	466,947	156,659	2,893,482	2,498,541
2	Fuels-No. 6 Fuel	172,737,329	-	172,737,329	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	87,140	87,140	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	3,473,690	3,473,690	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Supply Deferral	1,991,280	1,991,280															
6	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Power Purchases-Other	58,109,820	21,243,193	36,173,623	-	693,003	-	-	-	-	-	-	-	-	-	-	-	-
8	Depreciation	57,258,885	25,847,265	15,957,538	6,626,284	2,633,324	640,918	1,865,577	509,067	222,971	394,678	287,367	318,054	154,332	271,957	139,092	203,182	1,187,278
	Expense Credits																	
9	Sundry	(505,072)	(218,282)	(111,934)	(51,252)	(18,862)	(6,632)	(32,901)	(8,534)	(2,064)	(3,653)	(4,896)	(5,347)	(2,213)	(2,224)	(746)	(13,780)	(11,899)
10	Building Rental Income	(17,472)	(6,795)	(5,229)	(2,318)	(936)	(196)	(775)	(201)	(49)	(86)	(115)	(126)	(52)	(43)	(18)	-	(534)
11	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Suppliers' Discounts	(78,683)	(34,005)	(17,438)	(7,984)	(2,938)	(1,033)	(5,126)	(1,330)	(321)	(569)	(763)	(833)	(345)	(346)	(116)	(2,147)	(1,854)
13	Pole Attachments	(1,263,389)	-	-	-	-	-	(730,679)	(249,711)	-	-	(129,331)	(153,669)	-	-	-	-	-
14	Secondary Energy	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Application Fees	(11,476)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(11,476)	-
17	Meter Test Revenues	(2,075)	-	-	-	-	-	-	-	-	-	-	-	-	(2,075)	-	-	-
18	**Total Expense Credits**	(1,878,167)	(259,082)	(134,601)	(61,554)	(22,735)	(7,861)	(769,480)	(259,776)	(2,434)	(4,308)	(135,105)	(159,975)	(2,610)	(4,688)	(880)	(27,403)	(14,287)
19	**Subtotal Expenses**	397,832,760	98,217,380	248,237,320	17,326,353	7,264,059	2,025,667	8,004,604	2,041,264	653,849	1,157,367	1,180,381	1,280,920	616,479	734,216	294,871	3,069,261	3,671,532
20	Disposal Gain / Loss	3,555,647	1,415,652	1,161,484	442,675	156,425	34,899	128,397	36,972	10,029	17,753	22,154	24,210	13,295	8,024	3,130	5,395	75,152
21	**Subtotal Revenue Requirement Ex. Return**	401,388,407	99,633,032	249,398,804	17,769,028	7,420,484	2,060,566	8,133,001	2,078,237	663,878	1,175,120	1,202,535	1,305,130	629,774	742,240	298,000	3,074,656	3,746,684
22	Return on Debt	80,364,761	30,958,458	28,103,522	9,622,905	3,407,761	760,022	2,801,418	805,099	217,973	385,831	482,054	526,792	288,075	174,768	68,191	118,798	1,643,095
23	Return on Equity	30,587,624	11,783,096	10,696,479	3,662,573	1,297,028	289,272	1,066,247	306,428	82,963	146,851	183,475	200,502	109,644	66,518	25,954	45,216	625,378
24	**Total Revenue Reqmt**	512,340,792	142,374,585	288,198,804	31,054,507	12,125,272	3,109,859	12,000,667	3,189,764	964,815	1,707,802	1,868,064	2,032,424	1,027,493	983,526	392,145	3,238,670	6,015,157

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax	20 Revenue Related PUB Assessment	21 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	1,357,786	710,839	Carryforward from Sch.2.4 L.30
2	Fuels-No. 6 Fuel	-	-	Production - Demand, Energy ratios Sch.4.1 L.10
3	Fuels-Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.12
4	Fuels-Gas Turbine	-	-	Production - Demand, Energy ratios Sch.4.1 L.11
5	Fuel Supply Deferral			
6	Power Purchases -CF(L)Co	-	-	
7	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.8
8	Depreciation	-	-	Carryforward from Sch.2.5 L.40
	Expense Credits			
9	Sundry	(6,466)	(3,385)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
10	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.34
11	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
12	Suppliers' Discounts	(1,007)	(527)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.30
13	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
14	Secondary Energy	-	-	Production - Energy
15	Wheeling Revenues	-	-	Transmission - Demand
16	Application Fees	-	-	Accounting - Customer
17	Meter Test Revenues	-	-	Meters - Customer
18	**Total Expense Credits**	**(7,474)**	**(3,913)**	
19	**Subtotal Expenses**	**1,350,312**	**706,926**	
20	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.40
21	**Subtotal Revenue Requirement Ex. Return**	**1,350,312**	**706,926**	
22	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.9
23	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.11
24	**Total Revenue Reqmt**	**1,350,312**	**706,926**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Primary Lines Customer ($)	10 Line Transformers Demand ($)	11 Line Transformers Customer ($)	12 Secondary Lines Demand ($)	13 Secondary Lines Customer ($)	14 Services Customer ($)	15 Meters Customer ($)	16 Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	224,163,991	100,704,132	123,459,859	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	174,849,492	78,549,933	96,299,560	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	82,714,770	37,159,042	45,555,728	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	272,937,726	122,615,397	150,322,329	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	22,264,052	10,001,972	12,262,080	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	112,087,573	50,354,572	61,733,001	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Hydraulic	5,330,264	2,394,585	2,935,680	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**894,347,869**	**401,779,633**	**492,568,236**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	256,920,692	185,599,508	71,321,184	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	155,106,747	155,106,747	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	10,395,824	10,395,824	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**1,316,771,131**	**752,881,711**	**563,889,420**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	286,645,674	-	-	162,412,792	87,840,416	-	-	-	-	-	-	-	-	-	-	-	36,392,465
15	Lines - Hydraulic	55,792,306	25,064,310	30,727,996	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	160,127,899	-	-	110,982,351	22,520,123	-	-	-	-	-	-	-	-	-	-	-	26,625,425
17	Term Stns - Hydraulic	35,992,419	16,169,347	19,823,072	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	8,772,062	6,336,937	2,435,124	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	700,311	700,311	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	13,916,403	-	-	-	-	13,916,403	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**219,509,093**	**23,206,595**	**22,258,197**	**110,982,351**	**22,520,123**	**13,916,403**	-	-	-	-	-	-	-	-	-	-	**26,625,425**
22	**Subtotal Transmission**	**561,947,073**	**48,270,905**	**52,986,192**	**273,395,144**	**110,360,539**	**13,916,403**	-	-	-	-	-	-	-	-	-	-	**63,017,890**
	Distribution																	
23	Substations	9,597,162	414,826	-	-	-	9,182,337	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	3,994,373	-	-	-	-	-	3,011,558	383,660	-	-	349,308	249,848	-	-	-	-	-
25	Poles	105,894,476	-	-	-	-	-	61,243,858	20,930,255	-	-	10,840,206	12,880,157	-	-	-	-	-
26	Primary Conductor & Eqpt	21,201,429	-	-	-	-	-	18,805,668	2,395,762	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	8,345,651	-	-	-	-	-	8,345,651	-	-	-	-	-	-	-	-	-	-
28	Transformers	15,881,322	-	-	-	-	-	-	-	5,733,157	10,148,165	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	4,139,916	-	-	-	-	-	-	-	-	-	2,413,571	1,726,345	-	-	-	-	-
30	Services	6,149,220	-	-	-	-	-	-	-	-	-	-	-	6,149,220	-	-	-	-
31	Meters	5,035,413	-	-	-	-	-	-	-	-	-	-	-	-	5,035,413	-	-	-
32	Street Lighting	2,072,755	-	-	-	-	-	-	-	-	-	-	-	-	-	2,072,755	-	-
33	**Subtotal Distribution**	**182,311,718**	**414,826**	-	-	-	**9,182,337**	**91,406,735**	**23,709,676**	**5,733,157**	**10,148,165**	**13,603,085**	**14,856,350**	**6,149,220**	**5,035,413**	**2,072,755**	-	-
34	**Subttl Prod, Trans, & Dist**	**2,061,029,922**	**801,567,441**	**616,875,613**	**273,395,144**	**110,360,539**	**23,098,739**	**91,406,735**	**23,709,676**	**5,733,157**	**10,148,165**	**13,603,085**	**14,856,350**	**6,149,220**	**5,035,413**	**2,072,755**	-	**63,017,890**
35	General	185,063,996	84,755,553	42,619,321	16,482,878	5,867,173	2,332,857	11,965,798	3,103,767	750,511	1,328,468	1,780,742	1,944,803	804,977	846,236	271,338	6,373,405	3,836,168
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	739,425	739,425	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	200,794	78,092	60,098	26,635	10,752	2,250	8,905	2,310	559	989	1,325	1,447	599	491	202	-	6,139
39	Software - General	4,159,436	1,617,671	1,244,938	551,748	222,722	46,616	184,471	47,849	11,570	20,480	27,453	29,982	12,410	10,162	4,183	-	127,179
40	**Total Plant**	**2,251,193,572**	**888,758,182**	**660,799,970**	**290,456,405**	**116,461,186**	**25,480,463**	**103,565,909**	**26,863,602**	**6,495,798**	**11,498,102**	**15,412,605**	**16,832,583**	**6,967,206**	**5,892,302**	**2,348,478**	**6,373,405**	**66,987,376**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	19 Basis of Functional Classification
	Production	
	Hydraulic	
1	Bay D'Espoir	Production - Demand, Energy ratios Sch.4.1 L.1
2	Upper Salmon	Production - Demand, Energy ratios Sch.4.1 L.1
3	Hinds Lake	Production - Demand, Energy ratios Sch.4.1 L.1
4	Cat Arm	Production - Demand, Energy ratios Sch.4.1 L.1
5	Paradise River	Production - Demand, Energy ratios Sch.4.1 L.1
6	Granite Canal	Production - Demand, Energy ratios Sch.4.1 L.1
7	Other Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.1, 2
8	**Subtotal Hydraulic**	
9	Holyrood	Production - Demand, Energy ratios Sch.4.1 L.3
10	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.4
11	Roddickton	Production - Demand, Energy ratios Sch.4.1 L.3
12	Diesel	Production - Demand, Energy ratios Sch.4.1 L.5
13	**Subtotal Production**	
	Transmission	
14	Lines	Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
15	Lines - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.17
16	Terminal Stations	Production - Demand, Energy subtotals, L. 13; Transmission - Demand; Spec Assigned - Custmr
17	Term Stns - Hydraulic	Production - Demand, Energy ratios Sch.4.1 L.20
18	Term Stns - Holyrood	Production - Demand, Energy ratios Sch.4.1 L.21
19	Term Stns - Gas Tur/Dsl	Production - Demand, Energy ratios Sch.4.1 L.22, 23
20	Term Stns - Distribution	Distribution - Substations Demand
21	**Subtotal Term Stns**	
22	**Subtotal Transmission**	
	Distribution	
23	Substations	Production - Demand; Dist Substns - Demand
24	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
25	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
26	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
27	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
28	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
29	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
30	Services	Services Customer
31	Meters	Meters - Customer
32	Street Lighting	Street Lighting - Customer
33	**Subtotal Distribution**	
34	**Subttl Prod, Trans, & Dist**	
35	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.15, 16
36	Telecontrol - Custmr & Spec	Specifically Assigned - Customer
37	Feasibility Studies	Production, Transmission - Demand
38	Feasibility Studies - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
39	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.34
40	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Primary Lines Customer ($)	10 Line Transformers Demand ($)	11 Line Transformers Customer ($)	12 Secondary Lines Demand ($)	13 Secondary Lines Customer ($)	14 Services Customer ($)	15 Meters Customer ($)	16 Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	159,292,385	71,561,009	87,731,376	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	150,562,745	67,639,278	82,923,467	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	68,558,878	30,799,605	37,759,274	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	236,005,894	106,024,026	129,981,868	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	18,634,236	8,371,302	10,262,933	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	99,568,098	44,730,284	54,837,814	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	3,369,380	1,513,671	1,855,709	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**735,991,616**	**330,639,175**	**405,352,441**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	69,827,001	50,443,026	19,383,976	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	134,651,525	134,651,525	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	3,510,510	3,510,510	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**943,980,652**	**519,244,235**	**424,736,417**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	168,220,778	-	-	103,496,354	47,180,089	-	-	-	-	-	-	-	-	-	-	-	17,544,336
15	Lines - Hydraulic	45,062,465	20,244,002	24,818,462	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	99,426,556	-	-	72,472,177	14,985,747	-	-	-	-	-	-	-	-	-	-	-	11,968,632
17	Term Stns - Hydraulic	21,686,911	9,742,696	11,944,215	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	1,522,380	1,099,767	422,613	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	400,885	400,885	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	9,753,683	-	-	-	-	9,753,683	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**132,790,415**	**11,243,348**	**12,366,828**	**72,472,177**	**14,985,747**	**9,753,683**	-	-	-	-	-	-	-	-	-	-	**11,968,632**
22	**Subtotal Transmission**	**346,073,658**	**31,487,350**	**37,185,290**	**175,968,530**	**62,165,835**	**9,753,683**	-	-	-	-	-	-	-	-	-	-	**29,512,968**
	Distribution																	
23	Substations	3,895,381	135,275	-	-	-	3,760,106	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	2,670,404	-	-	-	-	-	2,013,351	256,492	-	-	233,527	167,034	-	-	-	-	-
25	Poles	66,098,651	-	-	-	-	-	38,228,022	13,064,530	-	-	6,766,387	8,039,711	-	-	-	-	-
26	Primary Conductor & Eqpt	6,865,462	-	-	-	-	-	6,089,665	775,797	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	2,211,614	-	-	-	-	-	2,211,614	-	-	-	-	-	-	-	-	-	-
28	Transformers	10,680,793	-	-	-	-	-	-	-	3,855,766	6,825,027	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	2,529,075	-	-	-	-	-	-	-	-	-	1,474,451	1,054,624	-	-	-	-	-
30	Services	5,177,339	-	-	-	-	-	-	-	-	-	-	-	5,177,339	-	-	-	-
31	Meters	2,999,527	-	-	-	-	-	-	-	-	-	-	-	-	2,999,527	-	-	-
32	Street Lighting	1,190,297	-	-	-	-	-	-	-	-	-	-	-	-	-	1,190,297	-	-
33	**Subtotal Distribution**	**104,318,541**	**135,275**	-	-	-	**3,760,106**	**48,542,652**	**14,096,820**	**3,855,766**	**6,825,027**	**8,474,364**	**9,261,369**	**5,177,339**	**2,999,527**	**1,190,297**	-	-
34	**Subttl Prod, Trans, & Dist**	**1,394,372,851**	**550,866,860**	**461,921,707**	**175,968,530**	**62,165,835**	**13,513,789**	**48,542,652**	**14,096,820**	**3,855,766**	**6,825,027**	**8,474,364**	**9,261,369**	**5,177,339**	**2,999,527**	**1,190,297**	-	**29,512,968**
35	General	64,497,334	29,538,469	14,853,416	5,744,509	2,044,790	813,033	4,170,244	1,081,705	261,564	462,989	620,613	677,790	280,546	294,925	94,565	2,221,219	1,336,957
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	739,425	739,425	-	-	-	0	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Software - General	4,226,155	1,669,603	1,400,022	533,337	188,416	40,958	147,126	42,726	11,686	20,686	25,685	28,070	15,692	9,091	3,608	-	89,450
40	**Total Net Book Value**	**1,463,835,765**	**582,814,357**	**478,175,145**	**182,246,376**	**64,399,042**	**14,367,780**	**52,860,022**	**15,221,251**	**4,129,016**	**7,308,701**	**9,120,661**	**9,967,229**	**5,473,576**	**3,303,543**	**1,288,470**	**2,221,219**	**30,939,375**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Distribution Primary Lines Customer ($)	10 Distribution Line Transformers Demand ($)	11 Distribution Line Transformers Customer ($)	12 Distribution Secondary Lines Demand ($)	13 Distribution Secondary Lines Customer ($)	14 Distribution Services Customer ($)	15 Distribution Meters Customer ($)	16 Distribution Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
1	Hydraulic	12,112,026	5,441,244	6,670,781	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Holyrood / Thermal	19,459,003	14,057,184	5,401,819	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Gas Turbine	5,995,298	5,995,298	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Diesel	362,481	362,481	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	2,635,738	1,507,019	1,128,719	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Production**	**40,564,546**	**27,363,226**	**13,201,320**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																	
8	Transmission Lines	3,910,236	286,205	350,877	1,854,562	1,003,033	-	-	-	-	-	-	-	-	-	-	-	415,559
9	Terminal Stations	5,102,709	539,461	517,414	2,579,896	523,503	323,501	-	-	-	-	-	-	-	-	-	-	618,935
10	Other	2,237,357	192,188	210,961	1,088,506	439,394	55,407	-	-	-	-	-	-	-	-	-	-	250,902
11	**Subtotal Transmission**	**11,250,301**	**1,017,853**	**1,079,253**	**5,522,963**	**1,965,930**	**378,908**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,285,395**
	Distribution																	
12	Other	7,775,946	18,196	-	-	-	402,769	4,009,413	1,039,988	251,476	445,133	596,678	651,650	269,726	-	90,918	-	-
13	Meters	283,551	-	-	-	-	-	-	-	-	-	-	-	-	283,551	-	-	-
14	**Subtotal Distribution**	**8,059,497**	**18,196**	**-**	**-**	**-**	**402,769**	**4,009,413**	**1,039,988**	**251,476**	**445,133**	**596,678**	**651,650**	**269,726**	**283,551**	**90,918**	**-**	**-**
15	**Subttl Prod, Trans, & Dist**	**59,874,344**	**28,399,275**	**14,280,572**	**5,522,963**	**1,965,930**	**781,677**	**4,009,413**	**1,039,988**	**251,476**	**445,133**	**596,678**	**651,650**	**269,726**	**283,551**	**90,918**	**-**	**1,285,395**
16	Customer Accounting	2,135,554	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,135,554	-
	Administrative & General:																	
	Plant-Related:																	
17	Production	6,089,665	3,481,848	2,607,816	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Prod - Gas Turb & Diesel	1,583,881	1,583,881	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Transmission	5,300,429	455,304	499,779	2,578,733	1,040,949	131,263	-	-	-	-	-	-	-	-	-	-	594,401
20	Distribution	2,446,265	5,566	-	-	-	123,209	1,226,499	318,137	76,928	136,168	182,527	199,343	82,510	67,565	27,812	-	-
21	Prod, Trans, Distn	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Prod, Trans, Distn and General Plant	343,528	135,623	100,837	44,323	17,772	3,888	15,804	4,099	991	1,755	2,352	2,569	1,063	899	358	973	10,222
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	1,425,303	335,564	83,012	428,322	172,899	36,188	143,205	37,145	8,982	15,899	21,312	23,275	9,634	7,889	3,247	-	98,729
24	Property Insurance	1,595,772	794,003	579,666	117,511	26,171	23,446	11,031	2,861	692	1,225	1,642	1,793	742	780	250	5,876	28,083
	Revenue-Related:																	
25	Municipal Tax	1,357,786	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	PUB Assessment	710,839	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	All Expense-Related	21,809,014	9,988,086	5,022,508	1,942,438	691,422	274,917	1,410,119	365,766	88,445	156,554	209,853	229,187	94,863	99,725	31,976	751,079	452,076
28	Prod, Trans, and Distn Expense-Related	1,380,404	654,746	329,239	127,332	45,325	18,022	92,437	23,977	5,798	10,263	13,756	15,024	6,219	6,537	2,096	-	29,635
29	**Subtotal Admin & General**	**44,042,884**	**17,434,619**	**9,222,858**	**5,238,660**	**1,994,537**	**610,933**	**2,899,095**	**751,986**	**181,835**	**321,864**	**431,441**	**471,190**	**195,031**	**183,396**	**65,740**	**757,927**	**1,213,146**
30	**Total Operating & Maintenance Expenses**	**106,052,783**	**45,833,894**	**23,503,430**	**10,761,623**	**3,960,467**	**1,392,610**	**6,908,508**	**1,791,974**	**433,311**	**766,997**	**1,028,119**	**1,122,841**	**464,757**	**466,947**	**156,659**	**2,893,482**	**2,498,541**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax	20 Revenue Related PUB Assessment	21 Basis of Functional Classification
	Production			
1	Hydraulic	-	-	Prorated on Hydraulic Plant in Service - Sch.2.2 L.8
2	Holyrood / Thermal	-	-	Prorated on Holyrood Plant in Service - Sch.2.2 L.9
3	Roddickton	-	-	Prorated on Roddickton Plant in Service - Sch.2.2 L.11
4	Gas Turbine	-	-	Prorated on Gas Turbines Plant in Service - Sch.2.2 L.10
5	Diesel	-	-	Prorated on Diesel Plant in Service - Sch.2.2 L.12
6	Other	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
7	**Subtotal Production**	-	-	
	Transmission			
8	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.14, 15
9	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.21
10	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
11	**Subtotal Transmission**	-	-	
	Distribution			
12	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 33, less L. 31
13	Meters	-	-	Meters - Customer
14	**Subtotal Distribution**	-	-	
15	**Subtl Prod, Trans, & Dist**	-	-	
16	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
17	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.13
18	Prod - Gas Turb & Diesel		-	Prorated on Gas Turbine & Diesel Production Plant in Service - Sch.2.2 L.10, 12
19	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.22
20	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.33
21	Prod, Trans, Distn	-	-	Prorated on Prod, Trans & Distribution Plant in Service - Sch.2.2 L.34
22	Prod, Trans, Distn and General Plant	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 40
23	Prod, Trans, Distn, Excl Hydraulic & Holyrood	-	-	Prorated on Total Plant in Service, Sch. 2.2, L. 34 Less L. 8 and L. 9
24	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.13, 21, 23, 35 - 36
	Revenue-Related:			
25	Municipal Tax	1,357,786	-	Revenue-related
26	PUB Assessment	-	710,839	Revenue-related
27	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 15, 16
28	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L 15
29	**Subtotal Admin & General**	**1,357,786**	**710,839**	
30	**Total Operating & Maintenance Expenses**	**1,357,786**	**710,839**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Distribution Primary Lines Customer ($)	10 Distribution Line Transformers Demand ($)	11 Distribution Line Transformers Customer ($)	12 Distribution Secondary Lines Demand ($)	13 Distribution Secondary Lines Customer ($)	14 Distribution Services Customer ($)	15 Distribution Meters Customer ($)	16 Distribution Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
	Production																	
	Hydraulic																	
1	Bay D'Espoir	4,592,375	2,063,093	2,529,282	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Upper Salmon	3,044,289	1,367,626	1,676,663	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Hinds Lake	1,408,226	632,636	775,590	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Cat Arm	5,429,147	2,439,007	2,990,140	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Paradise River	454,623	204,236	250,387	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Granite Canal	2,418,851	1,086,652	1,332,199	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Other Small Hydraulic	79,620	35,769	43,851	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	**Subtotal Hydraulic**	**17,427,132**	**7,829,019**	**9,598,112**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	Holyrood	12,849,648	9,282,586	3,567,062	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Gas Turbines	4,293,739	4,293,739	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Roddickton	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Diesel	124,574	124,574	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	**Subtotal Production**	**34,695,092**	**21,529,917**	**13,165,175**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																	
14	Lines	5,911,528	-	-	3,586,621	1,708,499	-	-	-	-	-	-	-	-	-	-	-	616,408
15	Lines - Hydraulic	1,399,044	628,511	770,533	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Terminal Stations	3,539,774	-	-	2,412,149	696,864	-	-	-	-	-	-	-	-	-	-	-	430,761
17	Term Stns - Hydraulic	728,807	327,412	401,396	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Term Stns - Holyrood	63,247	45,689	17,557	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Term Stns - Gas Tur/Dsl	14,370	14,370	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Term Stns - Distribution	398,412	-	-	-	-	398,412	-	-	-	-	-	-	-	-	-	-	-
21	**Subtotal Term Stns**	**4,744,610**	**387,471**	**418,953**	**2,412,149**	**696,864**	**398,412**	-	-	-	-	-	-	-	-	-	-	**430,761**
22	**Subtotal Transmission**	**12,055,183**	**1,015,982**	**1,189,486**	**5,998,770**	**2,405,363**	**398,412**	-	-	-	-	-	-	-	-	-	-	**1,047,169**
	Distribution																	
23	Substations	163,174	4,515	-	-	-	158,659	-	-	-	-	-	-	-	-	-	-	-
24	Land & Land Improvements	70,663	-	-	-	-	-	53,277	6,787	-	-	6,179	4,420	-	-	-	-	-
25	Poles	1,850,616	-	-	-	-	-	1,070,300	365,778	-	-	189,444	225,094	-	-	-	-	-
26	Primary Conductor & Eqpt	271,631	-	-	-	-	-	240,936	30,694	-	-	-	-	-	-	-	-	-
27	Submarine Conductor	94,774	-	-	-	-	-	94,774	-	-	-	-	-	-	-	-	-	-
28	Transformers	542,150	-	-	-	-	-	-	-	195,716	346,434	-	-	-	-	-	-	-
29	Secondary Conductor&Eqpt	53,374	-	-	-	-	-	-	-	-	-	31,117	22,257	-	-	-	-	-
30	Services	126,517	-	-	-	-	-	-	-	-	-	-	-	126,517	-	-	-	-
31	Meters	240,881	-	-	-	-	-	-	-	-	-	-	-	-	240,881	-	-	-
32	Street Lighting	128,260	-	-	-	-	-	-	-	-	-	-	-	-	-	128,260	-	-
33	**Subtotal Distribution**	**3,542,041**	**4,515**	-	-	-	**158,659**	**1,459,287**	**403,259**	**195,716**	**346,434**	**226,741**	**251,771**	**126,517**	**240,881**	**128,260**	-	-
34	**Subttl Prod, Trans, & Dist**	**50,292,315**	**22,550,415**	**14,354,661**	**5,998,770**	**2,405,363**	**557,071**	**1,459,287**	**403,259**	**195,716**	**346,434**	**226,741**	**251,771**	**126,517**	**240,881**	**128,260**	-	**1,047,169**
35	General	5,899,788	2,701,983	1,358,692	525,470	187,044	74,371	381,466	98,947	23,926	42,351	56,770	62,000	25,662	26,978	8,650	203,182	122,296
36	Telecontrol - Custmr & Spec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37	Feasibility Studies	211,264	211,264	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Feasibility Studies - General	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Software - General	855,517	383,603	244,186	102,044	40,917	9,476	24,824	6,860	3,329	5,893	3,857	4,283	2,152	4,098	2,182	-	17,813
40	**Total Deprecn Expense**	**57,258,885**	**25,847,265**	**15,957,538**	**6,626,284**	**2,633,324**	**640,918**	**1,865,577**	**509,067**	**222,971**	**394,678**	**287,367**	**318,054**	**154,332**	**271,957**	**139,092**	**203,182**	**1,187,278**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Rural Prod & Transmission Demand ($)	7 Distribution Substations Demand ($)	8 Distribution Primary Lines Demand ($)	9 Distribution Primary Lines Customer ($)	10 Distribution Line Transformers Demand ($)	11 Distribution Line Transformers Customer ($)	12 Distribution Secondary Lines Demand ($)	13 Distribution Secondary Lines Customer ($)	14 Distribution Services Customer ($)	15 Distribution Meters Customer ($)	16 Distribution Street Lighting Customer ($)	17 Accounting Customer ($)	18 Specifically Assigned Customer ($)
1	Average Net Book Value	1,463,835,765	582,814,357	478,175,145	182,246,376	64,399,042	14,367,780	52,860,022	15,221,251	4,129,016	7,308,701	9,120,661	9,967,229	5,473,576	3,303,543	1,288,470	2,221,219	30,939,375
2	Cash Working Capital	6,345,094	2,526,248	2,072,682	789,959	279,142	62,278	229,125	65,978	17,897	31,680	39,534	43,204	23,726	14,319	5,585	9,628	134,109
3	Fuel Inventory - No. 6 Fuel	58,916,050	-	58,916,050	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	186,223	186,223	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	3,992,487	3,992,487	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	24,359,458	9,616,973	7,150,309	3,142,937	1,260,190	275,716	1,120,654	290,683	70,289	124,417	166,775	182,140	75,390	63,759	25,412	68,965	724,849
7	Deferred Charges: Holyrood	-	-	-														
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	69,871,776	27,818,882	22,824,245	8,698,980	3,073,894	685,803	2,523,113	726,540	197,086	348,859	435,347	475,756	261,265	157,685	61,501	106,023	1,476,798
9	Total Rate Base	**1,627,506,853**	**626,955,169**	**569,138,432**	**194,878,252**	**69,012,267**	**15,391,577**	**56,732,915**	**16,304,451**	**4,414,289**	**7,813,658**	**9,762,318**	**10,668,329**	**5,833,957**	**3,539,306**	**1,380,968**	**2,405,835**	**33,275,131**
10	Less: Rural Asset Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Rate Base Available for Equity Return	**1,627,506,853**	**626,955,169**	**569,138,432**	**194,878,252**	**69,012,267**	**15,391,577**	**56,732,915**	**16,304,451**	**4,414,289**	**7,813,658**	**9,762,318**	**10,668,329**	**5,833,957**	**3,539,306**	**1,380,968**	**2,405,835**	**33,275,131**
12	Return on Debt	80,364,761	30,958,458	28,103,522	9,622,905	3,407,761	760,022	2,801,418	805,099	217,973	385,831	482,054	526,792	288,075	174,768	68,191	118,798	1,643,095
13	Return on Equity	30,587,624	11,783,096	10,696,479	3,662,573	1,297,028	289,272	1,066,247	306,428	82,963	146,851	183,475	200,502	109,644	66,518	25,954	45,216	625,378
14	Return on Rate Base	**110,952,385**	**42,741,554**	**38,800,000**	**13,285,478**	**4,704,789**	**1,049,293**	**3,867,666**	**1,111,527**	**300,936**	**532,682**	**665,529**	**727,294**	**397,720**	**241,286**	**94,145**	**164,014**	**2,268,473**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	19
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 40
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	Production - Demand, Energy ratios Sch.4.1 L.10
4	Fuel Inventory - Diesel	Production - Demand, Energy ratios Sch.4.1 L.12
5	Fuel Inventory - Gas Turbine	Production - Demand, Energy ratios Sch.4.1 L.11
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 40
7	Deferred Charges: Holyrood	Production - Demand, Energy ratios Sch.4.1 L.3
8	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
9	Total Rate Base	
10	Less: Rural Asset Portion	N/A
11	Rate Base Available for Equity Return	
12	Return on Debt	L.9 x Sch.1.1,p2,L.14
13	Return on Equity	L.11 x Sch.1.1,p2,L.17
14	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production and Transmission Energy	5 Transmission Demand	6 Rural Prod & Transmission Demand	7 Distribution Substations Demand	8 Primary Lines Demand	9 Primary Lines Customer	10 Line Transformers Demand	11 Line Transformers Customer	12 Secondary Lines Demand	13 Secondary Lines Customer	14 Services Customer	15 Meters Customer	16 Street Lighting Customer	17 Accounting Customer	18 Specifically Assigned Customer
			(1 CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
	Amounts																	
1	Newfoundland Power	-	1,296,985	6,118,065	1,288,081	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Industrial - Firm	-	75,597	641,746	73,040	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	-	24,404	123,746	23,579	23,579	22,367	22,367	11,538	20,572	11,538	20,572	11,538	11,538	11,538	-	11,538	-
5	1.12 Domestic All Electric	-	32,264	158,460	31,173	31,173	29,571	29,571	8,236	27,197	8,236	27,197	8,236	8,236	8,236	-	8,236	-
6	1.3 Special	-	103	389	99	99	94	94	1	87	1	87	1	1	1	-	1	-
7	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.2 GS 10-100 kW	-	14,958	85,347	14,452	14,452	13,709	13,709	2,908	12,609	2,908	12,609	2,908	13,871	13,871	-	2,908	-
9	2.3 GS 110-1,000 kVa	-	12,610	67,875	12,184	12,184	11,558	11,558	92	10,589	92	10,589	92	774	774	-	92	-
10	2.4 GS Over 1,000 kVa	-	6,505	40,115	6,285	6,285	5,962	5,962	8	3,987	8	3,987	8	67	67	-	8	-
11	4.1 Street and Area Lighting	-	791	3,157	765	765	725	725	947	667	947	667	947	-	-	1	947	-
12	**Subtotal Rural**	-	**91,636**	**479,089**	**88,537**	**88,537**	**83,988**	**83,988**	**23,729**	**75,706**	**23,729**	**75,706**	**23,729**	**34,487**	**34,487**	**1**	**23,729**	-
13	**Total**	-	**1,464,218**	**7,238,900**	**1,449,658**	**88,537**	**83,988**	**83,988**	**23,729**	**75,706**	**23,729**	**75,706**	**23,729**	**34,487**	**34,487**	**1**	**23,729**	-
	Ratios Excluding Return on Equity																	
14	Newfoundland Power	-	0.8858	0.8452	0.8885	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Industrial - Firm	-	0.0516	0.0887	0.0504	-	-	-	-	-	-	-	-	-	-	-	-	-
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	-	0.0167	0.0171	0.0163	0.2663	0.2663	0.2663	0.4862	0.2717	0.4862	0.2717	0.4862	0.3346	0.3346	-	0.4862	-
18	1.12 Domestic All Electric	-	0.0220	0.0219	0.0215	0.3521	0.3521	0.3521	0.3471	0.3592	0.3471	0.3592	0.3471	0.2388	0.2388	-	0.3471	-
19	1.3 Special	-	0.0001	0.0001	0.0001	0.0011	0.0011	0.0011	0.0000	0.0011	0.0000	0.0011	0.0000	0.0000	0.0000	-	0.0000	-
20	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.2 GS 10-100 kW	-	0.0102	0.0118	0.0100	0.1632	0.1632	0.1632	0.1225	0.1665	0.1225	0.1665	0.1225	0.4022	0.4022	-	0.1225	-
22	2.3 GS 110-1,000 kVa	-	0.0086	0.0094	0.0084	0.1376	0.1376	0.1376	0.0039	0.1399	0.0039	0.1399	0.0039	0.0224	0.0224	-	0.0039	-
23	2.4 GS Over 1,000 kVa	-	0.0044	0.0055	0.0043	0.0710	0.0710	0.0710	0.0003	0.0527	0.0003	0.0527	0.0003	0.0020	0.0020	-	0.0003	-
24	4.1 Street and Area Lighting	-	0.0005	0.0004	0.0005	0.0086	0.0086	0.0086	0.0399	0.0088	0.0399	0.0088	0.0399	-	-	1.0000	0.0399	-
25	**Subtotal Rural**	-	**0.0626**	**0.0662**	**0.0611**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-
26	**Total**	-	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	-

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	20 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	Newfoundland Power	-	447,430,477
2	Industrial - Firm	-	16,126,195
3	Industrial - Non-Firm	-	4,881
	Rural		
4	1.1 Domestic	13,662,764	13,662,764
5	1.12 Domestic All Electric	17,059,306	17,059,306
6	1.3 Special	19,235	19,235
7	2.1 GS 0-10 kW	-	-
8	2.2 GS 10-100 kW	9,534,018	9,534,018
9	2.3 GS 110-1,000 kVa	6,258,109	6,258,109
10	2.4 GS Over 1,000 kVa	3,348,569	3,348,569
11	4.1 Street and Area Lighting	1,030,113	1,030,113
12	**Subtotal Rural**	**50,912,113**	**50,912,113**
13	**Total**	**50,912,113**	**514,473,667**
	Ratios Excluding Return on Equity		
14	Newfoundland Power	-	0.8697
15	Industrial - Firm	-	0.0313
16	Industrial - Non-Firm	-	0.0000
	Rural		
17	1.1 Domestic	0.2684	0.0266
18	1.12 Domestic All Electric	0.3351	0.0332
19	1.3 Special	0.0004	0.0000
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	0.1873	0.0185
22	2.3 GS 110-1,000 kVa	0.1229	0.0122
23	2.4 GS Over 1,000 kVa	0.0658	0.0065
24	4.1 Street and Area Lighting	0.0202	0.0020
25	**Subtotal Rural**	**1.0000**	**0.0990**
26	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production and Transmission Energy	5 Transmission Demand	6 Rural Prod & Transmission Demand	7 Substations Demand	8 Primary Lines Demand	9 Primary Lines Customer	10 Line Transformers Demand	11 Line Transformers Customer	12 Secondary Lines Demand	13 Secondary Lines Customer	14 Services Customer	15 Meters Customer	16 Street Lighting Customer	17 Accounting Customer	18 Specifically Assigned Customer
							Distribution											
	Allocated Rev Reqmt Excl Return		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	Newfoundland Power	317,913,495	88,253,611	210,783,143	15,788,515	-	-	-	-	-	-	-	-	-	-	-	-	2,473,421
2	Industrial - Firm	29,444,503	5,144,005	22,109,796	895,280	-	-	-	-	-	-	-	-	-	-	-	-	1,273,263
3	Industrial - Non-Firm	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
4	1.1 Domestic	15,962,581	1,660,605	4,263,362	289,017	1,976,210	548,766	2,165,967	1,010,468	180,395	571,360	326,764	634,573	210,691	248,317	-	1,494,942	-
5	1.12 Domestic All Electric	18,362,008	2,195,429	5,459,361	382,100	2,612,680	725,505	2,863,550	721,319	238,495	407,863	432,004	452,987	150,401	177,260	-	1,067,158	-
6	1.3 Special	44,386	6,989	13,404	1,216	8,318	2,310	9,116	88	759	50	1,375	55	18	22	-	130	-
7	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.2 GS 10-100 kW	9,074,547	1,017,811	2,940,429	177,143	1,211,251	336,348	1,327,555	254,669	110,567	144,000	200,279	159,932	253,296	298,530	-	376,771	-
9	2.3 GS 110-1,000 kVa	6,265,817	858,078	2,338,460	149,343	1,021,160	283,562	1,119,212	8,053	92,853	4,554	168,193	5,057	14,137	16,662	-	11,914	-
10	2.4 GS Over 1,000 kVa	3,349,164	442,661	1,382,065	77,042	526,790	146,282	577,373	701	34,959	396	63,325	440	1,230	1,450	-	1,037	-
11	4.1 Street and Area Lighting	971,901	53,842	108,784	9,371	64,075	17,793	70,228	82,939	5,849	46,897	10,595	52,086	-	-	298,000	122,705	-
12	**Subtotal Rural**	**54,030,403**	**6,235,416**	**16,505,864**	**1,085,233**	**7,420,484**	**2,060,566**	**8,133,001**	**2,078,237**	**663,878**	**1,175,120**	**1,202,535**	**1,305,130**	**629,774**	**742,240**	**298,000**	**3,074,656**	-
13	**Total**	**401,388,407**	**99,633,032**	**249,398,804**	**17,769,028**	**7,420,484**	**2,060,566**	**8,133,001**	**2,078,237**	**663,878**	**1,175,120**	**1,202,535**	**1,305,130**	**629,774**	**742,240**	**298,000**	**3,074,656**	**3,746,684**
	Allocated Return on Debt																	
14	Newfoundland Power	61,066,285	27,422,589	23,752,113	8,550,349	-	-	-	-	-	-	-	-	-	-	-	-	1,341,234
15	Industrial - Firm	4,876,518	1,598,370	2,491,444	484,843	-	-	-	-	-	-	-	-	-	-	-	-	301,861
16	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
17	1.1 Domestic	4,246,957	515,991	480,417	156,519	907,549	202,408	746,069	391,450	59,230	187,597	130,988	256,134	96,376	58,469	-	57,761	-
18	1.12 Domestic All Electric	4,957,518	682,174	615,188	206,928	1,199,839	267,596	986,352	279,435	78,306	133,915	173,175	182,840	68,797	41,738	-	41,233	-
19	1.3 Special	13,044	2,172	1,510	659	3,820	852	3,140	34	249	16	551	22	8	5	-	5	-
20	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.2 GS 10-100 kW	2,408,915	316,259	331,342	95,933	556,251	124,059	457,277	98,657	36,303	47,280	80,285	64,553	115,864	70,292	-	14,558	-
22	2.3 GS 110-1,000 kVa	1,685,486	266,626	263,510	80,877	468,954	104,589	385,513	3,120	30,487	1,495	67,422	2,041	6,467	3,923	-	460	-
23	2.4 GS Over 1,000 kVa	868,146	137,546	155,738	41,723	241,922	53,955	198,876	271	11,478	130	25,385	178	563	341	-	40	-
24	4.1 Street and Area Lighting	241,893	16,730	12,258	5,075	29,426	6,563	24,190	32,130	1,920	15,398	4,247	21,024	-	-	68,191	4,741	-
25	**Subtotal Rural**	**14,421,958**	**1,937,499**	**1,859,964**	**587,713**	**3,407,761**	**760,022**	**2,801,418**	**805,099**	**217,973**	**385,831**	**482,054**	**526,792**	**288,075**	**174,768**	**68,191**	**118,798**	-
26	**Total**	**80,364,761**	**30,958,458**	**28,103,522**	**9,622,905**	**3,407,761**	**760,022**	**2,801,418**	**805,099**	**217,973**	**385,831**	**482,054**	**526,792**	**288,075**	**174,768**	**68,191**	**118,798**	**1,643,095**
	Allocated Return on Equity																	
27	Newfoundland Power	23,242,433	10,437,309	9,040,290	3,254,347	-	-	-	-	-	-	-	-	-	-	-	-	510,487
28	Industrial - Firm	1,856,051	608,356	948,268	184,536	-	-	-	-	-	-	-	-	-	-	-	-	114,891
29	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
30	1.1 Domestic	1,616,434	196,391	182,852	59,573	345,422	77,038	283,961	148,990	22,543	71,401	49,855	97,487	36,682	22,254	-	21,984	-
31	1.12 Domestic All Electric	1,886,880	259,642	234,147	78,759	456,671	101,850	375,415	106,356	29,804	50,969	65,912	69,591	26,185	15,886	-	15,694	-
32	1.3 Special	4,965	827	575	251	1,454	324	1,195	13	95	6	210	8	3	2	-	2	-
33	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	2.2 GS 10-100 kW	916,857	120,371	126,112	36,513	211,715	47,218	174,044	37,550	13,817	17,995	30,557	24,570	44,099	26,754	-	5,541	-
35	2.3 GS 110-1,000 kVa	641,513	101,481	100,294	30,783	178,489	39,808	146,730	1,187	11,604	569	25,662	777	2,461	1,493	-	175	-
36	2.4 GS Over 1,000 kVa	330,425	52,351	59,275	15,880	92,078	20,536	75,694	103	4,369	50	9,662	68	214	130	-	15	-
37	4.1 Street and Area Lighting	92,067	6,368	4,666	1,932	11,200	2,498	9,207	12,229	731	5,861	1,616	8,002	-	-	25,954	1,804	-
38	**Subtotal Rural**	**5,489,140**	**737,431**	**707,921**	**223,689**	**1,297,028**	**289,272**	**1,066,247**	**306,428**	**82,963**	**146,851**	**183,475**	**200,502**	**109,644**	**66,518**	**25,954**	**45,216**	-
39	**Total**	**30,587,624**	**11,783,096**	**10,696,479**	**3,662,573**	**1,297,028**	**289,272**	**1,066,247**	**306,428**	**82,963**	**146,851**	**183,475**	**200,502**	**109,644**	**66,518**	**25,954**	**45,216**	**625,378**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax	20 Revenue Related PUB Assessment ($)
	Allocated Rev Reqmt Excl Return		
1	Newfoundland Power	-	614,804
2	Industrial - Firm	-	22,159
3	Industrial - Non-Firm	-	7
	Rural		
4	1.1 Domestic	362,369	18,774
5	1.12 Domestic All Electric	452,454	23,441
6	1.3 Special	510	26
7	2.1 GS 0-10 kW	-	-
8	2.2 GS 10-100 kW	252,865	13,100
9	2.3 GS 110-1,000 kVa	165,980	8,599
10	2.4 GS Over 1,000 kVa	88,812	4,601
11	4.1 Street and Area Lighting	27,321	1,415
12	**Subtotal Rural**	**1,350,312**	**69,957**
13	**Total**	**1,350,312**	**706,926**
	Allocated Return on Debt		
14	Newfoundland Power	-	-
15	Industrial - Firm	-	-
16	Industrial - Non-Firm	-	-
	Rural		
17	1.1 Domestic	-	-
18	1.12 Domestic All Electric	-	-
19	1.3 Special	-	-
20	2.1 GS 0-10 kW	-	-
21	2.2 GS 10-100 kW	-	-
22	2.3 GS 110-1,000 kVa	-	-
23	2.4 GS Over 1,000 kVa	-	-
24	4.1 Street and Area Lighting	-	-
25	**Subtotal Rural**	-	-
26	**Total**	-	-
	Allocated Return on Equity		
27	Newfoundland Power	-	-
28	Industrial - Firm	-	-
29	Industrial - Non-Firm	-	-
	Rural		
30	1.1 Domestic	-	-
31	1.12 Domestic All Electric	-	-
32	1.3 Special	-	-
33	2.1 GS 0-10 kW	-	-
34	2.2 GS 10-100 kW	-	-
35	2.3 GS 110-1,000 kVa	-	-
36	2.4 GS Over 1,000 kVa	-	-
37	4.1 Street and Area Lighting	-	-
38	**Subtotal Rural**	-	-
39	**Total**	-	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production and Transmission Energy	5 Transmission Demand	6 Rural Prod & Transmission Demand	7 Substations Demand	8 Distribution Primary Lines Demand	9 Primary Lines Customer	10 Line Transformers Demand	11 Line Transformers Customer	12 Secondary Lines Demand	13 Secondary Lines Customer	14 Services Customer	15 Meters Customer	16 Street Lighting Customer	17 Accounting Customer	18 Specifically Assigned Customer
	Total Revenue Requiremt	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
40	Newfoundland Power	402,222,213	126,113,509	243,575,546	27,593,211	-	-	-	-	-	-	-	-	-	-	-	-	4,325,142
41	Industrial - Firm	36,177,072	7,350,731	25,549,509	1,564,660	-	-	-	-	-	-	-	-	-	-	-	-	1,690,015
42	Industrial - Non-Firm	7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
43	1.1 Domestic	21,825,972	2,372,988	4,926,630	505,109	3,229,181	828,212	3,195,997	1,550,909	262,169	830,358	507,608	988,194	343,748	329,039	-	1,574,688	-
44	1.12 Domestic All Electric	25,206,406	3,137,246	6,308,696	667,787	4,269,190	1,094,951	4,225,318	1,107,110	346,604	592,748	671,092	705,418	245,383	234,883	-	1,124,085	-
45	1.3 Special	62,394	9,988	15,489	2,126	13,591	3,486	13,452	134	1,103	72	2,136	86	30	29	-	136	-
46	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	2.2 GS 10-100 kW	12,400,318	1,454,442	3,397,883	309,589	1,979,217	507,625	1,958,877	390,876	160,687	209,275	311,121	249,055	413,260	395,576	-	396,869	-
48	2.3 GS 110-1,000 kVa	8,592,816	1,226,185	2,702,264	261,003	1,668,603	427,959	1,651,455	12,360	134,944	6,618	261,277	7,876	23,066	22,079	-	12,550	-
49	2.4 GS Over 1,000 kVa	4,547,734	632,558	1,597,078	134,645	860,790	220,773	851,944	1,075	50,807	576	98,371	685	2,007	1,921	-	1,092	-
50	4.1 Street and Area Lighting	1,305,861	76,940	125,708	16,377	104,701	26,853	103,625	127,299	8,500	68,156	16,458	81,111	-	-	392,145	129,251	-
51	**Subtotal Rural**	**73,941,500**	**8,910,345**	**19,073,749**	**1,896,636**	**12,125,272**	**3,109,859**	**12,000,667**	**3,189,764**	**964,815**	**1,707,802**	**1,868,064**	**2,032,424**	**1,027,493**	**983,526**	**392,145**	**3,238,670**	**-**
52	**Total**	**512,340,792**	**142,374,585**	**288,198,804**	**31,054,507**	**12,125,272**	**3,109,859**	**12,000,667**	**3,189,764**	**964,815**	**1,707,802**	**1,868,064**	**2,032,424**	**1,027,493**	**983,526**	**392,145**	**3,238,670**	**6,015,157**
	Re-classification of Revenue-Related																	
53	Newfoundland Power	-	193,062	372,879	42,241	-	-	-	-	-	-	-	-	-	-	-	-	6,621
54	Industrial - Firm	-	4,505	15,659	959	-	-	-	-	-	-	-	-	-	-	-	-	1,036
55	Industrial - Non-Firm	(7)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
56	1.1 Domestic	0	42,176	87,562	8,977	57,393	14,720	56,803	27,565	4,660	14,758	9,022	17,563	6,110	5,848	-	27,987	-
57	1.12 Domestic All Electric	0	60,371	121,400	12,850	82,153	21,070	81,309	21,304	6,670	11,406	12,914	13,575	4,722	4,520	-	21,631	-
58	1.3 Special	(0)	87	134	18	118	30	117	1	10	1	19	1	0	0	-	1	-
59	2.1 GS 0-10 kW																	
60	2.2 GS 10-100 kW	(0)	31,879	74,476	6,786	43,381	11,126	42,935	8,567	3,522	4,587	6,819	5,459	9,058	8,670	-	8,699	-
61	2.3 GS 110-1,000 kVa	(0)	25,429	56,040	5,413	34,604	8,875	34,248	256	2,798	137	5,418	163	478	458	-	260	-
62	2.4 GS Over 1,000 kVa	(0)	13,266	33,493	2,824	18,052	4,630	17,866	23	1,065	12	2,063	14	42	40	-	23	-
63	4.1 Street and Area Lighting	-	1,731	2,829	369	2,356	604	2,332	2,864	191	1,534	370	1,825	-	-	8,824	2,908	-
64	**Subtotal Rural**	**0**	**174,938**	**375,934**	**37,237**	**238,057**	**61,056**	**235,610**	**60,581**	**18,916**	**32,435**	**36,625**	**38,600**	**20,410**	**19,537**	**8,824**	**61,510**	**-**
65	**Total**	**(7)**	**372,505**	**764,472**	**80,437**	**238,057**	**61,056**	**235,610**	**60,581**	**18,916**	**32,435**	**36,625**	**38,600**	**20,410**	**19,537**	**8,824**	**61,510**	**7,657**
	Total Allocated Revenue Requirement																	
66	Newfoundland Power	402,222,213	126,306,571	243,948,426	27,635,453	-	-	-	-	-	-	-	-	-	-	-	-	4,331,763
67	Industrial - Firm	36,177,072	7,355,236	25,565,167	1,565,619	-	-	-	-	-	-	-	-	-	-	-	-	1,691,050
68	Industrial - Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																	
69	1.1 Domestic	21,825,972	2,415,163	5,014,192	514,086	3,286,574	842,932	3,252,800	1,578,473	266,828	845,116	516,630	1,005,757	349,858	334,887	-	1,602,675	-
70	1.12 Domestic All Electric	25,206,406	3,197,617	6,430,096	680,637	4,351,343	1,116,022	4,306,627	1,128,415	353,274	604,154	684,006	718,993	250,105	239,403	-	1,145,716	-
71	1.3 Special	62,394	10,074	15,623	2,144	13,709	3,516	13,568	136	1,113	73	2,155	86	30	29	-	138	-
72	2.1 GS 0-10 kW																	
73	2.2 GS 10-100 kW	12,400,318	1,486,321	3,472,360	316,375	2,022,598	518,751	2,001,813	399,443	164,209	213,862	317,941	254,514	422,318	404,246	-	405,568	-
74	2.3 GS 110-1,000 kVa	8,592,816	1,251,614	2,758,305	266,416	1,703,206	436,834	1,685,703	12,617	137,742	6,755	266,695	8,039	23,544	22,536	-	12,810	-
75	2.4 GS Over 1,000 kVa	4,547,734	645,823	1,630,571	137,468	878,842	225,403	869,810	1,098	51,872	588	100,434	700	2,049	1,961	-	1,115	-
76	4.1 Street and Area Lighting	1,305,861	78,671	128,536	16,746	107,057	27,458	105,956	130,163	8,692	69,689	16,829	82,936	-	-	400,969	132,159	-
77	**Subtotal Rural**	**73,941,500**	**9,085,283**	**19,449,683**	**1,933,872**	**12,363,329**	**3,170,915**	**12,236,277**	**3,250,344**	**983,731**	**1,740,237**	**1,904,689**	**2,071,025**	**1,047,904**	**1,003,063**	**400,969**	**3,300,180**	**-**
78	**Total**	**512,340,785**	**142,747,090**	**288,963,276**	**31,134,944**	**12,363,329**	**3,170,915**	**12,236,277**	**3,250,344**	**983,731**	**1,740,237**	**1,904,689**	**2,071,025**	**1,047,904**	**1,003,063**	**400,969**	**3,300,180**	**6,022,814**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	19 Revenue Related Municipal Tax ($)	20 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requiremt			
40	Newfoundland Power	-	614,804	
41	Industrial - Firm	-	22,159	
42	Industrial - Non-Firm	-	7	
	Rural			
43	1.1 Domestic	362,369	18,774	
44	1.12 Domestic All Electric	452,454	23,441	
45	1.3 Special	510	26	
46	2.1 GS 0-10 kW	-	-	
47	2.2 GS 10-100 kW	252,865	13,100	
48	2.3 GS 110-1,000 kVa	165,980	8,599	
49	2.4 GS Over 1,000 kVa	88,812	4,601	
50	4.1 Street and Area Lighting	27,321	1,415	
51	**Subtotal Rural**	**1,350,312**	**69,957**	
52	**Total**	**1,350,312**	**706,926**	
	Re-classification of Revenue-Related			
53	Newfoundland Power	-	(614,804)	Re-classification to demand, energy and customer is based on rate class revenue
54	Industrial - Firm	-	(22,159)	requirements excluding revenue-related items.
55	Industrial - Non-Firm	-	(7)	
	Rural			
56	1.1 Domestic	(362,369)	(18,774)	
57	1.12 Domestic All Electric	(452,454)	(23,441)	
58	1.3 Special	(510)	(26)	
59	2.1 GS 0-10 kW	-	-	
60	2.2 GS 10-100 kW	(252,865)	(13,100)	
61	2.3 GS 110-1,000 kVa	(165,980)	(8,599)	
62	2.4 GS Over 1,000 kVa	(88,812)	(4,601)	
63	4.1 Street and Area Lighting	(27,321)	(1,415)	
64	**Subtotal Rural**	**(1,350,312)**	**(69,957)**	
65	**Total**	**(1,350,312)**	**(706,926)**	
	Total Allocated Revenue Requirement			
66	Newfoundland Power	-	-	
67	Industrial - Firm	-	-	
68	Industrial - Non-Firm	-	-	
	Rural			
69	1.1 Domestic	-	-	
70	1.12 Domestic All Electric	-	-	
71	1.3 Special	-	-	
72	2.1 GS 0-10 kW	-	-	
73	2.2 GS 10-100 kW	-	-	
74	2.3 GS 110-1,000 kVa	-	-	
75	2.4 GS Over 1,000 kVa	-	-	
76	4.1 Street and Area Lighting	-	-	
77	**Subtotal Rural**	-	-	
78	**Total**	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Interconnected
Allocation of Specifically Assigned Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 OM&A Transmission Lines ($) (Plant)	4 OM&A Transmission Terminals ($) (Plant)	5 OM&A Administrative & General ($) (C3 & C4)	6 OM&A Other ($) (C3 & C4)	7 Depreciation Transmission Lines ($) (Direct)	8 Depreciation Transmission Terminals ($) (Direct)	9 Depreciation Telecontrol & Feasibility Study ($) (Direct)	10 Depreciation General ($) (Exp C3,4,6)	11 Expense Credits Rental Income ($) (Plant)	12 Expense Credits Other ($) (C6)	13 Gains/Losses ($) (NBV)	14 Subtotal Excluding Return ($)	15 Return on Debt ($) (NBV)	16 Return on Equity ($) (NBV)	17 Subtotal Excl Rev Related ($)	18 Revenue Related ($)
	Basis of Allocation - Amounts																	
1	Newfoundland Power		25,304,070	13,005,806	38,309,875	38,309,875	-	-	-	743,804	38,309,875	38,309,875	24,090,999	-	24,090,999	24,090,999	-	-
	Industrial																	
2	Vale		6,554,033	4,509,884	11,063,917	11,063,917	-	-	-	223,726	11,063,917	11,063,917	346,327	-	346,327	346,327	-	-
3	Abitibi Consolidated - GF		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Corner Brook P& P - CB		-	7,052,376	7,052,376	7,052,376	-	-	-	192,018	7,052,376	7,052,376	4,753,752	-	4,753,752	4,753,752	-	-
5	Corner Brook P& P - DL		-	19,788	19,788	19,788	-	-	-	539	19,788	19,788	11,393	-	11,393	11,393	-	-
6	North Atlantic Refining Limited		-	1,127,618	1,127,618	1,127,618	-	-	-	30,702	1,127,618	1,127,618	310,497	-	310,497	310,497	-	-
7	Teck Resources		4,534,363	909,953	5,444,315	5,444,315	-	-	-	94,606	5,444,315	5,444,315	0	-	0	0	-	-
8	**Subtotal Industrial**		**11,088,396**	**13,619,619**	**24,708,015**	**24,708,015**	**-**	**-**	**-**	**541,591**	**24,708,015**	**24,708,015**	**5,421,969**	**-**	**5,421,969**	**5,421,969**	**-**	**-**
9	**Total**		**36,392,465**	**26,625,425**	**63,017,890**	**63,017,890**	**-**	**-**	**-**	**1,285,395**	**63,017,890**	**63,017,890**	**29,512,968**	**-**	**29,512,968**	**29,512,968**	**-**	**-**
10	**Basis of Allocation - Ratios**																	
11	Newfoundland Power		0.6953	0.4885	0.6079	0.6079	-	-	-	0.5787	0.6079	0.6079	0.8163	-	0.8163	0.8163	-	-
	Industrial																	
12	Vale		0.1801	0.1694	0.1756	0.1756	-	-	-	0.1741	0.1756	0.1756	0.0117	-	0.0117	0.0117	-	-
13	Abitibi Consolidated - GF		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Corner Brook P& P - CB		-	0.2649	0.1119	0.1119	-	-	-	0.1494	0.1119	0.1119	0.1611	-	0.1611	0.1611	-	-
15	Corner Brook P& P - DL		-	0.0007	0.0003	0.0003	-	-	-	0.0004	0.0003	0.0003	0.0004	-	0.0004	0.0004	-	-
16	North Atlantic Refining Ltd.		-	0.0424	0.0179	0.0179	-	-	-	0.0239	0.0179	0.0179	0.0105	-	0.0105	0.0105	-	-
17	Teck Resources		0.1246	0.0342	0.0864	0.0864	-	-	-	0.0736	0.0864	0.0864	0.0000	-	0.0000	0.0000	-	-
18	**Subtotal Industrial**		**0.3047**	**0.5115**	**0.3921**	**0.3921**	**-**	**-**	**-**	**0.4213**	**0.3921**	**0.3921**	**0.1837**	**-**	**0.1837**	**0.1837**	**-**	**-**
19	**Total**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**	**-**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**	**1.0000**	**1.0000**	**-**	**-**
	Amounts Allocated																	
20	Newfoundland Power	4,331,763	288,942	302,333	737,496	152,528	616,408	241,978	-	81,075	(325)	(8,361)	61,345	2,473,421	1,341,234	510,487	4,325,142	6,621
	Industrial																	
21	Vale	499,568	74,839	104,837	212,989	44,050	-	13,167	-	24,386	(94)	(2,415)	882	472,643	19,281	7,339	499,262	306
22	Abitibi Consolidated - GF	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Corner Brook P& P - CB	888,302	-	163,940	135,764	28,079	-	163,149	-	20,930	(60)	(1,539)	12,105	522,367	264,659	100,732	887,758	544
24	Corner Brook P& P - DL	2,823	-	460	381	79	-	943	-	59	(0)	(4)	29	1,946	634	241	2,822	2
25	North Atlantic Refining Ltd.	91,738	-	26,213	21,708	4,490	-	11,524	-	3,347	(10)	(246)	791	67,815	17,287	6,579	91,681	56
26	Teck Resources	208,619	51,777	21,153	104,808	21,676	-	-	-	10,312	(46)	(1,188)	0	208,491	0	0	208,491	128
27	**Subtotal Industrial**	**1,691,050**	**126,616**	**316,602**	**475,649**	**98,373**	**-**	**188,783**	**-**	**59,034**	**(209)**	**(5,392)**	**13,806**	**1,273,263**	**301,861**	**114,891**	**1,690,015**	**1,036**
28	**Total**	**6,022,814**	**415,559**	**618,935**	**1,213,146**	**250,902**	**616,408**	**430,761**	**-**	**140,109**	**(534)**	**(13,753)**	**75,152**	**3,746,684**	**1,643,095**	**625,378**	**6,015,157**	**7,657**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
							Distribution										
	Expenses																
1	Operating & Maintenance	5,871,802	1,939,392	2,414,951	-	12,798	624,399	187,510	49,354	87,360	113,076	123,039	57,047	27,472	15,900	178,224	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	1,916,489	-	1,916,489	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	232,400	-	232,400	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	538,967	181,831	226,761	-	1,596	53,496	17,104	6,956	12,312	9,514	10,823	4,561	6,922	4,001	3,090	-
	Expense Credits																
8	Sundry	(27,964)	(9,236)	(11,501)	-	(61)	(2,974)	(893)	(235)	(416)	(539)	(586)	(272)	(131)	(76)	(849)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(4,356)	(1,439)	(1,792)	-	(9)	(463)	(139)	(37)	(65)	(84)	(91)	(42)	(20)	(12)	(132)	-
12	Pole Attachments	(24,203)	-	-	-	-	(13,998)	(4,784)	-	-	(2,478)	(2,944)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(168)	-	-	-	-	-	-	-	-	-	-	-	-	-	(168)	-
16	Meter Test Revenues	(57)	-	-	-	-	-	-	-	-	-	-	-	(57)	-	-	-
17	**Total Expense Credits**	(56,749)	(10,675)	(13,293)	-	(70)	(17,435)	(5,816)	(272)	(481)	(3,100)	(3,621)	(314)	(208)	(88)	(1,149)	-
18	**Subtotal Expenses**	8,502,910	2,110,548	4,777,308	-	14,324	660,460	198,798	56,038	99,192	119,490	130,241	61,295	34,185	19,814	180,164	-
19	Disposal Gain / Loss	133,059	41,560	51,619	-	406	18,151	5,740	1,549	2,741	3,327	3,718	2,335	999	444	469	-
20	**Subtotal Revenue Requirement Ex. Return**	8,635,969	2,152,108	4,828,927	-	14,730	678,612	204,537	57,587	101,933	122,817	133,960	63,629	35,184	20,258	180,634	-
21	Return on Debt	609,802	188,181	241,902	-	1,830	81,847	25,859	6,974	12,345	15,000	16,755	10,473	4,500	2,003	2,134	-
22	Return on Equity	232,097	71,624	92,070	-	697	31,152	9,842	2,654	4,698	5,709	6,377	3,986	1,713	762	812	-
23	**Total Revenue Requirement**	9,477,867	2,411,913	5,162,898	-	17,257	791,610	240,238	67,215	118,976	143,527	157,092	78,088	41,396	23,022	183,580	-

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	39,247	2,033	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(187)	(10)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(29)	(2)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(216)**	**(11)**	
18	**Subtotal Expenses**	**39,031**	**2,022**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**39,031**	**2,022**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**39,031**	**2,022**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	15,123,439	6,639,068	8,484,371	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**15,123,439**	**6,639,068**	**8,484,371**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	253,721	201,749	-	-	51,973	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	76,483	-	-	-	-	57,665	7,346	-	-	6,688	4,784	-	-	-	-	-
8	Poles	3,549,836	-	-	-	-	2,053,041	701,632	-	-	363,390	431,774	-	-	-	-	-
9	Primary Conductor & Equipment	489,822	-	-	-	-	434,472	55,350	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	557,274	-	-	-	-	-	-	201,176	356,098	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	155,817	-	-	-	-	-	-	-	-	90,841	64,976	-	-	-	-	-
13	Services	232,537	-	-	-	-	-	-	-	-	-	-	232,537	-	-	-	-
14	Meters	138,516	-	-	-	-	-	-	-	-	-	-	-	138,516	-	-	-
15	Street Lighting	64,813	-	-	-	-	-	-	-	-	-	-	-	-	64,813	-	-
16	**Subtotal Distribution**	**5,518,820**	**201,749**	**-**	**-**	**51,973**	**2,545,177**	**764,328**	**201,176**	**356,098**	**460,919**	**501,533**	**232,537**	**138,516**	**64,813**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**20,642,259**	**6,840,817**	**8,484,371**	**-**	**51,973**	**2,545,177**	**764,328**	**201,176**	**356,098**	**460,919**	**501,533**	**232,537**	**138,516**	**64,813**	**-**	**-**
18	General	2,438,631	866,586	1,088,920	-	3,735	182,919	54,931	14,458	25,592	33,126	36,045	16,712	6,193	4,658	104,756	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	41,659	13,806	17,123	-	105	5,137	1,543	406	719	930	1,012	469	280	131	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**23,122,548**	**7,721,208**	**9,590,414**	**-**	**55,813**	**2,733,232**	**820,802**	**216,040**	**382,409**	**494,975**	**538,590**	**249,718**	**144,988**	**69,601**	**104,756**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.6
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	7,081,070	3,108,533	3,972,537	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**7,081,070**	**3,108,533**	**3,972,537**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	126,876	93,751	-	-	33,125	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	50,783	-	-	-	-	38,288	4,878	-	-	4,441	3,176	-	-	-	-	-
8	Poles	2,252,619	-	-	-	-	1,302,798	445,235	-	-	230,596	273,991	-	-	-	-	-
9	Primary Conductor & Equipment	148,786	-	-	-	-	131,973	16,813	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	349,358	-	-	-	-	-	-	126,118	223,240	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	60,286	-	-	-	-	-	-	-	-	35,146	25,139	-	-	-	-	-
13	Services	192,060	-	-	-	-	-	-	-	-	-	-	192,060	-	-	-	-
14	Meters	82,512	-	-	-	-	-	-	-	-	-	-	-	82,512	-	-	-
15	Street Lighting	35,944	-	-	-	-	-	-	-	-	-	-	-	-	35,944	-	-
16	**Subtotal Distribution**	**3,299,223**	**93,751**	**-**	**-**	**33,125**	**1,473,059**	**466,925**	**126,118**	**223,240**	**270,184**	**302,306**	**192,060**	**82,512**	**35,944**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**10,380,293**	**3,202,284**	**3,972,537**	**-**	**33,125**	**1,473,059**	**466,925**	**126,118**	**223,240**	**270,184**	**302,306**	**192,060**	**82,512**	**35,944**	**-**	**-**
18	General	931,299	330,944	415,852	-	1,426	69,856	20,978	5,522	9,774	12,651	13,765	6,382	2,365	1,779	40,006	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	31,461	9,706	12,040	-	100	4,465	1,415	382	677	819	916	582	250	109	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**11,343,054**	**3,542,934**	**4,400,430**	**-**	**34,652**	**1,547,379**	**489,318**	**132,022**	**233,690**	**283,653**	**316,988**	**199,024**	**85,127**	**37,832**	**40,006**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	2,130,539	935,289	1,195,250	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	314,161	137,914	176,247	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**2,444,700**	**1,073,204**	**1,371,497**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
8	Other	487,018	18,262	-	-	4,704	230,386	69,186	18,210	32,234	41,722	45,398	21,049	-	5,867	-	-
9	Meters	7,800	-	-	-	-	-	-	-	-	-	-	-	7,800	-	-	-
10	**Subtotal Distribution**	**494,818**	**18,262**	**-**	**-**	**4,704**	**230,386**	**69,186**	**18,210**	**32,234**	**41,722**	**45,398**	**21,049**	**7,800**	**5,867**	**-**	**-**
11	**Subttl Prod, Trans, & Dist**	**2,939,518**	**1,091,466**	**1,371,497**	**-**	**4,704**	**230,386**	**69,186**	**18,210**	**32,234**	**41,722**	**45,398**	**21,049**	**7,800**	**5,867**	**-**	**-**
12	Customer Accounting	131,940	-	-	-	-	-	-	-	-	-	-	-	-	-	131,940	-
	Administrative & General:																
	Plant-Related:																
13	Production	668,726	293,565	375,160	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	571,487	20,892	-	-	5,382	263,559	79,148	20,832	36,875	47,729	51,935	24,080	14,344	6,712	-	-
16	Prod, Trans, Distn Plant	356,326	118,086	146,457	-	897	43,935	13,194	3,473	6,147	7,956	8,657	4,014	2,391	1,119	-	-
17	Prod, Trans, Distn and Gen Plt	3,528	1,178	1,463	-	9	417	125	33	58	76	82	38	22	11	16	-
18	Property Insurance	16,396	7,093	8,810	-	51	168	51	13	24	30	33	15	6	4	96	-
	Revenue Related:																
19	Municipal Tax	39,247	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	2,033	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	1,074,830	381,949	479,943	-	1,646	80,622	24,211	6,373	11,280	14,600	15,887	7,366	2,730	2,053	46,171	-
22	Prod, Trans, and Distn Expense-Related	67,771	25,164	31,620	-	108	5,312	1,595	420	743	962	1,047	485	180	135	-	-
23	**Subtotal Admin & General**	**2,800,343**	**847,927**	**1,043,454**	**-**	**8,094**	**394,012**	**118,324**	**31,144**	**55,127**	**71,354**	**77,641**	**35,998**	**19,672**	**10,033**	**46,284**	**-**
24	**Total Operating & Maintenance Expenses**	**5,871,802**	**1,939,392**	**2,414,951**	**-**	**12,798**	**624,399**	**187,510**	**49,354**	**87,360**	**113,076**	**123,039**	**57,047**	**27,472**	**15,900**	**178,224**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L6
2	Other	-		Production - Demand, Energy ratios Sch.4.1 L6
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod, Trans, Distn and Gen Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	39,247	-	Revenue-related
20	PUB Assessment	-	2,033	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**39,247**	**2,033**	
24	**Total Operating & Maintenance Expenses**	**39,247**	**2,033**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
						Distribution											
	Production																
1	Diesel	341,149	149,762	191,388	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**341,149**	**149,762**	**191,388**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substn Struct & Eqpt	5,357	3,895	-	-	1,461	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	1,458	-	-	-	-	1,100	140	-	-	128	91	-	-	-	-	-
8	Poles	74,203	-	-	-	-	42,915	14,666	-	-	7,596	9,025	-	-	-	-	-
9	Primary Conductor & Equipment	3,700	-	-	-	-	3,282	418	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	17,784	-	-	-	-	-	-	6,420	11,364	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	1,151	-	-	-	-	-	-	-	-	671	480	-	-	-	-	-
13	Services	4,000	-	-	-	-	-	-	-	-	-	-	4,000	-	-	-	-
14	Meters	6,626	-	-	-	-	-	-	-	-	-	-	-	6,626	-	-	-
15	Street Lighting	3,799	-	-	-	-	-	-	-	-	-	-	-	-	3,799	-	-
16	**Subtotal Distribution**	**118,079**	**3,895**	**-**	**-**	**1,461**	**47,297**	**15,225**	**6,420**	**11,364**	**8,395**	**9,597**	**4,000**	**6,626**	**3,799**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**459,228**	**153,657**	**191,388**	**-**	**1,461**	**47,297**	**15,225**	**6,420**	**11,364**	**8,395**	**9,597**	**4,000**	**6,626**	**3,799**	**-**	**-**
18	General	71,927	25,560	32,118	-	110	5,395	1,620	426	755	977	1,063	493	183	137	3,090	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	7,812	2,614	3,256	-	25	805	259	109	193	143	163	68	113	65	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**538,967**	**181,831**	**226,761**	**-**	**1,596**	**53,496**	**17,104**	**6,956**	**12,312**	**9,514**	**10,823**	**4,561**	**6,922**	**4,001**	**3,090**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
1	Average Net Book Value	11,343,054	3,542,934	4,400,430	-	34,652	1,547,379	489,318	132,022	233,690	283,653	316,988	199,024	85,127	37,832	40,006	-
2	Cash Working Capital	49,167	15,357	19,074	-	150	6,707	2,121	572	1,013	1,230	1,374	863	369	164	173	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	165,549	-	165,549	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	250,202	83,549	103,775	-	604	29,575	8,882	2,338	4,138	5,356	5,828	2,702	1,569	753	1,134	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	541,426	169,111	210,041	-	1,654	73,859	23,356	6,302	11,154	13,539	15,130	9,500	4,063	1,806	1,910	-
8	Total Rate Base	**12,349,399**	**3,810,951**	**4,898,870**	**-**	**37,060**	**1,657,521**	**523,677**	**141,234**	**249,995**	**303,778**	**339,320**	**212,089**	**91,128**	**40,555**	**43,222**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**12,349,399**	**3,810,951**	**4,898,870**	**-**	**37,060**	**1,657,521**	**523,677**	**141,234**	**249,995**	**303,778**	**339,320**	**212,089**	**91,128**	**40,555**	**43,222**	**-**
11	Return on Debt	609,802	188,181	241,902	-	1,830	81,847	25,859	6,974	12,345	15,000	16,755	10,473	4,500	2,003	2,134	-
12	Return on Equity	232,097	71,624	92,070	-	697	31,152	9,842	2,654	4,698	5,709	6,377	3,986	1,713	762	812	-
13	Return on Rate Base	**841,898**	**259,805**	**333,972**	**-**	**2,526**	**112,999**	**35,701**	**9,628**	**17,043**	**20,710**	**23,133**	**14,459**	**6,213**	**2,765**	**2,947**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Substations Demand (CP kW)	7 Primary Lines Demand (CP kW)	8 Primary Lines Customer (Rural Cust)	9 Line Transformers Demand (CP kW)	10 Line Transformers Customer (Rural Cust)	11 Secondary Lines Demand (CP kW)	12 Secondary Lines Customer (Rural Cust)	13 Services Customer (Wtd Rural Cust)	14 Meters Customer	15 Street Lighting Customer (Rural Cust)	16 Accounting Customer (Rural Cust)	17 Specifically Assigned Customer
	Amounts																
1	1.2 Domestic Diesel	-	1,207	5,660	1,207	1,166	1,166	698	1,103	698	1,103	698	698	698	-	698	-
2	1.2G Government Domestic Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	126	784	126	121	121	96	115	96	115	96	180	180	-	96	-
5	2.2 GS 10-100 kW	-	110	726	110	106	106	13	100	13	100	13	62	62	-	13	-
6	2.3 GS 110-1,000 kVa	-	88	370	88	85	85	1	81	1	81	1	8	8	-	1	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	25	105	25	24	24	38	23	38	23	38	-	-	38	38	-
11	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**-**	**1,556**	**7,646**	**1,556**	**1,502**	**1,502**	**846**	**1,421**	**846**	**1,421**	**846**	**949**	**949**	**38**	**846**	**-**
	Ratios																
13	1.2 Domestic Diesel	-	0.7760	0.7402	0.7760	0.7760	0.7760	0.8251	0.7760	0.8251	0.7760	0.8251	0.7358	0.7358	-	0.8251	-
14	1.2G Government Domestic Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.0807	0.1026	0.0807	0.0807	0.0807	0.1135	0.0807	0.1135	0.0807	0.1135	0.1900	0.1900	-	0.1135	-
17	2.2 GS 10-100 kW	-	0.0707	0.0950	0.0707	0.0707	0.0707	0.0154	0.0707	0.0154	0.0707	0.0154	0.0654	0.0654	-	0.0154	-
18	2.3 GS 110-1,000 kVa	-	0.0567	0.0484	0.0567	0.0567	0.0567	0.0012	0.0567	0.0012	0.0567	0.0012	0.0089	0.0089	-	0.0012	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0160	0.0138	0.0160	0.0160	0.0160	0.0449	0.0160	0.0449	0.0160	0.0449	-	-	1.0000	0.0449	-
23	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	19 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	796,792	796,792
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	205,730	205,730
5	2.2 GS 10-100 kW	427,531	427,531
6	2.3 GS 110-1,000 kVa	-	-
7	2.4 GS Over 1,000 kVa	-	-
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	41,568	41,568
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**1,471,621**	**1,471,621**
	Ratios		
13	1.2 Domestic Diesel	0.5414	0.5414
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1398	0.1398
17	2.2 GS 10-100 kW	0.2905	0.2905
18	2.3 GS 110-1,000 kVa	-	-
19	2.4 GS Over 1,000 kVa	-	-
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0282	0.0282
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
						Distribution											
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	6,529,973	1,670,036	3,574,564	-	11,431	526,603	168,756	44,687	84,101	95,306	110,525	46,816	25,887	-	149,033	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	834,376	173,603	495,302	-	1,188	54,741	23,210	4,645	11,567	9,907	15,201	12,089	6,685	-	20,497	-
5	2.2 GS 10-100 kW	700,532	152,082	458,776	-	1,041	47,955	3,143	4,069	1,566	8,679	2,058	4,159	2,300	-	2,776	-
6	2.3 GS 110-1,000 kVa	406,839	121,953	233,763	-	835	38,455	242	3,263	120	6,960	158	565	312	-	214	-
7	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	164,250	34,434	66,522	-	236	10,858	9,187	921	4,579	1,965	6,017	-	-	20,258	8,114	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**8,635,969**	**2,152,108**	**4,828,927**	**-**	**14,730**	**678,612**	**204,537**	**57,587**	**101,933**	**122,817**	**133,960**	**63,629**	**35,184**	**20,258**	**180,634**	**-**
	Allocated Return on Debt and Equity																
13	1.2 Domestic Diesel	642,260	201,609	247,219	-	1,961	87,687	29,455	7,472	14,061	16,071	19,086	10,638	4,571	-	2,431	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	79,851	20,958	34,255	-	204	9,115	4,051	777	1,934	1,671	2,625	2,747	1,180	-	334	-
17	2.2 GS 10-100 kW	62,959	18,360	31,729	-	179	7,985	549	680	262	1,463	355	945	406	-	45	-
18	2.3 GS 110-1,000 kVa	39,432	14,722	16,167	-	143	6,403	42	546	20	1,174	27	128	55	-	3	-
19	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	17,397	4,157	4,601	-	40	1,808	1,604	154	766	331	1,039	-	-	2,765	132	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**841,898**	**259,805**	**333,972**	**-**	**2,526**	**112,999**	**35,701**	**9,628**	**17,043**	**20,710**	**23,133**	**14,459**	**6,213**	**2,765**	**2,947**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	21,133	1,095	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	5,456	283	
5	2.2 GS 10-100 kW	11,339	587	
6	2.3 GS 110-1,000 kVa	-	-	
7	2.4 GS Over 1,000 kVa	-	-	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	1,102	57	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**39,031**	**2,022**	
	Allocated Return on Debt and Equity			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Distribution Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Total Revenue Requirement																
25	1.2 Domestic Diesel	7,172,233	1,871,645	3,821,783	-	13,391	614,290	198,211	52,159	98,162	111,377	129,610	57,455	30,458	-	151,465	-
26	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	2.1 GS 0-10 kW	914,227	194,561	529,557	-	1,392	63,857	27,261	5,422	13,501	11,578	17,826	14,836	7,865	-	20,832	-
29	2.2 GS 10-100 kW	763,491	170,442	490,505	-	1,219	55,940	3,692	4,750	1,828	10,143	2,414	5,104	2,706	-	2,821	-
30	2.3 GS 110-1,000 kVa	446,270	136,675	249,930	-	978	44,858	284	3,809	141	8,133	186	693	367	-	217	-
31	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	4.1 Street and Area Lighting	181,646	38,591	71,123	-	276	12,666	10,791	1,075	5,344	2,296	7,056	-	-	23,022	8,246	-
35	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Total**	**9,477,867**	**2,411,913**	**5,162,898**	**-**	**17,257**	**791,610**	**240,238**	**67,215**	**118,976**	**143,527**	**157,092**	**78,088**	**41,396**	**23,022**	**183,580**	**-**
	Re-classification of Revenue-Related																
37	1.2 Domestic Diesel	0	5,819	11,881	-	42	1,910	616	162	305	346	403	179	95	-	471	-
38	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40	2.1 GS 0-10 kW	(0)	1,229	3,345	-	9	403	172	34	85	73	113	94	50	-	132	-
41	2.2 GS 10-100 kW	0	2,705	7,784	-	19	888	59	75	29	161	38	81	43	-	45	-
42	2.3 GS 110-1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	4.1 Street and Area Lighting	0	248	457	-	2	81	69	7	34	15	45	-	-	148	53	-
47	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	**Total**	**0**	**10,000**	**23,467**	**-**	**72**	**3,282**	**916**	**279**	**454**	**595**	**599**	**353**	**187**	**148**	**700**	**-**
	Total Allocated Revenue Requirement																
49	1.2 Domestic Diesel	7,172,233	1,877,463	3,833,664	-	13,433	616,199	198,827	52,321	98,467	111,723	130,013	57,633	30,553	-	151,935	-
50	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	2.1 GS 0-10 kW	914,227	195,790	532,903	-	1,401	64,260	27,433	5,456	13,586	11,651	17,939	14,930	7,915	-	20,963	-
53	2.2 GS 10-100 kW	763,491	173,147	498,289	-	1,239	56,828	3,750	4,825	1,857	10,304	2,452	5,185	2,749	-	2,866	-
54	2.3 GS 110-1,000 kVa	446,270	136,675	249,930	-	978	44,858	284	3,809	141	8,133	186	693	367	-	217	-
55	2.4 GS Over 1,000 kVa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58	4.1 Street and Area Lighting	181,646	38,839	71,580	-	278	12,747	10,860	1,082	5,378	2,311	7,101	-	-	23,170	8,299	-
59	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	**Total**	**9,477,867**	**2,421,913**	**5,186,366**	**-**	**17,329**	**794,892**	**241,155**	**67,494**	**119,430**	**144,122**	**157,691**	**78,441**	**41,584**	**23,170**	**184,281**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Island Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
25	1.2 Domestic Diesel	21,133	1,095	
26	1.2G Government Domestic Diesel	-	-	
27	1.23 Churches, Schools & Com Halls	-	-	
28	2.1 GS 0-10 kW	5,456	283	
29	2.2 GS 10-100 kW	11,339	587	
30	2.3 GS 110-1,000 kVa	-	-	
31	2.4 GS Over 1,000 kVa	-	-	
32	2.5 GS Diesel	-	-	
33	2.5G Gov't General Service Diesel	-	-	
34	4.1 Street and Area Lighting	1,102	57	
35	4.1G Gov't Street and Area Lighting	-	-	
36	**Total**	**39,031**	**2,022**	
	Re-classification of Revenue-Related			
37	1.2 Domestic Diesel	(21,133)	(1,095)	Re-classification to demand, energy and customer is based on rate class revenue
38	1.2G Government Domestic Diesel	-	-	requirements excluding revenue-related items.
39	1.23 Churches, Schools & Com Halls	-	-	
40	2.1 GS 0-10 kW	(5,456)	(283)	
41	2.2 GS 10-100 kW	(11,339)	(587)	
42	2.3 GS 110-1,000 kVa	-	-	
43	2.4 GS Over 1,000 kVa	-	-	
44	2.5 GS Diesel	-	-	
45	2.5G Gov't General Service Diesel	-	-	
46	4.1 Street and Area Lighting	(1,102)	(57)	
47	4.1G Gov't Street and Area Lighting	-	-	
48	**Total**	**(39,031)**	**(2,022)**	
	Total Allocated Revenue Requirement			
49	1.2 Domestic Diesel	-	-	
50	1.2G Government Domestic Diesel	-	-	
51	1.23 Churches, Schools & Com Halls	-	-	
52	2.1 GS 0-10 kW	-	-	
53	2.2 GS 10-100 kW	-	-	
54	2.3 GS 110-1,000 kVa	-	-	
55	2.4 GS Over 1,000 kVa	-	-	
56	2.5 GS Diesel	-	-	
57	2.5G Gov't General Service Diesel	-	-	
58	4.1 Street and Area Lighting	-	-	
59	4.1G Gov't Street and Area Lighting	-	-	
60	**Total**	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	14,032,074	4,016,294	7,363,460	-	89,448	918,485	255,505	39,607	70,108	171,472	176,730	54,274	53,030	23,754	612,750	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	13,063,614	-	13,063,614	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	2,620,505	774,829	1,430,585	-	22,023	179,641	54,682	7,019	12,424	31,629	35,040	17,560	26,357	13,905	14,812	-
	Expense Credits																
8	Sundry	(66,827)	(19,127)	(35,068)	-	(426)	(4,374)	(1,217)	(189)	(334)	(817)	(842)	(258)	(253)	(113)	(2,918)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(10,411)	(2,980)	(5,463)	-	(66)	(681)	(190)	(29)	(52)	(127)	(131)	(40)	(39)	(18)	(455)	-
12	Pole Attachments	(105,320)	-	-	-	-	(60,912)	(20,817)	-	-	(10,781)	(12,810)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(1,472)	-	-	-	-	-	-	-	-	-	-	-	-	-	(1,472)	-
16	Meter Test Revenues	(215)	-	-	-	-	-	-	-	-	-	-	-	(215)	-	-	-
17	**Total Expense Credits**	**(184,245)**	**(22,107)**	**(40,531)**	**-**	**(492)**	**(65,967)**	**(22,223)**	**(218)**	**(386)**	**(11,725)**	**(13,783)**	**(299)**	**(507)**	**(131)**	**(4,845)**	**-**
18	**Subtotal Expenses**	**29,531,948**	**4,769,015**	**21,817,128**	**-**	**110,978**	**1,032,159**	**287,964**	**46,408**	**82,146**	**191,376**	**197,987**	**71,535**	**78,881**	**37,528**	**622,717**	**-**
19	Disposal Gain / Loss	273,138	75,592	137,665	-	2,466	24,997	8,118	1,382	2,446	6,077	6,273	4,727	1,697	674	1,024	-
20	**Subtotal Revenue Requirement Ex. Return**	**29,805,086**	**4,844,607**	**21,954,792**	**-**	**113,444**	**1,057,156**	**296,082**	**47,790**	**84,592**	**197,452**	**204,260**	**76,262**	**80,577**	**38,202**	**623,742**	**-**
21	Return on Debt	2,915,201	764,728	1,544,334	-	25,028	253,778	82,166	13,964	24,717	61,393	63,373	47,300	17,159	6,841	10,420	-
22	Return on Equity	1,109,554	291,063	587,789	-	9,526	96,591	31,273	5,315	9,407	23,367	24,120	18,003	6,531	2,604	3,966	-
23	**Total Revenue Requirement**	**33,829,840**	**5,900,399**	**24,086,916**	**-**	**147,998**	**1,407,525**	**409,521**	**67,068**	**118,716**	**282,212**	**291,753**	**141,565**	**104,267**	**47,648**	**638,127**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	177,937	9,219	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.12
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(847)	(44)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(132)	(7)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(979)**	**(51)**	
18	**Subtotal Expenses**	**176,958**	**9,168**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**176,958**	**9,168**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**176,958**	**9,168**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	60,226,751	20,632,369	39,594,383	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**60,226,751**	**20,632,369**	**39,594,383**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	2,739,332	1,827,404	-	-	911,928	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	243,333	-	-	-	-	183,461	23,372	-	-	21,280	15,221	-	-	-	-	-
8	Poles	11,493,527	-	-	-	-	6,647,258	2,271,719	-	-	1,176,569	1,397,981	-	-	-	-	-
9	Primary Conductor & Equipment	2,952,695	-	-	-	-	2,619,040	333,655	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	1,128,800	-	-	-	-	-	-	407,497	721,303	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	971,404	-	-	-	-	-	-	-	-	566,328	405,075	-	-	-	-	-
13	Services	558,391	-	-	-	-	-	-	-	-	-	-	558,391	-	-	-	-
14	Meters	521,956	-	-	-	-	-	-	-	-	-	-	-	521,956	-	-	-
15	Street Lighting	244,392	-	-	-	-	-	-	-	-	-	-	-	-	244,392	-	-
16	**Subtotal Distribution**	**20,853,830**	**1,827,404**	**-**	**-**	**911,928**	**9,449,760**	**2,628,745**	**407,497**	**721,303**	**1,764,177**	**1,818,277**	**558,391**	**521,956**	**244,392**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**81,080,582**	**22,459,773**	**39,594,383**	**-**	**911,928**	**9,449,760**	**2,628,745**	**407,497**	**721,303**	**1,764,177**	**1,818,277**	**558,391**	**521,956**	**244,392**	**-**	**-**
18	General	8,718,632	2,556,398	4,722,682	-	47,627	493,534	137,292	21,282	37,672	92,138	94,963	29,163	28,898	12,764	444,218	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	163,632	45,327	79,907	-	1,840	19,071	5,305	822	1,456	3,560	3,670	1,127	1,053	493	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**89,962,845**	**25,061,497**	**44,396,971**	**-**	**961,396**	**9,962,365**	**2,771,342**	**429,602**	**760,430**	**1,859,876**	**1,916,910**	**588,681**	**551,908**	**257,649**	**444,218**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.7
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch 2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	36,782,536	12,600,893	24,181,643	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**36,782,536**	**12,600,893**	**24,181,643**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	1,143,035	693,537	-	-	449,498	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	154,588	-	-	-	-	116,551	14,848	-	-	13,519	9,669	-	-	-	-	-
8	Poles	7,326,313	-	-	-	-	4,237,159	1,448,060	-	-	749,980	891,114	-	-	-	-	-
9	Primary Conductor & Equipment	222,450	-	-	-	-	197,313	25,137	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	704,180	-	-	-	-	-	-	254,209	449,971	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	609,075	-	-	-	-	-	-	-	-	355,091	253,984	-	-	-	-	-
13	Services	888,870	-	-	-	-	-	-	-	-	-	-	888,870	-	-	-	-
14	Meters	310,922	-	-	-	-	-	-	-	-	-	-	-	310,922	-	-	-
15	Street Lighting	123,038	-	-	-	-	-	-	-	-	-	-	-	-	123,038	-	-
16	**Subtotal Distribution**	**11,482,471**	**693,537**	**-**	**-**	**449,498**	**4,551,023**	**1,488,045**	**254,209**	**449,971**	**1,118,589**	**1,154,768**	**888,870**	**310,922**	**123,038**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**48,265,007**	**13,294,429**	**24,181,643**	**-**	**449,498**	**4,551,023**	**1,488,045**	**254,209**	**449,971**	**1,118,589**	**1,154,768**	**888,870**	**310,922**	**123,038**	**-**	**-**
18	General	3,846,949	1,127,967	2,083,804	-	21,015	217,764	60,578	9,390	16,622	40,654	41,901	12,868	12,751	5,632	196,004	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	146,285	40,294	73,291	-	1,362	13,794	4,510	770	1,364	3,390	3,500	2,694	942	373	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**52,258,240**	**14,462,690**	**26,338,738**	**-**	**471,876**	**4,782,580**	**1,553,133**	**264,370**	**467,957**	**1,162,634**	**1,200,169**	**904,432**	**324,615**	**129,043**	**196,004**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	6,968,482	2,387,250	4,581,233	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	337,907	115,760	222,147	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**7,306,389**	**2,503,009**	**4,803,380**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
8	Other	1,080,020	97,071	-	-	48,441	501,967	139,638	21,646	38,315	93,712	96,586	29,662	-	12,982	-	-
9	Meters	29,392	-	-	-	-	-	-	-	-	-	-	-	29,392	-	-	-
10	**Subtotal Distribution**	**1,109,412**	**97,071**	**-**	**-**	**48,441**	**501,967**	**139,638**	**21,646**	**38,315**	**93,712**	**96,586**	**29,662**	**29,392**	**12,982**	**-**	**-**
11	**Subttl Prod, Trans, & Dist**	**8,415,802**	**2,600,080**	**4,803,380**	**-**	**48,441**	**501,967**	**139,638**	**21,646**	**38,315**	**93,712**	**96,586**	**29,662**	**29,392**	**12,982**	**-**	**-**
12	Customer Accounting	451,809	-	-	-	-	-	-	-	-	-	-	-	-	-	451,809	-
	Administrative & General:																
	Plant-Related:																
13	Production	769,010	263,446	505,564	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	395,021	34,615	-	-	17,274	179,001	49,795	7,719	13,663	33,418	34,442	10,577	9,887	4,629	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn and General Plt	447,836	124,757	221,009	-	4,786	49,593	13,796	2,139	3,785	9,258	9,542	2,930	2,747	1,283	2,211	-
18	Property Insurance	63,792	22,262	39,437	-	854	439	122	19	34	82	85	26	26	11	395	-
	Revenue Related:																
19	Municipal Tax	177,937	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	9,219	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	3,107,623	911,189	1,683,327	-	16,976	175,913	48,936	7,586	13,427	32,841	33,848	10,395	10,300	4,549	158,335	-
22	Prod, Trans, and Distn Expense-Related	194,026	59,945	110,742	-	1,117	11,573	3,219	499	883	2,161	2,227	684	678	299	-	-
23	**Subtotal Admin & General**	**5,164,463**	**1,416,213**	**2,560,080**	**-**	**41,007**	**416,518**	**115,867**	**17,961**	**31,793**	**77,760**	**80,144**	**24,612**	**23,638**	**10,772**	**160,941**	**-**
24	**Total Operating & Maintenance Expenses**	**14,032,074**	**4,016,294**	**7,363,460**	**-**	**89,448**	**918,485**	**255,505**	**39,607**	**70,108**	**171,472**	**176,730**	**54,274**	**53,030**	**23,754**	**612,750**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L7
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L7
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod, Trans, Distn and General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	177,937	-	Revenue-related
20	PUB Assessment	-	9,219	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**177,937**	**9,219**	
24	**Total Operating & Maintenance Expenses**	**177,937**	**9,219**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	1,904,132	652,314	1,251,818	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**1,904,132**	**652,314**	**1,251,818**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substn Struct & Eqpt	45,833	25,740	-	-	20,093	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	3,936	-	-	-	-	2,967	378	-	-	344	246	-	-	-	-	-
8	Poles	232,509	-	-	-	-	134,471	45,956	-	-	23,801	28,280	-	-	-	-	-
9	Primary Conductor & Equipment	25,949	-	-	-	-	23,017	2,932	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	17,184	-	-	-	-	-	-	6,204	10,981	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	6,746	-	-	-	-	-	-	-	-	3,933	2,813	-	-	-	-	-
13	Services	16,310	-	-	-	-	-	-	-	-	-	-	16,310	-	-	-	-
14	Meters	24,969	-	-	-	-	-	-	-	-	-	-	-	24,969	-	-	-
15	Street Lighting	13,254	-	-	-	-	-	-	-	-	-	-	-	-	13,254	-	-
16	**Subtotal Distribution**	**386,690**	**25,740**	**-**	**-**	**20,093**	**160,455**	**49,266**	**6,204**	**10,981**	**28,079**	**31,340**	**16,310**	**24,969**	**13,254**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**2,290,822**	**678,054**	**1,251,818**	**-**	**20,093**	**160,455**	**49,266**	**6,204**	**10,981**	**28,079**	**31,340**	**16,310**	**24,969**	**13,254**	**-**	**-**
18	General	290,714	85,240	157,473	-	1,588	16,456	4,578	710	1,256	3,072	3,166	972	964	426	14,812	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	38,969	11,534	21,295	-	342	2,729	838	106	187	478	533	277	425	225	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**2,620,505**	**774,829**	**1,430,585**	**-**	**22,023**	**179,641**	**54,682**	**7,019**	**12,424**	**31,629**	**35,040**	**17,560**	**26,357**	**13,905**	**14,812**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Distribution Accounting Customer ($)	17 Specifically Assigned Customer ($)
1	Average Net Book Value	52,258,240	14,462,690	26,338,738	-	471,876	4,782,580	1,553,133	264,370	467,957	1,162,634	1,200,169	904,432	324,615	129,043	196,004	-
2	Cash Working Capital	226,517	62,689	114,167	-	2,045	20,730	6,732	1,146	2,028	5,040	5,202	3,920	1,407	559	850	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	3,084,574	-	3,084,574	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	973,460	271,183	480,406	-	10,403	107,800	29,988	4,649	8,228	20,125	20,742	6,370	5,972	2,788	4,807	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	2,494,389	690,333	1,257,200	-	22,524	228,282	74,134	12,619	22,337	55,495	57,286	43,170	15,495	6,159	9,356	-
8	Total Rate Base	**59,037,180**	**15,486,895**	**31,275,084**	**-**	**506,847**	**5,139,392**	**1,663,987**	**282,783**	**500,550**	**1,243,294**	**1,283,400**	**957,892**	**347,489**	**138,550**	**211,016**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**59,037,180**	**15,486,895**	**31,275,084**	**-**	**506,847**	**5,139,392**	**1,663,987**	**282,783**	**500,550**	**1,243,294**	**1,283,400**	**957,892**	**347,489**	**138,550**	**211,016**	**-**
11	Return on Debt	2,915,201	764,728	1,544,334	-	25,028	253,778	82,166	13,964	24,717	61,393	63,373	47,300	17,159	6,841	10,420	-
12	Return on Equity	1,109,554	291,063	587,789	-	9,526	96,591	31,273	5,315	9,407	23,367	24,120	18,003	6,531	2,604	3,966	-
13	Return on Rate Base	**4,024,755**	**1,055,792**	**2,132,123**	**-**	**34,553**	**350,369**	**113,439**	**19,278**	**34,124**	**84,759**	**87,493**	**65,303**	**23,689**	**9,445**	**14,386**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Substations Demand (CP kW)	7 Primary Lines Demand (CP kW)	8 Primary Lines Customer (Rural Cust)	9 Line Transformers Demand (CP kW)	10 Line Transformers Customer (Rural Cust)	11 Secondary Lines Demand (CP kW)	12 Secondary Lines Customer (Rural Cust)	13 Services Customer (Wtd Rural Cust)	14 Meters Customer	15 Street Lighting Customer (Rural Cust)	16 Accounting Customer (Rural Cust)	17 Specifically Assigned Customer
							Distribution										
	Amounts																
1	1.2 Domestic Diesel	-	4,715	22,197	4,715	4,562	4,562	2,070	4,330	2,070	4,330	2,070	2,070	2,070	-	2,070	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	-	738	4,466	738	714	714	416	677	416	677	416	781	781	-	416	-
5	2.2 GS 10-100 kW	-	2,023	12,284	2,023	1,957	1,957	139	1,857	139	1,857	139	665	665	-	139	-
6	2.3 GS 110-1,000 kVa	-	150	3,038	150	145	145	6	138	6	138	6	51	51	-	6	-
7	2.4 GS Over 1,000 kVa	-	93	2,607	93	90	90	1	86	1	86	1	8	8	-	1	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	-	80	319	80	77	77	83	74	83	74	83	-	-	83	83	-
11	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**-**	**7,799**	**44,912**	**7,799**	**7,545**	**7,545**	**2,715**	**7,162**	**2,715**	**7,162**	**2,715**	**3,575**	**3,575**	**83**	**2,715**	**-**
	Ratios																
13	1.2 Domestic Diesel	-	0.6046	0.4942	0.6046	0.6046	0.6046	0.7624	0.6046	0.7624	0.6046	0.7624	0.5791	0.5791	-	0.7624	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	-	0.0946	0.0994	0.0946	0.0946	0.0946	0.1531	0.0946	0.1531	0.0946	0.1531	0.2184	0.2184	-	0.1531	-
17	2.2 GS 10-100 kW	-	0.2593	0.2735	0.2593	0.2593	0.2593	0.0514	0.2593	0.0514	0.2593	0.0514	0.1861	0.1861	-	0.0514	-
18	2.3 GS 110-1,000 kVa	-	0.0193	0.0676	0.0193	0.0193	0.0193	0.0022	0.0193	0.0022	0.0193	0.0022	0.0141	0.0141	-	0.0022	-
19	2.4 GS Over 1,000 kVa	-	0.0120	0.0581	0.0120	0.0120	0.0120	0.0004	0.0120	0.0004	0.0120	0.0004	0.0024	0.0024	-	0.0004	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	0.0103	0.0071	0.0103	0.0103	0.0103	0.0306	0.0103	0.0306	0.0103	0.0306	-	-	1.0000	0.0306	-
23	4.1G Gov't Street and Area Lighting		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	19 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.2 Domestic Diesel	3,083,957	3,083,957
2	1.2G Government Domestic Diesel	-	-
3	1.23 Churches, Schools & Com Halls	-	-
4	2.1 GS 0-10 kW	1,096,168	1,096,168
5	2.2 GS 10-100 kW	1,957,521	1,957,521
6	2.3 GS 110-1,000 kVa	178,644	178,644
7	2.4 GS Over 1,000 kVa	240,507	240,507
8	2.5 GS Diesel	-	-
9	2.5G Gov't General Service Diesel	-	-
10	4.1 Street and Area Lighting	115,211	115,211
11	4.1G Gov't Street and Area Lighting	-	-
12	**Total**	**6,672,008**	**6,672,008**
	Ratios		
13	1.2 Domestic Diesel	0.4622	0.4622
14	1.2G Government Domestic Diesel	-	-
15	1.23 Churches, Schools & Com Halls	-	-
16	2.1 GS 0-10 kW	0.1643	0.1643
17	2.2 GS 10-100 kW	0.2934	0.2934
18	2.3 GS 110-1,000 kVa	0.0268	0.0268
19	2.4 GS Over 1,000 kVa	0.0360	0.0360
20	2.5 GS Diesel	-	-
21	2.5G Gov't General Service Diesel	-	-
22	4.1 Street and Area Lighting	0.0173	0.0173
23	4.1G Gov't Street and Area Lighting	-	-
24	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Allocated Revenue Requirement Excluding Return																
1	1.2 Domestic Diesel	15,734,122	2,928,880	10,850,946	-	68,585	639,120	225,728	28,892	64,491	119,373	155,724	44,162	46,661	-	475,530	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	3,025,323	458,199	2,183,324	-	10,729	99,985	45,334	4,520	12,952	18,675	31,275	16,652	17,594	-	95,504	-
5	2.2 GS 10-100 kW	7,774,283	1,256,419	6,004,807	-	29,421	274,167	15,206	12,394	4,344	51,208	10,490	14,191	14,994	-	32,034	-
6	2.3 GS 110-1,000 kVa	1,615,338	93,298	1,484,903	-	2,185	20,359	654	920	187	3,803	451	1,078	1,139	-	1,378	-
7	2.4 GS Over 1,000 kVa	1,357,181	58,052	1,274,639	-	1,359	12,668	109	573	31	2,366	75	180	190	-	230	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	298,838	49,759	156,174	-	1,165	10,858	9,051	491	2,586	2,028	6,244	-	-	38,202	19,066	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**29,805,086**	**4,844,607**	**21,954,792**	**-**	**113,444**	**1,057,156**	**296,082**	**47,790**	**84,592**	**197,452**	**204,260**	**76,262**	**80,577**	**38,202**	**623,742**	**-**
	Allocated Return on Debt and Equity																
13	1.2 Domestic Diesel	2,229,388	638,295	1,053,782	-	20,890	211,821	86,484	11,655	26,016	51,243	66,703	37,815	13,718	-	10,967	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	415,758	99,856	212,032	-	3,268	33,138	17,369	1,823	5,225	8,016	13,397	14,259	5,173	-	2,203	-
17	2.2 GS 10-100 kW	1,013,144	273,813	583,152	-	8,961	90,866	5,826	5,000	1,753	21,982	4,493	12,151	4,408	-	739	-
18	2.3 GS 110-1,000 kVa	175,763	20,333	144,205	-	665	6,747	251	371	75	1,632	193	923	335	-	32	-
19	2.4 GS Over 1,000 kVa	142,598	12,651	123,786	-	414	4,198	42	231	13	1,016	32	154	56	-	5	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	48,103	10,844	15,167	-	355	3,599	3,468	198	1,043	871	2,674	-	-	9,445	440	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**4,024,755**	**1,055,792**	**2,132,123**	**-**	**34,553**	**350,369**	**113,439**	**19,278**	**34,124**	**84,759**	**87,493**	**65,303**	**23,689**	**9,445**	**14,386**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.2 Domestic Diesel	81,794	4,238	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	29,073	1,506	
5	2.2 GS 10-100 kW	51,918	2,690	
6	2.3 GS 110-1,000 kVa	4,738	245	
7	2.4 GS Over 1,000 kVa	6,379	330	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	3,056	158	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**176,958**	**9,168**	
	Allocated Return on Debt and Equity			
13	1.2 Domestic Diesel	-	-	
14	1.2G Government Domestic Diesel	-	-	
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	-	-	
17	2.2 GS 10-100 kW	-	-	
18	2.3 GS 110-1,000 kVa	-	-	
19	2.4 GS Over 1,000 kVa	-	-	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	-	-	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
						Distribution											
	Total Revenue Requirement																
1	1.2 Domestic Diesel	17,963,510	3,567,174	11,904,728	-	89,474	850,940	312,212	40,547	90,507	170,615	222,428	81,977	60,379	-	486,497	-
2	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.1 GS 0-10 kW	3,441,081	558,055	2,395,356	-	13,998	133,123	62,704	6,343	18,177	26,691	44,672	30,911	22,767	-	97,707	-
5	2.2 GS 10-100 kW	8,787,428	1,530,232	6,587,960	-	38,382	365,033	21,032	17,394	6,097	73,190	14,984	26,342	19,402	-	32,773	-
6	2.3 GS 110-1,000 kVa	1,791,102	113,631	1,629,108	-	2,850	27,106	905	1,292	262	5,435	645	2,001	1,473	-	1,410	-
7	2.4 GS Over 1,000 kVa	1,499,779	70,704	1,398,425	-	1,773	16,866	151	804	44	3,382	107	333	246	-	235	-
8	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	4.1 Street and Area Lighting	346,941	60,603	171,340	-	1,520	14,457	12,518	689	3,629	2,899	8,918	-	-	47,648	19,506	-
11	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	**Total**	**33,829,840**	**5,900,399**	**24,086,916**	**-**	**147,998**	**1,407,525**	**409,521**	**67,068**	**118,716**	**282,212**	**291,753**	**141,565**	**104,267**	**47,648**	**638,127**	**-**
	Re-classification of Revenue-Related																
13	1.2 Domestic Diesel	-	17,166	57,289	-	431	4,095	1,502	195	436	821	1,070	394	291	-	2,341	-
14	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16	2.1 GS 0-10 kW	0	5,004	21,477	-	126	1,194	562	57	163	239	401	277	204	-	876	-
17	2.2 GS 10-100 kW	0	9,569	41,196	-	240	2,283	132	109	38	458	94	165	121	-	205	-
18	2.3 GS 110-1,000 kVa	0	317	4,545	-	8	76	3	4	1	15	2	6	4	-	4	-
19	2.4 GS Over 1,000 kVa	0	318	6,284	-	8	76	1	4	0	15	0	1	1	-	1	-
20	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	4.1 Street and Area Lighting	-	567	1,602	-	14	135	117	6	34	27	83	-	-	446	182	-
23	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total**	**0**	**32,940**	**132,394**	**-**	**826**	**7,858**	**2,316**	**374**	**672**	**1,576**	**1,650**	**843**	**621**	**446**	**3,610**	**-**
	Total Allocated Revenue Requirement																
25	1.2 Domestic Diesel	17,963,510	3,584,340	11,962,017	-	89,905	855,035	313,714	40,742	90,943	171,436	223,498	82,372	60,669	-	488,838	-
26	1.2G Government Domestic Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	1.23 Churches, Schools & Com Halls	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
28	2.1 GS 0-10 kW	3,441,081	563,058	2,416,833	-	14,123	134,316	63,266	6,400	18,340	26,931	45,072	31,188	22,971	-	98,583	-
29	2.2 GS 10-100 kW	8,787,428	1,539,801	6,629,155	-	38,622	367,316	21,163	17,502	6,135	73,648	15,077	26,507	19,523	-	32,977	-
30	2.3 GS 110-1,000 kVa	1,791,102	113,948	1,633,653	-	2,858	27,182	907	1,295	263	5,450	646	2,006	1,478	-	1,414	-
31	2.4 GS Over 1,000 kVa	1,499,779	71,021	1,404,709	-	1,781	16,942	151	807	44	3,397	108	335	247	-	236	-
32	2.5 GS Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
33	2.5G Gov't General Service Diesel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	4.1 Street and Area Lighting	346,941	61,170	172,942	-	1,534	14,592	12,635	695	3,663	2,926	9,002	-	-	48,093	19,688	-
35	4.1G Gov't Street and Area Lighting	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	**Total**	**33,829,840**	**5,933,339**	**24,219,309**	**-**	**148,824**	**1,415,383**	**411,838**	**67,443**	**119,388**	**283,787**	**293,404**	**142,408**	**104,888**	**48,093**	**641,737**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Isolated
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
1	1.2 Domestic Diesel	81,794	4,238	
2	1.2G Government Domestic Diesel	-	-	
3	1.23 Churches, Schools & Com Halls	-	-	
4	2.1 GS 0-10 kW	29,073	1,506	
5	2.2 GS 10-100 kW	51,918	2,690	
6	2.3 GS 110-1,000 kVa	4,738	245	
7	2.4 GS Over 1,000 kVa	6,379	330	
8	2.5 GS Diesel	-	-	
9	2.5G Gov't General Service Diesel	-	-	
10	4.1 Street and Area Lighting	3,056	158	
11	4.1G Gov't Street and Area Lighting	-	-	
12	**Total**	**176,958**	**9,168**	
	Re-classification of Revenue-Related			
13	1.2 Domestic Diesel	(81,794)	(4,238)	Re-classification to demand, energy and customer is based on rate class revenue
14	1.2G Government Domestic Diesel	-	-	requirements excluding revenue-related items.
15	1.23 Churches, Schools & Com Halls	-	-	
16	2.1 GS 0-10 kW	(29,073)	(1,506)	
17	2.2 GS 10-100 kW	(51,918)	(2,690)	
18	2.3 GS 110-1,000 kVa	(4,738)	(245)	
19	2.4 GS Over 1,000 kVa	(6,379)	(330)	
20	2.5 GS Diesel	-	-	
21	2.5G Gov't General Service Diesel	-	-	
22	4.1 Street and Area Lighting	(3,056)	(158)	
23	4.1G Gov't Street and Area Lighting	-	-	
24	**Total**	**(176,958)**	**(9,168)**	
	Total Allocated Revenue Requirement			
25	1.2 Domestic Diesel	-	-	
26	1.2G Government Domestic Diesel	-	-	
27	1.23 Churches, Schools & Com Halls	-	-	
28	2.1 GS 0-10 kW	-	-	
29	2.2 GS 10-100 kW	-	-	
30	2.3 GS 110-1,000 kVa	-	-	
31	2.4 GS Over 1,000 kVa	-	-	
32	2.5 GS Diesel	-	-	
33	2.5G Gov't General Service Diesel	-	-	
34	4.1 Street and Area Lighting	-	-	
35	4.1G Gov't Street and Area Lighting	-	-	
36	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	1,633,449	671,446	-	-	6,653	392,993	115,376	18,049	31,949	72,277	77,201	16,964	23,924	6,971	123,341	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	507,629	-	507,629	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	3,054,696	-	3,054,696	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	435,327	228,245	-	-	3,268	90,590	27,412	8,845	15,657	14,526	16,588	6,597	13,821	4,943	4,835	-
	Expense Credits																
8	Sundry	(7,779)	(3,198)	-	-	(32)	(1,872)	(549)	(86)	(152)	(344)	(368)	(81)	(114)	(33)	(587)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(1,212)	(498)	-	-	(5)	(292)	(86)	(13)	(24)	(54)	(57)	(13)	(18)	(5)	(92)	-
12	Pole Attachments	(69,837)	-	-	-	-	(40,390)	(13,803)	-	-	(7,149)	(8,494)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(412)	-	-	-	-	-	-	-	-	-	-	-	-	-	(412)	-
16	Meter Test Revenues	(110)	-	-	-	-	-	-	-	-	-	-	-	(110)	-	-	-
17	**Total Expense Credits**	(79,350)	(3,696)	-	-	(37)	(42,553)	(14,438)	(99)	(176)	(7,547)	(8,919)	(93)	(242)	(38)	(1,091)	-
18	**Subtotal Expenses**	**5,551,750**	**895,995**	**3,562,325**	-	**9,884**	**441,029**	**128,350**	**26,795**	**47,430**	**79,256**	**84,870**	**23,468**	**37,503**	**11,876**	**127,085**	-
19	Disposal Gain / Loss	70,800	33,389	-	-	504	18,097	5,551	1,098	1,943	2,939	3,369	2,093	1,135	314	368	-
20	**Subtotal Revenue Requirement Ex. Return**	**5,622,550**	**929,383**	**3,562,325**	-	**10,388**	**459,126**	**133,901**	**27,893**	**49,373**	**82,195**	**88,239**	**25,561**	**38,638**	**12,190**	**127,454**	-
21	Return on Debt	560,525	263,052	2,187	-	3,945	143,003	43,826	8,629	15,275	23,287	26,656	16,321	8,935	2,480	2,930	-
22	Return on Equity	213,341	100,120	832	-	1,501	54,428	16,680	3,284	5,814	8,863	10,146	6,212	3,401	944	1,115	-
23	**Total Revenue Requirement**	**6,396,417**	**1,292,555**	**3,565,344**	-	**15,834**	**656,557**	**194,407**	**39,807**	**70,462**	**114,345**	**125,041**	**48,093**	**50,974**	**15,614**	**131,499**	-

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	72,546	3,758	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	Production - Energy
3	Fuels-Diesel	-	-	Production - Energy
4	Fuels-Gas Turbine	-	-	Production - Energy
5	Power Purchases -CF(L)Co	-	-	
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.13
7	Depreciation	-	-	Carryforward from Sch.2.5 L.23
	Expense Credits			
8	Sundry	(345)	(18)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.17
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(54)	(3)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(399)**	**(21)**	
18	**Subtotal Expenses**	**72,147**	**3,738**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.23
20	**Subtotal Revenue Requirement Ex. Return**	**72,147**	**3,738**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**72,147**	**3,738**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	8,253,654	8,253,654	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**8,253,654**	**8,253,654**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	153,816	66,299	-	-	87,518	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	66,393	-	-	-	-	50,057	6,377	-	-	5,806	4,153	-	-	-	-	-
8	Poles	7,062,374	-	-	-	-	4,084,510	1,395,892	-	-	722,961	859,011	-	-	-	-	-
9	Primary Conductor & Equipment	1,278,301	-	-	-	-	1,133,853	144,448	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	670,272	-	-	-	-	-	-	241,968	428,304	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	411,959	-	-	-	-	-	-	-	-	240,172	171,787	-	-	-	-	-
13	Services	227,423	-	-	-	-	-	-	-	-	-	-	227,423	-	-	-	-
14	Meters	267,499	-	-	-	-	-	-	-	-	-	-	-	267,499	-	-	-
15	Street Lighting	93,455	-	-	-	-	-	-	-	-	-	-	-	-	93,455	-	-
16	**Subtotal Distribution**	**10,231,494**	**66,299**	**-**	**-**	**87,518**	**5,268,420**	**1,546,717**	**241,968**	**428,304**	**968,939**	**1,034,950**	**227,423**	**267,499**	**93,455**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**18,485,147**	**8,319,952**	**-**	**-**	**87,518**	**5,268,420**	**1,546,717**	**241,968**	**428,304**	**968,939**	**1,034,950**	**227,423**	**267,499**	**93,455**	**-**	**-**
18	General	1,621,900	685,657	-	-	6,712	404,063	118,626	18,558	32,849	74,313	79,376	17,442	25,322	7,168	151,814	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	37,306	16,791	-	-	177	10,632	3,121	488	864	1,955	2,089	459	540	189	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Plant**	**20,144,353**	**9,022,400**	**-**	**-**	**94,407**	**5,683,116**	**1,668,465**	**261,014**	**462,017**	**1,045,208**	**1,116,415**	**245,324**	**293,361**	**100,812**	**151,814**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Diesel	Production - Demand, Energy ratios Sch.4.1 L.8
2	**Subtotal Production**	
	Transmission	
3	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
4	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
5	**Subtotal Transmission**	
	Distribution	
6	Substation Structures & Equipment	Production - Demand; Dist Substns - Demand
7	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
8	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
9	Primary Conductor & Equipment	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
10	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
11	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
12	Secondary Conductors & Equipment	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
13	Services	Services Customer
14	Meters	Meters - Customer
15	Street Lighting	Street Lighting - Customer
16	**Subtotal Distribution**	
17	**Subttl Prod, Trans, & Dist**	
18	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch.2.4 L.11, 12
19	Telecontrol - Specific	Specifically Assigned - Customer
20	Feasibility Studies	Production, Transmission - Demand
21	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.17
22	Software - Cust Acctng	Customer Accounting
23	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	4,695,369	4,695,369	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**4,695,369**	**4,695,369**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
6	Substation Structures & Equipment	85,750	13,428	-	-	72,322	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	19,937	-	-	-	-	15,032	1,915	-	-	1,744	1,247	-	-	-	-	-
8	Poles	3,690,889	-	-	-	-	2,134,618	729,512	-	-	377,829	448,930	-	-	-	-	-
9	Primary Conductor & Equipment	440,736	-	-	-	-	390,933	49,803	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	432,823	-	-	-	-	-	-	156,249	276,574	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	51,198	-	-	-	-	-	-	-	-	29,849	21,350	-	-	-	-	-
13	Services	304,411	-	-	-	-	-	-	-	-	-	-	304,411	-	-	-	-
14	Meters	159,346	-	-	-	-	-	-	-	-	-	-	-	159,346	-	-	-
15	Street Lighting	43,987	-	-	-	-	-	-	-	-	-	-	-	-	43,987	-	-
16	**Subtotal Distribution**	**5,229,078**	**13,428**	**-**	**-**	**72,322**	**2,540,583**	**781,230**	**156,249**	**276,574**	**409,421**	**471,527**	**304,411**	**159,346**	**43,987**	**-**	**-**
17	**Subttl Prod, Trans, & Dist**	**9,924,446**	**4,708,797**	**-**	**-**	**72,322**	**2,540,583**	**781,230**	**156,249**	**276,574**	**409,421**	**471,527**	**304,411**	**159,346**	**43,987**	**-**	**-**
18	General	585,888	247,684	-	-	2,425	145,962	42,852	6,704	11,866	26,845	28,673	6,301	9,147	2,589	54,841	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	30,080	14,272	-	-	219	7,700	2,368	474	838	1,241	1,429	923	483	133	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Net Book Value**	**10,540,414**	**4,970,752**	**-**	**-**	**74,966**	**2,694,245**	**826,449**	**163,427**	**289,279**	**437,507**	**501,630**	**311,634**	**168,976**	**46,710**	**54,841**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	360,321	360,321	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	44,529	44,529	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**404,850**	**404,850**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
4	Transmission Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Distribution																
8	Other	454,593	3,025	-	-	3,993	240,364	70,567	11,039	19,541	44,206	47,218	10,376	-	4,264	-	-
9	Meters	15,063	-	-	-	-	-	-	-	-	-	-	-	15,063	-	-	-
10	**Subtotal Distribution**	**469,656**	**3,025**	**-**	**-**	**3,993**	**240,364**	**70,567**	**11,039**	**19,541**	**44,206**	**47,218**	**10,376**	**15,063**	**4,264**	**-**	**-**
11	**Subttl Prod, Trans, & Dist**	**874,506**	**407,874**	**-**	**-**	**3,993**	**240,364**	**70,567**	**11,039**	**19,541**	**44,206**	**47,218**	**10,376**	**15,063**	**4,264**	**-**	**-**
12	Customer Accounting	90,309	-	-	-	-	-	-	-	-	-	-	-	-	-	90,309	-
	Administrative & General:																
	Plant-Related:																
13	Production	91,127	91,127	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	113,348	734	-	-	970	58,365	17,135	2,681	4,745	10,734	11,466	2,519	2,963	1,035	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod,Trans, Distn & General Plt	3,074	1,377	-	-	14	867	255	40	71	159	170	37	45	15	23	-
18	Property Insurance	14,284	12,826	-	-	134	575	169	26	47	106	113	25	36	10	216	-
	Revenue Related:																
19	Municipal Tax	72,546	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	3,758	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	350,335	148,104	-	-	1,450	87,279	25,624	4,009	7,095	16,052	17,145	3,768	5,470	1,548	32,792	-
22	Prod, Trans, and Distn Expense-Related	20,162	9,404	-	-	92	5,542	1,627	255	451	1,019	1,089	239	347	98	-	-
23	**Subtotal Admin & General**	**668,634**	**263,571**	**-**	**-**	**2,660**	**152,629**	**44,809**	**7,010**	**12,408**	**28,071**	**29,983**	**6,589**	**8,861**	**2,707**	**33,032**	**-**
24	**Total Operating & Maintenance Expenses**	**1,633,449**	**671,446**	**-**	**-**	**6,653**	**392,993**	**115,376**	**18,049**	**31,949**	**72,277**	**77,201**	**16,964**	**23,924**	**6,971**	**123,341**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Production			
1	Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L8
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L8
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.3
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.4
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 16, less L. 14
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.2
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.5
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.16
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission & Distribution Plant in Service - Sch.2.2 L.17
17	Prod,Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.23
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.2, 4, 6, 18 - 19
	Revenue Related:			
19	Municipal Tax	72,546	-	Revenue-related
20	PUB Assessment	-	3,758	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L.11, 12
22	Prod, Trans, and Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	72,546	3,758	
24	**Total Operating & Maintenance Expenses**	72,546	3,758	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Diesel	202,525	202,525	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	**Subtotal Production**	**202,525**	**202,525**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
	Transmission																
3	Lines	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Terminal Stations	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	**Subtotal Transmission**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
6	Substation Structures & Equipment	3,432	429	-	-	3,003	-	-	-	-	-	-	-	-	-	-	-
7	Land & Land Improvements	505	-	-	-	-	381	48	-	-	44	32	-	-	-	-	-
8	Poles	108,921	-	-	-	-	62,994	21,528	-	-	11,150	13,248	-	-	-	-	-
9	Primary Conductor & Equipment	14,707	-	-	-	-	13,045	1,662	-	-	-	-	-	-	-	-	-
10	Submarine Conductor	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Transformers	22,483	-	-	-	-	-	-	8,116	14,366	-	-	-	-	-	-	-
12	Secondary Conductors & Equipment	1,306	-	-	-	-	-	-	-	-	762	545	-	-	-	-	-
13	Services	5,940	-	-	-	-	-	-	-	-	-	-	5,940	-	-	-	-
14	Meters	12,796	-	-	-	-	-	-	-	-	-	-	-	12,796	-	-	-
15	Street Lighting	4,636	-	-	-	-	-	-	-	-	-	-	-	-	4,636	-	-
16	**Subtotal Distribution**	**174,725**	**429**	**-**	**-**	**3,003**	**76,420**	**23,239**	**8,116**	**14,366**	**11,956**	**13,825**	**5,940**	**12,796**	**4,636**	**-**	**-**
17	**Subtotal Prod Tran & Dist**	**377,250**	**202,954**	**-**	**-**	**3,003**	**76,420**	**23,239**	**8,116**	**14,366**	**11,956**	**13,825**	**5,940**	**12,796**	**4,636**	**-**	**-**
18	General	51,660	21,839	-	-	214	12,870	3,778	591	1,046	2,367	2,528	556	807	228	4,835	-
19	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Software - General	6,417	3,452	-	-	51	1,300	395	138	244	203	235	101	218	79	-	-
22	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	**Total Depreciation Expense**	**435,327**	**228,245**	**-**	**-**	**3,268**	**90,590**	**27,412**	**8,845**	**15,657**	**14,526**	**16,588**	**6,597**	**13,821**	**4,943**	**4,835**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
1	Average Net Book Value	10,540,414	4,970,752	-	-	74,966	2,694,245	826,449	163,427	289,279	437,507	501,630	311,634	168,976	46,710	54,841	-
2	Cash Working Capital	45,688	21,546	-	-	325	11,678	3,582	708	1,254	1,896	2,174	1,351	732	202	238	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	44,283	-	44,283	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	217,976	97,629	-	-	1,022	61,495	18,054	2,824	4,999	11,310	12,080	2,655	3,174	1,091	1,643	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	503,115	237,264	-	-	3,578	128,602	39,448	7,801	13,808	20,883	23,944	14,875	8,066	2,230	2,618	-
8	Total Rate Base	**11,351,476**	**5,327,191**	**44,283**	**-**	**79,890**	**2,896,020**	**887,534**	**174,760**	**309,340**	**471,596**	**539,828**	**330,515**	**180,948**	**50,232**	**59,339**	**-**
9	Less: Rural Portion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Rate Base Available for Equity Return	**11,351,476**	**5,327,191**	**44,283**	**-**	**79,890**	**2,896,020**	**887,534**	**174,760**	**309,340**	**471,596**	**539,828**	**330,515**	**180,948**	**50,232**	**59,339**	**-**
11	Return on Debt	560,525	263,052	2,187	-	3,945	143,003	43,826	8,629	15,275	23,287	26,656	16,321	8,935	2,480	2,930	-
12	Return on Equity	213,341	100,120	832	-	1,501	54,428	16,680	3,284	5,814	8,863	10,146	6,212	3,401	944	1,115	-
13	Return on Rate Base	**773,867**	**363,172**	**3,019**	**-**	**5,446**	**197,431**	**60,506**	**11,914**	**21,089**	**32,150**	**36,802**	**22,532**	**12,336**	**3,425**	**4,045**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 23
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Energy
5	Fuel Inventory - Gas Turbine	
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 23
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand (CP kW)	4 Production and Transmission Energy (MWh @ Gen)	5 Transmission Demand (CP kW)	6 Substations Demand (CP kW)	7 Primary Lines Demand (CP kW)	8 Primary Lines Customer (Rural Cust)	9 Line Transformers Demand (CP kW)	10 Line Transformers Customer (Rural Cust)	11 Secondary Lines Demand (CP kW)	12 Secondary Lines Customer (Rural Cust)	13 Services Customer (Wtd Rural Cust)	14 Meters Customer	15 Street Lightin Customer	16 Accounting Customer (Rural Cust)	17 Specifically Assigned Customer
						Distribution											
	Amounts																
1	1.1 Domestic Diesel	-	1,199	4,441	1,199	1,141	1,141	407	1,053	407	1,053	407	407	407	-	407	-
2	1.12 Domestic All Electric	-	2,844	11,369	2,844	2,704	2,704	386	2,497	386	2,497	386	386	386	-	386	-
3	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.2 GS 10-100 kW	-	1,411	6,942	1,411	1,341	1,341	209	1,239	209	1,239	209	997	997	-	209	-
5	2.3 GS 110-1,000 kVa	-	246	2,055	246	234	234	5	216	5	216	5	42	42	-	5	-
6	4.1 Street and Area Lighting	-	36	146	36	35	35	33	32	33	32	33	-	-	1	33	-
7	**Total**	**-**	**5,736**	**24,953**	**5,736**	**5,455**	**5,455**	**1,040**	**5,037**	**1,040**	**5,037**	**1,040**	**1,832**	**1,832**	**1**	**1,040**	**0**
	Ratios																
8	1.1 Domestic Diesel	-	0.2091	0.1780	0.2091	0.2091	0.2091	0.3915	0.2091	0.3915	0.2091	0.3915	0.2222	0.2222	-	0.3915	-
9	1.12 Domestic All Electric	-	0.4958	0.4556	0.4958	0.4958	0.4958	0.3713	0.4958	0.3713	0.4958	0.3713	0.2107	0.2107	-	0.3713	-
10	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2.2 GS 10-100 kW	-	0.2459	0.2782	0.2459	0.2459	0.2459	0.2011	0.2459	0.2011	0.2459	0.2011	0.5442	0.5442	-	0.2011	-
12	2.3 GS 110-1,000 kVa	-	0.0428	0.0824	0.0428	0.0428	0.0428	0.0048	0.0428	0.0048	0.0428	0.0048	0.0230	0.0230	-	0.0048	-
13	4.1 Street and Area Lighting	-	0.0064	0.0059	0.0064	0.0064	0.0064	0.0313	0.0064	0.0313	0.0064	0.0313	-	-	1.0000	0.0313	-
14	**Total**	**-**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**0.0000**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Basis of Allocation to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	19 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	1.1 Domestic Diesel	570,211	570,211
2	1.12 Domestic All Electric	1,122,691	1,122,691
3	2.1 GS 0-10 kW	-	-
4	2.2 GS 10-100 kW	709,945	709,945
5	2.3 GS 110-1,000 kVa	272,034	272,034
6	4.1 Street and Area Lighting	45,335	45,335
7	**Total**	**2,720,217**	**2,720,217**
	Ratios		
8	1.1 Domestic Diesel	0.2096	0.2096
9	1.12 Domestic All Electric	0.4127	0.4127
10	2.1 GS 0-10 kW	-	-
11	2.2 GS 10-100 kW	0.2610	0.2610
12	2.3 GS 110-1,000 kVa	0.1000	0.1000
13	4.1 Street and Area Lighting	0.0167	0.0167
14	**Total**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
											Distribution						
Line		Total	Production	Production and Transmission	Transmsn	Substations	Primary Lines		Line Transformers		Secondary Lines		Services	Meters	Street Lightin	Accounting	Specifically Assigned
No.	Description	Amount	Demand	Energy	Demand	Demand	Demand	Customer	Demand	Customer	Demand	Customer	Customer	Customer	Customer	Customer	Customer
		($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
	Allocated Revenue Requirement Excluding Return																
1	1.1 Domestic Diesel	1,135,866	194,337	633,954	-	2,172	96,005	52,427	5,833	19,331	17,187	34,549	5,678	8,584	-	49,902	-
2	1.12 Domestic All Electric	2,564,141	460,771	1,623,019	-	5,150	227,626	49,722	13,829	18,334	40,751	32,766	5,385	8,141	-	47,328	-
3	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.2 GS 10-100 kW	1,497,110	228,556	991,061	-	2,555	112,909	26,922	6,860	9,927	20,214	17,741	13,910	21,026	-	25,626	-
5	2.3 GS 110-1,000 kVa	369,048	39,814	293,420	-	445	19,669	644	1,195	237	3,521	424	587	888	-	613	-
6	4.1 Street and Area Lighting	56,385	5,904	20,871	-	66	2,917	4,186	177	1,544	522	2,759	-	-	12,190	3,985	-
7	**Total**	**5,622,550**	**929,383**	**3,562,325**	**-**	**10,388**	**459,126**	**133,901**	**27,893**	**49,373**	**82,195**	**88,239**	**25,561**	**38,638**	**12,190**	**127,454**	**-**
	Allocated Return on Debt and Equity																
8	1.1 Domestic Diesel	183,800	75,941	537	-	1,139	41,284	23,690	2,491	8,257	6,723	14,409	5,006	2,740	-	1,584	-
9	1.12 Domestic All Electric	356,671	180,054	1,375	-	2,700	97,883	22,468	5,907	7,831	15,939	13,666	4,747	2,599	-	1,502	-
10	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2.2 GS 10-100 kW	194,473	89,312	840	-	1,339	48,553	12,165	2,930	4,240	7,906	7,399	12,261	6,713	-	813	-
12	2.3 GS 110-1,000 kVa	27,776	15,558	249	-	233	8,458	291	510	101	1,377	177	518	283	-	19	-
13	4.1 Street and Area Lighting	11,146	2,307	18	-	35	1,254	1,892	76	659	204	1,151	-	-	3,425	126	-
14	**Total**	**773,867**	**363,172**	**3,019**	**-**	**5,446**	**197,431**	**60,506**	**11,914**	**21,089**	**32,150**	**36,802**	**22,532**	**12,336**	**3,425**	**4,045**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Allocated Revenue Requirement Excluding Return			
1	1.1 Domestic Diesel	15,123	784	
2	1.12 Domestic All Electric	29,776	1,543	
3	2.1 GS 0-10 kW	-	-	
4	2.2 GS 10-100 kW	18,829	976	
5	2.3 GS 110-1,000 kVa	7,215	374	
6	4.1 Street and Area Lighting	1,202	62	
7	**Total**	**72,147**	**3,738**	
	Allocated Return on Debt and Equity			
8	1.1 Domestic Diesel	-	-	
9	1.12 Domestic All Electric	-	-	
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	-	-	
12	2.3 GS 110-1,000 kVa	-	-	
13	4.1 Street and Area Lighting	-	-	
14	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production and Transmission Energy ($)	5 Transmsn Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lightin Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
							Distribution										
	Total Revenue Requirement																
1	1.1 Domestic Diesel	1,319,666	270,278	634,491	-	3,311	137,288	76,117	8,324	27,588	23,910	48,958	10,684	11,324	-	51,486	-
2	1.12 Domestic All Electric	2,920,813	640,825	1,624,395	-	7,850	325,509	72,190	19,736	26,165	56,690	46,432	10,133	10,740	-	48,830	-
3	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2.2 GS 10-100 kW	1,691,583	317,868	991,901	-	3,894	161,462	39,087	9,789	14,167	28,120	25,141	26,171	27,739	-	26,439	-
5	2.3 GS 110-1,000 kVa	396,823	55,373	293,669	-	678	28,127	935	1,705	339	4,899	601	1,105	1,171	-	633	-
6	4.1 Street and Area Lighting	67,532	8,212	20,889	-	101	4,171	6,078	253	2,203	726	3,909	-	-	15,614	4,111	-
7	**Total**	**6,396,417**	**1,292,555**	**3,565,344**	**-**	**15,834**	**656,557**	**194,407**	**39,807**	**70,462**	**114,345**	**125,041**	**48,093**	**50,974**	**15,614**	**131,499**	**-**
	Re-classification of Revenue-Related																
8	1.1 Domestic Diesel	0	3,298	7,741	-	40	1,675	929	102	337	292	597	130	138	-	628	-
9	1.12 Domestic All Electric	0	6,946	17,607	-	85	3,528	782	214	284	614	503	110	116	-	529	-
10	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	2.2 GS 10-100 kW	(0)	3,766	11,751	-	46	1,913	463	116	168	333	298	310	329	-	313	-
12	2.3 GS 110-1,000 kVa	(0)	1,080	5,726	-	13	548	18	33	7	96	12	22	23	-	12	-
13	4.1 Street and Area Lighting	(0)	157	399	-	2	80	116	5	42	14	75	-	-	298	78	-
14	**Total**	**0**	**15,245**	**43,223**	**-**	**187**	**7,744**	**2,308**	**470**	**837**	**1,349**	**1,485**	**572**	**606**	**298**	**1,561**	**-**
	Total Allocated Revenue Requirement																
15	1.1 Domestic Diesel	1,319,666	273,575	642,232	-	3,351	138,963	77,046	8,425	27,925	24,202	49,555	10,814	11,462	-	52,115	-
16	1.12 Domestic All Electric	2,920,813	647,771	1,642,002	-	7,935	329,037	72,972	19,950	26,448	57,305	46,935	10,243	10,856	-	49,359	-
17	2.1 GS 0-10 kW	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	2.2 GS 10-100 kW	1,691,583	321,634	1,003,651	-	3,940	163,375	39,550	9,905	14,335	28,453	25,438	26,481	28,067	-	26,752	-
19	2.3 GS 110-1,000 kVa	396,823	56,452	299,395	-	692	28,675	953	1,739	346	4,994	613	1,127	1,194	-	645	-
20	4.1 Street and Area Lighting	67,532	8,368	21,287	-	103	4,251	6,194	258	2,245	740	3,984	-	-	15,912	4,190	-
21	**Total**	**6,396,417**	**1,307,801**	**3,608,567**	**-**	**16,021**	**664,301**	**196,716**	**40,277**	**71,299**	**115,694**	**126,526**	**48,665**	**51,580**	**15,912**	**133,060**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
L'Anse au Loup
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
1	1.1 Domestic Diesel	15,123	784	
2	1.12 Domestic All Electric	29,776	1,543	
3	2.1 GS 0-10 kW	-	-	
4	2.2 GS 10-100 kW	18,829	976	
5	2.3 GS 110-1,000 kVa	7,215	374	
6	4.1 Street and Area Lighting	1,202	62	
7	**Total**	**72,147**	**3,738**	
	Re-classification of Revenue-Related			
8	1.1 Domestic Diesel	(15,123)	(784)	Re-classification to demand, energy and customer is based on rate class revenue
9	1.12 Domestic All Electric	(29,776)	(1,543)	requirements excluding revenue-related items.
10	2.1 GS 0-10 kW	-	-	
11	2.2 GS 10-100 kW	(18,829)	(976)	
12	2.3 GS 110-1,000 kVa	(7,215)	(374)	
13	4.1 Street and Area Lighting	(1,202)	(62)	
14	**Total**	**(72,147)**	**(3,738)**	
	Total Allocated Revenue Requirement			
15	1.1 Domestic Diesel	-	-	
16	1.12 Domestic All Electric	-	-	
17	2.1 GS 0-10 kW	-	-	
18	2.2 GS 10-100 kW	-	-	
19	2.3 GS 110-1,000 kVa	-	-	
20	4.1 Street and Area Lighting	-	-	
21	**Total**	**-**	**-**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Revenue Requirement

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Expenses																
1	Operating & Maintenance	11,976,563	966,930	-	4,616,674	764,144	1,475,238	388,283	318,850	564,392	204,387	226,099	98,950	207,358	44,142	1,596,495	-
2	Fuels	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Fuels-Diesel	74,521	74,521	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuels-Gas Turbine	199,303	199,303	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Power Purchases -CF(L)Co	1,856,851	542,700	1,314,151	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Power Purchases-Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Depreciation	3,485,835	381,749	-	685,056	677,424	510,250	147,252	215,761	381,915	87,269	95,298	50,343	121,063	45,429	87,027	-
	Expense Credits																
8	Sundry	(57,038)	(4,605)	-	(21,987)	(3,639)	(7,026)	(1,849)	(1,519)	(2,688)	(973)	(1,077)	(471)	(988)	(210)	(7,603)	-
9	Building Rental Income	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Tax Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	Suppliers' Discounts	(8,886)	(717)	-	(3,425)	(567)	(1,095)	(288)	(237)	(419)	(152)	(168)	(73)	(154)	(33)	(1,184)	-
12	Pole Attachments	(255,733)	-	-	-	-	(147,903)	(50,546)	-	-	(26,179)	(31,105)	-	-	-	-	-
13	Secondary Energy Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Wheeling Revenues	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Application Fees	(13,016)	-	-	-	-	-	-	-	-	-	-	-	-	-	(13,016)	-
16	Meter Test Revenues	(943)	-	-	-	-	-	-	-	-	-	-	-	(943)	-	-	-
17	**Total Expense Credits**	**(335,615)**	**(5,322)**	**-**	**(25,412)**	**(4,206)**	**(156,023)**	**(52,683)**	**(1,755)**	**(3,107)**	**(27,304)**	**(32,350)**	**(545)**	**(2,084)**	**(243)**	**(21,804)**	**-**
18	**Subtotal Expenses**	**17,257,457**	**2,159,880**	**1,314,151**	**5,276,318**	**1,437,362**	**1,829,465**	**482,851**	**532,856**	**943,200**	**264,352**	**289,047**	**148,749**	**326,336**	**89,328**	**1,661,718**	**-**
19	Disposal Gain / Loss	41,737	3,617	-	7,297	8,159	8,190	2,377	2,260	4,000	1,491	1,596	1,134	742	213	662	-
20	**Subtotal Revenue Requirement Ex. Return**	**17,299,194**	**2,163,497**	**1,314,151**	**5,283,614**	**1,445,521**	**1,837,655**	**485,228**	**535,116**	**947,199**	**265,843**	**290,643**	**149,883**	**327,077**	**89,541**	**1,662,380**	**-**
21	Return on Debt	4,531,956	411,874	-	792,770	877,893	886,989	257,066	243,787	431,523	160,835	172,197	121,725	80,288	23,168	71,842	-
22	Return on Equity	1,724,907	156,763	-	301,736	334,135	337,597	97,842	92,788	164,242	61,215	65,540	46,330	30,559	8,818	27,344	-
23	**Total Revenue Requirement**	**23,556,057**	**2,732,135**	**1,314,151**	**6,378,120**	**2,657,548**	**3,062,240**	**840,136**	**871,690**	**1,542,964**	**487,893**	**528,380**	**317,938**	**437,924**	**121,528**	**1,761,565**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Revenue Requirement (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Expenses			
1	Operating & Maintenance	480,471	24,151	Carryforward from Sch.2.4 L.24
2	Fuels	-	-	
3	Fuels-Diesel	-	-	Production - Demand
4	Fuels-Gas Turbine	-	-	Production - Demand
5	Power Purchases -CF(L)Co	-	-	Carryforward from Sch.4.4 L.9
6	Power Purchases-Other	-	-	Carryforward from Sch.4.4 L.10
7	Depreciation	-	-	Carryforward from Sch.2.5 L.24
	Expense Credits			
8	Sundry	(2,288)	(115)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
9	Building Rental Income	-	-	Prorated on Production, Transmission & Distribution Plant - Sch.2.2 L.18
10	Tax Refunds	-	-	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
11	Suppliers' Discounts	(356)	(18)	Prorated on Total Operating & Maintenance Expenses - Sch 2.4 L.24
12	Pole Attachments	-	-	Prorated on Distribution Poles - Sch.4.1 L.37
13	Secondary Energy Revenues	-	-	Production - Energy
14	Wheeling Revenues	-	-	Transmission - Demand, Energy ratios Sch.4.1 L.16
15	Application Fees	-	-	Accounting - Customer
16	Meter Test Revenues	-	-	Meters - Customer
17	**Total Expense Credits**	**(2,645)**	**(133)**	
18	**Subtotal Expenses**	**477,827**	**24,018**	
19	Disposal Gain / Loss	-	-	Prorated on Total Net Book Value - Sch.2.3 L.24
20	**Subtotal Revenue Requirement Ex. Return**	**477,827**	**24,018**	
21	Return on Debt	-	-	Prorated on Rate Base - Sch.2.6 L.8
22	Return on Equity	-	-	Prorated on Rate Base - Sch.2.6 L.10
23	**Total Revenue Requirement**	**477,827**	**24,018**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbines	23,666,030	23,666,030	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	3,323,334	3,323,334	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**26,989,364**	**26,989,364**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	17,100,852	-	-	17,100,852	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	18,092,147	-	-	6,420,032	11,672,115	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	**35,192,999**	-	-	**23,520,884**	11,672,115	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	5,667,946	-	-	-	5,667,946	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	1,083,634	-	-	-	-	817,006	104,083	-	-	94,764	67,781	-	-	-	-	-
9	Poles	30,428,760	-	-	-	-	17,598,412	6,014,305	-	-	3,114,931	3,701,111	-	-	-	-	-
10	Primary Conductor & Eqpt	9,200,174	-	-	-	-	8,160,554	1,039,620	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	620,108	-	-	-	-	620,108	-	-	-	-	-	-	-	-	-	-
12	Transformers	16,282,605	-	-	-	-	-	-	5,878,020	10,404,585	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	957,432	-	-	-	-	-	-	-	-	558,183	399,249	-	-	-	-	-
14	Services	1,824,154	-	-	-	-	-	-	-	-	-	-	1,824,154	-	-	-	-
15	Meters	2,288,365	-	-	-	-	-	-	-	-	-	-	-	2,288,365	-	-	-
16	Street Lighting	813,762	-	-	-	-	-	-	-	-	-	-	-	-	813,762	-	-
17	**Subtotal Distribution**	**69,166,939**	-	-	-	5,667,946	**27,196,080**	**7,158,008**	**5,878,020**	**10,404,585**	**3,767,878**	**4,168,141**	**1,824,154**	**2,288,365**	**813,762**	-	-
18	**Subttl Prod, Trans, & Dist**	**131,349,302**	**26,989,364**	-	**23,520,884**	**17,340,061**	**27,196,080**	**7,158,008**	**5,878,020**	**10,404,585**	**3,767,878**	**4,168,141**	**1,824,154**	**2,288,365**	**813,762**	-	-
19	General	16,334,186	1,039,489	-	7,136,203	899,853	1,912,135	503,274	413,279	731,538	264,917	293,059	128,255	297,178	57,215	2,657,793	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	265,081	54,468	-	47,468	34,995	54,885	14,446	11,863	20,998	7,604	8,412	3,681	4,618	1,642	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Plant**	**147,948,569**	**28,083,321**	-	**30,704,555**	**18,274,908**	**29,163,100**	**7,675,728**	**6,303,162**	**11,157,121**	**4,040,398**	**4,469,612**	**1,956,091**	**2,590,160**	**872,619**	**2,657,793**	-

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Plant in Service for the Allocation of O&M Expense (CONT'D.)

Line No.	1 Description	18 Basis of Functional Classification
	Production	
1	Gas Turbines	Production - Demand, Energy ratios Sch.4.1 L.9
2	Diesel	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	
	Transmission	
4	Lines	Production, Transmission - Demand; Distribution - Primary Demand; Spec Assigned - Custmr
5	Terminal Stations	Production, Transmission - Demand; Spec Assigned - Custmr
6	**Subtotal Transmission**	
	Distribution	
7	Substations	Production - Demand; Dist Substns - Demand
8	Land & Land Improvements	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.32
9	Poles	Primary, Secondary - Demand, Customer - zero intercept ratios Sch.4.1 L.37
10	Primary Conductor & Eqpt	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.38
11	Submarine Conductor	Primary - Demand, Customer - zero intercept ratios Sch.4.1 L.39
12	Transformers	Transformers - Demand, Customer - zero intercept ratios Sch.4.1 L.40
13	Secondary Conductor&Eqpt	Secondary - Demand, Customer - zero intercept ratios Sch. 4.1 L.41
14	Services	Services Customer
15	Meters	Meters - Customer
16	Street Lighting	Street Lighting - Customer
17	**Subtotal Distribution**	
18	**Subttl Prod, Trans, & Dist**	
19	General	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - Sch2.4 L.11, 12
20	Telecontrol - Specific	Specifically Assigned - Customer
21	Feasibility Studies	Production, Transmission - Demand
22	Software - General	Prorated on subtotal Production, Transmission, & Distribution plant - L.18
23	Software - Cust Acctng	
24	**Total Plant**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Net Book Value

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbines	6,276,550	6,276,550	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	580,257	580,257	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**6,856,807**	**6,856,807**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	7,907,366	-	-	7,907,366	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	18,265,060	-	-	3,363,187	14,901,873	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	**26,172,426**	-	-	**11,270,553**	**14,901,873**	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	1,300,884	-	-	-	1,300,884	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	482,081	-	-	-	-	363,465	46,304	-	-	42,158	30,154	-	-	-	-	-
9	Poles	21,235,511	-	-	-	-	12,281,515	4,197,241	-	-	2,173,837	2,582,918	-	-	-	-	-
10	Primary Conductor & Eqpt	3,143,393	-	-	-	-	2,788,189	355,203	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	317,759	-	-	-	-	317,759	-	-	-	-	-	-	-	-	-	-
12	Transformers	12,198,757	-	-	-	-	-	-	4,403,751	7,795,006	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	1,191,190	-	-	-	-	-	-	-	-	694,464	496,726	-	-	-	-	-
14	Services	2,250,759	-	-	-	-	-	-	-	-	-	-	2,250,759	-	-	-	-
15	Meters	1,363,148	-	-	-	-	-	-	-	-	-	-	-	1,363,148	-	-	-
16	Street Lighting	406,579	-	-	-	-	-	-	-	-	-	-	-	-	406,579	-	-
17	**Subtotal Distribution**	**43,890,061**	-	-	-	**1,300,884**	**15,750,928**	**4,598,748**	**4,403,751**	**7,795,006**	**2,910,459**	**3,109,798**	**2,250,759**	**1,363,148**	**406,579**	-	-
18	**Subttl Prod, Trans, & Dist**	**76,919,294**	**6,856,807**	-	**11,270,553**	**16,202,757**	**15,750,928**	**4,598,748**	**4,403,751**	**7,795,006**	**2,910,459**	**3,109,798**	**2,250,759**	**1,363,148**	**406,579**	-	-
19	General	8,331,016	530,176	-	3,639,717	458,957	975,257	256,688	210,787	373,110	135,117	149,470	65,415	151,571	29,182	1,355,569	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	233,132	20,782	-	34,160	49,108	47,739	13,938	13,347	23,626	8,821	9,425	6,822	4,132	1,232	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Net Book Value**	**85,483,442**	**7,407,766**	-	**14,944,430**	**16,710,822**	**16,773,924**	**4,869,374**	**4,627,885**	**8,191,742**	**3,054,397**	**3,268,694**	**2,322,995**	**1,518,850**	**436,993**	**1,355,569**	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Production																
1	Gas Turbine / Diesel	390,996	390,996	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Other	59,743	59,743	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**450,738**	**450,738**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Transmission Lines	2,894,754	-	-	2,894,754	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	252,281	-	-	89,522	162,758	-	-	-	-	-	-	-	-	-	-	-
6	Other	164,722	-	-	110,091	54,632	-	-	-	-	-	-	-	-	-	-	-
7	**Subtotal Transmission**	**3,311,757**	-	-	**3,094,366**	**217,390**	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
8	Other	2,038,937	-	-	-	172,800	829,131	218,227	179,204	317,206	114,872	127,075	55,613	-	24,809	-	-
9	Meters	128,861	-	-	-	-	-	-	-	-	-	-	-	128,861	-	-	-
10	**Subtotal Distribution**	**2,167,798**	-	-	-	**172,800**	**829,131**	**218,227**	**179,204**	**317,206**	**114,872**	**127,075**	**55,613**	**128,861**	**24,809**	-	-
11	**Subttl Prod, Trans, & Dist**	**5,930,293**	**450,738**	-	**3,094,366**	**390,190**	**829,131**	**218,227**	**179,204**	**317,206**	**114,872**	**127,075**	**55,613**	**128,861**	**24,809**	-	-
12	Customer Accounting	1,152,459	-	-	-	-	-	-	-	-	-	-	-	-	-	1,152,459	-
	Administrative & General:																
	Plant-Related:																
13	Production	179,997	179,997	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Transmission	228,756	-	-	152,886	75,869	-	-	-	-	-	-	-	-	-	-	-
15	Distribution	500,419	-	-	-	41,007	196,762	51,788	42,527	75,277	27,260	30,156	13,198	16,556	5,888	-	-
16	Prod, Trans, Distn Plant	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	Prod, Trans, Distn & General Plt	601,388	114,154	-	124,809	74,285	118,543	31,201	25,621	45,352	16,424	18,168	7,951	10,529	3,547	10,804	-
18	Property Insurance	104,909	43,833	-	21,200	28,524	2,990	787	646	1,144	414	458	201	465	89	4,156	-
	Revenue-Related:																
19	Municipal Tax	480,471	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	PUB Assessment	24,151	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	All Expense-Related	2,636,998	167,816	-	1,152,072	145,273	308,696	81,249	66,720	118,100	42,768	47,312	20,706	47,976	9,237	429,075	-
22																	
	Prod,Trans & Distn Expense-Related	136,723	10,392	-	71,341	8,996	19,116	5,031	4,132	7,313	2,648	2,930	1,282	2,971	572	-	-
23	**Subtotal Admin & General**	**4,893,811**	**516,192**	-	**1,522,308**	**373,954**	**646,107**	**170,055**	**139,646**	**247,186**	**89,515**	**99,024**	**43,337**	**78,497**	**19,333**	**444,035**	-
24	**Total Operating & Maintenance Expenses**	**11,976,563**	**966,930**	-	**4,616,674**	**764,144**	**1,475,238**	**388,283**	**318,850**	**564,392**	**204,387**	**226,099**	**98,950**	**207,358**	**44,142**	**1,596,495**	-

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Operating & Maintenance Expense (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax	19 Revenue Related PUB Assessment	20 Basis of Functional Classification
	Production			
1	Gas Turbine / Diesel	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
2	Other	-	-	Production - Demand, Energy ratios Sch.4.1 L.9
3	**Subtotal Production**	-	-	
	Transmission			
4	Transmission Lines	-	-	Prorated on Transmission Lines Plant in Service - Sch.2.2 L.4
5	Terminal Stations	-	-	Prorated on Transmission Terminal Stations Plant in Service - Sch.2.2 L.5
6	Other	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L.6
7	**Subtotal Transmission**	-	-	
	Distribution			
8	Other	-	-	Prorated on Distribution Plant, excluding Meters - Sch. 2.2 L. 17, less L. 15
9	Meters	-	-	Meters - Customer
10	**Subtotal Distribution**	-	-	
11	**Subttl Prod, Trans, & Dist**	-	-	
12	Customer Accounting	-	-	Accounting - Customer
	Administrative & General:			
	Plant-Related:			
13	Production	-	-	Prorated on Production Plant in Service - Sch.2.2 L.3
14	Transmission	-	-	Prorated on Transmission Plant in Service - Sch.2.2 L. 6
15	Distribution	-	-	Prorated on Distribution Plant in Service - Sch.2.2 L.17
16	Prod, Trans, Distn Plant	-	-	Prorated on Production, Transmission, Distribution Plant in Service - Sch.2.2 L. 18
17	Prod, Trans, Distn & General Plt	-	-	Prorated on Production, Transmission, Distribution & General Plant in Service - Sch.2.2 L.24
18	Property Insurance	-	-	Prorated on Prod., Trans. Terminal, Dist. Sub & General Plant in Service - Sch.2.2 L.3, 5, 7, 19 - 20
	Revenue-Related:			
19	Municipal Tax	480,471	-	Revenue-related
20	PUB Assessment	-	24,151	Revenue-related
21	All Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution, Accounting Expenses - L 11, 12
22				
	Prod,Trans & Distn Expense-Related	-	-	Prorated on Subtotal Production, Transmission, Distribution Expenses - L.11
23	**Subtotal Admin & General**	**480,471**	**24,151**	
24	**Total Operating & Maintenance Expenses**	**480,471**	**24,151**	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Depreciation Expense

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
							Distribution										
	Production																
1	Gas Turbines	320,518	320,518	-	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Diesel	21,377	21,377	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	**Subtotal Production**	**341,896**	**341,896**	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Transmission																
4	Lines	318,196	-	-	318,196	-	-	-	-	-	-	-	-	-	-	-	-
5	Terminal Stations	693,857	-	-	125,641	568,216	-	-	-	-	-	-	-	-	-	-	-
6	**Subtotal Transmission**	**1,012,053**	-	-	**443,837**	**568,216**	-	-	-	-	-	-	-	-	-	-	-
	Distribution																
7	Substations	68,905	-	-	-	68,905	-	-	-	-	-	-	-	-	-	-	-
8	Land & Land Improvements	14,988	-	-	-	-	11,300	1,440	-	-	1,311	937	-	-	-	-	-
9	Poles	598,894	-	-	-	-	346,369	118,373	-	-	61,308	72,845	-	-	-	-	-
10	Primary Conductor & Eqpt	77,637	-	-	-	-	68,864	8,773	-	-	-	-	-	-	-	-	-
11	Submarine Conductor	13,618	-	-	-	-	13,618	-	-	-	-	-	-	-	-	-	-
12	Transformers	550,820	-	-	-	-	-	-	198,846	351,974	-	-	-	-	-	-	-
13	Secondary Conductor&Eqpt	25,148	-	-	-	-	-	-	-	-	14,661	10,487	-	-	-	-	-
14	Services	45,372	-	-	-	-	-	-	-	-	-	-	45,372	-	-	-	-
15	Meters	109,470	-	-	-	-	-	-	-	-	-	-	-	109,470	-	-	-
16	Street Lighting	42,827	-	-	-	-	-	-	-	-	-	-	-	-	42,827	-	-
17	**Subtotal Distribution**	**1,547,678**	-	-	-	**68,905**	**440,151**	**128,585**	**198,846**	**351,974**	**77,280**	**84,269**	**45,372**	**109,470**	**42,827**	-	-
18	**Subttl Prod, Trans, & Dist**	**2,901,627**	**341,896**	-	**443,837**	**637,121**	**440,151**	**128,585**	**198,846**	**351,974**	**77,280**	**84,269**	**45,372**	**109,470**	**42,827**	-	-
19	General	534,848	34,037	-	233,669	29,465	62,611	16,479	13,532	23,954	8,674	9,596	4,200	9,731	1,873	87,027	-
20	Telecontrol - Specific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Feasibility Studies	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Software - General	49,359	5,816	-	7,550	10,838	7,487	2,187	3,383	5,987	1,315	1,433	772	1,862	729	-	-
23	Software - Cust Acctng	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	**Total Depreciation Expense**	**3,485,835**	**381,749**	-	**685,056**	**677,424**	**510,250**	**147,252**	**215,761**	**381,915**	**87,269**	**95,298**	**50,343**	**121,063**	**45,429**	**87,027**	-

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Rate Base

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Distribution Substations Demand ($)	7 Distribution Primary Lines Demand ($)	8 Distribution Primary Lines Customer ($)	9 Distribution Line Transformers Demand ($)	10 Distribution Line Transformers Customer ($)	11 Distribution Secondary Lines Demand ($)	12 Distribution Secondary Lines Customer ($)	13 Distribution Services Customer ($)	14 Distribution Meters Customer ($)	15 Distribution Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
1	Average Net Book Value	85,483,442	7,407,766	-	14,944,430	16,710,822	16,773,924	4,869,374	4,627,885	8,191,742	3,054,397	3,268,694	2,322,995	1,518,850	436,993	1,355,569	-
2	Cash Working Capital	370,534	32,109	-	64,778	72,434	72,708	21,107	20,060	35,508	13,239	14,168	10,069	6,584	1,894	5,876	-
3	Fuel Inventory - No. 6 Fuel	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Fuel Inventory - Diesel	37,715	37,715	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Fuel Inventory - Gas Turbine	206,011	206,011	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Inventory/Supplies	1,600,905	303,881	-	332,244	197,747	315,565	83,057	68,205	120,728	43,720	48,364	21,166	28,027	9,442	28,759	-
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	4,080,294	353,587	-	713,327	797,641	800,653	232,425	220,898	391,008	145,792	156,021	110,881	72,498	20,859	64,704	-
8	Total Rate Base	**91,778,900**	**8,341,069**	**-**	**16,054,779**	**17,778,644**	**17,962,849**	**5,205,962**	**4,937,048**	**8,738,985**	**3,257,148**	**3,487,248**	**2,465,112**	**1,625,959**	**469,188**	**1,454,908**	**-**
9	Less: Rural Portion	-															
10	Rate Base Available for Equity Return	**91,778,900**	**8,341,069**	**-**	**16,054,779**	**17,778,644**	**17,962,849**	**5,205,962**	**4,937,048**	**8,738,985**	**3,257,148**	**3,487,248**	**2,465,112**	**1,625,959**	**469,188**	**1,454,908**	**-**
11	Return on Debt	4,531,956	411,874	-	792,770	877,893	886,989	257,066	243,787	431,523	160,835	172,197	121,725	80,288	23,168	71,842	-
12	Return on Equity	1,724,907	156,763	-	301,736	334,135	337,597	97,842	92,788	164,242	61,215	65,540	46,330	30,559	8,818	27,344	-
13	Return on Rate Base	**6,256,863**	**568,638**	**-**	**1,094,506**	**1,212,027**	**1,224,585**	**354,907**	**336,574**	**595,765**	**222,050**	**237,737**	**168,055**	**110,847**	**31,986**	**99,186**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Functional Classification of Rate Base (CONT'D.)

	1	18
Line No.	Description	Basis of Functional Classification
1	Average Net Book Value	Sch. 2.3 , L. 24
2	Cash Working Capital	Prorated on Average Net Book Value, L. 1
3	Fuel Inventory - No. 6 Fuel	
4	Fuel Inventory - Diesel	Production - Demand
5	Fuel Inventory - Gas Turbine	Production - Demand
6	Inventory/Supplies	Prorated on Total Plant in Service, Sch. 2.2, L. 24
7	Deferred Charges: Foreign Exchange Loss and Regulatory Costs	Prorated on Average Net Book Value, L. 1
8	Total Rate Base	
9	Less: Rural Portion	
10	Rate Base Available for Equity Return	
11	Return on Debt	L.8 x Sch.1.1,p2,L.14
12	Return on Equity	L.10 x Sch.1.1,p2,L.17
13	Return on Rate Base	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Basis of Allocation to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production Energy	5 Transmission Demand	6 Substations Demand	7 Primary Lines Demand	8 Primary Lines Customer	9 Line Transformers Demand	10 Line Transformers Customer	11 Secondary Lines Demand	12 Secondary Lines Customer	13 Services Customer	14 Meters Customer	15 Street Lighting Customer	16 Accounting Customer	17 Specifically Assigned Customer
						Distribution											
	Amounts		(CP kW)	(MWh @ Gen)	(CP kW)	(CP kW)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(CP kW)	(Rural Cust)	(Wtd Rural Cust)			(Rural Cust)	
1	CFB - Goose Bay Secondary	-	-	10,973	-	-	-	-	-	-	-	-	-	-	-	-	-
2	IOCC Firm	-	273,606	1,925,673	243,000	-	-	1	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
4	1.1Domestic	-	662	2,462	588	569	569	360	540	360	540	360	360	360	-	360	-
5	1.1A Domestic All Electric	-	83,785	356,271	74,412	72,008	72,008	9,442	68,372	9,442	68,372	9,442	9,442	9,442		9,442	
6	2.1GS 0-10 kW	-	1,355	7,536	1,203	1,164	1,164	515	1,105	515	1,105	515	967	967	-	515	-
7	2.2GS 10-100 kW	-	17,297	84,020	15,362	14,866	14,866	728	14,032	728	14,032	728	3,470	3,470	-	728	-
8	2.3GS 110-1,000 kVa	-	27,494	129,670	24,418	23,629	23,629	164	22,029	164	22,029	164	1,383	1,383	-	164	-
9	2.4GS Over 1,000 kVa	-	27,058	158,274	24,031	23,255	23,255	6	15,536	6	15,536	6	51	51	-	6	-
10	4.1Street and Area Lighting	-	521	2,021	463	448	448	385	425	385	425	385	-	-	1	385	-
11	**Subtotal Rural**		**158,171**	**740,254**	**140,477**	**135,938**	**135,938**	**11,600**	**122,039**	**11,600**	**122,039**	**11,600**	**15,673**	**15,673**	**1**	**11,600**	**-**
12	**Total Labrador Interconnected**		**431,777**	**2,676,900**	**383,477**	**135,938**	**135,938**	**11,601**	**122,039**	**11,600**	**122,039**	**11,600**	**15,673**	**15,673**	**1**	**11,600**	**-**
	Ratios																
13	CFB - Goose Bay Boiler	-	-	0.0041	-	-	-	-	-	-	-	-	-	-	-	-	-
14	IOCC Firm	-	0.6337	0.7194	0.6337	-	-	0.0001	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
16	1.1Domestic	-	0.0015	0.0009	0.0015	0.0042	0.0042	0.0310	0.0044	0.0310	0.0044	0.0310	0.0230	0.0230	-	0.0310	-
17	1.1A Domestic All Electric	-	0.1940	0.1331	0.1940	0.5297	0.5297	0.8139	0.5602	0.8140	0.5602	0.8140	0.6025	0.6025	-	0.8140	-
18	2.1GS 0-10 kW	-	0.0031	0.0028	0.0031	0.0086	0.0086	0.0444	0.0091	0.0444	0.0091	0.0444	0.0617	0.0617	-	0.0444	-
19	2.2GS 10-100 kW	-	0.0401	0.0314	0.0401	0.1094	0.1094	0.0627	0.1150	0.0627	0.1150	0.0627	0.2214	0.2214	-	0.0627	-
20	2.3GS 110-1,000 kVa	-	0.0637	0.0484	0.0637	0.1738	0.1738	0.0142	0.1805	0.0142	0.1805	0.0142	0.0882	0.0882	-	0.0142	-
21	2.4GS Over 1,000 kVa	-	0.0627	0.0591	0.0627	0.1711	0.1711	0.0005	0.1273	0.0005	0.1273	0.0005	0.0032	0.0032	-	0.0005	-
22	4.1Street and Area Lighting	-	0.0012	0.0008	0.0012	0.0033	0.0033	0.0332	0.0035	0.0332	0.0035	0.0332	-	-	1.0000	0.0332	-
23	**Subtotal Rural**		**0.3663**	**0.2765**	**0.3663**	**1.0000**	**1.0000**	**0.9999**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
24	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
	Ratios Excluding IOCC																
25	CFB - Goose Bay Boiler	-	-	0.0146	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural																
26	1.1Domestic	-	0.0042	0.0033	0.0042	0.0042	0.0042	0.0310	0.0044	0.0310	0.0044	0.0310	0.0230	0.0230	-	0.0310	-
27	1.1A Domestic All Electric	-	0.5297	0.4743	0.5297	0.5297	0.5297	0.8140	0.5602	0.8140	0.5602	0.8140	0.6025	0.6025	-	0.8140	-
28	2.1GS 0-10 kW	-	0.0086	0.0100	0.0086	0.0086	0.0086	0.0444	0.0091	0.0444	0.0091	0.0444	0.0617	0.0617	-	0.0444	-
29	2.2GS 10-100 kW	-	0.1094	0.1118	0.1094	0.1094	0.1094	0.0627	0.1150	0.0627	0.1150	0.0627	0.2214	0.2214	-	0.0627	-
30	2.3GS 110-1,000 kVa	-	0.1738	0.1726	0.1738	0.1738	0.1738	0.0142	0.1805	0.0142	0.1805	0.0142	0.0882	0.0882	-	0.0142	-
31	2.4GS Over 1,000 kVa	-	0.1711	0.2107	0.1711	0.1711	0.1711	0.0005	0.1273	0.0005	0.1273	0.0005	0.0032	0.0032	-	0.0005	-
32	4.1Street and Area Lighting	-	0.0033	0.0027	0.0033	0.0033	0.0033	0.0332	0.0035	0.0332	0.0035	0.0332	-	-	1.0000	0.0332	-
33	**Subtotal Rural**		**1.0000**	**0.9854**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**
34	**Total Labrador Interconnected**		**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**1.0000**	**-**

NEWFOUNDLAND & LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Basis of Allocation to Classes of Service (CONT'D.)

Line No.		18 Revenue Related Municipal Tax (Prior Year (Rural Revenues)	19 Revenue Related PUB Assessment (Prior Year (Revenues + RSP)
	Amounts		
1	CFB - Goose Bay Secondary	-	333,112
2	IOCC Firm	-	-
3	IOCC Non-Firm	-	-
		-	-
	Rural		
4	1.1Domestic	102,994	102,994
5	1.1A Domestic All Electric	10,056,863	10,056,863
6	2.1GS 0-10 kW	398,087	398,087
7	2.2GS 10-100 kW	2,191,392	2,191,392
8	2.3GS 110-1,000 kVa	2,999,815	2,999,815
9	2.4GS Over 1,000 kVa	1,974,167	1,104,411
10	4.1Street and Area Lighting	292,637	292,637
11	**Subtotal Rural**	**18,015,954**	**17,146,198**
12	**Total Labrador Interconnected**	**18,015,954**	**17,479,310**
	Ratios		
13	CFB - Goose Bay Boiler	-	0.0191
14	IOCC Firm	-	-
15	IOCC Non-Firm	-	-
		-	-
	Rural		
16	1.1Domestic	0.0057	0.0059
17	1.1A Domestic All Electric	0.5582	0.5754
18	2.1GS 0-10 kW	0.0221	0.0228
19	2.2GS 10-100 kW	0.1216	0.1254
20	2.3GS 110-1,000 kVa	0.1665	0.1716
21	2.4GS Over 1,000 kVa	0.1096	0.0632
22	4.1Street and Area Lighting	0.0162	0.0167
23	**Subtotal Rural**	**1.0000**	**0.9809**
24	**Total Labrador Interconnected**	**1.0000**	**1.0000**
	Ratios Excluding IOCC		
25	CFB - Goose Bay Boiler	-	0.0191
		-	-
	Rural		
26	1.1Domestic	0.0057	0.0059
27	1.1A Domestic All Electric	0.5582	0.5754
28	2.1GS 0-10 kW	0.0221	0.0228
29	2.2GS 10-100 kW	0.1216	0.1254
30	2.3GS 110-1,000 kVa	0.1665	0.1716
31	2.4GS Over 1,000 kVa	0.1096	0.0632
32	4.1Street and Area Lighting	0.0162	0.0167
33	**Subtotal Rural**	**1.0000**	**0.9809**
34	**Total Labrador Interconnected**	**1.0000**	**1.0000**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service

Line No.	1 Description	2 Total Amount	3 Production Demand	4 Production Energy	5 Transmission Demand	6 Substations Demand	7 Primary Lines Demand	8 Primary Lines Customer	9 Line Transformers Demand	10 Line Transformers Customer	11 Secondary Lines Demand	12 Secondary Lines Customer	13 Services Customer	14 Meters Customer	15 Street Lighting Customer	16 Accounting Customer	17 Specifically Assigned Customer
						Distribution											
	Allocated Rev Reqmt Excl Return	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)	($)
1	CFB - Goose Bay Boiler	19,653	-	19,196	-	-	-	-	-	-	-	-	-	-	-	-	-
2	IOCC Firm	4,375,195	1,027,059	-	3,348,095	-	-	42	-	-	-	-	-	-	-	-	-
3	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
4	1.1Domestic	153,345	4,756	4,307	8,100	6,050	7,691	15,058	2,369	29,396	1,177	9,020	3,443	7,513	-	51,592	-
5	1.1A Domestic All Electric	7,761,919	601,984	623,238	1,025,266	765,708	973,425	394,934	299,797	771,004	148,938	236,579	90,298	197,049	-	1,353,149	-
6	2.1GS 0-10 kW	265,699	9,733	13,182	16,576	12,380	15,738	21,541	4,847	42,053	2,408	12,904	9,247	20,179	-	73,806	-
7	2.2GS 10-100 kW	1,313,106	124,275	146,980	211,659	158,075	200,957	30,429	61,528	59,405	30,567	18,228	33,188	72,422	-	104,259	-
8	2.3GS 110-1,000 kVa	1,649,794	197,540	226,837	336,440	251,266	319,428	6,870	96,591	13,412	47,986	4,115	13,225	28,860	-	23,539	-
9	2.4GS Over 1,000 kVa	1,523,164	194,408	276,875	331,106	247,283	314,364	251	68,120	490	33,842	150	483	1,054	-	860	-
10	4.1Street and Area Lighting	237,318	3,742	3,535	6,373	4,760	6,051	16,104	1,864	31,438	926	9,647	-	-	89,541	55,175	-
11	**Subtotal Rural**	**12,904,345**	**1,136,438**	**1,294,955**	**1,935,520**	**1,445,521**	**1,837,655**	**485,187**	**535,116**	**947,199**	**265,843**	**290,643**	**149,883**	**327,077**	**89,541**	**1,662,380**	**-**
12	**Total**	**17,299,194**	**2,163,497**	**1,314,151**	**5,283,614**	**1,445,521**	**1,837,655**	**485,228**	**535,116**	**947,199**	**265,843**	**290,643**	**149,883**	**327,077**	**89,541**	**1,662,380**	**-**
	Allocated Return on Debt																
13	CFB - Goose Bay Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	IOCC Firm	763,375	260,994	-	502,359	-	-	22	-	-	-	-	-	-	-	-	-
15	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
16	1.1Domestic	44,608	631	-	1,215	3,674	3,712	7,977	1,079	13,392	712	5,344	2,796	1,844	-	2,230	-
17	1.1A Domestic All Electric	2,276,150	79,923	-	153,834	465,029	469,847	209,229	136,581	351,252	90,107	140,165	73,334	48,370	-	58,478	-
18	2.1GS 0-10 kW	76,427	1,292	-	2,487	7,518	7,596	11,412	2,208	19,159	1,457	7,645	7,510	4,953	-	3,190	-
19	2.2GS 10-100 kW	391,001	16,499	-	31,758	96,002	96,997	16,121	28,031	27,064	18,493	10,800	26,953	17,778	-	4,506	-
20	2.3GS 110-1,000 kVa	487,552	26,227	-	50,480	152,599	154,180	3,640	44,005	6,110	29,031	2,438	10,741	7,084	-	1,017	-
21	2.4GS Over 1,000 kVa	430,048	25,811	-	49,680	150,179	151,736	133	31,034	223	20,474	89	392	259	-	37	-
22	4.1Street and Area Lighting	62,795	497	-	956	2,891	2,921	8,531	849	14,322	560	5,715	-	-	23,168	2,384	-
23	**Subtotal Rural**	**3,768,581**	**150,880**	**-**	**290,411**	**877,893**	**886,989**	**257,043**	**243,787**	**431,523**	**160,835**	**172,197**	**121,725**	**80,288**	**23,168**	**71,842**	**-**
24	**Total**	**4,531,956**	**411,874**	**-**	**792,770**	**877,893**	**886,989**	**257,066**	**243,787**	**431,523**	**160,835**	**172,197**	**121,725**	**80,288**	**23,168**	**71,842**	**-**
	Allocated Return on Equity																
25	CFB - Goose Bay Boiler	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	IOCC Firm	290,548	99,337	-	191,203	-	-	8	-	-	-	-	-	-	-	-	-
27	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
28	1.1Domestic	16,978	240	-	463	1,398	1,413	3,036	411	5,097	271	2,034	1,064	702	-	849	-
29	1.1A Domestic All Electric	866,325	30,419	-	58,551	176,995	178,829	79,635	51,984	133,690	34,296	53,348	27,911	18,410	-	22,257	-
30	2.1GS 0-10 kW	29,089	492	-	947	2,862	2,891	4,344	840	7,292	554	2,910	2,858	1,885	-	1,214	-
31	2.2GS 10-100 kW	148,819	6,280	-	12,087	36,539	36,918	6,136	10,669	10,301	7,039	4,110	10,258	6,766	-	1,715	-
32	2.3GS 110-1,000 kVa	185,567	9,982	-	19,213	58,081	58,682	1,385	16,749	2,326	11,050	928	4,088	2,696	-	387	-
33	2.4GS Over 1,000 kVa	163,680	9,824	-	18,909	57,160	57,752	51	11,812	85	7,793	34	149	98	-	14	-
34	4.1Street and Area Lighting	23,900	189	-	364	1,100	1,112	3,247	323	5,451	213	2,175	-	-	8,818	908	-
35	**Subtotal Rural**	**1,434,359**	**57,426**	**-**	**110,533**	**334,135**	**337,597**	**97,833**	**92,788**	**164,242**	**61,215**	**65,540**	**46,330**	**30,559**	**8,818**	**27,344**	**-**
36	**Total**	**1,724,907**	**156,763**	**-**	**301,736**	**334,135**	**337,597**	**97,842**	**92,788**	**164,242**	**61,215**	**65,540**	**46,330**	**30,559**	**8,818**	**27,344**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Allocated Rev Reqmt Excl Return			
1	CFB - Goose Bay Boiler	-	458	
2	IOCC Firm	-	-	
3	IOCC Non-Firm	-	-	
		-	-	
	Rural:			
4	1.1Domestic	2,732	142	
5	1.1A Domestic All Electric	266,732	13,819	
6	2.1GS 0-10 kW	10,558	547	
7	2.2GS 10-100 kW	58,121	3,011	
8	2.3GS 110-1,000 kVa	79,562	4,122	
9	2.4GS Over 1,000 kVa	52,360	1,518	
10	4.1Street and Area Lighting	7,761	402	
11	**Subtotal Rural**	**477,827**	**23,560**	
12	**Total**	**477,827**	**24,018**	
	Allocated Return on Debt			
13	CFB - Goose Bay Boiler	-	-	
14	IOCC Firm	-	-	
15	IOCC Non-Firm	-	-	
	Rural:			
16	1.1Domestic	-	-	
17	1.1A Domestic All Electric	-	-	
18	2.1GS 0-10 kW	-	-	
19	2.2GS 10-100 kW	-	-	
20	2.3GS 110-1,000 kVa	-	-	
21	2.4GS Over 1,000 kVa	-	-	
22	4.1Street and Area Lighting	-	-	
23	**Subtotal Rural**	-	-	
24	**Total**	-	-	
	Allocated Return on Equity			
25	CFB - Goose Bay Boiler	-	-	
26	IOCC Firm	-	-	
27	IOCC Non-Firm	-	-	
	Rural:			
28	1.1Domestic	-	-	
29	1.1A Domestic All Electric	-	-	
30	2.1GS 0-10 kW	-	-	
31	2.2GS 10-100 kW	-	-	
32	2.3GS 110-1,000 kVa	-	-	
33	2.4GS Over 1,000 kVa	-	-	
34	4.1Street and Area Lighting	-	-	
35	**Subtotal Rural**	-	-	
36	**Total**	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	2 Total Amount ($)	3 Production Demand ($)	4 Production Energy ($)	5 Transmission Demand ($)	6 Substations Demand ($)	7 Primary Lines Demand ($)	8 Primary Lines Customer ($)	9 Line Transformers Demand ($)	10 Line Transformers Customer ($)	11 Secondary Lines Demand ($)	12 Secondary Lines Customer ($)	13 Services Customer ($)	14 Meters Customer ($)	15 Street Lighting Customer ($)	16 Accounting Customer ($)	17 Specifically Assigned Customer ($)
	Total Revenue Requirement																
37	CFB - Goose Bay Boiler	19,653	-	19,196	-	-	-	-	-	-	-	-	-	-	-	-	-
38	IOCC Firm	5,429,118	1,387,390	-	4,041,656	-	-	72	-	-	-	-	-	-	-	-	-
39	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
40	1.1Domestic	214,932	5,628	4,307	9,778	11,122	12,816	26,071	3,858	47,886	2,160	16,398	7,303	10,059	-	54,670	-
41	1.1A Domestic All Electric	10,904,394	712,326	623,238	1,237,650	1,407,732	1,622,101	683,797	488,362	1,255,947	273,341	430,093	191,543	263,829	-	1,433,884	-
42	2.1GS 0-10 kW	371,215	11,517	13,182	20,010	22,760	26,226	37,297	7,896	68,504	4,419	23,459	19,615	27,017	-	78,209	-
43	2.2GS 10-100 kW	1,852,925	147,055	146,980	255,504	290,617	334,872	52,686	100,228	96,770	56,099	33,138	70,399	96,966	-	110,480	-
44	2.3GS 110-1,000 kVa	2,322,913	233,749	226,837	406,133	461,945	532,291	11,895	157,344	21,848	88,067	7,482	28,054	38,641	-	24,943	-
45	2.4GS Over 1,000 kVa	2,116,892	230,043	276,875	399,695	454,622	523,852	435	110,966	798	62,109	273	1,025	1,412	-	911	-
46	4.1Street and Area Lighting	324,013	4,428	3,535	7,693	8,750	10,083	27,882	3,036	51,212	1,699	17,537	-	-	121,528	58,467	-
47	**Subtotal Rural**	**18,107,285**	**1,344,744**	**1,294,955**	**2,336,465**	**2,657,548**	**3,062,240**	**840,063**	**871,690**	**1,542,964**	**487,893**	**528,380**	**317,938**	**437,924**	**121,528**	**1,761,565**	**-**
48	**Total**	**23,556,057**	**2,732,135**	**1,314,151**	**6,378,120**	**2,657,548**	**3,062,240**	**840,136**	**871,690**	**1,542,964**	**487,893**	**528,380**	**317,938**	**437,924**	**121,528**	**1,761,565**	**-**
	Re-classification of Revenue-Related																
49	CFB - Goose Bay Boiler	-	-	458	-	-	-	-	-	-	-	-	-	-	-	-	-
50	IOCC Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:																
52	1.1Domestic	(0)	76	58	132	151	174	353	52	649	29	222	99	136	-	741	-
53	1.1A Domestic All Electric	0	18,811	16,458	32,683	37,175	42,836	18,058	12,897	33,167	7,218	11,358	5,058	6,967	-	37,866	-
54	2.1GS 0-10 kW	(0)	355	407	617	702	809	1,150	243	2,113	136	723	605	833	-	2,412	-
55	2.2GS 10-100 kW	(0)	5,017	5,015	8,717	9,915	11,425	1,798	3,420	3,302	1,914	1,131	2,402	3,308	-	3,769	-
56	2.3GS 110-1,000 kVa	(0)	8,736	8,477	15,178	17,264	19,893	445	5,880	817	3,291	280	1,048	1,444	-	932	-
57	2.4GS Over 1,000 kVa	(0)	6,008	7,231	10,438	11,873	13,681	11	2,898	21	1,622	7	27	37	-	24	-
58	4.1Street and Area Lighting	0	114	91	199	226	261	721	78	1,324	44	453	-	-	3,141	1,511	-
59	**Subtotal Rural**	**(0)**	**39,117**	**37,737**	**67,965**	**77,305**	**89,078**	**22,535**	**25,469**	**41,391**	**14,255**	**14,174**	**9,239**	**12,726**	**3,141**	**47,255**	**-**
60	**Total**	**0**	**39,117**	**38,195**	**67,965**	**77,305**	**89,078**	**22,535**	**25,469**	**41,391**	**14,255**	**14,174**	**9,239**	**12,726**	**3,141**	**47,255**	**-**
	Total Allocated Revenue Requirement																
61	CFB - Goose Bay Boiler	19,653	-	19,653	-	-	-	-	-	-	-	-	-	-	-	-	-
62	IOCC Firm	5,429,118	1,387,390	-	4,041,656	-	-	72	-	-	-	-	-	-	-	-	-
63	IOCC Non-Firm	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Rural:		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	1.1Domestic	214,932	5,704	4,365	9,911	11,273	12,990	26,425	3,911	48,535	2,189	16,621	7,402	10,195	-	55,411	-
65	1.1A Domestic All Electric	10,904,394	731,136	639,697	1,270,334	1,444,907	1,664,937	701,855	501,259	1,289,113	280,559	441,450	196,601	270,796	-	1,471,750	-
66	2.1GS 0-10 kW	371,215	11,872	13,589	20,627	23,462	27,034	38,447	8,139	70,616	4,556	24,182	20,220	27,850	-	80,621	-
67	2.2GS 10-100 kW	1,852,925	152,072	151,994	264,222	300,532	346,297	54,484	103,648	100,071	58,013	34,269	72,801	100,275	-	114,249	-
68	2.3GS 110-1,000 kVa	2,322,913	242,484	235,315	421,311	479,209	552,183	12,340	163,224	22,665	91,358	7,761	29,102	40,085	-	25,876	-
69	2.4GS Over 1,000 kVa	2,116,892	236,051	284,106	410,133	466,495	537,533	446	113,864	819	63,731	280	1,052	1,448	-	935	-
70	4.1Street and Area Lighting	324,013	4,542	3,627	7,892	8,977	10,344	28,603	3,114	52,535	1,743	17,990	-	-	124,669	59,978	-
71	**Subtotal Rural**	**18,107,285**	**1,383,862**	**1,332,693**	**2,404,430**	**2,734,854**	**3,151,318**	**862,598**	**897,159**	**1,584,355**	**502,148**	**542,554**	**327,177**	**450,650**	**124,669**	**1,808,820**	**-**
72	**Total**	**23,556,057**	**2,771,252**	**1,352,346**	**6,446,086**	**2,734,854**	**3,151,318**	**862,671**	**897,159**	**1,584,355**	**502,148**	**542,554**	**327,177**	**450,650**	**124,669**	**1,808,820**	**-**

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Labrador Interconnected
Allocation of Functionalized Amounts to Classes of Service (CONT'D.)

Line No.	1 Description	18 Revenue Related Municipal Tax ($)	19 Revenue Related PUB Assessment ($)	Basis of Proration
	Total Revenue Requirement			
37	CFB - Goose Bay Boiler	-	458	
38	IOCC Firm	-	-	
39	IOCC Non-Firm	-	-	
	Rural:			
40	1.1Domestic	2,732	142	
41	1.1A Domestic All Electric	266,732	13,819	
42	2.1GS 0-10 kW	10,558	547	
43	2.2GS 10-100 kW	58,121	3,011	
44	2.3GS 110-1,000 kVa	79,562	4,122	
45	2.4GS Over 1,000 kVa	52,360	1,518	
46	4.1Street and Area Lighting	7,761	402	
47	**Subtotal Rural**	**477,827**	**23,560**	
48	**Total**	**477,827**	**24,018**	
	Re-classification of Revenue-Related			
49	CFB - Goose Bay Boiler	-	(458)	Re-classification to demand, energy and customer is based on rate class revenue
50	IOCC Firm	-	-	requirements excluding revenue-related items.
51	IOCC Non-Firm	-	-	
	Rural:			
52	1.1Domestic	(2,732)	(142)	
53	1.1A Domestic All Electric	(266,732)	(13,819)	
54	2.1GS 0-10 kW	(10,558)	(547)	
55	2.2GS 10-100 kW	(58,121)	(3,011)	
56	2.3GS 110-1,000 kVa	(79,562)	(4,122)	
57	2.4GS Over 1,000 kVa	(52,360)	(1,518)	
58	4.1Street and Area Lighting	(7,761)	(402)	
59	**Subtotal Rural**	**(477,827)**	**(23,560)**	
60	**Total**	**(477,827)**	**(24,018)**	
	Total Allocated Revenue Requirement			
61	CFB - Goose Bay Boiler	-	-	
62	IOCC Firm	-	-	
63	IOCC Non-Firm	-	-	
	Rural:	-	-	
64	1.1Domestic	-	-	
65	1.1A Domestic All Electric	-	-	
66	2.1GS 0-10 kW	-	-	
67	2.2GS 10-100 kW	-	-	
68	2.3GS 110-1,000 kVa	-	-	
69	2.4GS Over 1,000 kVa	-	-	
70	4.1Street and Area Lighting	-	-	
71	**Subtotal Rural**	-	-	
72	**Total**	-	-	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Functionalization & Classification Ratios

Line No.	1 Description	2 Total Amount (%)	3 Production Demand (%)	4 Production & Transmission Energy (%)	5 Transmission Demand (%)	6 Rural Prod & Transmission Demand (%)	7 Distribution Substations Demand (%)	8 Distribution Primary Lines Demand (%)	9 Distribution Primary Lines Customer (%)	10 Distribution Line Transformers Demand (%)	11 Distribution Line Transformers Customer (%)	12 Distribution Secondary Lines Demand (%)	13 Distribution Secondary Lines Customer (%)	14 Distribution Services Customer (%)	15 Distribution Meters Customer (%)	16 Distribution Street Lighting Customer (%)	17 Accounting Customer (%)	18 Specifically Assigned Customer (%)
	Generation																	
1	Hydraulic	100%	44.92%	55.08%														
2	Hydraulic - GNP	100%	44.92%	55.08%		0.0%												
3	Holyrood	100%	72.24%	27.76%														
4	Gas Tur Island Interconctd	100%	100.00%	0.00%														
5	Diesel Island Interconctd - GNP	100%	100.00%	0.00%		0.0%												
6	Dsl / Gas Tur Island Isolated	100%	43.90%	56.10%														
7	Dsl / Gas Tur Labrador Isolated	100%	34.26%	65.74%														
8	Dsl / Gas Tur L'Anse au Loup	100%	100.00%	0.00%														
9	Dsl / Gas Tur Labrador Interconctd	100%	100.00%	0.00%														
	Fuel																	
10	No. 6 Fuel	100%	0.00%	100.00%														
11	Gas Tur Island Interconctd	100%	100.00%	0.00%														
12	Diesel Island Interconctd - GNP	100%	100.00%	0.00%		0.0%												
13	Dsl / Gas Tur Island / Lab Isolated	100%	0.00%	100.00%														
14	Dsl / Gas Tur L'Anse au Loup	100%	0.00%	100.00%														
15	Dsl / Gas Tur Labrador Interconctd	100%	100.00%	0.00%														
	Transmission Lines & Terminals																	
16	Lines	100%		0.00%	100%													
17	Lines - Hydraulic	100%	44.92%	55.08%														
18	Lines - Customer Specific	100%																100%
19	Terminal Stations	100%		0.00%	100%													
20	Term Stns - Hydraulic	100%	44.92%	55.08%														
21	Term Stns - Holyrood	100%	72.24%	27.76%														
22	Term Stns - Gas Tur	100%	100%															
23	Term Stns - Diesel GNP	100%	100.00%	0.00%		0.0%												
24	Terminal Stations - Distribution	100%					100%											
25	Term Stns - Custmr Specific	100%																100%
26	Rural Lines	100%				100.0%												
27	Rural Terminal Stations	100%				100.0%												

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Functionalization & Classification Ratios (CONT'D.)

Line No.	1 Description	2 Total Amount (%)	3 Production Demand (%)	4 Production & Transmission Energy (%)	5 Transmission Demand (%)	6 Rural Prod & Transmission Demand (%)	7 Distribution Substations Demand (%)	8 Distribution Primary Lines Demand (%)	9 Distribution Primary Lines Customer (%)	10 Distribution Line Transformers Demand (%)	11 Distribution Line Transformers Customer (%)	12 Distribution Secondary Lines Demand (%)	13 Distribution Secondary Lines Customer (%)	14 Distribution Services Customer (%)	15 Distribution Meters Customer (%)	16 Distribution Street Lighting Customer (%)	17 Accounting Customer (%)	18 Specifically Assigned Customer (%)
	Distribution																	
28	Substation Structures & Equipment						100%											
29	Land & Land Improvements - by Sub-function:																	
30	Primary	85%						88.7%	11.3%									
31	Secondary	15%										58.3%	41.7%					
32	Land & Land Improvements	100%						75.4%	9.6%			8.7%	6.3%					
33	Poles - by Subfunction:																	
34	3 phase - Primary	41.2%						100.0%										
35	Other Primary	36.4%						45.7%	54.3%									
36	Secondary	22.4%										45.7%	54.3%					
37	Poles	100%						57.8%	19.8%			10.2%	12.2%					
38	Primary Condctr & Equip	100%						88.7%	11.3%									
39	Submarine Conductor	100%						100.0%										
40	Transformers	100%								36.1%	63.9%							
41	Secondary Condctr & Equip	100%										58.3%	41.7%					
42	Services	100%												100.0%				
43	Meters	100%													100.0%			
44	Street Lighting	100%														100.0%		
45	Customer Accounting	100%															100.0%	

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service

System Load Factor

Line No.	1	2	3	4	5	6
		Island Interconnected	**Island Isolated**	**Labrador Isolated**	**L'Anse au Loup**	**Labrador Interconnected**
1	Sales+Losses for System Load Factor (MWh)	7,238,900	7,646	44,912	24,953	2,676,900
2	Hours in Year	8,760	8,760	8,760	8,760	8,760
3	Average Demand (kW)	826,358	873	5,127	2,848	305,582
4	Coincident Peak at Generation (kW)	1,500,405	1,556	7,799	5,736	431,777
5	System Load Factor	55.08%	56.10%	65.74%	49.66%	70.77%

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Holyrood Capacity Factor

Line No.	1 Year	2 Net Production (kWh)	3 Net Capacity (MW)	4 Net Production Hours	5 Net Capacity Factor
1	**2011 Actual**	**885,313,869**	**466**	**8,760**	21.69%
2	**2012 Actual**	**855,826,207**	**466**	**8,784**	20.93%
3	**2013 Actual**	**957,442,307**	**466**	**8,760**	23.48%
4	**2014 Forecast**	**1,373,039,000**	**466**	**8,760**	33.67%
5	**2015 Forecast**	**1,592,992,000**	**466**	**8,760**	39.07%
6	5-Year Average	1,132,922,677	466	8,765	27.76%

NEWFOUNDLAND AND LABRADOR HYDRO
2015 Test Year Cost of Service
Total System
Power Purchases

Line No.		1	2	3	4	5	6	7	
		Total ($)	Production Demand ($)	Production & Transmission Energy ($)	Transmission Demand ($)	Rural Transmission Demand ($)	Distribution Demand ($)	Basis of Functional Classification
	Island Interconnected:							
1	DLP Secondary	-		-				Production - Energy (Same as RSP Sec Load Var)
2	AP Secondary	-		-				Production - Energy (Secondary)
3	Wheeling	693,003				693,003		Rural Transmission
4	Interruptible Demand	2,122,400	2,122,400	-				Production - Demand
5	Interruptible Energy	-		-				Production - Energy
6	Non-utility Generation excluding wind	42,562,239	19,120,793	23,441,445				Energy: System Load Factor
7	Wind Purchases	12,732,178		12,732,178				Production - Energy
8	**Subtotal**	**58,109,820**	**21,243,193**	**36,173,623**	**-**	**693,003**	**-**	
	Labrador Interconnected:							
9	CF(L)Co	1,856,851	542,700	1,314,151				Energy: System Load Factor
10	Other	-					-	
11	**Subtotal**	**1,856,851**	**542,700**	**1,314,151**	**-**	**-**	**-**	
	Isolated Systems:							
12	Mary's Harbour	-		-				Production - Energy
13	L'Anse au Loup	3,054,696		3,054,696				Production - Energy
14	Ramea Wind	232,400		232,400				Production - Energy
15	**Subtotal**	**3,287,096**	**0**	**3,287,096**	**0**	**0**	**0**	
16	**Total**	**63,253,767**	**21,785,893**	**40,774,870**	**-**	**693,003**	**-**	

Q. (Re: 2015 Interim Rates Application) The Alberta Utilities Commission has used a test to evaluate an interim rates application in *"ENMAX Power Corporation; 2015 Interim Distribution and Transmission Tariff Application "* dated November 12, 2014 (see http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-311.pdf). The test is identified below and includes two parts. The first part of the test relates to quantum and need for the rate increase and the second part of the test relates to the general public interest. Does Hydro's 2015 Interim Rates Application meet this test? Please elaborate the response, as applicable:

Part One

i. Is the identified revenue deficiency probable and material?

ii. Can all or some portion of any contentious items be excluded from the amount collected?

iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?

iv. Can the applicant continue safe utility operations without the interim adjustment?

Part Two

i. Do the interim rates promote rate stability and ease rate shock?

ii. Do the interim adjustments help maintain intergenerational equity?

iii. Can interim rate increases be avoided through the use of carrying costs?

iv. Are the interim rate increases required to provide appropriate price signals to customers?

v. Is it appropriate to apply the interim rider on an across-the- board basis?

A. As noted above, the Alberta Utilities Commission (AUC) has established a two-part test applicable to interim rate applications. It is the opinion of Hydro that its interim rate application dated January 28, 2015 meets the requirements of this test.

The first part of the test relates to quantum and need, and includes the following considerations:

i. Is the identified revenue deficiency probable and material?
ii. Can all or some portion of any contentious items be excluded from the amount collected?
iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
iv. Can the applicant continue safe utility operations without the interim adjustment?

The second part of the test relates to the public interest and includes the following considerations:

i. Will the interim rates promote rate stability and ease rate shock?
ii. Will the interim adjustments help to maintain intergenerational equity?
iii. Can the interim rate increases be avoided through the use of carrying costs?
iv. Are the interim rate increases required to provide appropriate price signals to customers?
v. Is it appropriate to apply the interim rider on an across the board basis?

Part I: Quantum and Need

(i) Is the identified revenue deficiency probable and material?

Yes.

As noted in Hydro's Amended Application, the continuation of 2007 base rates in 2015 would result in a net loss for Hydro of $34.6 million, and a return on rate base of 3.33%.[1] This loss would undoubtedly be material to Hydro and would result in a return on rate base materially lower than that approved in 2007 and proposed for 2015.[2]

Hydro's proposed interim rates would recover 2015 forecast test year costs if implemented on January 1, 2015 and provide the opportunity to earn a 2015 net income of $33.2 million. The difference in forecast 2015 net income between proposed rates and existing rates is $67.8 million. Delayed implementation to March 1, 2015, as reflected in the 2015 Interim Rates Application, will result in a forecast 2015 net income deficiency of approximately $20 million.[3] Therefore, approval of the proposed interim rates will permit Hydro the opportunity to recover approximately 70% of the forecast 2015 net income deficiency.[4] However, rate implementation on March 1, 2015 is currently uncertain given the current application review in progress.

[1] See Finance evidence, Schedule II, Page 1 of 1, Lines 34 and 43 of Hydro's Amended Application.
[2] Hydro's 2007 rate of return on rate base of 7.44% was approved by the Board in P.U. 8(2007).
[3] The net income deficiency is based upon the difference between revenue from existing and proposed base rates for 2015.
[4] $20 million net income deficiency represents approximately 30% of the $67.8 million forecast net income deficiency for 2015 under existing rates.

Approval of the proposed interim rates to become effective April 1, 2015 will permit Hydro to recover slightly less than 60% of the 2015 forecast net income deficiency.[5] The hearing on Hydro's Amended Application is not scheduled to start until September 2015 and final rates are not likely to be implemented at the earliest until December 1, 2015. In this scenario, Hydro's net income deficiency would be approximately $61 million.[6]

Hydro submits that delayed implementation of proposed rates for 2015 demonstrates that the identified net income deficiency is both probable and material.

(ii) Can all or some portion of any contentious items be excluded from the amount collected?

Exclusion of any costs reflected in the proposed rates will further increase the forecast 2015 net income deficiency proposed to be deferred for future recovery from customers.[7]

Approval of the proposed interim rates effective March 1, 2015 provides the opportunity to recover only 70% of the forecast net income deficiency for 2015 and a further delay in implementation on April 1, 2015 reduces the recovery percentage of the 2015 net income deficiency to slightly less than 60%. A 60% recovery of the

[5] $28 million net income deficiency represents approximately 41% of the $67.8 million forecast net income deficiency for 2015 under existing rates.
[6] The actual 2015 net income shortfall will be finalized upon the Board's determination of the final 2015 Test Year revenue requirement and customer rates.
[7] In the Amended Application dated November 10, 2014, Hydro proposed a deferral account to provide recovery of the 2015 net income deficiency that results from delayed rate implementation.

forecast net income deficiency provides a forecast net income for 2015 of approximately $5.2 million.[8]

Given the 2015 forecast net income if proposed interim rates are approved effective either March 1, 2015 ($13.2 million) or April 1, 2015 ($5.2 million), Hydro does not believe it is appropriate to make further adjustments to reduce 2015 Test Year revenue requirement for the purpose of establishing interim rates. Delayed implementation also further exacerbates intergenerational equity concerns by increasing the amount of historical costs to be recovered from customers in future years.

If upon final testing of 2015 costs, the Board determines that 2015 cost adjustments are required, then these amounts would be applied to reduce the 2015 net income deficiency to be recovered through customer rates in future years. Hydro's proposed approach ensures (i) customers do not pay rates in 2015 that exceed the cost of providing service in 2015, and (ii) the amount of 2015 costs to be recovered from customers in future years is minimized.

<u>(iii) Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?</u>

Yes.

The 2013 GRA filed in July 2013 proposed new rates to become effective January 1, 2014. There has been no change in base rates yet approved for any customers with the exception of the Labrador transmission rate approved on an interim basis

[8] $5.2 million = $33.2 million forecast net income if rates were in effect for the full year less the $28 million net income impact if proposed rates are not implemented until April 1.

effective January 1, 2015. The Board has approved a $45.9 million deferral account to provide the opportunity to recover the 2014 net income deficiency in the future, subject to the Board's prudency review. Delayed approval of new interim rates for 2015 is creating another material net income deficiency for 2015. The cumulative effect of delayed rate implementation from January 1, 2014 to March 1, 2015 is an under-recovery from customers of approximately $66 million in costs (excluding No. 6 fuel, which is recovered through the RSP).

The impact of a continued denial of the Board to permit cost recovery on Hydro's creditworthiness needs to be considered over the longer-term. Because the Province has unconditionally guaranteed Hydro's existing long-term debt, there is a direct linkage between Hydro's creditworthiness, which is influenced by Hydro's ability to achieve financial targets consistent with an investment-grade utility, and the credit rating of the Province. To the extent that credit rating agencies continue to view Hydro to be self-supporting, then the Province's credit rating is not likely to be affected. A poor financial position for Hydro over the long-term could adversely impact the Province's credit rating and thereby, increase the borrowing costs of the Province, and hence Hydro's own borrowing costs.

The Government directive on Hydro's return on equity being set to equal that approved for Newfoundland Power along with the $100 million equity contribution in 2009 would imply an expectation that Hydro should maintain a strong stand-alone financial position and performance. If Hydro's Interim Rates Application is not approved, Hydro could incur a $34.6 million net loss for 2015 unless the Board approves a deferral account to provide for recovery of the 2015 net income deficiency resulting from delayed rate implementation. Hydro's 2015 financial forecast under existing rates is inconsistent with the notion of a self-supporting entity.

The approval of the proposed interim increase in base rates will reduce financial uncertainty for 2015. Board approval of new customer rates to recover 2015 revenue requirement is necessary to preserve Hydro's financial integrity and to avoid potential long term hardship to both Hydro and ratepayers through increased long-term borrowing costs.

(iv) Can the applicant continue safe utility operations without the interim adjustment?

Yes. However, if the 2015 Interim Rates Application is not approved and Hydro is not provided certainty of recovering the 2015 net income deficiency, then Hydro must plan to minimize its financial losses in 2015. Absent other information, Hydro's 2015 financial forecast without interim rates signals a fiduciary obligation to cut costs.

While Hydro is always seeking ways to minimize costs, it does not think it would be prudent, practical or safe to reduce costs to the magnitude of the net income deficiency.

Part II: Public Interest Factors

(i) Will the interim rates promote rate stability and ease rate shock?

Yes.

The proposed interim rates would avoid confusion for retail customers. The 2015 Interim Rate Application includes a proposal to reflect the material reduction in 2015 fuel costs which would normally be implemented on July 1, 2015 at the same

time as implementing new customer base rates to provide increased income to Hydro for 2015. This proposal should be less confusing for customers than implementing two rate changes over a very short time period.[9]

The Industrial Customer (IC) Group indicated that the proposed interim rates reflected in the Amended Application constituted rate shock. The phase-in approach of Island IC rates provided in the 2015 Interim Rates Application appears to address the IC Group concerns with respect to rate shock.

In addition, delayed implementation of Hydro's 2015 base rates would further increase amounts that Hydro will propose for deferred recovery from customers.[10] Not only could this add to any potential rate increase relating to Hydro's 2015 net income deficiency, it further compounds the issue of intergenerational equity, which will be discussed in Part II(ii).

<u>(ii) Will the interim adjustments help to maintain intergenerational equity?</u>

Yes.

Approval of the 2015 Interim Rates Application will help maintain intergenerational equity. The 2015 Interim Rates Application proposes to use the IC RSP Surplus balance and the 2014 year-end credit balance in the RSP load variation component

[9] If the 2015 Interim Rates Application is not approved, customer rates will decrease in July and subsequently increase to reflect the GRA final rates order.
[10] On December 24, 2014, the Board issued order number P.U. 58(2014), approving the deferral of $45.9 million with respect to Hydro's 2014 revenue requirement.

to provide recovery of the $6.8 million year-end RSP balance owing from Island IC. The proposed approach is consistent with maintaining intergenerational equity.[11]

If the 2015 Interim Rates Application is not approved, there is a substantial risk that customers' rates for 2015 will not reflect the costs associated with the service provided in that period. In this circumstance, 2007 base rates will be in place for much and potentially all of 2015. Rates charged to customers in 2014, and now potentially 2015, will not accurately reflect the costs associated with the service provided in that period. Denying Hydro's 2015 Interim Rates Application will further increase the 2015 net income deficiency and place an increased cost burden on future customers to fund recovery of costs incurred in previous years.

As noted in evidence filed by Newfoundland Power, in their 2011 Sale of Joint Use Support Structures application[12], *"As time passes, the makeup and usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the intergenerational equity principle… cost deficiencies should be recovered over as short a period as is reasonable, so the customer group that eventually pays for the costs is similar to the one benefiting from the costs."* Hydro submits this concept is particularly relevant with respect to 2015 interim rates. The greater the delay with respect to Hydro's 2015 base rate implementation, interim or otherwise, the greater the concern with intergenerational equity.

[11] See page 6 to the Evidence of the 2015 Interim Rates Application.
[12] Newfoundland Power, Sale of Joint Use Support Structures, Consent #2, the Report of J.T. Browne Consulting, Appendix 3, Page 4 of 4.

(iii) Can interim rate increases be avoided through the use of carrying costs?

This is not a reasonable approach in the current circumstances. Carrying costs do nothing to address the underlying problem, namely the existence of a significant net income deficiency that must be recovered from customers because customer base rates do not recover the cost to provide service.

As stated earlier, Hydro filed its GRA in July 2013 for new base rates to become effective January 1, 2014. Further delay in implementing new customer rates on an interim basis will only increase the cost recovery burden to be imposed on future customers upon final rates being established.

(iv) Are the interim rate increases required to provide appropriate price signals to customers?

Yes.

Hydro's forecasted price of No. 6 fuel used for generation at the Holyrood Thermal Generation Station has decreased materially for 2015. Blending Hydro's base rate increase with savings on No. 6 Fuel will reduce the number of required rate changes in 2015 and potential rate confusion for customers.

(v) Is it appropriate to apply the Distribution interim rate increase on an across the board basis?

Rate changes to customers of Newfoundland Power will be determined in accordance with Board-approved rate design for Newfoundland Power customers.

The proposed interim rate increase to Labrador Interconnected customers is proposed on an across the board basis, with the exception of the proposed rates for Street and Area lighting.

Conclusion

Hydro submits that the 2015 Interim Rates Application meets the two-part test originally established by the AUC for consideration of interim rate adjustments. Hydro has shown that the net income deficiency for 2015 is both probable and material.

Approval of the proposed interim rates will provide an approximate 70% recovery of the 2015 forecast net income deficiency if implemented on March 1, 2015 and a recovery of slightly below 60% if implemented April 1, 2015. A 60% recovery of the 2015 forecast net income deficiency provides a forecast net income for 2015 of approximately $5.2 million.

Hydro does not believe it is appropriate to make further adjustments to reduce 2015 Test Year revenue requirement for the purpose of establishing interim rates. If upon final testing of 2015 costs, the Board determines that 2015 cost adjustments are required, then these amounts would be applied to reduce the 2015 net income deficiency to be recovered through customer rates in future years.

The proposed interim rates will add rate stability for 2015, enable the phase-in of Island IC rates with materially lower customer impacts and help mitigate intergenerational equity concerns caused by delayed rate implementation. Delayed implementation of Hydro's 2015 base rates will further increase net income

deficiency proposed for recovery from customers upon establishment of final customer rates.

Approval of Hydro's 2015 Interim Rates Application provides a reasonable balance of the interests of both the utility and its customers.

Q. (Re: 2015 Interim Rates Application) Please provide a table identifying the following: 1) Hydro 's proposed revenue requirement for 2015; 2) the amount of revenue expected to be collected in 2015 under current rates; 3) the amount of revenue expected to be collected under the rates proposed in the 2015 Interim Rates Application if these rates were implemented retroactively to January 1, 2015; and 4) the amount of revenue expected to be collected under the rates proposed in the 2015 Interim Rates Application if these rates were implemented as proposed on March 1, 2015.

A. Please see TIR-CA-NLH-002 Attachment 1.

Newfoundland and Labrador Hydro
Revenue and Revenue Requirement Restated for Reforecasted No. 6 Fuel Cost

Line No.	Table 1	($000)	
1	2015 Revenue Requirement	$ 583,917	[1]
2	2015 Revenue: Current Rates	$ 520,329	[2]
3	2015 Revenue: Interim Rates Effective January 1	$ 583,911	[2]
4	2015 Revenue: Interim Rates Effective March 1	$ 570,261	[2]

Notes:

[1] Revenue requirement of $661,394,670 from Hydro's November 2014 Amended GRA Application, Volume 2, Exhibit 13, Page 1 of 109, Column 2 Line 25, less an adjustment for No. 6 Fuel Cost of $72,668,833 from Hydro's January 2015 Interim Rates Application, Appendix B, Page 1 of 1, Column B Line 10, and an adjustment of $4,809,223 for change in the Rural Deficit due to the change in No. 6 Fuel Cost. Any difference remaining between row 1 and 3 is due to rate rounding.

[2] As per Hydro's response to TIR-CA-NLH-003.

Q. (Re: 2015 Interim Rates Application Evidence) Please provide a table comparing Hydro's 2015 revenue, net income and return on rate base assuming Board approval of interim rates under the following scenarios: 1) as proposed in the 2015 Interim Rates Application with rates effective January 1, 2015; 2) as proposed in the 2015 Interim Rates Application with rates effective March 1, 2015; 3) assuming rates effective January 1, 2015 based on the current Board-approved rate of return; 4) assuming rates effective January 1, 2015 with all costs that have been identified by the Board as being subject to prudency review removed from the revenue requirement; and 5) assuming rates effective January 1, 2015 with 50% of all costs that have been identified by the Board as being subject to prudency review removed from the revenue requirement.

A. Please see the following table. In providing this response, Hydro revised revenue from energy sales, net income, and percentage return on rate base based on the scenarios identified above.

$000s	**Part 1**	**Part 2**	**Part 3**	**Part 4** [1]	**Part 5** [1]
Rates Effective	*January 1, 2015*	*March 1, 2015*	*January 1, 2015*	*January 1, 2015*	*January 1, 2015*
Scenario	*Proposed interim rates*	*Proposed interim rates*	*4.47% ROE*	*100% of 2015 prudency costs removed*	*50% of prudency costs removed*
Revenue from Energy Sales	583,911	570,261	566,687	575,901	579,611
Net Income	33,911	14,026	16,687	21,211	27,266
Return on Rate Base %	6.85%	5.75%	5.90%	6.67%	6.75%

[1] For Parts 4 and 5 of the table, only those costs identified in the prudency review for 2015 have been removed. For items classified as capital, opening and closing average rate base have been adjusted.

Q. (Re: 2015 Interim Rates Application Evidence) Please provide a table comparing Hydro's 2015 revenue, net income and return on rate base assuming Board approval of interim rates effective January 1, 2015 based on the following percentages of the 2015 revenue requirement proposed for 2015 in the Amended 2013 GRA: 50%, 60%, 75%, 90% and 100%.

A. Please see the following table. In each scenario, Hydro has calculated revised revenue requirements by applying the percentage of change between the revenue computed based on existing base rates and the revenue proposed for 2015 (i.e., [2007 Base Rates + [[2015 Test Year Rates – 2007 Base Rates] * Percentage Noted]]).

$000s	**Revenue Requirement Adjustment**				
Interim Rates Effective % of 2015 revenue requirement	*January 1, 2015 50%*	*January 1, 2015 60%*	*January 1, 2015 75%*	*January 1, 2015 90%*	*January 1, 2015 100%*
Revenue from Energy Sales	552,120	558,478	568,015	577,553	583,911
Net Income	2,120	8,478	18,015	27,553	33,911
Return on Rate Base %	5.09%	5.44%	5.97%	6.50%	6.85%

Q. (Re: 2015 Interim Rates Application Evidence) Please extend Table 5 (page 16) to show the cases assuming the Board approves interim rates effective January 1, 2015 that recover 50%, 60%, 75% and 90% of the 2015 revenue requirement proposed in the Amended 2013 GRA.

A. The revised table is provided in TIR-CA-NLH-005 Attachment 1. In providing the response, Hydro revised the customer impacts provided in the 2015 Interim Rates Application to reflect the requested percentage adjustments to the change in revenue requirement from existing rates to the proposed interim rates.

Newfoundland and Labrador Hydro
Revenue Requirement Recovery Scenarios

Line No.		A	B	C	D	E	F
		2015 Proposed Customer Rate Impacts					
		Amended Application	**2015 Interim Application**	**% Recovery of Interim Base Rate Rev. Increase**			
				90%	**75%**	**60%**	**50%**
	Island Interconnected System						
1	Newfoundland Power – Utility rate	4.1%	-9.3%	-10.3%	-11.8%	-13.2%	-14.2%
2	Estimated end consumers rate impact	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
3	Estimated rural consumers rate impact	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
4	Industrial Customers	39.2%	18.1%	16.3%	13.6%	10.9%	9.0%
	Island Isolated systems						
5	Domestic	7.1%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
6	General Service 0-10	18.5%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
7	General Service Over 10 kW	19.2%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
8	Street and Area Lighting	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
	Island Isolated - Gov. Departments						
9	General Service 0-10	24.7%	16.6%	14.9%	12.4%	10.0%	8.3%
10	General Service Over 10 kW	25.4%	16.9%	15.2%	12.7%	10.1%	8.5%
11	Street and Area Lighting	27.5%	27.5%	24.8%	20.6%	16.5%	13.8%
	Labrador Interconnected System						
12	Domestic	1.9%	1.9%	1.7%	1.4%	1.1%	0.9%
13	General Service 0-10	1.9%	1.9%	1.7%	1.4%	1.1%	0.9%
14	General Service 10 100 kW	1.9%	1.9%	1.7%	1.4%	1.1%	0.9%
15	General Service 110 1000 kVA	1.9%	1.9%	1.7%	1.4%	1.1%	0.9%
16	General Service 1000 kVA and Over	1.9%	1.9%	1.7%	1.4%	1.2%	1.0%
17	Street and Area Lighting	17.5%	17.5%	15.8%	13.1%	10.5%	8.8%
	Labrador Isolated Systems						
18	Domestic	7.1%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
19	General Service 0-10	18.5%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
20	General Service Over 10 kW	19.2%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
21	Street and Area Lighting	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
	Labrador Isolated - Gov. Departments						
22	Domestic	21.5%	14.0%	12.6%	10.5%	8.4%	7.0%
23	General Service 0-10	24.7%	16.6%	14.9%	12.4%	10.0%	8.3%
24	General Service Over 10 kW	25.4%	16.9%	15.2%	12.7%	10.1%	8.5%
25	Street and Area Lighting	27.5%	27.5%	24.8%	20.6%	16.5%	13.8%
	L'Anse au Loup System						
26	Domestic	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
27	General Service 0-10	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%
28	Street and Area Lighting	2.8%	-6.3%	-6.9%	-7.9%	-8.9%	-9.6%

Note:

Column A reflects Amended Application, Column B reflects 2015 Interim Rates Application, Columns C through F represent the percentage recovery of the difference in revenue at existing rates and revenues at the proposed rates in Hydro's 2015 Interim Rates Application.

Q. (Re: 2015 Interim Rates Application Evidence) If during the review of the Amended 2013 GRA the Board decides that there are costs that are not to be passed through to consumers, how does Hydro propose that consumers receive cost/rate reductions if the Board has approved the interim rates as proposed in the 2015 Interim Rates Application?

A. Once the GRA has been completed and the Board has determined if costs are to be removed from revenue requirement, Hydro proposes a two step process for the finalization of customer rates for 2015:

(i) New rates would be implemented on a prospective basis to reflect the final 2015 revenue requirement adjusted to remove any costs that are not to be passed through to customers. This approach would ensure prospective rates reflect Board approved 2015 Test Year costs.

(ii) The 2015 forecast net income deficiency resulting from delayed implementation would be recalculated using the 2015 final rates for the period of delayed implementation.

In establishing final rates, the Board would also need to consider the approach to recovering the 2015 net income deficiency. This could be achieved though the implementation of a rate rider calculated separately from base rates or by increasing base rates to reflect an amortization of the amount to be recovered.

Q. (Re: 2015 Interim Rates Application Evidence) Is Hydro aware of cases in this Province where the Board has gone back and adjusted interim rates after the fact? Please elaborate.

A. Yes.

AUR Resources Interim Rates Refund

On January 20, 2006, the Board issued Order No. P.U. 1(2006), approving, on an interim basis, rates for AUR Resources which included the Historical Plan Balance portion of the Rate Stabilization Plan (RSP), a specifically assigned charge of $150,000, and a demand charge which for 2006 was based upon the highest firm demand in the month.

In Order No. P.U. 1(2007), the Board approved that final 2006 rates, rules and regulations for AUR Resources Inc. should be similar to those of the other Island Industrial Customers of Hydro except that:

i) for 2006 the demand charge should be based on the highest firm demand in the month;
ii) rates should exclude the historical plan balance of the RSP; and
iii) until a new full cost of service study is completed and reviewed, rates should not include a specifically assigned charge.

The Board approved a refund or credit to AUR Resources Inc., of the difference for 2006 between the approved final rates and those approved in Order No. P.U. 1(2006).[1]

NP 1998-99 Cost of Capital Review

On November 10, 1997, pursuant to Section 82 of the *Public Utilities Act*, the Board commenced an investigation on its own motion into the cost of capital reflected in the rates of Newfoundland Power (NP). The rates at the time were approved as final based upon a 1997 Test Year. On November 21, 1997, the Board received correspondence from the City of St. John's requesting that a hearing be held to set rates for 1998 and beyond.

Upon conclusion of the preliminary investigation, the Board ordered a hearing into the matter of rate of return and capital structure for NP. The commencement of a hearing on the appropriate cost of capital for 1998 effectively made NP's customer rates interim effective January 1, 1998.

In Order No. P.U. 16(1998-99) dated July 31, 1998 as a result of the cost of capital hearing, the Board approved interim rate adjustments to the rates that were in effect for billing customers for the period January 1, 1998 to August 31, 1998. Refunds were paid to customers to reflect the reduced cost of capital approved in the Board's order. The Board also did a further review of the reasonableness of the adjusted interim rates in NP's 1998 fall hearing. The review conducted during the NP GRA in the fall determined no further adjustment was required.

Excerpts from Order No. P.U. 16(1998-99) are provided below:[2]

[1] Schedules B and C to Order P.U. 1(2007) provide the final rates for AUR Resources for 2006.

The Company will be ordered to submit adjusted rates to be effective January 1, 1998, based upon the allowed rate of return on rate base of 9.91% for the 1997 test year. The rate of return on rate base for 1998 will be finalized following the Fall 1998 hearing.

The Board will be ordering a reduction in rates for 1998. The rate adjustment will be effected under Section 75 of the Act, and will be interim rates. The Board will be ordering that this rate adjustment be reflected in monthly bills with effect from September 1st, 1998, and that refunds be paid to consumers before October 31, 1998 to reflect the rate reduction for the period January 1st, 1998 to the date of their last billing in the month of August. The rate adjustment will apply to power consumed on or after January 1, 1998 and without any adjustment for the one-half month revenue recognition lag. Rate adjustments are to be made without any adjustment of revenue to cost ratios for the different rate classes.

[2] See pages 101-102 of Order No. P.U. 16(1998-99).

Q. (Re: 2015 Interim Rates Application Evidence) Based on past experience, how long has it taken Newfoundland Power to pass through to its customers cost increases/decreases owing to changes in Hydro's Utility Rate?

A. Based upon the implementation period required as a result of Hydro's 2006 General Rate Application (GRA), the process of revising customer rates to reflect a new Utility rate can proceed quickly if Newfoundland Power starts the implementation process early.

In 2006, Hydro filed a revised GRA dated December 6, 2006 ("Hydro's Revised Application") which proposed, among other things, (i) increased purchased power costs for Newfoundland Power, and (ii) a revised RSP adjustment, both to be effective January 1, 2007. Newfoundland Power, in turn, filed an application with the Board on December 8, 2006 for approval of revised customer rates to be effective January 1, 2007.

In Order No. P.U. 41(2006), issued on December 14, 2006, the Board approved the 2007 Utility rate proposed in Hydro's Revised Application on an interim basis to be effective January 1, 2007. The Board also issued Order No. P.U. 42(2006) on December 14, 2006 approving revised Newfoundland Power customers rates on an interim basis to become effective January 1, 2007.

Hydro observes that the 2015 Interim Rates Application was filed January 28, 2015 requesting implementation March 1, 2015. Hydro believes the filing date provides Newfoundland Power adequate time to complete the flow-through process in order

to be capable of implementing new customer rates to become effective March 1, 2015.

Q. (Amended 2013 GRA) On page 420 (lines 1 to 2) it is stated *"Delayed implementation beyond January I, 2015 will result in continuing growth in the forecast $8 million current RSP balance due from the IC at December 31, 2014".* On March 1, 2015, what will be the amount of the RSP balance due from the ICs, and how much of it will be attributable to Teck Resources? Given that Teck Resources is expected to close operations in June 2015, what avenues are available to Hydro for collecting any revenue shortfall from Teck Resources, and how does Hydro propose to recover any Teck Resources revenue shortfall from other customers? Please show the expected impact on each customer class of any revenue shortfall not recovered from Teck Resources and comment on inter-generational equity issues.

A. The amount of the RSP current balance due from the Island IC on March 1, 2015 is dependent upon the approved approach to recover the 2014 year-end Island IC RSP balance. As outlined in Hydro's 2015 Interim Rates Application, the actual December 31, 2014 closing IC RSP balance was $6.8 million[1]. Hydro has proposed to reduce the balance owing by $2.1 million by applying the IC prorated share of the credit balance in the RSP load variation component as at December 31, 2014, leaving a net balance owing of $4.7 million.[2] In its 2015 Interim Rates Application, Hydro also proposed a one-time transfer using a portion of the IC RSP Surplus balance of $10.9 million at December 31, 2014 to provide full recovery of the 2014 year-end RSP current balance. The proposed approach to recovery of the 2014 year-end RSP current balance limits inter-generational equity concerns with respect to the closure of Teck Resources.[3]

[1] See 2015 Interim Rates Application, Appendix A, page 11.
[2] The segregated load variation balance as at December 31, 2014 was $35.5 million, IC share based on year-to-date energy sales is 5.8% or $2.1 million.
[3] See pages 4 to 6 of the Evidence to the 2015 Interim Rates Application.

If the Board approves Hydro's proposals for the recovery of the 2014 year-end IC RSP current balance and implements interim IC rates reflecting the 2015 Test Year adjusted for the revised fuel forecast, then the RSP is proposed to operate for 2015 based upon the 2015 Test Year forecast. As a result, under Hydro's proposals there is currently no forecast balance due from the Island IC as of March 1, 2015.

Q. Please provide revised version of Table 2 **(page 9, 2015 Interim Rates Application Evidence)** using 2016 forecast billing determinants for the "January 1, 2016" and "September 1, 2016" columns.

A. Please see the revised version of Table 2 below which reflects the IC phase-in rate impacts for the proposed approach reflected in the 2015 Interim Rates Application using 2016 forecast billing determinants as requested.

Table 2 – Revised
Interim Rates Application - IC Rate Impacts

	March 1, 2015	**January 1, 2016[1]**	**September 1, 2016[2]**
Island IC rate impacts	2.7%	6.9%	9.7%

[1] 2016 billing determinants at existing rates vs 2016 billing determinants at proposed 2015 Test Year rates with 60% RSP Surplus Credit for 12 months.
[2] 2016 billing determinants at proposed 2015 Test Year rates with 60% RSP Surplus Credit for 12 months vs 2016 billing determinants at proposed 2015 Test Year rates with no RSP Surplus Credit.

Q. Please provide revised versions of Table 2 and Table 3 **(page 9, 2015 Interim Rates Application Evidence)** assuming the IC RSP current plan balance of $6.8 million by end of 2014 would be recovered over a two-year period as proposed by Hydro in the 2013 Amended GRA Application **(Section 4.6.5: Phase-in of Island Industrial Customer Rates).**

A. The two-year RSP balance amortization was proposed in Hydro's Amended Application to reduce the customer impacts of phasing in the proposed 39.2% base rate increase. As outlined in Hydro's 2015 Interim Rates Application, the proposed 2015 Test Year base rate increase for the Island IC has decreased to 18.1% as a result of the lower No. 6 fuel forecast (i.e., $93.32/bbl vs $65.63/bbl). If the IC RSP Surplus is not used to provide at least partial recovery of the IC RSP current plan balance at end of 2014, there would be approximately $1 million funds remaining in the IC RSP Surplus balance as at August 31, 2016.[1] Therefore, the scenario presented is not a viable option.

Hydro's response to TIR-IC-NLH-004 provides the revised Tables 2 and 3 if Board approval is not granted for the disposition of the load variation balance at year-end 2014 and $6.8 million (rather than the proposed $4.7 million) is fully funded through the IC RSP Surplus.

[1] This assumes 100% RSP Surplus Credit Adjustment for the period March 1, 2015 to August 31, 2016.

Q. Please confirm that the updated fuel price will also have impact to the rate base through lower fuel inventory cost.

A. It is so confirmed. Please see Hydro's response to TIR-NP-NLH-008.

Q. Please provide revised versions of Tables 2 and 3 **(page 9, 2015 Interim Rates Application Evidence)** and a comparison of the rates being sought for Newfoundland Power (NP) and IC for March 1, 2015 for each of the following scenarios:

a. Hydro's proposal per the January 28, 2015 Interim Rate Application.

b. An alternative scenario where only $2.1 million of the load variation credit is allocated to the IC and no other allocation of the deferred load variation is undertaken at this time (i.e., the remainder stays as a segregated, deferred balance in the RSP). All other proposals as per Hydro's interim rate application.

c. An alternative scenario where no allocation of the load variation credit in the RSP is undertaken at this time.

A. Under scenario (b), the proposed 2015 Test Year base rates for the Industrial Customers (IC) and Newfoundland Power (NP) would be consistent with the 2015 Interim Rates Application.[1] The proposed IC base rate phase-in would also not be impacted. Modifying Hydro's proposal with regard to the deferred load variation balance would impact the NP July 1, 2015 RSP adjustment rate which Hydro is currently proposing to suspend until the Board rules on final rates.[2]

Under scenario (c), the proposed 2015 Test Year base rates for the IC and NP would also be consistent with the 2015 Interim Rates Application. However, the proposed IC phase-in approach would need to be modified to account for the additional $2.1

[1] See Section 2.5, page 10 and Section 3.2, page 12 and 13 of the 2015 Interim Rates Application for a summary of proposed 2015 Test Year base rates for the Island IC and NP, respectively.

[2] An additional $33 million transfer from the deferred load variation at year-end 2014 would permit the existing RSP recovery adjustment to continue until the end of June 2016 without resulting in a large balance owing from NP customers.

million balance owing at the end of 2014.[3] For the purpose of this requested scenario, Hydro has assumed the recovery of the $6.8 million balance owing from the IC at the end of 2014 from the IC RSP Surplus. The remainder of the IC RSP Surplus to is applied to fund RSP Surplus Credit Adjustments of 70% for the period March 1, 2015 to December 31, 2015 and 30% for the period January 1, 2016 to August 31, 2016.

See the revised versions of Tables 2 and 3 reflecting the requested scenario.

Table 2 – Revised
Interim Rates Application - IC Rate Impacts [4]

Scenario	March 1, 2015	January 1, 2016	September 1, 2016
No disposition of load variation	5.5%	6.9%	4.8%

Table 3 - Revised
Forecast IC RSP Surplus Drawdown Balances ($millions)

Scenario	March 1, 2015	January 1, 2016	September 1, 2016
No disposition of load variation	4.2	1.1	0.2

In the 2015 Interim Rates Application, Hydro has proposed disposition of the $35.5 million load variation balance at the end of 2014 using an energy ratio allocation. Hydro believes it is reasonable to apply the $2.1 million IC portion of this balance to reduce the customer rate impact of recovering the $6.8 million RSP current balance due from IC. The 2015 Interim Rates Application reflects this proposal.

[3] In the Interim Rates Application, Hydro has proposed to use $2.1 million from the deferred load variation balance to offset a portion of the $6.8 million IC RSP balance owing at the end of 2014.
[4] Teck Resources is scheduled to close operations in 2015.

Board approval of the proposed disposition of the segregated RSP load variation component, effective December 31, 2014, would reduce the IC RSP current balance to $4.7 million due from customers (i.e., $6.8 million less $2.1 million). The remainder of the $35.5 million segregated RSP load variation balance would flow through the RSP for disposition to retail customers, resulting in a credit of approximately $33 million to the NP RSP current balance. This credit balance transfer of $33 million, effective year-end 2014, would permit the existing RSP recovery adjustment to continue until the end of June 2016 without resulting in a large RSP balance owing from customers. This approach supports the proposed suspension of the NP RSP adjustment scheduled for July 1, 2015.

Q. Please provide an estimate of the division of the current deferred load variation balance between customer classes under the following scenarios:

a. Divided based on energy ratios for 2015 forecast consumption.

b. Divided based on a first allocation to eliminate any negative balances in the RSP as at December 31, 2014 (amounts owing from customers) and the remainder allocated based on 2015 forecast energy ratios.

c. Divided based on the same ratio as the Government directed allocation of the pre-Sept 2013 load variation balance.

d. Divided only to address RSP negative balances as of Dec 31, 2014, and the remainder used for common benefit of Hydro's customers to address rate impacts not yet addressed as part of the GRA base rates (e.g., 2014 revenue deficiency, 2015 shortfalls for January and February, COM balances otherwise proposed to be collected via rider, reliability hearing and capacity assistance costs not yet proposed for recovery that are expected to be recovered through future riders, etc.).

A. Please see TIR-IC-NLH-005 Attachment 1 for estimates of the division of the current deferred load variation balance between customer classes under the following scenarios:

a. Dividing the historic load variation balance as at December 31, 2014 of $35.5 million between classes using 2015 forecast consumption data rather than historic consumption data as proposed in the Amended Application and 2015 Interim Rates Application;

b. Dividing the historic load variation balance as at December 31, 2014 of $35.5 million between classes by first eliminating the $6.8 million IC RSP

balance owing[1] and then using 2015 forecast consumption data to allocate the remaining balance;

c. Dividing the historic load variation balance as at December 31, 2014 of $35.5 million between classes using the same Government directed allocations used for the pre-September 2013 segregated load variation;[2] and

d. Using the historic load variation balance as at December 31, 2014 of $35.5 million to provide recovery of the $6.8 million IC RSP balance owing from IC and providing no further disposition at this time.

In the 2015 Interim Rates Application, Hydro has proposed to allocate the year-end 2014 load variation between customer groups based on 12 months-to-date energy sales. This method will allocate the net cost effect of load variation on a basis consistent with the manner that fuel cost variation is currently allocated in the RSP. The proposed method is also consistent with the cost allocation effects of changes in load in a Test Year Cost of Service Study.

Hydro does not believe that any of the proposed scenarios presented in this request for information provide an allocation basis that is consistent with the principle of cost causality reflected in the current RSP approach for disposition of fuel cost variances.

[1] Newfoundland Power (NP) closing RSP balance for 2014 was credit of ($39 million).

[2] Per Government Order-in-Council, the total August 31, 2013 segregated load balance accumulated since January 2007 of $161 million was first applied to the IC August 31, 2013 closing RSP balance of $38 million and an additional $10.9 million was set up as separate balance to phase-in base IC rates (IC RSP Surplus). The remaining $112 million was allocated to an NP RSP Surplus account.

Allocation of Deferred Load Variation by Customer Group ($millions)

Line No.		A As Filed[1]	B Scenario a	C Scenario b	D Scenario c	E Scenario d	Reference
1	December 31, 2014 Load Variation	(35.5)	(35.5)	(35.5)	(35.5)	(35.5)	December 2014 RSP Report, page 12
2	Adjusted for any RSP Customer Balance owing	-	-	6.8	-	6.8	December 2014 RSP Report, page 11
3	Adjusted Load Variation Balance	(35.5)	(35.5)	(28.7)	(35.5)	(28.7)	
4	Newfoundland Power before Rural allocation	(30.9)	(30.0)	(24.2)	(24.7)	-	
5	Island IC	(2.1)	(3.1)	(2.5)	(10.8)	-	
6	Rural	(2.5)	(2.3)	(1.9)	-	-	
7	Total	(35.5)	(35.5)	(28.7)	(35.5)	-	
	Rural allocation[2]						
8	Newfoundland Power	(2.4)	(2.2)	(1.8)	-	-	
9	Labrador Interconnected	(0.1)	(0.1)	(0.1)	-	-	
		(2.5)	(2.3)	(1.9)	-	-	
10	Newfoundland Power including Rural allocation	(33.3)	(32.2)	(26.1)	-	-	Line 4 + Line 8
11	Island IC	(2.1)	(3.1)	(2.5)	-	-	Line 5
12	Labrador Interconnected	(0.1)	(0.1)	(0.1)	-	-	Line 9
13	Total	(35.5)	(35.5)	(28.7)	-	-	

[1] Allocated based on 12 months-to-date energy sales in accordance with RSP Rules approved by the Board.

[2] Balance initially allocated to Rural Customers is reallocated between NP and Labrador Int based on Test Year rural deficit allocation.

Q. Please confirm that an interim order of the Board that approves only (a) a $2.1 million allocation of the deferred load variation provision to the IC, (b) the one-time transfers of IC phase-in funds as proposed by Hydro, and (c) a suspension of the NP RSP fuel rider as of March 1, 2015, gives the same rate impact outcomes as sought by Hydro with fewer allocation commitments by the Board at this time.

A. Approval of the proposals provided above would not provide the same customer rate impacts as the proposals included in the 2015 Interim Rates Application. For example, the suspension of the Newfoundland Power (NP) fuel rider does not suspend the update to the RSP recovery rider. Hydro also proposed disposition of the balance in the RSP segregated load variation balance effective December 31, 2014. Approval of the proposed disposition would result in a credit of approximately $33 million to the NP RSP current balance. The proposed transfer would permit the existing RSP recovery adjustment to continue until the end of June 2016 without resulting in a large RSP balance owing from customers.

Hydro believes the Board should follow a principled approach in making decisions on the proposals provided in the 2015 Interim Rates Application. Hydro respectfully submits that the Board should consider the reasonableness of the end result when evaluating the proposals in the 2015 Interim Rates Application.

Q. That Newfoundland Labrador Hydro provide information on electricity rates for various customer categories and types of charges as specified in the chart below for: a) 2014 rates and charges; b) projected 2015 rates under the 2015 Interim Rate Application; and c) electricity rates and charges in a scenario assuming the 2015 Interim Rate Application structure and 2014 average diesel fuel prices.

For purposes of consistency, all rates / charges presented shall: a) include all municipal taxes and applicable rate stabilization adjustments; b) shall not include HST;

CUSTOMER CATEGORY/CHARGE TYPE	2014 Electricity Rates/Charges	Projected 2015 Electricity Rates/ Charges Under the 2015 Interim Rate Application	Electricity Rates/ Charges Rate in a Scenario Assuming 2015 Interim Rate Application Structure & 2014 Average Diesel Fuel Prices
DOMESTIC DIESEL CATEGORY			
Basic Customer Charge			
Exceeding 200 Amp Service			
Energy Charge: First Block			
Energy Charge: Second Block			
Energy Charge: Over 1000 kWh			
GENERAL SERVICE DIESEL 0-10 kWh			
Basic Customer Charge			
Energy Charge (all kWh)			
Minimum Monthly Charge (Single Phase)			
Minimum Monthly Charge (Three Phase)			
GENERAL SERVICE DIESEL OVER 10 kWh			
Basic Customer Charge			
Demand Charge			
Energy Charge (all kWh)			
Minimum Monthly Charge (Single Phase)			
Minimum Monthly Charge (Three Phase)			

A. Please see TIR-NG-NLH-001 Attachment 1. The proposed rate changes for customers on Hydro's Isolated Diesel Systems are based upon the estimated proposed rate change for the customers of Newfoundland Power. Therefore, the

proposed rates in TIR-NG-NLH-001 Attachment 1 are the same under both scenarios requested.

Newfoundland and Labrador Hydro
Comparison of Existing and Proposed Isolated Diesel Rates

Line No.	CUSTOMER CATEGORY/CHARGE TYPE	A 2014 Electricity Rates/Charges	B Projected 2015 Electricity Rates/ Charges Under the 2015 Interim Rate Application [1]	C Electricity Rates/ Charges Rate in a Scenario Assuming 2015 Interim Rate Application Structure & 2014 Average Diesel Fuel Prices [2]
	DOMESTIC DIESEL CATEGORY			
1	Basic Customer Charge	$ 15.68	$ 14.69	$ 14.69
2	Exceeding 200 Amp Service	$ 20.68	$ 19.38	$ 19.38
3	Energy Charge: First Block	$ 0.11178	$ 0.10474	$ 0.10474
4	Energy Charge: Second Block	$ 0.12608	$ 0.11814	$ 0.11814
5	Energy Charge: Over 1000 kWh	$ 0.17095	$ 0.16018	$ 0.16018
	GENERAL SERVICE DIESEL 0-10 kWh			
6	Basic Customer Charge	$ 20.03	$ 18.77	$ 18.77
7	Energy Charge (all kWh)	$ 0.17073	$ 0.15997	$ 0.15997
8	Minimum Monthly Charge (Single Phase)	$ 20.03	$ 18.77	$ 18.77
9	Minimum Monthly Charge (Three Phase)	$ 36.73	$ 34.42	$ 34.42
	GENERAL SERVICE DIESEL OVER 10 kWh			
10	Basic Customer Charge	$ 29.45	$ 27.59	$ 27.59
11	Demand Charge	$ 13.08	$ 12.26	$ 12.26
12	Energy Charge (all kWh)	$ 0.16616	$ 0.15569	$ 0.15569
13	Minimum Monthly Charge (Single Phase)	$ 29.45	$ 27.59	$ 27.59
14	Minimum Monthly Charge (Three Phase)	$ 62.22	$ 58.30	$ 58.30

Notes:

[1] Hydro's Isolated Diesel rates are adjusted in line with Newfoundland Power's rate adjustments, and as such the rates that result from Hydro's Interim Rate Application will vary depending on Newfoundland Power's rate design. For purposes of this table, the average decrease of 6.3% has been applied evenly across rate classes and all rate components.

[2] As Hydro's Isolated Diesel rates are adjusted to reflect changes approved for Newfoundland Power's customer rates and do not reflect the actuals costs to serve the Isolated Diesel Systems, a change in forecast diesel fuel costs will not materially affect the rates proposed for Isolated Diesel customers; therefore, the rates in column C equal the rates proivded in column B.

Q. Please provide a comparison of revenues and RSP at the December 31, 2014 existing rates and the March 1, 2015 proposed interim rates in the same format as Table 4.15 in Hydro's 2013 Amended General Rate Application ("amended rate application"), page 4.50.

A. Please see TIR-NP-NLH-001 Attachment 1.

Newfoundland and Labrador Hydro
Comparison of Revenues and RSP

Line No.	Revenues and RSP Charges - Existing and Proposed Interim Rates				
		Dec 31/14 Existing Rates	Mar 1/15 Proposed Interim Rates	$ Change	% Change
	Newfoundland Power				
1	Firm	$ 415,402,365	$ 461,740,238	$ 46,337,873	11.2%
2	RSP	57,759,975	(32,641,791)	(90,401,766)	
3	Total Firm NP	$ 473,162,340	$ 429,098,447	$ (44,063,893)	-9.3%
	Island Industrial				
4	Island Industrial Firm	$ 30,546,755	$ 36,074,170	$ 5,527,415	
	Island Industrial Non-Firm	-	-	-	
5	Island Industrial Total	$ 30,546,755	$ 36,074,170	$ 5,527,415	18.1%
	Labrador Industrial				
6	Transmission	-	$ 4,050,000	$ 4,050,000	
7	Generation Cost Recovery	2,270,848	1,387,390	(883,458)	
8	Labrador Industrial Total	$ 2,270,848	$ 5,437,390	$ 3,166,542	139.4%
9	Canadian Forces Base Goose Bay	$ 932,221	$ 932,221	-	0.0%
10	Rural Island Interconnected	$ 51,653,313	$ 48,399,154	$ (3,254,159)	-6.3%
11	Rural Isolated Systems	9,257,429	9,067,350	(190,079)	-2.1%
12	L'Anse au Loup	2,881,421	2,699,891	(181,530)	-6.3%
	Rural Labrador Interconnected				
13	Domestic	11,150,910	11,359,109	208,199	1.9%
14	GS 2.1 0 - 10 kW	410,227	417,993	7,766	1.9%
15	GS 2.2 10 - 100 kW	2,342,225	2,386,562	44,337	1.9%
16	GS 2.3 110 - 1000 kVA	3,071,096	3,129,052	57,956	1.9%
17	GS 2.4 Over 1000 kVA	2,806,310	2,860,240	53,930	1.9%
18	Street & Area Lighting	312,471	367,187	54,716	17.5%
19	Rural Labrador Interconnected Total	$ 20,093,239	$ 20,520,143	$ 426,904	2.1%
20	All Rural Systems Total	$ 83,885,402	$ 80,686,538	$ (3,198,864)	-3.8%
21	Grand Total	$ 590,797,566	$ 552,228,766	$ (38,568,800)	-6.5%

Q. Please provide a comparison of revenues and RSP at the January 1, 2015 proposed rates and the March 1, 2015 proposed interim rates in the same format as Table 4.15 in the amended rate application, page 4.50.

A. Please see TIR-NP-NLH-002 Attachment 1 for a comparison of revenues at the proposed 2015 rates reflected in Hydro's Amended Application and the proposed rates to become effective March 1, 2015 reflected in the 2015 Interim Rates Application.

Newfoundland and Labrador Hydro
Comparison of Revenues and RSP Charges

Line No.	Revenues and RSP Charges - Amended Application vs 2015 Interim Rates Application				
		Amended Application 2015 Proposed Rates	**Mar 1/15 Proposed Interim Rates**	**$ Change**	**% Change**
	Newfoundland Power				
1	Firm	$ 525,340,174	$ 461,740,238	$ (63,599,936)	
2	RSP	(32,641,791)	(32,641,791)	-	
3	Total Firm NP	$ 492,698,383	$ 429,098,447	$ (63,599,936)	-12.9%
	Island Industrial				
4	Island Industrial Firm	$ 42,517,934	$ 36,074,170	$ (6,443,764)	
	Island Industrial Non-Firm	-	-	-	
5	Island Industrial Total	$ 42,517,934	$ 36,074,170	$ (6,443,764)	-15.2%
	Labrador Industrial				
6	Transmission	4,050,000	$ 4,050,000	$ -	
7	Generation Cost Recovery	1,387,390	1,387,390	-	
8	Labrador Industrial Total	$ 5,437,390	$ 5,437,390	$ -	0.0%
9	Canadian Forces Base Goose Bay	$ 932,221	$ 932,221	-	0.0%
10	Rural Island Interconnected	$ 53,097,023	$ 48,399,154	$ (4,697,869)	-8.8%
11	Rural Isolated Systems	10,519,193	9,067,350	(1,451,843)	-13.8%
12	L'Anse au Loup	2,961,956	2,699,891	(262,065)	-8.8%
	Rural Labrador Interconnected				
13	Domestic	11,359,109	11,359,109	-	0.0%
14	GS 2.1 0 - 10 kW	417,993	417,993	-	0.0%
15	GS 2.2 10 - 100 kW	2,386,562	2,386,562	-	0.0%
16	GS 2.3 110 - 1000 kVA	3,129,052	3,129,052	-	0.0%
17	GS 2.4 Over 1000 kVA	2,860,240	2,860,240	-	0.0%
18	Street & Area Lighting	367,187	367,187	-	0.0%
19	Rural Labrador Interconnected Total	$ 20,520,143	$ 20,520,143	$ -	0.0%
20	All Rural Systems Total	$ 87,098,315	$ 80,686,538	$ (6,411,777)	-7.4%
21	Grand Total	$ 628,684,243	$ 552,228,766	$ (76,455,477)	-12.2%

Q. Reference: Amended Rate Application, Page 3.19, Footnote 14:

"The calculation of rate base for 2014 and 2015 includes the cost of a number of capital projects that the Board has determined require further review before being approved for inclusion in rate base. These include the following (i) 2014 capital projects: the new Holyrood combustion turbine, the Western Avalon tap changer, the Sunnyside transformer; (ii) 2014 Allowance for Unforeseen Items: Holyrood Unit 3 Fan, Sunnyside Breaker and Holyrood Breaker; and (iii) other: January 2013 Holyrood repairs, expenditures over budget on Labrador City Terminal Station, and Black Tickle Fire Repair costs."

Please provide the amount of amortization included in 2015 test year adjusted revenue requirement ("2015 revenue requirement") related to capital projects that are subject to further review before being approved for inclusion in rate base.

A. Please see the following table:

	2015 Test Year		
Project ($000's)	**Amortization**	**Return on Rate Base [1]**	**Average Rate Base [2]**
Holyrood CT	3,164	7,683	112,656
Western Avalon Tap Charger	41	97	1,429
Sunnyside Transformer	110	263	3,855
Holyrood Unit 3 Fan, Holyrood and Sunnyside Breakers	75	74	1,078
January 2013 Holyrood Repair	812	271	3,970
Lab City Terminal Station	142	267	3,909
Black Tickle Fire Repair	51	83	1,211
Total	**4,395**	**8,738**	**128,108**

[1] Return on rate base has been calculated using Hydro's proposed 2015 Test Year rate of return on average rate base of 6.82%.

[2] For items classified as capital, both opening and closing average rate base have been adjusted.

Q. Reference: Amended Rate Application, Page 3.19, Footnote 14:

"The calculation of rate base for 2014 and 2015 includes the cost of a number of capital projects that the Board has determined require further review before being approved for inclusion in rate base. These include the following (i) 2014 capital projects: the new Holyrood combustion turbine, the Western Avalon tap changer, the Sunnyside transformer; (ii) 2014 Allowance for Unforeseen Items: Holyrood Unit 3 Fan, Sunnyside Breaker and Holyrood Breaker; and (iii) other: January 2013 Holyrood repairs, expenditures over budget on Labrador City Terminal Station, and Black Tickle Fire Repair costs."

Please provide the amount of return on rate base included in 2015 revenue requirement related to capital projects that are subject to further review before being approved for inclusion in rate base.

A. Please see Hydro's response to TIR-NP-NLH-003.

Q. Reference: Amended Rate Application, Page 3.19, Footnote 14:

"The calculation of rate base for 2014 and 2015 includes the cost of a number of capital projects that the Board has determined require further review before being approved for inclusion in rate base. These include the following (i) 2014 capital projects: the new Holyrood combustion turbine, the Western Avalon tap changer, the Sunnyside transformer; (ii) 2014 Allowance for Unforeseen Items: Holyrood Unit 3 Fan, Sunnyside Breaker and Holyrood Breaker; and (iii) other: January 2013 Holyrood repairs, expenditures over budget on Labrador City Terminal Station, and Black Tickle Fire Repair costs."

Please detail the amount included in 2015 test year average rate base related to capital projects that are subject to further review before being approved for inclusion in rate base.

A. Please see Hydro's response to TIR-NP-NLH-003.

Q. Please detail the costs included in 2015 revenue requirement related to the matters under review in the Board's Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System.

A. For capital items related to the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*, please see Hydro's response to TIR-NP-NLH-003.

Hydro has included approximately $1 million hearing and consulting costs in its 2015 revenue requirement related to the matters under review in the Board's *Investigation and Hearing into the Supply Issues and Power Outages on the Island Interconnected System*. However, Hydro expects the additional regulatory costs to continue into 2016 and 2017 with the anticipated filings on the cost of service methodology, rate design review and RSP review expected to be before the Board prior to the implementation of customer rates reflecting the costs of the Labrador-Island interconnection.

Q. Please quantify the impact on 2015 revenue requirement if the Holyrood conversion rate currently approved for ratemaking purposes of 630 kWh/bbl was used rather than Hydro's proposed 607 kWh/bbl. The response should consider the lower average No. 6 fuel cost of $65.63 per barrel.

A. The impact on 2015 revenue requirement if the Holyrood conversion rate currently approved for ratemaking purposes of 630 kWh/bbl was used rather than Hydro's proposed 607 kWh/bbl is outlined in the following table.

Table 1

	Fuel Conversion Rate		
	607	630	Impact
Net Holyrood production (GWh)	1,593	1,593	-
No. 6 Fuel Oil Consumption (bbls)	2,624	2,529	(95)
No. 6 Fuel Oil Costs ($000)	172,225	165,109	(7,116)
Average Consumption price ($/bbl)	65.63	65.30	(0.33)

Note that the average No. 6 fuel cost is slightly less in the 630 kWh/bbl scenario (to $65.30 kWh/bbl) due to the lower consumption rate and timing of fuel shipments.

Section 2.6.1 of Hydro's Amended Application outlines the reasons for the decline in fuel conversion performance at Holyrood in recent years and why Hydro is proposing a lower conversion rate at this time.

Q. Reference: 2015 Cost of Service Study (29-Jan-2015):
Please confirm whether all amounts in the revised cost of service study have been updated to reflect the lower cost of fuels. If not, why not? For any amounts that have not been updated to reflect the lower cost of fuels, please indicate the dollar impact on 2015 revenue requirement if such amounts were updated.

A. Not all amounts in the revised cost of service study have been updated to reflect the lower cost of fuels. The revised cost of service does not reflect rate base and cash flow effects of the revised price of fuel. However, the revenue requirement impacts of these items will be reflected in the final cost of service filed to reflect the Board's final GRA order. The fuel cost forecast for combustion turbine fuel was also not revised (see Hydro's response to TIR-NP-NLH-010). These effects were not considered material for the purpose of estimating the fuel cost reduction for the purposes of the 2015 Interim Rates Application.

The reduction in No. 6 fuel cost reflected in the 2015 Interim Rates Application is equal to approximately 11.8% of the 2015 Test Year revenue requirement for the Island Interconnected System provided in the Amended Application.[1] Given the change in forecast fuel prices, and the magnitude of this change with respect to Hydro's overall revenue requirement and customer rate impacts, Hydro determined this was a material change that warranted updating.

Hydro's Amended Application was based upon $18.8 million forecast cost of No. 2 fuel in 2015 for Hydro's Isolated Diesel Systems. In the 2015 Interim Rates

[1] 11.8% =$73 million/$621 million. The $621 million is provided in Schedule 1.2, page 2 of 8 in the 2015 Test Year Cost of Service Study (Exhibit 13 to the Amended Application).

Application, the forecast cost of No. 2 fuel in 2015 for Hydro's Isolated Diesel Systems is $15.6 million. Because the change in the diesel fuel cost forecast materially reduced the forecast rate increase for Hydro Rural Isolated Government customers (from approximately 25% to 16%), Hydro also modified the No. 2 fuel cost on the Isolated Diesel Systems for use in the 2015 Interim Rates Application.[2]

[2] See response to TIR-PUB-NLH-001.

Q. Reference: 2015 Interim Rates Application, Appendix B, Footnote 1:
Please provide the supporting calculation for the lower diesel costs of $3.2 million.

A. Please see the table below, which provides the forecasted diesel fuel quantities, consumption prices and diesel fuel costs by system for both Hydro's Amended Application and the 2015 Interim Rates Application. In the Amended Application, diesel fuel cost was prepared by Hydro in October 2014 and was based on forecast diesel fuel prices available as of October 1, 2014. For the 2015 Interim Rates Application, fuel cost for the isolated systems was prepared by Hydro in January 2015 and is based on forecast diesel fuel prices available as of January 6, 2015. As indicated by the table and TIR-NP-NLH-010, diesel fuel costs for the Labrador Interconnected and Island Interconnected Systems were not updated to reflect the diesel fuel prices available as of January 6, 2015.

The lower diesel costs of $3.2 million is the difference between the Amended Application total diesel fuel cost of $18.8 million and the 2015 Interim Rates Application total diesel fuel cost of $15.6 million.

	Amended GRA			Interim Rates Application		
	Fuel Requirement Forecast (Millions of liters)	Fuel Consumption Price ($/liter)	Diesel Fuel Cost (Millions of $)	Fuel Requirement Forecast (Millions of liters)	Fuel Consumption Price ($/liter)	Diesel Fuel Cost (Millions of $)
Island Isolated	2.152	1.111	2.39	2.152	0.891	1.92
Labrador Isolated	14.163	1.099	15.57	14.163	0.922	13.06
L'Anse au Loup	0.638	0.997	0.64	0.638	0.795	0.51
Island Interconnected	0.103	0.846	0.087	0.103	0.846	0.087
Labrador Interconnected	0.0687	1.085	0.075	0.0687	1.085	0.075
Total Diesel Fuel Cost (Rounded)			**18.8**			**15.6**

Q. Please provide the impact, if any, of lower fuel prices on Hydro's gas turbine fuel expense included in its 2015 revenue requirement.

A. Please see Hydro's response to TIR-PUB-NLH-006. The impact of lower fuel prices on Hydro's interconnected gas/combustion turbines diesel units and Holyrood ignition fuel expenses was not included in Hydro's revenue requirement in its Interim Rates filing. The overall difference is approximately $580,000.

Q. Please detail the impact on 2015 revenue revenue (*sic*) requirement of capital budget projects included in 2015 average rate base in Hydro's amended application that were not in service as of December 31, 2014. The detail should include (i) the capital expenditure, (ii) the net impact on 2015 aveage (*sic*) rate base, (iii) the impact on 2015 return on rate base and (iv) the impact on 2015 amortization expense.

A. Hydro's 2015 revenue requirement was forecasted to have additions to assets in service of $240.6 million in 2014 however; Hydro's 2014 actual additions to plant in service were $92.6 million. The difference of $148.0 million is primarily comprised of the Holyrood Combustion Turbine (CT). Please see the following table for the estimated impact of these reductions:

Project ($000's)	2014 Forecast Additions not in Service for 2014	2015 Average Rate Base Impact [1]	2015 Return on Rate Base Impact [2]	2015 Depreciation Imapct [3]
Holyrood CT	110,000	55,000	3,746	524
Other	37,971	18,985	1,296	664
Total	**147,971**	**73,985**	**5,042**	**1,188**

[1] Only the opening average rate base has been adjusted for 2015.
[2] Return on rate base has been calculated using Hydro's proposed 2015 Test Year rate of return on average rate base of 6.82%.
[3] The Holyrood CT has an estimated in-service date of February 2015. Other additions have an estimated in-service date of July 2015 with an average depreciation rate of 3.5%.

Q. Please list each proposal that has been changed in the Interim Rates Application from the Amended General Rate Application filed on November 10, 2014, explain in detail each change and provide details of how each change impacts customers' rates.

A. The modified proposals from Hydro's Amended Application are provided below:

1.0 2015 Test Year Fuel Costs

Proposal

Hydro's Amended Application was based upon an average No. 6 fuel cost of $93.32 per barrel. Based upon the most recent fuel forecast provided by PIRA, the average fuel cost for 2015 is forecast to be $65.63 per barrel.

Hydro's Amended Application was based upon $18.8 million forecast cost of No. 2 fuel in 2015 for Hydro's Isolated Diesel Systems. In the 2015 Interim Rates Application, the forecast cost of No. 2 fuel in 2015 for Hydro's Isolated Diesel Systems is $15.6 million.

Customer Impacts

Table 1 provides a comparison of the average customer impacts under both the Amended Application and the Interim Rates Application. These impacts resulted from the revised fuel forecast reflected in the 2015 Interim Rates Application. The Island Industrial Customer (IC) impact reflects the customer rate impact of the proposed change in the base rate. The impact of the phase-in proposals are not reflected in Table 1.

Table 1 **2015 Proposed Customer Rate Impacts**[1]		
	Amended Application	**2015 Interim Application**
Island Interconnected System		
Newfoundland Power – Wholesale rate	4.1%	(9.3%)
Estimated end consumers rate impact	2.8%	(6.3%)
Estimated rural consumers rate impact	2.8%	(6.3%)
Industrial Customers	39.2%	18.1%
Island Isolated Systems		
Domestic	7.1%	(6.3%)
General Service 0-10	18.5%	(6.3%)
General Service Over 10 kW	19.2%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)
Island Isolated - Government Departments		
General Service 0-10	24.7%	16.6%
General Service Over 10 kW	25.4%	16.9%
Street and Area Lighting	27.5%	27.5%
Labrador Interconnected System		
Domestic	1.9%	1.9%
General Service 0 – 10	1.9%	1.9%
General Service 10 - 100 kW	1.9%	1.9%
General Service 110 - 1000 kVA	1.9%	1.9%
General Service 1000 kVA and Over	1.9%	1.9%
Street and Area Lighting	17.5%	17.5%
Labrador Isolated Systems		
Domestic	7.1%	(6.3%)
General Service 0-10	18.5%	(6.3%)
General Service Over 10 kW	19.2%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)
Labrador Isolated - Government Departments		
Domestic	21.5%	14.0%
General Service 0-10	24.7%	16.6%
General Service Over 10 kW	25.4%	16.9%
Street and Area Lighting	27.5%	27.5%
L'Anse au Loup System		
Domestic	2.8%	(6.3%)
General Service 0-10	2.8%	(6.3%)
Street and Area Lighting	2.8%	(6.3%)

[1] Exclude the effects of the Northern Strategic Plan which applies to customers on isolated systems in Labrador.

2.0 RSP Load Variation Component

Proposal

The Amended Application proposes that the RSP rules related to the allocation of the load variation component be modified such that the year-to-date net load variation for both Newfoundland Power (NP) and IC is allocated among the customer groups based upon energy ratios. This proposal is also reflected in the 2015 Interim Rates Application. However, the 2015 Interim Rates Application also proposes disposition of the RSP load variation component effective December 31, 2014 based upon the proposed energy ratio allocation.[2]

Customer Impacts

Disposition of the $35.5 million credit balance in the segregated load variation component effective December 31, 2014 results in a credit of $2.1 million to the IC RSP current balance. The effect of the proposal is to reduce the $6.8 million RSP current balance due from IC to $4.7 million.

The remainder of the $35.5 million segregated RSP load variation balance would flow through the RSP for disposition to retail customers. The current RSP rules would allocate the portion related to Hydro Rural Interconnected between NP and customers on the Labrador Interconnected System. Approximately $33.3 million would be credited to NP customers and flow through the RSP for disposition.

Based upon the proposed Rural Deficit allocation methodology, approximately $100,000 of the balance would be credited to the Labrador Interconnected System. The disposition of this balance normally accrues to Hydro's net income. However, given 2014 is a test year, it would be appropriate for this balance to be applied to

[2] The Amended Application provided no recommendation on the timing of the disposition of the 2014 year-end balance of the RSP load variation component.

reduce cost recovery related to the net income deficiency from customers on the Labrador Interconnected System resulting from delayed rate implementation.

3.0 Island IC Rate Phase-in

Proposal

In Hydro's Amended Application, Hydro proposed that the RSP Surplus Credit Adjustment be set to 85% of each customer's bill increase resulting from the base rate change effective January 1, 2015.[3] Effective September 1, 2015, the RSP Surplus Credit Adjustment would reduce to 35% and on September 1, 2016, the RSP Surplus Credit Adjustment would be set to zero.

In the 2015 Interim Rates Application, Hydro proposes to dispose of $4.7 million of the IC RSP Surplus to provide recovery of the adjusted 2014 year-end IC RSP current balance. Hydro also proposes an RSP Surplus Credit Adjustment of 85% to apply for the period March 1, 2015 to December 31, 2015 and decrease to 60% for the period January 1, 2016 to August 31, 2016 and be eliminated on September 1, 2016.

Customer Impacts

Table 2 provides the forecast annualized customer rate impacts of the phase-in proposals included in the Amended Application updated for RSP balances at December 31, 2014.[4] These impacts reflect the combined effect of the base rate phase-in and the recovery of the 2014 year-end RSP balance over a two-year period.

[3] This means that 85% of the customer's monthly bill impact of implementation of new base rates will be recovered from the RSP Surplus.

[4] Table 1 assumes the next stage of the phase-in occurs on March 1, 2015 rather than January 1, 2015 as proposed in Hydro's Amended Application.

Table 2 Amended Application - IC rate impacts			
	March 1, 2015	**September 1, 2015**	**September 1, 2016**
Island IC	17.9%	16.7%	10.0%

Table 3 provides the forecast annualized customer rate impacts under the phase-in proposals included in the 2015 Interim Rates Application.

Table 3 Interim Rates Application - IC Rate Impacts [5]			
	March 1, 2015	**January 1, 2016**	**September 1, 2016**
Island IC	2.7%	4.4%	10.2%

4.0 July 1 2015 RSP Update

The Amended Application did not specifically request suspension of the NP RSP adjustment for 2015. However, Hydro proposed that the RSP rules included in its Amended Application be implemented January 1, 2015. The implementation of new base rates in 2015 to Island Industrial Customers requires modification to the values used in the operation of the RSP for the period while the interim rates are in effect.

To avoid any implications on NP's customers of the interim changes to the RSP rules, in a letter dated December 18, 2014, Hydro proposed to defer the RSP update scheduled for July 1, if necessary, until final rates and RSP rules are approved. The 2015 Interim Rates Application is proposing there be no RSP rate adjustment for 2015.

[5] Teck Resources is scheduled to close operations in 2015.

5.0 RSP Rules

The changes in the proposed RSP rules in the 2015 Interim Rates Application relative to the Amended Application are provided below. The customer impacts of the proposed changes have been addressed in the previous sections.

Revised Proposals

(i) The RSP rules in the 2015 Interim Rates Application are modified to provide for disposition of the 2014 year-end RSP segregated load variation balance of $35.5 million to the respective current RSP plan balances based upon 2014 energy ratios effective December 31, 2014;

(ii) The RSP rules include a new clause which suspends the NP RSP rate adjustment scheduled for July 1, 2015 until a further Order of the Board;

(iii) In the Amended Application, Hydro proposed a new Section E: Historical Balance. This section is no longer required under the 2015 Interim Rates Application;

(iv) The Board is requested to approve a one-time transfer from the IC RSP Surplus balance effective December 31, 2014 to provide recovery of the IC current plan balance;

(v) The RSP Surplus Credit Adjustment is proposed to be 85% for the period March 1, 2015 to December 31, 2015, decreased to 60% for the period January 1, 2016 to August 31, 2016 and eliminated September 1, 2016. This is a modification to the RSP Surplus Credit Adjustment proposed in the Amended Application; and

(vi) The Board is requested to approve implementation of an updated Teck Resources RSP Adjustment rate necessary to comply with Government direction.

Q. Please explain in detail how Hydro's 2015 return will be impacted if only a percentage of the proposed base rate increase is approved by the Board, including whether Hydro would propose to deal with any shortfall or surplus and, if so, how.

A. Please see Hydro's responses to TIR-CA-NLH-003 and TIR-CA-NLH-004, which provide the impact on earnings of making adjustments to the 2015 Test Year revenue requirement in establishing interim rates.

Hydro submits that its response to TIR-CA-NLH-001 demonstrates that Hydro’s 2015 Interim Rates Application meets the standard used in Alberta to justify approval of interim rates.

Q. The rates proposed in the Interim Rates Application are based on proposed changes in the currently approved methodology (e.g. the methodologies for the allocation of the RSP load variation balance and the allocation of the rural deficit) which will be ultimately determined in the General Rate Application. Please explain the implications for customers' rates and for Hydro if the proposed changes are not all ultimately approved, and whether Hydro would propose to deal with any shortfall or surplus.

A. If the Board did not approve Hydro's cost of service methodology proposals, the final 2014 Test Year Cost of Service Study and the final 2015 Test Year Cost of Service Study would increase revenue requirements for some classes and decrease revenue requirements for other classes.

For the 2014 Test Year, the cost of service methodology revisions would impact the allocation by class of the final 2014 net income deficiency that will be determined by the Board upon review of 2014 Test Year costs.

For the 2015 Test Year, Board approval of revisions to Hydro's cost of service methodology proposals would impact both the final rates by class to be implemented upon conclusion of the GRA and the allocation of the 2015 net income deficiency by class.

2015 Rate Implementation

Once the Board has made its rulings on the cost of service methodology and determined if any costs are to be removed from the 2015 Test Year revenue

requirement, Hydro will follow the following process for the finalization of customer rates for 2015:

(i) the final 2015 revenue requirement will be determined by making adjustments, if required, to remove any costs that may be disallowed for inclusion in the 2015 Test Year;

(ii) the final 2015 Test Year Cost of Service Study will be prepared to reflect the Board's decisions on the cost of service methodology;

(iii) customer rates will be derived to recover the 2015 Test Year revenue requirement by class in accordance with Government directives and the GRA Order;

(iv) The 2014 net income deficiency will be recalculated reflecting the approved cost of service methodology and approved 2014 Test Year costs;

(v) The 2015 net income deficiency will be recalculated reflecting the approved cost of service methodology and approved 2015 Test Year costs based upon the proposed 2015 final rates for the period of delayed implementation; and

(vi) Hydro will file an application proposing to implement final GRA rates and provide recovery of the net income deficiencies for 2014 and 2015.

Recovery of the 2014 and 2015 net income deficiencies are not reflected in the rates proposed in the 2015 Interim Rates Application. In Hydro's Amended Application, Hydro proposed the credit balance in the RSP Hydraulic Variation Account be used to provide recovery of the 2014 net income deficiency. Hydro still considers this proposal to be appropriate.[1]

[1] The credit balance in the RSP Hydraulic Variation Account at year-end 2014 is $43.4 million. See Appendix A to the Evidence for Hydro's 2015 Interim Rates Application.

Hydro proposes recovery of the 2015 net income deficiency[2] through the implementation of a rate rider calculated separately from base rates to apply to customer rates for a three-year period following rate implementation.

[2] Hydro also proposes that any portion of the 2014 net income deficiency not approved for recovery using the credit balance In the RSP also be reflected through the proposed rate rider.

Q. Page 5, footnote 18: Hydro is proposing that $100,000 from the segregated load variation component of the RSP be applied to the Labrador Interconnected System for its share of the 2014 net income deficiency. Provide an explanation for this proposal given that the Labrador Interconnected customers do not participate in the RSP.

A. Please see Hydro's response to TIR-PUB-NLH-001, Section 2.0.

Q. Page 6, footnote 20: List each PIRA fuel forecast Hydro has received from January 1, 2013 to the date of response to this request, including the date of the forecast and the forecast price.

A. Please note that Hydro accesses PIRA's published price forecasts either by request or via PIRA's website, which is updated subsequent to the completion of revised forecasts by PIRA. Under the license agreement for retainer services with PIRA Energy Group, Hydro is prohibited from releasing PIRA's proprietary content within the public domain and therefore cannot provide PIRA's forecast prices.

The following table provides forecasted purchase prices for Holyrood No. 6 fuel and Hardwoods combustion turbine diesel fuel for the year 2015 that were prepared by Hydro. The table of prices are based on the PIRA price forecasts which Hydro accessed and which are adjusted by Hydro for exchange and contract fuel delivery.

Forecasted Fuel Prices for the Year 2015

		Hydro's Calculated Price Forecast	
PIRA Price Forecast Publication	**PIRA Price Forecast Detail**	**Holyrood No. 6 ($Cdn/bbl)**	**Hardwoods No. 2 Diesel ($Cdn/l)**
Feb-13	Annual	94.40	0.830
Aug-13	Annual	98.30	0.895
Nov-13	Annual	100.20	0.915
Jan-14	Annual	95.80	0.866
Jan-14	Monthly	98.40	0.886
Feb-14	Monthly	100.00	0.905
May-14	Monthly	104.40	0.933
Jun-14	Monthly	117.20	1.070
Jul-14	Monthly	109.40	1.014
Aug-14	Monthly	98.60	0.942
Sep-14	Monthly	91.80	0.895
1-Dec-14	Monthly	77.70	0.770
15-Dec-14	Monthly	65.70	0.689
5-Jan-15	Monthly	64.30	0.688
6-Feb-15	Monthly	54.60	0.620

Note: Holyrood No. 6 fuel pricing is for 0.7% sulphur fuel.

Q. If fuel costs or any other costs change materially from the 2015 costs included in the Interim Rates Application, does Hydro intend to propose new rates in the future, prior to the finalization of the General Rate Application? In the response explain why Hydro updated only one of the cost factors in the revenue requirement (fuel, including diesel) from the GRA revenue requirement and not others such as interest?

A. Hydro's reasoning for updating the fuel cost forecast and not updating other cost factors was that of materiality. The reduction in No. 6 fuel cost reflected in the 2015 Interim Rates Application is equal to approximately 11.8% of the 2015 Test Year revenue requirement for the Island Interconnected System provided in the Amended Application.[1] Given the change in forecast fuel prices, and the magnitude of this change with respect to Hydro's overall revenue requirement and customer rate impacts, Hydro determined this was a material change that warranted updating.

The change in customer impact of the revised fuel price on Island Industrial Customers (IC) demonstrates the materiality of the revised fuel price forecast. The base rate increase for the Island IC required to recover the 2015 Test Year costs reflected in Hydro's Amended Application is 39.2%. Modifying the revenue requirement to reflect an updated Holyrood fuel cost of $65.63 per barrel reduces the proposed base rate increase to 18.1%. Hydro did not consider it reasonable to propose a 39.2% increase in 2015 Test Year rates to the Island IC when Hydro's

[1] 11.8% =$73 million/$621 million. The $621 million is provided in Schedule 1.2, page 2 of 8 in the 2015 Test Year Cost of Service Study (Exhibit 13 to the Amended Application).

updated forecast indicates that an increase of 18.1% is what is required to recover 2015 forecast costs.

Hydro also recognized that No. 6 fuel cost variances also get automatically adjusted through the RSP. Hydro believes it is appropriate to implement a lower base rate at this time rather than proposing to increase rates more than required and later reduce rates through an RSP adjustment.

Please also see Hydro's response to TIR-PUB-NLH-009.

Q. Page 11, lines 19-20: Please list the contribution of each of the following (by percent) to the proposed 11.2% base rate increase for Newfoundland Power: operating and maintenance expenses, fuel, power purchases, depreciation, interest, return on equity, rural deficit and other.

A. The changes in Newfoundland Power's revenue requirement from the 2007 Test Year to the proposed 2015 Test Year and the contribution of each to the 11.2% rate increase are shown in the table below.

	2007 COS [1]	2015 COS [1]	Variance ($)	Contribution to Rate Increase (%)
		($millions)		
Operating & Maintenance	48.7	72.1	23.4	1.8%
Fuels	109.3	150.9	41.6	3.3%
Power Purchases	27.1	49.4	22.3	1.7%
Depreciation	20.6	43.2	22.6	1.8%
Return on Debt	70.3	61.1	(9.2)	-0.7%
Return on Equity	6.4	23.2	16.9	1.3%
Rural Deficit	36.3	59.5	23.2	1.8%
Other	0.4	2.3	1.9	0.2%
Total Revenue Requirement [2]	319.1	461.7	142.6	11.2%

Notes:

[1] Amounts shown for Newfoundland Power (NP) are derived from the 2007 and 2015 COS and calculated using NP's cost sharing ratios applied to the Island Interconnected COS.

[2] The base rate increase of 11.2% for NP is calculated using 2015 billing determinents and 2015 existing and proposed rates as follows:

	Revenues at Existing Rates	Revenues at Proposed Rates	Variance ($)	Variance ($)
Revenues	415.3	461.7	46.4	11.2%

Q. Page 15, lines 9-11: List each diesel fuel forecast that Hydro has received from January 1, 2013 to the date of response to this request, including the date of the forecast and the forecast price.

A. Please see Hydro's response to TIR-PUB-NLH-005.

Q. Given the recent volatility in the price of oil, please explain why Hydro proposes that the RSP adjustment be suspended until July 1, 2016. Provide an explanation of the issues that should be considered if the July 1, 2015 RSP adjustment is not suspended and/or if an RSP adjustment is implemented when rates are finalized with the conclusion of the general rate application.

A. The 2015 Interim Rates Application is proposing there be no RSP rate adjustment for 2015. This is appropriate from a customer perspective and from the perspective of smooth operation of the RSP while interim 2015 Test Year values are in effect. The RSP rules will effectively require the 2016 fuel price forecast, that will be filed in October 2015, to be reflected through a fuel rider in the final customer rates that become effective as a result of the GRA.[1]

Section D of the RSP rules for Newfoundland Power (NP) and Island Industrial Customers (IC) states:

> *"When new test year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values"*

Board approval of interim base rates would require a rate change in March or April, 2015. If the NP RSP rate change is not suspended for 2015, an additional

[1] The GRA hearing is scheduled to start in September 2015. As a result, new final 2015 Test Year rates will not be approved until later in the fall. In October 2015, Hydro is required to provide an Island Industrial Customer fuel price projection for the period January to December, 2016 to estimate a change from the test year fuel cost reflected in base rates. The fuel price forecast is based upon a September forecast.

rate change will occur in July. As stated above, the RSP rules will require a revised fuel price forecast to be reflected in the final customer rates to be approved later in the fall. If the NP RSP July 2015 update is not suspended, there is currently the potential for three Hydro changes to NP rates in 2015.

The current RSP recovery adjustment effective July 1, 2014 of (0.551)¢ per kWh provides forecast reduced billings for 2015 of $32 million.[2] This credit is scheduled to expire on July 1, 2015. However, approval of the proposed disposition of the balance in the RSP segregated load variation balance effective December 31, 2014 would result in a credit of approximately $33 million to the NP RSP current balance. An additional credit balance transfer of $33 million effective year-end 2014 would permit the existing RSP recovery adjustment to continue until the end of June 2016 without resulting in a large RSP balance owing from customers.

The implementation of new base rates on an interim basis requires a modification to the values used in the operation of the RSP for the period while the interim rates are in effect. If the July 1, 2015 NP RSP rate adjustment proceeds, then the July 1, 2015 rate change will be based upon balances resulting from the operation of the RSP using the 2015 Test Year forecast. The RSP values and balances for 2015 will be updated upon approval of final customer rates at the conclusion of the GRA. Suspension of the July 2015 NP RSP rate adjustment avoids modifying customer rates based upon interim balances based upon the 2015 Test Year. Suspension of the July rate adjustment permits the RSP to operate on interim rates without any impact on customer rates until final rates are approved.

[2] See Table 4.15 on page 4.50 of the evidence in Hydro's Amended Application.

Q. Page 15, footnote 36: Explain how Hydro plans to reflect the higher rural deficit allocation in the 2015 Labrador Interconnected rates. In the response include the percentage impact on the 2015 Labrador Interconnected rates of the higher allocation.

A. The reduced 2015 revenue requirement from Newfoundland Power (NP) results in a reduced allocation of the Rural Deficit to be recovered from the rate to NP using the proposed revenue requirement approach. The update to the Rural Deficit allocation to reflect the revised 2015 Test Year revenue requirement would increase the required rate increase to customers on the Labrador Interconnected System from 2.1% to 3.4%.

Hydro has proposed to maintain the 2.1% increase for the purpose of establishing interim rates. Upon the Board's final determination of revenue requirement for setting customer rates, any net income deficiency from customers on the Labrador Interconnected System will be proposed to be recovered through future rates.

The net income deficiency to be recovered from Labrador Interconnected customers would be partially offset if the Board approves disposition of the RSP load variation balance as proposed in the 2015 Interim Rates Application and/or approves the disposition of the 2014 year-end credit balance in the RSP Hydraulic Variation Account to provide recovery of the 2014 net income deficiency. Because customers on the Labrador Interconnected System pay a portion of the Rural Deficit, a portion of the credit balances allocated to Hydro Rural would appropriately be credited to reduce the net income deficiency to be recovered from these customers.

Q. If the Interim Rates Application is approved with an effective date of April 1, 2015, what will be the impact on Hydro's return for 2015 and on customer rates? In the response include how Hydro plans to deal with these impacts.

A. Please see Hydro's response to TIR-CA-NLH-001.

Q. **Assume that effective April 1, 2015 the fuel rider for Newfoundland Power is reset to zero and the 11.2% base rate increase for Newfoundland Power is approved, but no other changes proposed in the Interim Rates Application for Newfoundland Power are approved.**

What would be the impact on customer rates and on Hydro's return for 2015 if the July 1, 2015 Rate Stabilization Plan adjustment takes place according to currently approved Rate Stabilization Plan rules? Provide any other assumptions used in this calculation, noting any that differ from the most recently filed Cost of Service.

A. TIR-PUB-NLH-012 Attachment 1 provides the customer rate impacts of the 11.2% base rate increase for Newfoundland Power (NP) effective April 1, 2015 and the July 1, 2015 NP Rate Stabilization Plan (RSP) Rate adjustment, under current rules.

The customer rate impact of the implementation of new base rates for NP effective April 1, 2015, as outlined in the 2015 Interim Rates Application, would be a (9.3%) rate decrease for NP and a (6.3%) decrease for the end consumer. The impact of the July 1, 2015 RSP Rate adjustment would be an increase of approximately 8.8% for NP and 6.0% for the end consumer. The RSP Rate adjustment was calculated assuming that under interim rates: the RSP operates based upon 2015 Test Year values; the RSP load variation balance continues to be segregated; and a new RSP fuel rider is implemented based upon a forecast fuel price of $76.05 per barrel for the period July 1, 2015 to June 30, 2016.

As explained in Hydro's response to TIR-PUB-NLH-009, Hydro has concerns with proceeding with the scheduled July 1 NP RSP adjustment based upon the use of

2015 Test Year values. The RSP values and balances for 2015 will be updated upon approval of final customer rates at the conclusion of the GRA. Suspension of the July 2015 NP RSP rate adjustment avoids modifying customer rates based upon interim balances. Suspension of the July 1 NP RSP rate adjustment for 2015 permits the RSP to operate on interim rates without any impact on customer rates until final rates are approved.

Assuming the Board approves the 11.2% base rate increase for April 1, 2015, there would be no additional impact to Hydro's return for 2015 if the July 1, 2015 RSP Rate adjustment proceeds as it is not recorded as revenue by Hydro. Rather, the amounts are credited to the RSP (i.e., a deferral account on the balance sheet). The impact to Hydro's return of the implementation of new base rates for NP effective April 1, 2015 would be a net income shortfall of $28 million.

NEWFOUNDLAND AND LABRADOR HYDRO
NP Rate Increase - Jan 1, 2015
No. 6 0.7% Sulphur Fuel

NP Total	2015 Billing Units	Unit	Existing	$	April 1 2015	$	Existing vs April 1, 2015 Percent Change NP	Consumer	July 1 2015	$	April 1 to July 1, 2015 Percent Change NP	Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	5.50	83,171,270	37.5%		5.50	83,171,270	0.0%	
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	34.11	102,330,000			34.11	102,330,000		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	94.46	276,210,486			94.46	276,210,486		
				415,335,201		461,711,756	11.2%			461,711,756	0.0%	
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(5.51)	(32,641,791)			(3.92)	(23,222,472)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766		-			4.80	28,435,680		
Total RSP				57,759,975	(5.51)	(32,641,791)			0.88	5,213,208		
Firm plus RSP				473,095,176		429,069,965	-9.3%	-6.3%		466,924,964	8.8%	6.0%

Q. **Assume that effective April 1, 2015 the fuel rider for Newfoundland Power is reset to zero and the 11.2% base rate increase for Newfoundland Power is approved, but no other changes proposed in the Interim Rates Application for Newfoundland Power are approved.**

What would be the impact on customer rates and on Hydro's return for 2015 if the July 1, 2015 Rate Stabilization Plan adjustment is suspended and the Rate Stabilization Plan adjustment set at March 1, 2015 remains in place until December 31, 2015? Provide any assumptions used in this calculation, noting any that differ from the most recently filed Cost of Service.

A. In accordance with the Rate Stabilization Plan (RSP) rules, the RSP recovery adjustment rate for Newfoundland Power (NP) is set effective July 1 annually based on the March 31 RSP balance. There is no RSP rules in place to calculate a revised RSP recovery adjustment set at March 1, 2015. Therefore, in responding to this request for information, Hydro has assumed a continuation of the RSP recovery adjustment rate of (0.551)¢ per kWh.

The proposed 11.2% base rate increase to NP reflects a fuel rider of zero and the continuation of the existing RSP recovery adjustment of (0.551)¢ per kWh. The customer impact of approving the proposed rate effective April 1, 2015 is a 9.3% final rate decrease to NP and an estimated 6.3% decrease to NP's customers (consistent with the 2015 Interim Rates Application).

The forecast customer impacts in July 2015 of not suspending July 1, 2015 RSP adjustment for 2015 are provided in Hydro's response to TIR-PUB-NLH-012. If the

July 1, 2015 RSP adjustment for 2015 is suspended, no further rate change reflecting fuel cost changes will occur subsequent to April 1, 2015 until the Board implements new final rates later in 2015.

Assuming the Board approves the 11.2% base rate increase for April 1, 2015, updating the RSP adjustment rates does not have any additional impact on Hydro's return as the RSP amounts are not recorded as revenue. Rather, the RSP amounts are credited to the RSP (i.e., a deferral account on the balance sheet).

Q. **Assume that effective April 1, 2015 the Board approves the allocation of the segregated load variation to the Industrial Customers and to Newfoundland Power Inc., that the fuel rider for Newfoundland Power Inc. is reset to zero and that the current Rate Stabilization Plan adjustment of (0.551)¢ per kWh will continue without change until July 1, 2016.**

Provide the total impact on the Rate Stabilization Plan balance at June 30, 2016 using of a Rate Stabilization Plan adjustment of (0.551)¢ per kWh. Provide all assumptions and the total amount that will be refunded over that period of time.

A. The total credit balance owing to Newfoundland Power (NP) that will have accumulated in the NP Rate Stabilization Plan (RSP) as of June 30, 2016 is approximately $8.2 million under the following assumptions: (i) continuation of the RSP adjustment rate of (0.551)¢ per kWh; (ii) allocation of segregated load variation effective December 31, 2014; (iii) the RSP operates based upon 2015 Test Year values; (iv) there are no forecast variances in hydrology;[1] and (v) any fuel cost variances for 2016 would be addressed by the implementation of a new fuel rider upon conclusion of the GRA.[2]

[1] Hydro has assumed that the credit balance in the RSP Hydraulic Variations Account is used to provide recovery of the 2014 net income deficiency. Therefore, it is assumed no amount is transferred from the RSP Hydraulic Variations Account to the 2015 NP RSP current balance at year-end 2015.

[2] Section D of the RSP states "When new test year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values.

Q. **Assume that effective April I, 2015 the Board approves the allocation of the segregated load variation to the Industrial Customers and to Newfoundland Power Inc., that the fuel rider for Newfoundland Power Inc. is reset to zero and that the Rate Stabilization Plan adjustment to become effective April 1, 2015 will recover/repay the net of the Rate Stabilization Plan balance of December 31, 2014, the projected total recovery/repayment of the balance for the following three months estimated using energy sales (kWh) for January, February and March of 2014, the forecast financing charges to the end of the recovery period (to June 30, 2016) and the newly allocated segregated load variation for Newfoundland Power Inc.**

Provide the Rate Stabilization Plan adjustment effective April 1, 2015 that would recover or repay the balance in the Rate Stabilization Plan. Provide all assumptions used and the total amount that will be recovered or refunded over the period from April 1, 2015 to July 1, 2016.

A. Under the current Rate Stabilization Plan (RSP) rules, the Newfoundland Power (NP) RSP adjustment for disposition of the RSP current plan balance (i.e., the recovery adjustment rate) would normally come into effect for the period July 1, 2015 to June 30, 2016. Under the above scenario, a forecast RSP recovery adjustment rate of (0.713)¢ per kWh would apply for the period April 1, 2015 to June 30, 2016 based on disposition of a credit balance of $51.9 million to customers. Board approval of revised RSP rules to become effective April 1, 2015 would be required to implement the scenario presented in this request for information.

The forecast RSP recovery adjustment rate was calculated assuming: (i) continuation of the RSP adjustment rate of (0.551)¢ per kWh until March 31, 2015; (ii) computation of the new adjustment to be in effect for the 15 month period of April 1, 2015 to June 30, 2016 was based upon the total NP usage for the 15 month period of April 1, 2014 to June 30, 2015; (iii) allocation of segregated load variation based upon energy ratios effective December 31, 2014; and (iv) the RSP operates based upon 2015 Test Year values.

Q. Assuming the Board does not approve the Interim Rate Application as proposed by Hydro and there are no changes to base rates or to the Rate Stabilization Plan methodology, what is the estimated impact on the July 1, 2015 Rate Stabilization Plan adjustment to Newfoundland Power Inc. rates and the average rates charged to Newfoundland Power Inc. customers? Provide supporting information regarding the forecast price per barrel of No. 6 fuel, the calculation of the current balance at March 31, 2015 in the NP Rate Stabilization Plan, the Adjustment and Financing included for April, May and June 2015, and the calculation of the Fuel Rider. As the March month end forecast may not be available the February 2015 month end forecast may be used for purposes of the calculation.

A. Assuming the Board does not approve the Interim Rate Application as proposed by Hydro and there are no changes to base rates or to the Rate Stabilization Plan methodology, the estimated rate impact of the July 1, 2015 Rate Stabilization Plan adjustment if the RSP continues to operate for 2015 based upon 2007 Test Year parameters is a decrease of 15.7% for Newfoundland Power Inc. or an estimated decrease of 10.6% for end consumers as outlined in the table below. Please see Attachment 1 for the supporting calculation of the RSP current plan rate and fuel rider using a March 31, 2015 closing balance based on January and February 2015 actuals and a March forecast.

Utility Total

	2015 Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Forecast Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.00	60,488,196		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	32.46	97,380,000		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	88.05	257,467,005		
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.49)	(44,371,509)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	4.68	27,724,788		
Total RSP			9.75	57,759,975	(2.81)	(16,646,721)		
Firm plus RSP				473,095,176		398,688,480	-15.7%	-10.6%

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN FUEL PRICE PROJECTION RIDER
No. 6 0.7% Sulphur Fuel Price Projection
July 1 2015 NP RSP Recovery Rate
Utility Customer

Line No	Customer Allocation	Amount	Comments
1	March Fuel Price Projection	$ 71.05	From Page 2
2	2007 Test Year Fuel Forecast Price	$ 55.40	
3	Forecast Fuel Price Variance	$ 15.65	Line 1 - Line 2
4	2007 Test Year No. 6 Barrels Consumed	1,878,188	From Line 41
5	Forecast Fuel Variance	$ 29,393,642	Line 3 x Line 4
6	Utility Customer Allocation Ratio for March	92.98%	From Line 8
7	Utility Customer Allocation	$ 27,330,209	Line 5 x Line 6

	Calculation of Customer Allocation	kWh	Percent of Total	Allocation of Rural	Total
8	12 months to date (Apr 2014-Mar 2015) Utility Sales	5,844,287,746	86.90%	6.08%	92.98%
9	12 months to date (Apr 2014-Mar 2015) Industrial Customer Sales	421,752,517	6.27%	0.00%	6.27%
10	12 months to date (Apr 2014-Mar 2015) Bulk Rural Energy	458,979,862	6.82%	-6.82%	0.00%
11	Total	6,725,020,125			

	Calculation of Utility Customer RSP Rate	Amount	Comments
	Rate Rider		
12	Utility Allocation March	$ 27,330,209	From Line 7
13	12 months to date Utility Sales (kWh)	5,844,287,746	From Line 8
14	Fuel Projection Rider (mills per kWh)	4.68	Line 12/Line 13 x 1000
15	March Balance	$ (48,449,271)	March RSP
16	Forecast Financing Costs	$ (2,627,036)	From Line 38
17	Forecast Recovery to June 30	$ 7,326,763	Lines 23 to 25
18	Total to be recovered	$ (43,749,543)	Lines 15 to 17
19	12 months to date (Apr 2014-Mar 2015) Utility Sales	5,844,287,746	From Line 8
20	Balance Rate (mills per kWh)	(7.49)	Line 18/Line 19 x 1000
21	RSP Adjustment Rate (mills per kWh)	-2.81	Line 14 + Line 20

Utility Forecast Recovery
2014-2015

2007 Test Year Weighted Average Cost of Capital per annum 7.529%
Nominal Financing Rate 7.281%

		Sales kWh	Financing Costs	Adjustment	Total To Date Balance
22	Balance Forward				$ (48,449,271)
23	April	543,018,070	$ (293,966)	$ 2,992,030	(45,751,207)
24	May	458,076,079	(277,595)	$ 2,523,999	(43,504,804)
25	June	328,626,921	(263,965)	$ 1,810,734	(41,958,035)
26	July	303,484,393	(254,580)	2,273,098	(39,939,517)
27	August	300,338,819	(242,333)	2,249,538	(37,932,312)
28	September	315,235,972	(230,154)	2,361,117	(35,801,349)
29	October	401,788,711	(217,225)	3,009,397	(33,009,176)
30	November	508,174,745	(200,283)	3,806,229	(29,403,231)
31	December	619,191,220	(178,404)	4,637,742	(24,943,892)
32	January	740,593,181	(151,347)	5,547,043	(19,548,197)
33	February	668,359,635	(118,609)	5,006,014	(14,660,792)
34	March	657,400,000	(88,954)	4,923,926	(9,825,820)
35	April	543,018,070	(59,618)	4,067,205	(5,818,233)
36	May	458,076,079	(35,302)	3,430,990	(2,422,545)
37	June	328,626,921	(14,699)	2,461,416	24,172
38	Total		$ (2,627,036)	$ 51,100,478	

2007 Test Year Barrels Adjusted for Reduction in Corner Brook Pulp and Paper Limited (CBPP) and Abitibi Consolidated (Grand Falls) Load

39	2007 Test Year Barrels of No. 6 Fuel forecast to be consumed at Holyrood	2,467,396
40	Less: Reduction in Test Year Barrels of No. 6 Fuel approved in Board Order No. P.U. 11 (2008) to reflect reduction in CBPP load and Board Order No. P.U.22 (2009) to reflect a reduction in Abitibi Consolidated (Grand Falls) Test Year load.	(589,208)
41	Adjusted 2007 Test Year Barrels of No. 6 Fuel forecast to be consumed at Holyrood	1,878,188

NEWFOUNDLAND AND LABRADOR HYDRO
Fuel Price Projection
As at March 31, 2015
July 1 2015 NP RSP Recovery Rate

	$/bbl
PIRA Forecast $ US/bbl[1]	
July	45.18
August	49.73
September	52.32
October	54.34
November	56.10
December	54.28
January	58.15
February	60.85
March	62.85
April	64.75
May	63.44
June	62.66
Average $US/bbl[2]	57.05
NLH TestYear Contract Discount ($US/bbl)	(0.218)
	$56.83
Can$/US$ Noon Exchange Rate[3]	1.2500
NLH Fuel Price Projection ($Can/bbl)[2]	$71.05

Notes:

[1] The forecast for July 2015 to June 2016 is based on the PIRA Energy Group World Oil Market Forecast dated March 2, 2015.

[2] Price per barrel is rounded to the nearest $0.05.

[3] Monthly average of the Bank of Canada Can$/US$ Noon Exchange Rate for the month of February 2015, rounded to 4 decimal places.

Q. Assuming that the Board approves, effective July 1, 2015, a 10% base rate increase for Island Industrial customers on an interim basis, and the use of only the RSP Surplus to partially offset this increase for an effective rate increase to Island Industrial customers of 2.7%, and assuming approval of no other changes what would be the impact on the IC RSP Surplus?

A. Assuming the Board does not approve the Interim Rate Application as proposed by Hydro, in order to achieve an annualized rate increase effective July 1, 2015 of 2.7% assuming a 10% base rate increase, the impact to the IC RSP Surplus would be a drawdown of $2.3 million for the period July 1, 2015 to December 31, 2015.

Q. Assuming that the Board approves, effective July 1, 2015, a 5% increase in the base rate to Newfoundland Power Inc., on an interim basis, the continuation of the currently approved Rate Stabilization Plan and cost of service methodology, and assuming approval of no other proposed changes, what would be the estimated overall rate impact for Newfoundland Power Inc. and for its customers at July 1, 2015? Show the impact on the base rate and the Rate Stabilization Plan adjustment, providing supporting information regarding the forecast price per barrel of No. 6 fuel, the calculation of the current balance at March 31, 2015 in the NP Rate Stabilization Plan, the Adjustment and Financing included for April, May and June 2015, and the calculation of the Fuel Rider. Explain any assumptions made to complete this exercise. As the March month end forecast may not be available the February 2015 month end forecast may be used for purposes of the calculation. Provide the same information for a 3%, an 8% and an 11.2% increase in the base rate to Newfoundland Power Inc.

A. Assuming the Board does not approve the Interim Rate Application as proposed by Hydro, the estimated overall rate impacts to Newfoundland Power Inc. and its customers for July 1, 2015, assuming the base increases provided in the question and assuming operation of the current RSP based on 2007 Test Year parameters, are outlined in the table below. Please see Attachment 1 for the supporting calculations. The calculation of the RSP current plan rate and fuel rider are provided in the response to TIR-PUB-NLH-016.

	Customer Rate Change	
Base Rate Increase	**Utility**	**End Consumer**
5%	-11.3%	-7.7%
3%	-13.1%	-8.8%
8%	-8.7%	-5.9%
11.2%	-5.9%	-4.0%

The fuel price reflected in the rate change reflects a price per barrel of $71.05. This compares to an average cost of $65.63 per barrel in the 2015 Test Year.

NEWFOUNDLAND AND LABRADOR HYDRO
NP Rate Increase - July 1, 2015

5% base rate increase

	2015 Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Forecast Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.20	63,512,606		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	34.08	102,249,000		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	92.45	270,340,355		
Total before RSP[1]				415,335,201		436,101,961	5.0%	3.4%
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.49)	(44,371,509)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	4.68	27,724,788		
Total RSP[2]			9.75	57,759,975	(2.81)	(16,646,721)		
Firm plus RSP				473,095,176		419,455,240	-11.3%	-7.7%

3% base rate increase

	2015 Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Forecast Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.12	62,302,842		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	33.43	100,301,400		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	90.69	265,191,015		
Total before RSP				415,335,201		427,795,257	3.0%	2.0%
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.49)	(44,371,509)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	4.68	27,724,788		
Total RSP			9.75	57,759,975	(2.81)	(16,646,721)		
Firm plus RSP				473,095,176		411,148,536	-13.1%	-8.8%

8% base rate increase

	2015 Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Forecast Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.32	65,327,252		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	35.06	105,170,400		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	95.09	278,064,365		
Total before RSP				415,335,201		448,562,017	8.0%	5.4%
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.49)	(44,371,509)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	4.68	27,724,788		
Total RSP			9.75	57,759,975	(2.81)	(16,646,721)		
Firm plus RSP				473,095,176		431,915,296	-8.7%	-5.9%

11.2% base rate increase

	2015 Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Forecast Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.45	67,262,874		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	36.10	108,286,560		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	97.91	286,303,310		
Total before RSP				415,335,201		461,852,744	11.2%	7.6%
RSP: Current Plan	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.49)	(44,371,509)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	4.68	27,724,788		
Total RSP			9.75	57,759,975	(2.81)	(16,646,721)		
Firm plus RSP				473,095,176		445,206,023	-5.9%	-4.0%

[1] Base rate increases applied to all components.

[2] See TIR-PUB-NLH-016 for computation.

Q. Assume that the Board approves, effective July 1, 2015, an interim base rate increase which is 50% of the rates that Hydro proposes and continuation of currently approved Rate Stabilization Plan and cost of service methodology, with no other changes, provide the estimated impact on Hydro's 2015 revenue requirement and rate of return.

A. Assuming the Board does not approve the Interim Rate Application as proposed by Hydro, Table 1 provides (i) the rate increases proposed in the 2015 Interim Rates Application and (ii) the interim base rate increases that would be implemented July 1, 2015 to provide 50% recovery of the base rates that Hydro would have proposed reflecting continuation of the existing cost of service methodology (i.e., primarily use of the existing Rural Deficit Methodology) and operation of the currently approved Rate Stabilization Plan rules.

Table 1
Comparison of Base Rate Increases

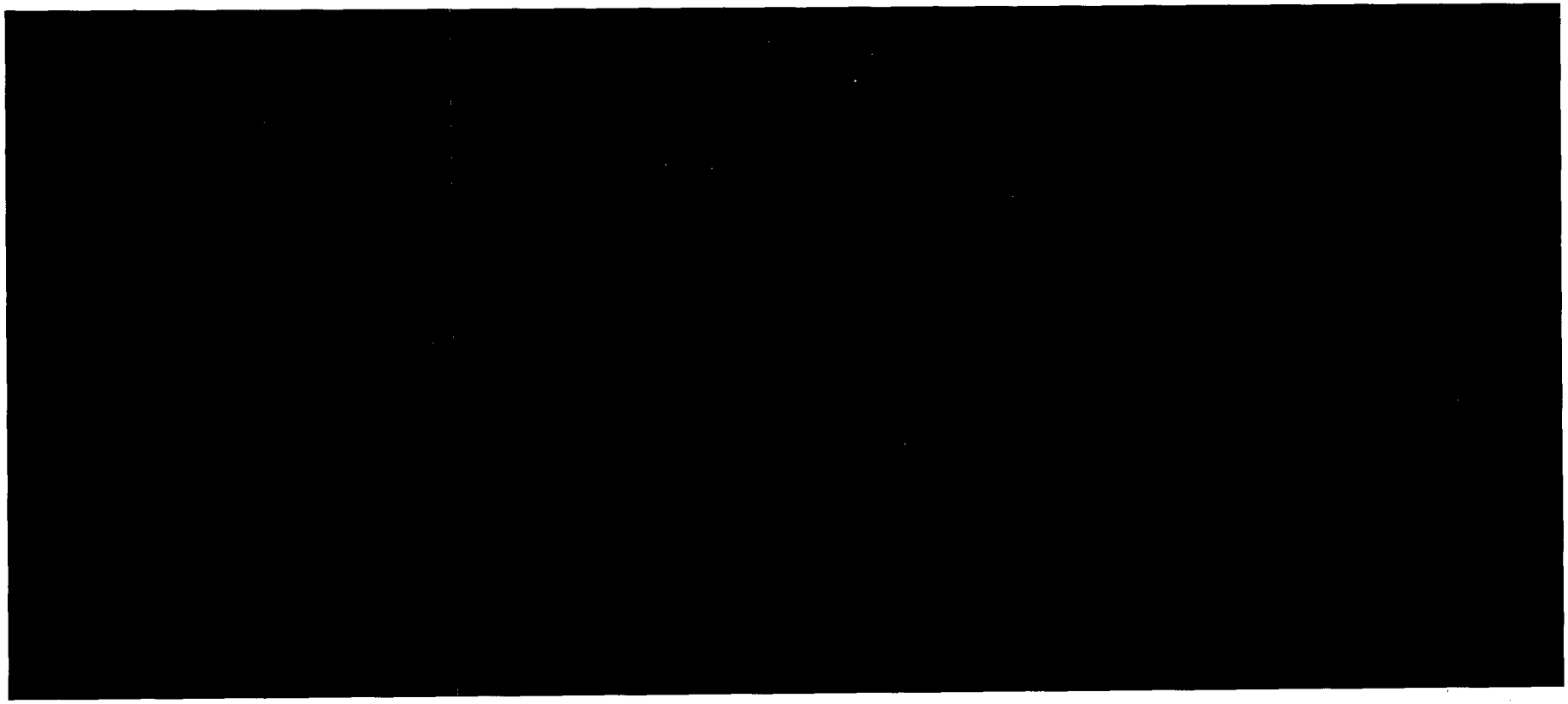
Customer Group	2015 Interim Rates Application	PUB Scenario
Newfoundland Power (NP)	11.2%	5.4%
Island Industrial Customers (IIC)	2.7%	9.1%
Labrador Interconnected	2.1%	14.5%
Hydro Rural Customers	-6.3%	-7.4%

Implementation of the rate changes provided in the scenario requested does not impact Hydro's 2015 Test Year Revenue Requirement. However, based on the assumptions provided, Hydro's financial results will be negatively impacted by both the further delay in rate implementation to July 1, 2015 and the differences in the

rate increases that would result. The forecast net income under this scenario would be a loss of $18.8 million and a rate of return of 3.93% for 2015.

Q. In a chart provide the actual monthly load for 2014 for each of the Industrial Customers and the most recent monthly load forecast for 2015 and for 2016 for each of the Industrial Customers, showing the percentage each is of the total annual figure.

A. Please see TIR-PUB-NLH-020 Attachment 1 for the monthly load forecasts for each Island Industrial Customer for 2014 actual, 2015 forecast and 2016 forecast.



Q. Reference: Interim Rate Application, Jan. 28, 2015, Evidence, Section 2. 3.2, pages 6 to 8

Lines 23 to 25 on page 6 state that "*Based upon the most recent fuel forecast provided by PIRA, the average fuel cost for 2015 is forecast to be $65.63 per barrel*". Using an illustrative example, please fully explain the net impact that a 1¢ to 5¢ (positive and negative) change from Hydro's forecasted Canadian dollar currency exchange rate would have on no. 6 fuel oil revenue requirement for each of the customer classes. Include all calculations in the example.

A. The net impacts of changes in the Canadian dollar currency exchange rate on the No. 6 fuel oil revenue requirement for each customer class are provided in Table 1 below, under four scenarios, +/- one cent and +/- five cents.

Table 1
Illustrative No. 6 Fuel Revenue Requirement Impact of Changes in Exchange Rate

	Base Case	- 1¢	- 5¢	+ 1¢	+ 5¢
Fuel Price ($Cdn/bbl)	65.63	66.16	68.55	65.09	63.03
No. 6 Fuel Revenue Requirement Impact ($millions)[1]					
Newfoundland Power	62	60	55	63	67
Island IC	6	6	6	7	7
Hydro Rural	5	5	4	5	5
Total ($ millions)	73	71	65	74	79
NP Rate Impact (%)	-9.3	-9.1	-7.9	-9.6	-10.5
Estimate End Consumer Rate Impact (%)	-6.3	-6.1	-5.4	-6.5	-7.1
Island IC Base Rate Impact (%)	18.1	18.5	20.3	17.7	16.1

[1] $93.32/bbl per Hydro's Amended Application vs adjusted fuel price times 2,624,371 bbls. The estimated impact by customer class is based upon the proportion of 2015 Test Year energy generation by class as provided in Appendix B to the 2015 Interim Rates Application.

Q. Reference: Interim Rate Application, Jan. 28, 2015, Evidence, Section 2. 3.2, pages 6 to 8

Further to TIR-V-NLH-001, please fully explain Hydro's procedure for forecasting the currency exchange, the forecasted exchange rate used in calculating the $65.63 per barrel, and Hydro's current confidence level on the forecast as a result of recent volatility in the Canadian dollar exchange rates.

A. Please note that the $65.63 per barrel referred to in Hydro's 2015 Interim Rate Application, Evidence, Section 2.3.2, pages 6 to 8 reflects the consumption price of fuel used by Hydro for the period based on a forecast of monthly fuel prices. For preparing its near term monthly fuel price forecasts, Hydro relies on currency exchange forecasts published by Canadian financial and banking institutions. The Canadian financial and banking institutions typically publish currency exchange forecasts on a regular basis from which Hydro calculates a composite forecast based on an average of the published forecasts. The table below provides the forecasted exchange rate used to determine the forecasted monthly fuel prices for 2015 that resulted in a consumption fuel price forecast of $65.63 per barrel.

Forecast Exchange (Cost of 1 US Dollar)

Q1 2015	1.158
Q2 2015	1.168
Q3 2015	1.183
Q4 2015	1.189

Note: Forecast exchange as of January 1, 2015

Please note that the Canadian financial and banking institutions do not provide a confidence level for their exchange forecasts.

O'DEA EARLE

February 18, 2015

Ms. G. Cheryl Blundon
Board of Commissioners of Public Utilities
120 Torbay Road, P.O. Box 12040
St. John's, NL A1A 5B2

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro ("Hydro") 2015 Interim Rates Application

In its Amended 2013 General Rate Application filed with the Board on November 10, 2014 (the "*Amended 2013 GRA*"), Hydro requested that the proposed customer rates be approved on an interim basis in advance of completing the GRA in order to reduce the amount of 2015 costs deferred for future recovery from customers. Hydro also proposed revised RSP rules effective January 1, 2015 to permit the continued phase-in of Island Industrial Customer (IIC) rates consistent with OC2013-089, as amended. In correspondence from the Board dated December 24, 2014, Hydro was directed to file a comprehensive interim rates application for rates to be charged March 1, 2015. In response to the Board directive, on January 28, 2015 Hydro submitted an Application to the Board (the "*2015 Interim Rates Application*") requesting interim rates effective March 1, 2015 (see 2015 Interim Rates Application Evidence – Background). This is Hydro's third application for interim rates since filing its 2013 GRA.

In the 2015 Interim Rates Application, Hydro makes application to the Board for an interim order approving (see 2015 Interim Rates Application Para. 23):

(i) The schedule of rates, tolls and charges set out in Schedule 1 to be effective March 1, 2015 until superseded by a final order of the Board relating to the Amended 2013 GRA;

(ii) Changes to the RSP rules to implement the phase-in of changes to the IIC rates and to remove the requirement for the RSP rate adjustment to Newfoundland Power scheduled for July 1, 2015 as set out in Schedule 1 as follows:
   a. to provide for the allocation and disposition of the RSP load variation balance effective December 31, 2014;
   b. to provide for a one-time transfer from the IIC surplus balance effective December 31, 2014 to provide recovery of the IIC current plan balance;
   c. to approve the proposed RSP surplus credit adjustments to mitigate the rate impacts of implementing 2015 test year IIC base rates; and
   d. to suspend for 2015 the requirement for the July 1 RSP adjustment for Utility rates.

To summarize, Hydro is requesting:

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t. 709-726-3524 | f. 709-726-9600 | www.odeaearle.ca

1. An interim increase in rates because it states it is in need of an immediate improvement in its financial position; and
2. Implementation of a rate phase-in plan to bring Industrial Customer rates up to the full cost of supply as contemplated in OC2013-089, as amended.

Hydro proposes that the Board conduct a full review of its costs at the Amended 2013 GRA, and to adjust rates and refund money to customers if it determines that the interim rates have collected excess revenues.

The Consumer Advocate's position with respect to Hydro's 2015 Interim Rates Application is set out below.

A. ***Qualifying the Need for Interim Rates***

In the Interim Rates Evidence dated November 2013 (Section 3, pages 4 to 6), Hydro documents historical use of interim rates in this Province. Hydro quotes the Board in Order No. P.U. 41(2006) as follows (page 4, lines 17 to 20):

> *WHEREAS section 75 of the Act provides that the Board may make an interim order unilaterally and without public hearing or notice, approving with or without modification a schedule of rates, tolls and charges submitted by a public utility upon the terms and conditions that it may decide; and …*

The Board goes on to state in the same Order (page 4, lines 21 to 24 of Hydro's November 2013 Interim Rates Evidence):

> *WHEREAS if, after a full review of Hydro's Revised Application, it is determined that excess revenue has been earned by Hydro as a result of the Interim Order the Board may order, pursuant to Section 75(3) of the Act, that customers of Hydro receive a refund; and*

Therefore, the Board has jurisdiction to approve interim rates, and if the review of the Amended 2013 General Rate Application determines that the interim rates have resulted in Hydro earning excess revenues, to refund the excess revenues to customers. Interim rates applications are common practice in other jurisdictions (see Amended 2013 GRA, page 4.20, footnote 30).

Hydro has now filed three different interim rates applications since the 2013 GRA[1] involving considerable time, resources and focus of the Board and the parties. The multiple interim rates applications demonstrate the lack of consensus among the parties and Hydro on what is required in the way of evidence and supporting documentation to afford a proper review of an interim rates application. The Consumer Advocate proposes that the Board apply the interim rates test used by the Alberta Utilities Commission. The Alberta interim rates test identified below includes two parts. The first part of the test relates to quantum and need for the rate increase and the second part of the test relates to the general public interest.

[1] The Board's February 4, 2015 email directed the Parties to preface requests for information with the letters TIR for "third interim rate application".

Part One

i. Is the identified revenue deficiency probable and material?

ii. Can all or some portion of any contentious items be excluded from the amount collected?

iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?

iv. Can the applicant continue safe utility operations without the interim adjustment?

Part Two

i. Do the interim rates promote rate stability and ease rate shock?

ii. Do the interim adjustments help maintain intergenerational equity?

iii. Can interim rate increases be avoided through the use of carrying costs?

iv. Are the interim rate increases required to provide appropriate price signals to customers?

v. Is it appropriate to apply the interim rider on an across-the-board basis?

Decisions involving interim rates filings of two transmission and distribution utilities, ENMAX and ATCO, where the Alberta Utilities Commission utilized its two-part interim rates test are summarized below.[2]

In the ENMAX interim rates application, the utility requested: 1) approval of interim rates that would collect 60% of its forecast revenue shortfall, and 2) that the interim rates increase be applied equally across the board to all customer classes in order to maintain the currently approved rate structure. In making its decision, the Commission applied the above-stated two-part test for interim rates, and found that collection of 60% of the utility's revenue deficiency would be sufficient to account for potentially contentious elements of the utility's revenue requirement calculation, noting that the proposed rate increases were requested on an interim basis and would be trued up once the final 2015 rates were approved. The Commission also noted that an equal across-the-board increase to all rate classes was a simple and cost effective method for applying the increase.

In the ATCO interim rates application, the utility requested recovery of 77% of its distribution revenue requirement and 86% of its transmission revenue requirement. For the purposes of the interim rates calculation, ATCO excluded two cost items that it considered potentially contentious.

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[2] Alberta Utilities Commission Decisions include "*ENMAX Power Corporation; 2015 Interim Distribution and Transmission Tariff Application*" dated November 12, 2014 (http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-311.pdf), and "*ATCO Electric Ltd.; 2009 Interim Distribution Tariff and Transmission Facility Owner's Tariff*" dated December 19, 2008 (http://www.auc.ab.ca/applications/decisions/Decisions/2008/2008-134.pdf).

In rendering its decision, the Alberta Utilities Commission applied the above stated two-part test for interim rates, but found that ATCO had provided limited information with respect to the test to support its interim rates request. The Commission found that some form of interim rates relief was justified, but was concerned that the final approved rates could be based on an amount that was less than the interim rate increase proposed by the utility. The Commission found that to provide gradualism and a transitional rate level, an intermediate position between current rates and proposed final rates was preferable. The Commission noted that past practice for interim rates orders had generally resulted in decisions maintaining existing rates or granting 50% of the proposed revenue requirement increase. Based on these circumstances, the Commission approved 50% of the proposed revenue increase for the utility's transmission component and 25% of the proposed revenue requirement increase for the utility's distribution component effective January 1, 2009.

We note that Newfoundland Power's 2009 application for interim rates effective January 1, 2010 would not have passed the two-part interim rates test. As stated in Hydro's November 2013 Interim Rates Evidence (page 5, lines 16 to 18), "*The application was filed on the basis of the uncertainty of the timing of the issuance of the Board's final Order and the potential impacts on NP's opportunity to earn a just and reasonable return*". The potential impact on a utility's opportunity to earn a just and reasonable return is not enough to pass the two-part interim rates test. In the absence of clear direction on filing requirements, Newfoundland Power did not show that additional revenue was needed: 1) because its revenue deficiency was material, and needed to preserve its financial integrity, 2) to avoid financial hardship, or 3) to continue safe operations.

B. ***Does Hydro's Application Meet the Two-part Interim Rates Test?***

In reply to TIR-CA-NLH-1, Hydro provides a defence of its 2015 Interim Rates Application on the basis of the two-part interim rates test. Hydro indicates that in its opinion its 2015 Interim Rates Application meets this test.

With regard to quantum and need for the interim rates, Hydro states that its revenue deficiency is probable and material as continuation of 2007 base rates would result in a net loss in 2015 of $34.6 million (TIR-CA-NLH-1, page 3 of 12, lines 7 to 9). If interim rates are made effective March 1, Hydro will recover 70% of the forecast net income deficiency for 2015 (TIR-CA-NLH-1, page 3 of 12, lines 18 to 20), therefore in effect, some portion, and perhaps all, of the contentious cost items in the Amended 2013 GRA have been removed from the proposed amount to be collected under interim rates. Delays in implementation of interim rates beyond March 1 would further worsen Hydro's financial position. For example, if interim rates were implemented effective April 1, the forecast net income for 2015 would be reduced to $5.2 million, or 60% recovery of the forecast net income deficiency (TIR-CA-NLH-1, page 4 of 12, lines 19 to 22, and page 5 of 12, lines 1 to 2). Although Hydro could continue to provide safe operations without interim rates, it would be forced to take actions to minimize financial losses and cut costs (TIR-CA-NLH-1, page 7 of 12, lines 10 to 14). Hydro states that Board approval of interim rates is necessary to "*preserve Hydro's financial integrity and to avoid potential long term hardship to both Hydro and ratepayers through increased long-term borrowing costs*" (TIR-CA-NLH-1, page 7 of 12, lines 2 to 5). In the ENMAX case cited earlier, the Alberta Utilities Commission noted that such revenue deficiencies reduce cash flow, which in turn requires increased short-term borrowing, and might also impact long-term borrowing (Para. 30).

It is clear that given these circumstances, Hydro requires an interim rate increase and its application passes Part 1 of the interim rates test. Hydro also shows that with respect to Part 2 of the interim rates test, its proposed interim rates will promote rate stability, ease rate shock, help to maintain inter-generational equity, and improve price signals to consumers. The Consumer Advocate submits that Hydro's 2015 Interim Rates Application meets the requirements set out in the two-part interim rates test. The key consideration in the assessment of this Application is the impact on the electricity consumers in the Province. The Consumer Advocate does not see how electricity consumers can possibly benefit from Hydro's continuing financial deterioration.

C. ***Should Hydro's 2015 Interim Rates Application be Approved as Proposed?***

The Consumer Advocate has reviewed Hydro's 2015 Interim Rates Application from the perspective of: 1) the amount of revenue requested in light of Hydro's financial position, 2) the impacts on customers in terms of rate smoothing, and 3) legal requirements under OC2013-089, as amended.

Regulatory boards that allow an interim rate increase often cap the amount at a percentage of the additional revenue needed to provide the utility a reasonable rate of return. In the ENMAX and ATCO cases cited above, the Alberta Utilities Commission limited both utilities to 60% or less of the utility's required increase in revenues. Such limits are imposed for several reasons, such as: 1) to acknowledge that the utility is at least partly responsible for needing the interim rates; i.e., because it filed its rate case too late; 2) to reduce the possibility that a rate reduction will be necessary when final rates are set; i.e., because the regulatory commission removes costs that have not met the prudency test, or because the regulatory commission allows a lower rate of return than requested by the utility; 3) to enable rate smoothing and reduce rate impacts on customers; and 4) to alleviate intergenerational equity concerns.

Hydro is in effect requesting 78.5% of its revenue deficiency for 2015[3] because the rates would become effective on March 1, 2015 rather than January 1, 2015 (see TIR-CA-NLH-2). Because the proposed rate increase would be implemented effective March 1, 2015, the Board is left to decide at the GRA how much of the $13.7 million of Hydro's 2015 revenue shortfall should be recoverable in final rates. Of course, if the Board found that more than $13.7 million should be removed from the revenue requirement, it could reduce rates and refund excess revenues to customers. However, $13.7 million covers off considerable uncertainty in Hydro's costs. For example, if the Board were to disallow recovery of 100% of the 2015 costs that are subject to its prudency review, the final allowed increase in Hydro revenues would still exceed by $5.6 million the amount resulting from proposed interim rates if implemented March 1, 2015 (see TIR-CA-NLH-3).[4] There are other applications relating to Hydro costs under Board review as well, such as Hydro's 2014 revenue

[3] Calculated as follows: ($570,261,000 – $520,329,000) / ($583,917,000 – $520,329,000) = 0.785, or 78.5%.

[4] In TIR-NP-NLH-3, Newfoundland Power requests the amount of amortization included in the 2015 test year adjusted revenue requirement related to capital projects that are subject to further review by the Board. Hydro's response indicates that $4.4 million in amortization costs and $8.7 million relating to return on rate base, for a total of $13.1 million, is included in the 2015 revenue requirement for these projects. It is understood that the difference between this response and the response to TIR-CA-NLH-3 (Part 4) relates to return on rate base which was frozen at the 6.82% level in TIR-NP-NLH-3 to be consistent with the revenue requirement calculation included in the Amended 2013 GRA. In either case, the revenues from proposed 2015 interim rates effective March 1, 2015 would be less than the 2015 revenue requirement even if all 2015 costs subject to the Board's prudency review were disallowed (by $0.5 million for the case considered in TIR-NP-NLH-3).

deficiency (see November 28, 2014 letter to Board entitled *Newfoundland and Labrador Hydro's 2013 Amended General Rate Application – 2014 Cost Recovery Application*) and the 2014 increased capacity-related supply costs on the Island Interconnected System (see October 8, 2014 letter to the Board entitled *An Application by Newfoundland and Labrador Hydro for the approval of the deferral and recovery of expenses associated with the increased capacity-related supply costs on the Island Interconnected System in 2014*). Therefore, there are ample opportunities for the Board to claw back any excess revenues that might accumulate to Hydro under the 2015 Interim Rates Application; i.e., rate riders established to recover these costs might be reduced, or eliminated altogether, as the Board sees fit.

With regard to rate shock, Table 5 (page 16) of the 2015 Interim Rates Application Evidence shows that rate increases are not only manageable, but in most cases, customer classes will see rate decreases owing to a steep drop in the oil price forecast.[5] A notable exception is the IIC class. Hydro states in the 2015 Interim Rates Application Evidence (page 1, lines 20 to 21), "*The Island IC Group presented the position that the impacts of the rate proposals reflected in the Amended Application constitute "rate shock"*".

Hydro has addressed this issue in its evidence (Section 2), and developed a phase-in plan for IIC rates that it believes to be consistent with OC2013-089, as amended. Table 2 (page 9) of the 2015 Interim Rates Evidence presents two alternative rate phase-in proposals for the IICs. The Consumer Advocate submits that both approaches violate OC2013-089, as amended, which requires that the IIC rate phase-in occur over a three-year period beginning September 1, 2013. The next steps in the IIC rate phase-in should therefore occur on September 1, 2014 and September 1, 2015, with IIC rates brought up to the full cost of supply on September 1, 2016. We note that when Step 1 of the IIC rate phase-in was approved in Order P.U. 26(2013) the subsequent steps were not approved at the same time (with adjustments for costs ultimately approved by the Board in the GRA). It is the Consumer Advocate's submission that OC2013-089, as amended, establishes a legal requirement that the next step of the IIC rate phase-in be implemented retroactively to September 1, 2014, with subsequent steps approved for implementation on September 1, 2015 and September 1, 2016, and that the IIC RSP operate in accordance with the approved methodology effective January 1, 2014.

Further, OC2013-089, as amended, is clear that the IIC rate phase-in is to be funded from the January 1, 2007 to August 31, 2013 accumulated Load Variation component of the Rate Stabilization Plan that was credited to the IIC Rate Stabilization Plan effective August 31, 2013 (the IIC RSP Surplus Fund). Hydro has proposed to offset part of the IIC rate increase by transferring $2.1 million from the balance of the load variation component of the RSP that has built up since September 1, 2013 (see 2015 Interim Rates Application Evidence, pages 4 and 5) . Hydro makes this proposal even though the Board has yet to rule on the methodology for disposition of this balance (page 5 of 2015 Interim Rates Application Evidence, lines 6 to 13). The Consumer Advocate submits that it is inappropriate to transfer $2.1 million from this account to fund the IIC rate phase-in when the Board has not yet ruled that these funds are owing to the IICs; neither is use of these funds for this purpose consistent with OC2013-089, as amended. The IIC rate phase-in scenario without the $2.1 million transfer is addressed in TIR-IC-NLH-4, scenario (c). Tables 2 and 3 (page 2 of 3) show the resulting impact on IIC rates and the IIC RSP Surplus Fund balance.

The argument that the IIC rate phase-in results in rate shock is not valid, given:

[5] The IICs, the Island and Labrador Isolated Government Departments, and Labrador Interconnected customers would see rate increases while all other classes would see rate decreases (see TIR-CA-NLH-5).

1) Under OC2013-089, as amended, it is a legal requirement that IIC rates be raised to the full cost of supply over a three year period (2015 Interim Rates Application Evidence, page 2, lines 21 to 22). As stated in the 2015 Interim Rates Application Evidence (page 1, lines 15 to 18), the interim rates are needed "*to permit the continued phase-in of the Island Industrial Customer (IC) rates and to ensure the forecast fuel costs reflected in the proposed interim rates were consistent with the forecast fuel costs used in the operation of the RSP*";
2) The IICs did not have a rate increase from 2008 through August 2013. As stated in the Second Interim Rates Application Evidence dated May 2014 (page 8, lines 22 to 24): "*The IC rates do not currently include a fuel rider and, as a result, their rates do not recover the increased cost of Holyrood fuel since the 2007 Test Year*". In 2007, the average Holyrood fuel purchase price was $56.86 per barrel. This compares to an average Holyrood fuel purchase price in 2012 of $115.26 (see 2013 GRA, page 2.47, lines 4 to 5), representing an increase of 103%. Conversely, Newfoundland Power customers have been subjected to annual rate adjustments to reflect increased fuel costs since the 2007 test year;
3) The IICs received a subsidy of $37.6 million granted through OC2013-089, as amended (based on a comparison of revenues that should have been collected from the IICs during the period 2008 through 2012 had the load variation component of the RSP been allocated on the basis of load ratio share as proposed by Hydro in the 2006, 2013 and the Amended 2013 GRAs – see RSP-CA-NLH-12)[6]. This subsidy is more than double the average annual revenue Hydro received from the entire IIC class during the period from 2008 to 2012 (see CA-NLH-183 of 2013 GRA);
4) The dramatic reduction in the recent oil price forecast has mitigated a significant portion of the required IIC rate increase. As stated by Hydro in the 2015 Interim Rates Evidence (page 7, lines 18 to 20): "*For the purpose of establishing interim rates, an adjusted revenue requirement for NP and the Island IC was determined to reflect the reduced No. 6 fuel cost forecast for 2015*". According to the Amended GRA (Table 1 on page 1.6R), the required IIC rate increase based on the 2013 Test Year was 73.1%. The required rate increase for the IICs was reduced to 39.2% in Hydro's Amended 2013 GRA, and to 18.1% in the 2015 Interim Rates Application owing to the updated Holyrood fuel cost (see TIR-PUB-NLH-6).
5) Teck Resources will cease to take power and no longer be a customer in June 2015 (see page 2.61 of Amended 2013 GRA, lines 15 to 17);
6) CBPP has received a considerable rate reduction in its bills owing to capacity assistance agreements, including $6.1 million in the first quarter of 2014 (see Table 1, page 2 of Hydro Application for Deferral and Recovery of 2014 Capacity-Related Supply Costs Evidence dated October 2014) and $1.7 million annually beginning in 2015 (see October 28, 2014 cover letter to *Application of Newfoundland and Labrador Hydro for approval of Agreement with Corner Brook Pulp and Paper Limited for Capacity Assistance*);
7) Vale will receive a rate reduction owing to its new capacity assistance agreement. It is understood that Vale will initially provide 10.8 MW of capacity assistance, increasing to 15.8 MW as Vale's load ramps up to full capacity. The payment is $28/kW, so the total annual payment will be $442,400 once the capacity assistance increases to 15.8 MW (see December 1, 2014 *Capacity Assistance Agreement between Hydro and Vale*);
8) Vale only began taking power in December 2012, and is not expected to reach full production levels until the end of 2016 (see page 2.60, lines 19 to 22 of Amended 2013 GRA); and

[6] The Board approved the transfer of RSP funds to the IICs consistent with OC2013-089, as amended, but the IIC rate phase-in has fallen behind the schedule required in OC2013-089, as amended. Step 2 of the rate phase-in should have been implemented on September 1, 2014. The purpose of the funds transfer was to pay for the phase-in of IIC rates.

9) Praxair only began taking power in October 2013 and is expected to ramp up operations through the end of 2014 (see page 2.61, lines 1 to 3 of Amended 2013 GRA).

D. Pass-through of Interim Rates to Newfoundland Power Customers

It is important that the Board's Order relating to Hydro's 2015 Interim Rates Application be quickly passed through to Newfoundland Power customers since it will result in a rate reduction. In the response to TIR-CA-NLH-8, Hydro indicates that Newfoundland Power has in the past been able to quickly file applications with the Board for increased rates to its customers when it has had advanced notice.

The Consumer Advocate supports Hydro's proposal that there be no RSP rate adjustment for Newfoundland Power customers in July 2015. As stated by Hydro (2015 Interim Rates Application Evidence, page 14, lines 7 to 10): "*Implementation of revised rates on March 1, 2015 reflect both the disposition of the balance in the RSP segregated load variation component and the updated fuel forecast avoids the requirement for a July 1, 2015 rate change*".

E. Recommendations

The Consumer Advocate recommends that the Board:

1) Approve Hydro's 2015 Interim Rates Application as proposed subject to adjustment following a full review of Hydro's costs at the Amended 2013 GRA (with implementation of rate adjustments in a manner similar to the method proposed in TIR-CA-NLH-6)[7]. The Consumer Advocate urges the Board to direct Newfoundland Power to implement these interim rates promptly so that its customers receive the rate reduction in a timely manner. Further, there should be no RSP rate adjustment for Newfoundland Power customers in July 2015;
2) Approve Hydro's proposed phase-in plan (the entire phase-in plan, not just the first step) for IIC rates subject to modifications stemming from the amended 2013 GRA, but implement the first step retroactively to September 1, 2014, the second step on September 1, 2015 and the third and final step on September 1, 2016 to be consistent with OC2013-089, as amended. Further, the proposal to offset part of the IIC rate increase by transferring $2.1 million from the balance of the load variation component of the RSP should not be allowed. The Board has not yet ruled on the methodology for disposition of this balance.

Please feel free to contact the undersigned if you have any questions.

[7] The Board has gone back to adjust interim rates in the past as documented in the response to TIR-CA-NLH-7.

Yours very truly,

O'DEA, EARLE

THOMAS JOHNSON, Q.C.

TJ/cel
Encl.

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HAND DELIVERED

February 18, 2015

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

Attention: G. Cheryl Blundon
Director of Corporate Services
and Board Secretary

Ladies and Gentlemen:

Re: Newfoundland and Labrador Hydro's 2015 Interim Rates Application

A. Introductory

On January 28th, 2015, Newfoundland and Labrador Hydro ("Hydro") filed an application for interim approval of customer electricity rates to be effective March 1st, 2015 (the "2015 interim rates application"). The 2015 interim rates application is the third application for interim rates since the July 2013 original filing of Hydro's currently outstanding general rate application (the "general rate application").

In principle, Newfoundland Power does not oppose interim rates for Hydro. However, the interim rates proposed in the 2015 interim rates application are not, in Newfoundland Power's view, consistent with the reasonableness requirement of the *Electrical Power Control Act, 1994*.

This letter contains Newfoundland Power's submissions on Hydro's 2015 interim rates application.

B. Overview of the 2015 Interim Rates Application

The 2015 interim rates application seeks to implement the rates proposed in the general rate application, adjusted for a reduced forecast for the price of fuel used by Hydro, revised implementation of Hydro's Industrial Customers rate increase, and modifications to Hydro's rate stabilization plan ("RSP").[1]

[1] See the response to Request for Information TIR-PUB-NLH-001.

The general rate application indicates a revenue deficiency for Hydro in 2015 of $67.8 million.[2] The rates proposed in the 2015 interim rates application would provide full recovery of this revenue deficiency on an annualized basis.

The evidence filed in support of the 2015 interim rates application asserts that "Hydro's forecast income statement under existing rates shows a net loss of $34.6 million for 2015."[3] In addition, Hydro indicates that exclusion of "any" costs, or delays in implementation, will increase future rates to customers.[4] The 2015 interim rates application appears to assume that Hydro's assertion of a forecast loss for 2015 provides, in and of itself, sufficient justification for the Board to approve interim rates for Hydro's customers which are based on untested costs.[5]

Section 3 of the *Electrical Power Control Act, 1994* requires that electricity rates should be reasonable. A key attribute of reasonable rates is that they permit recovery of only those costs reasonably attributed to the provision of service to customers. Section 4 of the *Electrical Power Control Act, 1994* directs that in setting electricity rates, the Board apply tests that are consistent with generally accepted sound public utility practice.

The Board has historically used tested costs to establish rates, even interim rates.[6] The use of tested costs ensures that the rates are reasonable. The costs which are included in the rates proposed in the general rate application have never been tested. This presents a challenge for the Board in determining reasonable interim rates.

Hydro asserts that a forecast 2015 loss provides sufficient regulatory justification for the Board's approval of the rates requested by Hydro in the 2015 interim rates application. This is not consistent with regulatory practice in this province or Canada generally. In determining the reasonableness of interim rates, Canadian regulators appear to look at factors in addition to any forecast utility revenue deficiency. Further, Hydro's 2015 rate base, costs and return reflected in the general rate application include amounts that are not reasonable for recovery in interim rates at this time.

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2 In the response to Request for Information TIR-CA-NLH-001, Hydro states that the difference in forecast 2015 net income between proposed rates and existing rates is $67.8 million.

3 See *2015 Interim Rates Application Evidence*, page 1, lines 8-9.

4 See the response to Request for Information TIR-CA-NLH-001, page 4, line 1, *et. seq.*

5 This is also evident in Hydro's responses to information requests. For example, the response to Request for Information TIR-CA-NLH-001 refers to a test used by the Alberta Utilities Commission ("AUC") to evaluate interim rates applications. This response, in evaluating the four factors used by the AUC to assess the quantum and need for a rate increase, appears to rely solely on Hydro's "forecast 2015 net income deficiency" to establish the quantum and need for the rate increase.

6 See, for example, Order Nos. P.U. 34 (2007), P.U. 37 (2008), P.U. 1 (2009), P.U. 6 (2009), P.U. 25 (2010), P.U. 6 (2012), and P.U. 9 (2013) which approved interim rates for Hydro's island industrial customers for the period January 1, 2008 to August 31, 2013 (based on costs tested in Order No. P.U. 8 (2007)). Similarly, in Order No. P.U. 16 (1998-99), the Board made Newfoundland Power's customer rates interim following testing of the utility's cost of capital. The interim rates approved by the Board were based on a combination of (i) the tested cost of capital and (ii) other costs approved by Order No. P.U. 7 (1996-97).

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A review of (i) the costs Hydro proposes be recovered in interim rates and (ii) regulatory practice in other Canadian provinces should inform the Board in assessing the reasonableness of the rates proposed in the 2015 interim rates application.

C. Hydro's Costs Proposed to be Recovered in Interim Rates

In the 2015 interim rates application, Hydro seeks to have the Board approve rates based on the test-year costs proposed in the general rate application, adjusted for the cost of fuel. The general rate application seeks recovery of costs which have not been tested. Hydro's recovery of some of these costs in interim rates at this time would be contentious. For other costs, such as Hydro's increased return, recovery in interim rates at this time would be premature.

Since January 2014, the Board has been conducting an *Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System* (the "supply investigation"). While the supply investigation has not concluded, the Board has indicated that it intends to review the prudency of over $200 million in Hydro expenditures. This review is outstanding. The rates proposed in the general rate application seek to recover both return and amortization in respect of some of those expenditures. Hydro has indicated that excluding the amortization and return on capital projects not approved for inclusion in its rate base and subject to prudency review would reduce the 2015 revenue requirement by $13.1 million.[7]

In the general rate application, Hydro proposes a fuel conversion rate for its Holyrood Thermal Generating Station of 607 kWh/bbl. This is inconsistent with longstanding practice. In Order Nos. P.U. 14 (2004) and P.U. 8 (2007), fuel conversion rates of 630 kWh/bbl were assumed for Hydro's Holyrood operations.[8] There is no clear evidence indicating why the lower fuel conversion rate proposed in the general rate application is reasonable. In fact, the lower fuel conversion rate appears contrary to the evidence.[9] Hydro has indicated that assuming a conversion rate of 630 kWh/bbl for Holyrood operations would reduce the 2015 revenue requirement by $7.2 million.[10]

In the general rate application, Hydro's evidence indicates that the government direction by which it would earn the same return on equity as Newfoundland Power was intended to take effect "…*following* Hydro's next [general rate application]" (emphasis added).[11] Hydro

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7 See the response to Request for Information TIR-NP-NLH-003.

8 The 630 kWh/bbl conversion rate approved in Order No. P.U. 8 (2007) was *agreed* to by Hydro in settlement negotiations.

9 See the response to Request for Information IC-NLH-093, Revision 1, lines 13-15 in the general rate application, where Hydro indicates the conversion rate is largely influenced by the level of loading of the Holyrood units. See Regulated Activities, Schedule V of Hydro's general rate application, where Hydro shows that 2015 forecast Holyrood production is forecast to be higher than 2007 test-year Holyrood production.

10 See the response to Request for Information TIR-NP-NLH-007.

11 See *Newfoundland and Labrador Hydro 2013 General Rate Application (Amended), Evidence, Section 1: Introduction*, page 1.27, lines 17-19.

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proposes to earn this return in interim rates. The implementation of OC2009-063 will increase Hydro's return on rate base from that approved by the Board following Hydro's last general rate application. While the entitlement to an improved return on equity has been determined by OC2009-063, the timing of its recovery is clearly linked to the conclusion of the general rate application, not an interim application prior to the general rate application. Use of the improved return in the setting of interim rates prior to conclusion of the general rate application, would therefore be premature. Hydro has indicated that the improved return on equity resulting from the implementation of OC2009-063 in interim rates increases the 2015 revenue requirement by $23.1 million.[12]

All of these cost factors should be considered by the Board in establishing interim rates that are *reasonable* for both Hydro and those it serves.[13]

D. Indications of Canadian Regulatory Practice

Interim rates are used in a number of Canadian regulatory jurisdictions. Typically, regulators consider a variety of factors in evaluating requests for changes in rates on an interim basis.

A good summary of the factors considered by the Alberta Utilities Commission (the "AUC") can be found in the 2008 Alberta Utilities Commission decision in *Re ATCO Electric Ltd.*.[14] The AUC considers factors such as the materiality of any identified revenue deficiency, the possibility of excluding contentious costs from interim rate recovery, the need to preserve the financial integrity and safe operations of the utility, and rate design considerations.[15] Where costs are contentious, the AUC's primary objective is to determine a revenue requirement level,

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12 See the response to Request for Information PUB-NLH-056, Revision 1 in the general rate application. The improved return on Hydro provided by OC2009-063, in effect, reflects a combination of (i) a rate of return on equity equivalent to that granted to Newfoundland Power and (ii) a return on equity on investment in rural assets.

13 As a matter of perspective, there are significant cost reductions to Hydro's current 2015 test-year which will likely be required by the Board for ratemaking purposes but are not mentioned in this submission. For example, lower rate base and cash flow requirements associated with materially lower Holyrood fuel prices are not yet reflected in the 2015 test-year. See the response to Request for Information TIR-NP-NLH-008. Similarly, 2014 forecast capital expenditures totaling $38 million are included in the current 2015 test-year rate base for assets which were not actually in service at year-end 2014. See the response to Request for Information TIR-NP-NLH-011. In Newfoundland Power's view, adjustments of this magnitude are best left for consideration in the general rate application.

14 See *Re ATCO Electric Ltd*., 2008 CarswellAlta 2098.

15 Ibid, and see the response to Request for Information TIR-CA-NLH-001 which outlines the application of this AUC test in *ENMAX Power Corporation; 2015 Interim Distribution and Transmission Tariff Application* (Decision 2014-311). Also see *Re ATCO Gas Ltd*., 2005 CarswellAlta 2281, where the predecessor of the AUC considered that an effective approach which could be used by a utility to determine an appropriate level of interim rates is to look at areas which may be contentious and to exclude all or some portion of those amounts from the amount to be collected through interim rates. In this manner, the potential of over-collection from interim rates would be minimized, which would, in turn, reduce potential fluctuations to customers' rates.

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on an interim basis, that would mitigate against significant revenue over-collection during the expected term of the interim rate.[16]

In their consideration of interim rates, the AUC does not automatically provide a utility with full recovery of a proposed revenue requirement increase. For example, the AUC has granted only a portion of the revenue requirement increase proposed in the principal rate case where such an approach seemed reasonable.[17]

It appears that the Manitoba Public Utilities Commission (the "MPUC") also considers a number of factors in its consideration of interim rate requests. The MPUC also will permit only partial recovery of proposed revenue requirement increases on an interim basis where the circumstances indicate this is reasonable.[18]

The Board has, on a number of occasions, indicated the fundamental principles which guide it in regulatory decision-making, including decision-making relating to the rates charged by Hydro.[19] These principles assist the Board in balancing the interests of both consumers and the utilities that serve them. They also appear to broadly reflect the practice of the AUC and the MPUC in balancing the utility and consumer interests when determining interim rates.

Canadian regulatory practice appears to be consistent with the requirement in section 3 of the *Electrical Power Control Act, 1994* that interim rates must be reasonable from the perspective of both the utility *and* those it serves.

E. Newfoundland Power's Submission

Hydro's last general rate application was filed in 2006. Given the substantial passage of time, it is not surprising that the amended general rate application filed in November 2014 would have substantially different costs. In addition, significant outstanding events, including the Board's prudency review, may affect Hydro's future cost recovery. Finally, the length of time the

[16] *AltaLink Management Ltd.*, Re, 2004 CarswellAlta 2064.

[17] See *Re ATCO Electric Ltd*., 2008 CarswellAlta 2098, paragraph 24; although in that case ATCO Electric was granted 50% of the proposed increase in the transmission revenue requirement and only 25% of the proposed increase in the distribution revenue requirement on an interim basis (paragraph 25).

[18] See *Re Manitoba Hydro*, 2011 CarswellMan 390, where Manitoba Hydro was granted a 2% rate increase on an interim basis after seeking a 2.9% increase.

[19] See, for example, Order No. P.U. 7 (2002-2003), page 27 *et. seq.* and Order No. P.U. 14 (2004), page 22, *et. seq.* which considered Hydro's first two general rate applications. The principles identified by the Board included fair return, cost of service, fair cost apportionment, efficiencies, rate stability and predictability and a fair and reasonable end result.

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general rate application has been outstanding is extraordinary.[20] All of these matters complicate the Board's determination of interim rates which satisfy the reasonableness requirement of section 3 of the *Electrical Power Control Act, 1994*.

The 2015 Hydro costs proposed to be recovered by the 2015 interim rates application include a significant amount of costs that are subject to prudency review by the Board or are inconsistent with longstanding practice. In addition, the 2015 interim rates application proposes recovery of higher returns *in advance* of conclusion of the general rate application as opposed to *following* the general rate application as directed by OC2009-063. Exclusion of costs such as these in the establishment of interim rates appears consistent with Canadian regulatory practice.

Canadian regulatory practice indicates partial recovery of a forecast utility revenue deficiency in interim rates may be appropriate in certain circumstances. This helps ensure that costs which are not clearly appropriate for interim rate recovery are not borne prematurely by customers. It also mitigates against revenue over-collection during the time the interim rates are in effect.[21] This type of approach is consistent with the Board's expressed view of reasonableness as a balance of the interests of the utility and those it serves.[22]

In Newfoundland Power's submission, reasonable interim rates for Hydro would not be based upon full recovery of the costs outlined in **C. Hydro's Costs Proposed to be Recovered in Interim Rates** above. Exclusion of all, or part, of such contentious 2015 Hydro costs would ensure greater benefit from the reduced price of fuel would flow to Newfoundland Power's customers. The resulting rate decrease for Newfoundland Power's customers would be materially greater than the 6.3% decrease indicated by Hydro in the 2015 interim rates application.

Based upon the foregoing, the Board should not approve the interim rates proposed by Hydro in the interim rate application because the rates have not been shown by Hydro to be reasonable.

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[20] The length of time since the July 2013 filing of the original general rate application has been attributable to a number of procedural considerations and developments. One was the length of time required by Hydro to respond to Requests for Information on the original general rate application. Another was the decision by Hydro a month before commencement of the hearing into the original general rate application to amend and re-file that application some five months later.

[21] From 2007 to 2013, large balances accumulated in the RSP under Hydro interim rates. These balances were not distributed in accordance with the approved operation of the RSP which is based upon cost causation. Instead, the provincial government by OC2013-089 (as amended by OC2013-207) directed the credit of $49 million (or 30%) to Hydro's Industrial Customers notwithstanding those customers accounted for less than 10% of system load during the period. This direction effectively reduced the amount of the balance that would have flowed to Newfoundland Power's customers based upon the regulatory principles which underlie the operation of the RSP.

[22] It is also consistent with the view expressed by the Newfoundland and Labrador Court of Appeal that the language contained in section 3 of the *Electrical Power Control Act, 1994* emphasizes the need for tempering each of the utility's and its customers' economic interests by consideration of the interests of the other. See the *Stated Case*, June 15, 1998, Docket: 96/141, paragraph 23.

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Instead, the Board should direct Hydro to create interim rates which exclude recovery of specified untested 2015 Hydro costs which the Board determines should not be included in interim rates. In the circumstances, this would satisfy the requirement in section 3 of the *Electrical Power Control Act, 1994* that interim rates must be reasonable from the perspective of both the utility *and* those it serves.

F. Concluding

A copy of this letter, together with copies of the regulatory decisions from other provinces referred to in it, has been forwarded directly to the parties listed below.

If you have any questions regarding the enclosed, please contact the undersigned at your convenience.

Yours very truly,

Gerard M. Hayes
Senior Counsel

Enclosures

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Newfoundland and Labrador Hydro

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2004 CarswellAlta 2064
Alta. E.U.B.

AltaLink Management Ltd., Re

2004 CarswellAlta 2064

AltaLink Management Ltd. and TransAlta Utilities Corporation, 2004-2005 Interim Transmission Tariff

B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member

Judgment: June 2, 2004
Docket: 2004-046

Subject: Public

Related Abridgment Classifications

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2004 CarswellAlta 2064

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered by *B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member*:

AltaLink Management Ltd., Re (2002), 2002 CarswellAlta 1955 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2003), 2003 CarswellAlta 2042 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2004), 2004 CarswellAlta 2031 (Alta. E.U.B.) — considered

AltaLink Management Ltd., Re (2004), 2004 CarswellAlta 2048 (Alta. E.U.B.) — considered

Statutes considered:

Electric Utilities Act, S.A. 2003, c. E-5.1
s. 37(1) — pursuant to

s. 119(1) — pursuant to

Regulations considered:

Electric Utilities Act, S.A. 2003, c. E-5.1
Liability Protection Regulation, Alta. Reg. 66/2004

Generally — referred to

Subject:

***B.T. McManus Member, Gordon J. Miller Member, and R.G. Lock Presiding Member*:**

1 Introduction and Background

1 On March 11, 2004, pursuant to sections 37(1) and 119(1) of the *Electric Utilities Act (EU Act)*, AltaLink Management Ltd. (AltaLink), in its capacity as General Partner of AltaLink, L.P. (ALP), and TransAlta Utilities Corporation (TransAlta)

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applied to the Alberta Energy and Utilities Board (EUB or Board) for approval of Transmission Facility Owner (TFO) tariffs, for each of AltaLink and TransAlta, on an interim and refundable basis and for terms and conditions of service (T&C), on an interim basis, both to take effect on May 1, 2004 (Interim Applications).

2 Previously, on February 27, 2004, AltaLink and TransAlta (the Applicants) applied to the EUB for approval of TFO tariffs and terms and conditions of service for May 1, 2004 to December 31, 2007 (2004-2007 GTAs). In a Notice, dated March 22, 2004, the Board established a process and schedule for dealing with the 2004-2007 GTAs, which includes an oral hearing commencing on September 21, 2004. Given the timing of the GTA hearing, the Board's final disposition of the 2004-2007 GTAs will likely not occur until sometime in the first part of 2005.

3 The Applicants' current tariffs, which were finalized and approved in Decision 2004-028, dated March 23, 2004, expire on April 30, 2004. Decision 2004-028 [*AltaLink Management Ltd., Re*, 2004 CarswellAlta 2048 (Alta. E.U.B.)] dealt with AltaLink's Second Refiling, which was required as a consequence of Decision 2003-061 [*AltaLink Management Ltd., Re*, 2003 CarswellAlta 2042 (Alta. E.U.B.)] respecting AltaLink's 2002/03 and 2003/04 GTA and Decision 2004-007 [*AltaLink Management Ltd., Re*, 2004 CarswellAlta 2031 (Alta. E.U.B.)] , respecting AltaLink's First Refiling. The tariff expiration date and the 2004 — 2007 GTA schedule necessitated the filing of the Interim Applications.

4 In recognition of the interim refundable nature of the applied-for TFO tariffs and the requirement for new AltaLink and TransAlta transmission tariffs to take effect from May 1, 2004, the Board established the expedited process and schedule set out below to deal with the Interim Applications.

5 *Table 1. Schedule for AltaLink and TransAlta 2004 Interim Transmission Tariff Applications*

Process Step	***Date***
Information Requests to Applicants	April 8, 2004
Information Responses from Applicants	April 16, 2004
Intervener Submissions	April 23, 2004
Reply Submissions	April 30, 2004

6 The Board considered that this process provided sufficient time for the Board to render a decision on the Interim Applications prior to the Applicants issuing an invoice to the Alberta Electric System Operator (AESO) for transmission services for the month of May 2004.

7 On April 7, 2004, the Board received correspondence from the Industrial Power Consumers Association of Alberta (IPCAA) respecting the Interim Applications. On April 23, 2004, the Board also received submissions from the City of Calgary (Calgary) and the FIRM Group of Customers (FIRM)[1] respecting the Interim Applications.

8 In accordance with the schedule, AltaLink filed its Reply Submission on April 30, 2004. TransAlta did not file a Reply Submission.

9 After review of the filed submissions, the Board determined that it required additional information to assist in its deliberations. The Board sent a supplemental Information Request (IR) to AltaLink on May 13, 2004, and requested AltaLink

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to provide a response by May 17, 2004.

10 The Board received AltaLink's response to the supplemental IR on May 17, 2004 and, therefore, considers the record of the Interim Applications to have closed on that date.

2 Details of the Applications

2.1 AltaLink Interim Application

11 AltaLink originally proposed to invoice the AESO the following monthly TFO charges on an interim refundable basis for use of AltaLink's transmission facilities:

- $15,640,000.00 per month for the 8-month period commencing May 1, 2004 and ending December 31, 2004.
- $17,908,139.00 per month for the period commencing January 1, 2005 and continuing thereafter until the Board renders a final decision on AltaLink's 2004-2007 GTA, or upon further order of the Board.

12 AltaLink explained that at the time of the filing of its Interim Application, interim tariffs reflecting dated parameters had been in effect for AltaLink for 15 months and the decision in respect of AltaLink's refiling application was pending. In addition, AltaLink had filed an application for review and variance of Decision 2003-061 (R&V Application) and was uncertain as to the prospect for, or scope of, any review of that decision.

13 With these uncertainties, and the time required from the filing of 2004-2007 GTA to final tariffs, AltaLink determined that it was appropriate to request interim tariffs for the 2005-2007 period that reflected an average of the revenue requirements for each of the years during the period.

14 When AltaLink filed its Information Responses on April 16, 2004, it advised the Board that on March 31, 2004, the *Liability Protection Regulation* (AR 66/2004) came into force and provided TFOs with liability protection from consequential losses. AltaLink indicated that, as a result of the promulgation of AR 66/2004, the $4 million forecast cost of insurance premiums relating to the $1.1 billion layer of third party liability insurance for the 2005, 2006 and 2007 test years was no longer necessary.

15 As noted, subsequent to the filing of AltaLink's Interim Application, the Board rendered Refiling Decision 2004-028 finalizing AltaLink's rates for the 2003/2004 period, subject only to any adjustments that might flow from the Board's ultimate disposition of AltaLink's R&V Application.

16 AltaLink also noted that interveners have raised concerns respecting AltaLink's use of an average of the forecast revenue requirements for the 2005-2007 period as the requested interim rate commencing January 1, 2005.

17 In light of these circumstances, AltaLink amended its Interim Application in its April 16, 2004 IR response letter by requesting that the Board approve monthly interim refundable AESO transmission charges in the amount of:

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- $ 15,640,000.00 May 1, 2004 through December 31, 2004
- $ 16,208,000.00 January 1, 2005 through December 31, 2005
- $ 17,650,000.00 January 1, 2006 through December 31, 2006
- $ 18,867,000.00 January 1, 2007 through December 31, 2007

18 AltaLink proposed that the amended monthly interim AESO charges continue until such time as the Board renders a final decision on the 2004-2007 GTAs, or upon further order of the Board.

19 AltaLink also requested that the Board approve, on an interim basis, the use of AltaLink's currently approved T&C effective May 1, 2004 and continuing in effect until final terms and conditions are approved for AltaLink when the Board renders a final decision on the 2004-2007 GTAs, or upon further order of the Board.

2.2 TransAlta Interim Application

20 With respect to the use of certain assets located on First Nations lands that were not transferred to AltaLink (Withheld Assets), TransAlta proposed to invoice the AESO the following monthly TFO charges on an interim refundable basis:

- $268,875 per month for the 8-month period commencing May 1, 2004 through December 31, 2004.
- $293,390 for the period from January 1, 2005 to December 31, 2007, or until the Board renders a final decision on TAU's 2004-2007 GTA, or upon further order of the Board.

21 TransAlta explained that the revenue requirement was higher relative to the interim ones in place at the time of the filing of its Interim Application because of increasing levels of capital maintenance and higher operating costs in the forecast test period. TransAlta confirmed that its revenue requirement forecast was tied to AltaLink's forecast for increases in operating expenses and capital maintenance and a number of other financial factors.

22 At the time of filing of its Interim Application, TransAlta expected its last approved T&C to be supplanted when it received the Board's final refiling approvals under Decision 2003-061. Accordingly, TransAlta requested that the interim relief provide that (i) TransAlta's existing T&C remain in effect as of May 1, 2004 as interim unless (ii) if prior to May 1, 2004, new T&C for TransAlta are otherwise approved by the Board, then such new T&C become TransAlta's interim T&C effective May 1, 2004.

3 Views of the Interveners

Views of Calgary

23 Calgary submitted that there were numerous areas of contention in AltaLink's 2004-2007 GTA filing and that these areas remain untested. In Calgary's view, amounts pertaining to contentious issues should be excluded in whole or in part. That is the practice that was adopted by other utilities and that is the practice that would be consistent with the Board's

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rulings with respect to AltaLink's previous interim application in 2002.

24 With respect to rate of return, Calgary stated that the current risk free rate is lower than when Decision 2003-061 was rendered and suggested that a 9.0% rate would be reasonable. Calgary submitted this, coupled with the current 66:34 debt to equity ratio, would reduce the annual revenue requirement by $12-13 million, using AltaLink's schedules.

25 Calgary noted AltaLink had acknowledged that its cost of debt has been reduced as a result of refinancing its $125 million Real Return Bridge Bond as of December 2003. The financing rate has been reduced from 6.7% to 5.288%. Based on a differential between these two rates of approximately 140 basis points, and a debt amount attributable to the book value of regulated transmission assets in excess of $100 million, Calgary claimed the impact on a reduced revenue requirement would be a minimum of $0.6 million.

26 Calgary noted that the income tax rate for Alberta had been reduced to 11.5%. Using the new rate, Calgary calculated the revenue requirement impact to be approximately $0.5 million, on a 12-month basis.

27 Calgary further noted that AltaLink had requested a $12.1 million, or 35%, increase in operating and maintenance expense (O&M). Calgary suggested a conservative approach would be to consider, at a maximum, 50% or $6.0 million of AltaLink's forecast increase in operating costs, in the context of the Interim Application. Underlying the increase were numerous contentious issues, including, but not limited to, non-arm's length transactions with affiliates, compensation, staff counts and inflation. It would not be prudent to consider any more of the O&M increase than that suggested above, and Calgary maintained it was arguable that even that amount may be overly generous given the circumstances.

28 With respect to capital expenditures, Calgary noted that AltaLink had attempted to make a case for unprecedented additions to rate base. The impact on revenue requirement was approximately $8.0 million in 2004 [annualized], accounting for over 5% of the revenue requirement increase. Calgary submitted there might be some component of the capital projects that will be necessary to preserve the safety and reliability of the system and provide assurance, on an interim basis, of financial integrity for the applicant. In Calgary's view, for the purposes of setting interim rates, one half of the capital expenditures forecast by AltaLink would likely achieve those objectives, reducing the revenue requirement impact by $4.0 million.

29 Calgary also noted that the depreciation update had caused an $8.0 million increase to depreciation expense in the requested revenue requirement, maintaining that none of this was associated with the change in net salvage rates. Calgary claimed the depreciation impact was not an amount related to net income and would not affect the return to its owners. As such it should have little or no bearing on the financial integrity of the Applicant. Therefore, in Calgary's view, exclusion of revenue requirement impact due to depreciation should not be considered a financial hardship.

30 Based on the foregoing analysis and summary of the key contentious issues, Calgary maintained that the difference between the requested increase and the amounts associated with contentious areas was not significant. Calgary submitted the Board should not award AltaLink an interim increase in rates, and that the existing rates should remain in place on an interim refundable basis. Calgary's suggested adjustments are summarized in Table 3.

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31 Calgary submitted that no increase should be granted to TransAlta either, as its request was based upon a pro-rata share of AltaLink's costs.

Views of FIRM

32 FIRM noted that in determining the level of the 2003 Interim Transmission Tariffs, the Board considered it appropriate and prudent to examine the areas which would be vigorously contested to determine whether reductions to the applied for revenue requirement were warranted. FIRM submitted that the circumstances of the Interim Applications are substantially comparable and that a similar approach to determining interim rates should be adopted by the Board, maintaining that the Board should examine the areas that would be vigorously contested to determine whether reductions to the applied for revenue requirement were warranted in an attempt to get the interim rates as close as possible to the final rates.

33 FIRM acknowledged that the Board had recently agreed to hear the R&V with respect to a number of matters arising from Decision 2003-061, but argued a Board Order was still in effect and that these matters should therefore not be allowed in interim TFO rates. FIRM therefore submitted that the 25% of the income tax component and Large Corporations Tax related to Ontario Teacher Pension Plan Board (OTPPB or Teachers) be excluded. FIRM estimated the impact of this adjustment to be $4.7 million.

34 FIRM noted that AltaLink had asked for a 10.5 % return on equity and a 37.5% equity ratio, in contrast to the 9.4% return on equity and 34% equity ratio allowed in Decision 2003-061. FIRM suggested that the lower amounts were adequate placeholders for interim rate purposes and estimated the impact of reducing the rate of return, including tax effects, to be $4.5 million. The impact of reducing the equity ratio was estimated to be $4.2 million, including tax effects.

35 FIRM also noted that AltaLink had a depreciation update completed as part of its discontinuation of the constant dollar net salvage (CDNS) methodology for the salvage component of depreciation. AltaLink claimed that this study indicated the composite depreciation rate should increase from 3.01% to 3.63%. FIRM submitted the reasons for these changes must be reviewed in the Phase I portion of the 2004-2007 GTA proceeding and should not be included on an interim basis without further testing. FIRM maintained that the previously approved composite depreciation rate should be used as a placeholder for interim rate purposes and that this non-cash item should not impact AltaLink's financial integrity. The estimated impact of maintaining the current composite depreciation rate, including the income tax and rate base effects, was approximately $13.3 million on an annualized basis.

36 With respect to O&M Expenses, FIRM noted that in refiling Decision 2004-007, the Board approved operating expenses of $35.5 million for the 2003/2004 test year while AltaLink has forecast $30.9 million for 8 months in 2004 (which equated to $46.4 million on an annualized basis). This represented a 31% increase over the 2003/2004 approved operating expense. FIRM submitted this situation was not unlike the previous interim application when AltaLink forecast a 33% increase in operating expenses. FIRM stated that until this significant operating expense increase could be fully tested it would be appropriate to reduce the increase in operating expenses by at least 50% or $7.6 million based on the same rationale relied upon in interim Decision 2002-110 [*AltaLink Management Ltd., Re*, 2002 CarswellAlta 1955 (Alta. E.U.B.)].

37 FIRM also proposed certain other adjustments. FIRM noted the opening balance of property, plant and equipment for the 8 month period May to December 2004 appeared to be overstated by about $8 million. Return, taxes and depreciation on this amount would overstate the 2004 annualized revenue requirement by $1.0 million. FIRM also noted AltaLink had

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over-estimated total capital projects excluding direct assigns by 6.5% in 2002/2003. Absent further evidence with respect to 2003/2004, FIRM submitted it would not be unreasonable to reduce forecast additions for 2004 annualized by a similar amount for interim purposes. FIRM submitted return, taxes and depreciation on this amount or approximately $0.5 million should be deducted from the applied for interim rates. Finally, FIRM noted the Alberta corporate tax rate had been reduced to 11.5%. As AltaLink had not used this rate, revenue requirement was overstated by a further $0.4 million.

38 FIRM's proposed adjustments are summarized in Table 3. FIRM noted that with its proposed adjustments the revised monthly tariff for the period May-December 2004 corresponded almost exactly to the existing monthly tariffs approved in refiling Decision 2004-028. FIRM submitted that based on the foregoing, the Board should set the interim tariff commencing May 1, 2004 at the existing approved monthly tariff of $12.5 million per month.

39 FIRM further submitted that no increase should be granted to TransAlta, as TransAlta's request was largely based upon a percentage of AltaLink's.

Views of IPCAA

40 IPCAA did not propose specific reductions to AltaLink's requested interim rates, stating that AltaLink had failed to discharge the onus on it to show its applied for costs are reasonable, and/or that it will suffer financial hardship if not granted interim rates above current levels. IPCCA submitted the proposed O&M increases were not supportable and were excessive, expressing similar concerns with respect to the significant increases in capital costs and maintenance. Additionally, the "placeholders" used for rate of return and the equity levels were not supportable given the current financial conditions, interest rates, and the low risk levels of TFOs.

41 IPCCA maintained financial hardship had not been shown and the Board should award interim rates at current levels.

4 Altalink Reply Submission

42 AltaLink stated that in its 2004-2007 GTA, Interim Application, and Information Responses, it had provided detailed reasons, explanations of cost drivers and supporting facts for the revenue requirement increase requested in its Interim Application. AltaLink maintained that adequate amounts of sustaining and replacement capital were critical to ensure the operational integrity of AltaLink's aging transmission system.

43 AltaLink noted that factors well known to the Board and beyond AltaLink's control were contributing significantly to the increase in forecast revenue requirement. AltaLink noted it was already incurring or committing to incur costs without being compensated for such costs through the current tariff and claimed this was a demonstration of financial hardship.

44 AltaLink disputed Calgary's claims regarding the $125 million debt issue, noting that if one referred to Schedule 8.2 of refiling Decision 2004-007 Refiling, the embedded cost rate for the $125 million debt had an opening balance of 4.99% and a closing balance of 6.68%. Under the mid-year methodology, the effective cost rate is the average of the opening and the closing cost rates and the opening balance was not restated to be the same as the closing balance.

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45 In response to Calgary's comments that AltaLink did not address the proposed reduction in the Alberta income tax rate proposed in the latest Alberta Government Budget, AltaLink cited its response to CAL.AML-005 a-b, which indicated that the proposed 2004 Budget is the subject of Bill 27 which received first Reading in the Alberta legislature on March 31, 2004, prior to the legislature's spring break. As Bill 27 had not yet been passed by the Alberta legislature and proclaimed in force at the time of filing, the corporate income tax rate in Alberta remained at 12.5%

46 AltaLink considered FIRM's suggestion to reduce gross labour by 50% until operating expenses can be fully tested to be unfounded and unreasonable. AltaLink submitted that an arbitrary 50% reduction in gross labour would directly impact both capital and operating work planned by an equivalent amount. AltaLink stated it would have to defer planned operating maintenance work, such as brushing, substation and line inspection, routine breaker and transformer maintenance and associated planned capital projects, including line and substation relay replacements.

47 AltaLink replied to Calgary's suggestion that 50% be cut from the capital forecast, by noting that Calgary was not prepared to identify which of the capital maintenance projects Calgary considered to be unnecessary to maintain the safety and reliability of the transmission system or which of the direct assigned projects Calgary considered unnecessary for AltaLink to undertake. AltaLink again stated that the forecast capital maintenance was required to maintain the safety and reliability of the system.

48 AltaLink noted that FIRM had questioned the employee incentive plan because it was partially linked to capital additions. AltaLink wanted the Board to clearly understand that capital projects were undertaken as a result of direct assignments from the AESO or to ensure the prudent, safe and reliable operation of the transmission system, stating it was important to customers that employees be motivated to complete projects within budget and on time.

49 AltaLink also noted that Calgary had recommended that the increase in depreciation expense be disallowed; claiming that the depreciation impact was not an amount related to net income and would not affect the return to its owners. AltaLink stated that Calgary's assertion was wrong, pointing out that depreciation was not neutral from the perspective of cash flow to the utility. AltaLink explained depreciation is capital that is recovered and is used to finance new capital additions required by the utility. The less depreciation recovered, the more that has to be borrowed.

50 Finally, AltaLink responded to FIRM's concern over the balance in the property, plant and equipment account. FIRM had noted the actual closing balance for 2002/2003 property, plant and equipment was $1,493.0 million as compared to the forecast of $1500.9 million in the GTA. AltaLink explained that FIRM had made an incorrect comparison. The $1500.9 million (line 19, column (e) of Schedule 7.9 included $10.4 million of computer software whereas the $1493.0 million did not include the computer software. Computer software was included in rate base through necessary working capital and appeared on Schedule 7.9 for the purposes of capital continuity only. AltaLink claimed the correct comparison was from line 15 of Schedule 7.9, column (e) that shows $1490.5 million, which can be compared to $1493.0 million shown in the Report on Operations.

5 Views of the Board

51 The Applicants' applied-for 2004, 2005, 2006 and 2007 interim rates are based on their 2004-2007 GTAs and are substantially higher than their revenue requirements and rates approved in Decision 2004-028.[2]

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52 AltaLink expects its revenue requirement over the May 1, 2004 to April 30, 2005 (Next Year) to be 26.5 % more than the currently approved annual revenue requirement of $150.1 million. The increase is attributable to five major areas in the percentages shown in Table 2.

53 *Table 2. AltaLink's Comparison of its Forecast Revenue Requirement for May 1, 2004 through April 30, 2005 with its 2003/04 Approved Revenue Requirement*

Forecast increase attributable to:	***Amount of Increase ($ Million)***	***% Increase***
Growth in Rate Base	8.0	5.3
Return and Taxes	9.5	6.3
Depreciation Technical Update	8.0	5.4
Operating Expenses	12.1	8.1
Insurance & Other	2.2	1.5
Total	39.8	26.5

54 Each of Calgary, FIRM and IPCAA submitted that the Board should approve the continuation of the tariff approved in Decision 2004-028 on an interim refundable basis. They contend that AltaLink's requested rates are unreasonable, given the amount of untested areas of the 2004-2007 revenue requirement on which the applied for interim rates are based. In coming to their conclusions that the currently approved rates should continue on an interim refundable basis, each of Calgary and FIRM reviewed various elements of AltaLink's applied for annual revenue requirements and substituted values that they considered to be more reasonable. In the end result, Calgary and FIRM's estimates of the monthly forecast revenue requirement were not significantly different than the currently approved monthly AESO charges. Table 3 summarizes the various reductions proposed by Calgary and FIRM.

55 *Table 3. Summary of Adjustments Proposed by Firm and Calgary ($ Millions)*

Description of Adjustment	***Calgary***	***FIRM***
Reduction in allowed rate of return	12.0	4.5
Reduction in allowed equity ratio		4.2
Elimination of income tax allowance for Teachers		4.7
Reduction to depreciation expense	8.0	13.3[3]
Reduction in O&M expense	6.0	7.6
Reduction in Alberta tax rate	0.5	0.4
Capital expenditures	4.0	0.5
May 2004 opening balance to PP&E		1.0
Insurance	2.0	
Debt interest adjustment	1.0	

56 To support their argument for a continuation of the currently approved rates on an interim refundable basis, each of Calgary, FIRM and IPCAA submitted that AltaLink has not shown that it would suffer financial hardship if the applied for higher interim rates were not approved.

57 In the Board's view, Decision E92036 and Decision 2002-110 established a reasonable and similar framework for setting an appropriate interim rate that would be in effect until a final decision on the Applicants' 2004-2007 GTA could be rendered.

58 In Decision E92036, the Board acknowledged that one approach would be to review those particularly contentious

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areas with a view to reducing the applied for amounts with the objective of mitigating what would otherwise be an over collection of revenues during the period in which interim rates would be in effect.

59 In Decision 2002-110, which dealt with the Applicants' interim tariffs for 2003, the Board examined a number of areas in which the Applicants and interveners held widely differing views on the level of forecast revenue requirement. The Board then determined whether reductions to the applied for revenue requirement were warranted. The primary objective was to determine a revenue requirement level, on an interim basis, that would mitigate against significant revenue over collection during the expected term of the interim rates.

60 Given the nature of the interveners' submissions in this proceeding and the significant increases in revenue requirement requested by the Applicants, the Board considers that it would be prudent in this instance to use an approach similar to that adopted in Decision 2002-110 to determine an appropriate interim tariff. Accordingly, the Board will examine the Interim Applications in the areas that are likely to attract much attention and debate in the 2004-2007 GTA review and hearing (Contentious Areas). For the most part, these areas represent the components of the revenue requirement where material cost increases are forecast to occur.

61 When determining whether changes to the applied for amounts in the Contentious Areas should be made for the purposes of the interim calculation, the Board will assess the likelihood and the magnitude of the applied for material cost increases that AltaLink has forecast to occur while the interim tariff is expected to be in effect. The Board considers that where material cost increases in the Contentious Areas appear probable, it is desirable to include those costs in AltaLink's transmission rates sooner rather than later to ensure that the customers who receive the service are the ones that actually pay for it. Including material and probable cost increases in interim rates also serve to provide proper price signals to the customers receiving the service. Furthermore, it enables better management of costs and revenues over the interim period, thereby reducing the possibility of financial hardship and excessive cost of interim borrowings to AltaLink.

62 The Board will also assess whether any reductions to the applied for amounts are likely to result in financial hardship to the Applicants or impact their ability to provide safe and reliable transmission services to the AESO for the benefit of all Albertans when making its determinations. However, in the event that AltaLink, as the operator, believes that certain expenditures are mandatory to maintain service reliability, even in the face of interim rates that the Board has determined appropriate, then AltaLink, as the operator, must decide how best to proceed and then rely on the subsequent processes to justify its actions.

63 The Board will now examine each of the major areas where costs are forecast to increase significantly and will determine how much of the forecast revenue requirement increase AltaLink should be allowed to recover on an interim refundable basis, pending a final decision on the 2004-2007 GTAs. However, the Board will first address the period of time during which the interim rate and T&C are expected to be in effect.

5.1 Expected Duration of Interim Rate and T&C

64 The Applicants have requested interim tariffs for the May 1, 2004 to December 31, 2007 period, or until such time as a final decision on their 2004-2007 GTAs is rendered, or upon further order of the Board.

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65 In the Board's view, the current schedule for the 2004-2007 GTAs should result in the completion of the evidentiary part of the proceedings by the end of 2004. On this basis, the Board expects that a final decision on the 2004-2007 GTAs would be rendered by June 30, 2005 at the latest. Therefore, the interim tariffs that result from this Decision will likely only be necessary for about 12 to 14 months.

66 Therefore, the Board considers that the term of the interim tariffs should be no longer than May 1, 2004 to June 30, 2005 period (Interim Term). Should more time be needed to render a final decision on the 2004-2007 GTAs, the Board believes that a short extension to the Interim Term could be easily accommodated.

67 For ease of comparison with the last approved May 1, 2003 to April 30, 2004 fiscal year, the Board will focus on the forecast revenue requirement for the Next Year, but will set interim tariffs for the Interim Term. In the Board's view, setting tariffs for the Interim Term would reduce, and possibly eliminate, the need to set new interim rates in 2005.

5.2 Growth in AltaLink Rate Base

68 AltaLink has forecast its rate base to increase by $235.5 million from May 1, 2004 to December 31, 2007.

69 Projects directly assigned from the AESO to serve projected load and generation growth contribute to approximately 61% of the applied for increase to rate base; replacement of aging assets through capital replacement projects accounts for 13% and the remaining 26% is attributable to sustaining projects, new technology projects, and IT projects. AltaLink has stated that the forecast growth is occurring already and is significant when measured against the past number of years.

70 Higher rate base is reflected in the revenue requirement forecast through increased returns, depreciation and income taxes. AltaLink has forecast increases in these revenue requirement components over the Next Year to be $3.7 million for increased return, $3.9 million for depreciation, and $0.3 million of income tax expense respectively for a total of $8.0 million.

71 For the 14-month Interim Term, AltaLink estimated that the revenue requirement would increase by $35.2 million.

72 It should be noted that the Interim Term consists of 14 months as compared to the 12 months contained in the Next Year period. Because of the two additional months in the Interim Term, comparisons of forecast revenue requirement increases over the Next Year and the Interim Term to the last approved 2003-2004 fiscal year can be misleading. Forecast revenue requirement over the 14-month Interim Term when compared to the last approved 12-month 2003-2004 fiscal year must include amounts for all revenue requirement components for the additional two months. In contrast, for the Next Year comparison, because the two periods are the same, only incremental forecast revenue requirement related to increased returns, depreciation and income taxes are included. This explains why the Interim Term increases are significantly higher than the Next Year increases.

73 While recognizing that some components of the capital projects are necessary for safety and reliability purposes, Calgary has suggested that only half may fall into this category and recommended a $4 million annual reduction to

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AltaLink's requested revenue requirement. Calgary has also questioned the accuracy of AltaLink's forecast and noted that AltaLink has at its disposal a deferral account mechanism for projects that it is required to build.

74 AltaLink has defended its forecast, observing that its previous forecasted increase in net plant was $41.5 million for the period in question[4] compared to the actual increase for that same period of $42.1 million.[5] AltaLink stated that it executed its capital projects not knowing what the Board would ultimately approve and came within 1.5% of forecast.

75 For purposes of this interim decision, the Board accepts AltaLink's statement that significant growth in rate base is already occurring and assumes that the aforementioned rate base cost drivers and their proportionate share of contribution to the increased revenue requirement over the May 1, 2004 to December 31, 2007 period will also be applicable in the Next Year. The Board is of the view that the lack of recent major additions to the bulk transmission system and the new Transmission Development Policy being developed by Alberta Energy will both contribute to the demand for new transmission facilities.

76 Calgary's suggestion that allowed capital expenditures be reduced by 50% is arbitrary and may cause AltaLink operational difficulties in determining capital expenditure priorities. The bulk of AltaLink's capital forecast is the result of direct assignments from the AESO. In the Board's view, these projects have a high probability of proceeding since they are underpinned by EUB applications in which the AESO would have justified the need for the projects. Therefore, for interim rate making purposes, the Board will consider that, at a minimum, this portion of the forecast rate base increase will occur and is needed for the reliable operation of the provincial transmission network. The Board recognizes that, while it may be desirable to do, it is not absolutely critical or urgent to ensure that the associated revenue requirement increases be precisely recovered through interim rates over the Next Year because the direct assigned capital projects are subject to a deferral account mechanism.

77 The Board's preliminary review of AltaLink's capital maintenance/upgrade forecast and AltaLink's recent forecasting accuracy persuade the Board that the majority of the expenditures in this area will be needed for system safety and reliability and are likely to be executed over the Next Year.

78 The Board considers that specific rate base increases due to IT projects, new technology, and sustaining projects for the Next Year are best determined by the full review of the 2004-2007 GTA process. However, in recognition that some of these projects could impact AltaLink's operations during the Next Year, it would be reasonable to include a portion of this rate base increase for interim rate making purposes in order to provide AltaLink with some measure of operational flexibility.

79 AltaLink's revenue requirement includes an income tax rate of 12.5% for Alberta. At the close of the Spring 2004 session of the Alberta Legislature, Bill 27 was passed and came into force on May 11, 2004. Given this, the Board considers that the 11.5% rate should be reflected in the determination of AltaLink's monthly rate for the Interim Term.

80 In light of the foregoing, the Board has determined that on a balance of probabilities, it would be reasonable to allow approximately 85% of AltaLink's forecast capital expenditures for purposes of calculating interim rates. This would result in an increased revenue requirement of some $30 million, or a reduction of some $5 million from the applied for increase in revenue requirement during the Interim Term.

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5.3 AltaLink's Assumptions on Equity Return, Capital structure and Income Tax Allowance

81 The equity return and equity ratio in AltaLink's Interim Application reflects AltaLink's position in the recently completed Generic Cost of Capital (GCC) proceeding that the appropriate equity rate of return for AltaLink is in the range of 10.50% to 10.75% on a common equity of 37.5%.[6]

82 In contrast, in Decisions 2003-061 and 2004-028, the Board approved an equity rate of return of 9.4% and a debt to equity ratio of 66% to 34%.

83 Noting that the risk free rate used for establishing AltaLink's equity return in Decisions 2003-061 and 2004-028 has changed since the Board's determination was made, Calgary recommended the use of a 9.0% equity rate of return for setting AltaLink's interim rates. While there may have been a change in the risk free rate, the Board is of the view that until a decision is rendered in respect of the GCC process, AltaLink's currently approved equity return and capital structure are the appropriate "placeholders" to be used for interim ratemaking purposes. Therefore, when determining rates for the Interim Term, the Board will use an equity return of 9.4% and a capital structure consisting of 34% equity.

84 AltaLink's applied for interim rates also include an allowance for deemed income tax and large corporations tax related to the OTPPB's investment in ALP (OTPPB Income Tax Expense). In Decisions 2003-061 and 2004-028, the Board denied such an allowance in the revenue requirement approved for the May 1, 2002 to April 30, 2004 period.

85 The OTPPB Income Tax Expense matter will be addressed in the AltaLink's R&V Application process that is currently before the Board. Therefore, consistent with its views on AltaLink's equity return and capital structure, the Board considers that, until the OTPPB Income Tax Expense matter is resolved through the R&V process, AltaLink should not be allowed to collect through its interim rates any deemed income tax expenses related to the OTPPB's investment in ALP.

86 Accordingly, in its determination of AltaLink's interim monthly AESO charges for the Interim Term, the Board will exclude any OTPPB Income Tax Expense included in AltaLink's applied for revenue requirement.

87 Based on its projected rate base additions over the Next Year, AltaLink estimated using the GCC applied for equity return and capital structure instead of the currently approved values, and assuming a full income tax allowance, would result in a $9.5 million increase in revenue requirement over the Next Year. The corresponding increase in revenue requirement during the Interim Term is estimated to be $11.1 million. For the reasons stated above, the Board will not allow AltaLink to recover this amount through its interim tariff and will reflect this finding in its determination of the amount of revenue requirement that should be used to determine the interim tariff.

88 Accordingly, for all of the above reasons, the Board will reduce AltaLink's applied for revenue requirement during the Interim Term by $ 11.1 million to reflect its decision respecting return, capital structure, and the income tax treatment of OTPPB.

5.4 AltaLink Depreciation Technical Update

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89 In Decision 2003-061, the Board directed AltaLink to return to the traditional method for determining net salvage rates. AltaLink stated that in order to carry out that directive, a technical update was required. AltaLink has estimated that the technical update, combined with the increase in depreciation expense associated with the significant growth in rate base, will lead to a revenue requirement increase of $8.0 million. This increase accounts for 5.4% of the 26.5 % revenue requirement increase over the Next Year. During the Interim Term the increase in revenue requirement is estimated to be $9.3 million. The increased revenue requirement results from a change in the composite depreciation rate from 3.01% to 3.63%.

90 Calgary has submitted that the depreciation impact is not an amount related to net income and will not affect the return to AltaLink's owners. FIRM's view is that the reasons for the changes in the composite rate must be reviewed in the 2004-2007 GTA proceeding and should not be included on an interim basis without further testing. FIRM proposed that the previously approved composite depreciation rate should be used as a placeholder for interim rate purposes and that this non-cash item should not impact AltaLink's financial integrity. AltaLink points out that depreciation affects its cash flow and the amount that it has to borrow to finance new capital additions.

91 The Board agrees that, absent an demonstration of financial harm, the appropriate approach to dealing with the revenue requirement resulting from the depreciation update is to use the approved composite depreciation as a placeholder for interim rate purposes, as suggested by FIRM. The Board acknowledges that depreciation expenses affect cash flow and can be used to fund capital projects. However, AltaLink has not demonstrated to the Board's satisfaction how exclusion of the technical depreciation increase from the revenue requirement for the Interim Term would cause it financial hardship.

92 Accordingly, the Board will not include the $9.3 million applied for increase in revenue requirement due to the technical update of depreciation costs when determining AltaLink's interim rates.

5.5 AltaLink Operating Expenses

93 AltaLink's operating expenses generally relate to net salary and wages, contract manpower and general operating expense. For the Next Year, AltaLink has forecast a $12.1 million increase in operating expenses from the $34.6 million that was approved for the 2003/04 test year. This represents an increase of approximately 35% from the previous fiscal year and accounts for 8.1% of the 26.5 % revenue requirement increase over the Next Year. For the Interim Term, the forecast increase in revenue requirement is $14.2 million.

94 Increases not accounted for by inflation, are primarily related to the following:

- Costs disallowed in the last GTA that are required to be expended to prudently, safely and reliably operate and maintain the transmission system;
- The need to prudently increase expenditures for operating and maintaining the expanding transmission system; and
- External factors beyond AltaLink's control that are driving cost increases for AltaLink.

95 Calgary has suggested that 50% of the overall operating expense increase from the last fiscal year, or $6.0 million, be used for determining AltaLink's interim rates. While FIRM had a different amount of reduction, it too recommended that only 50% of its estimated increase be allowed in the revenue requirement to be used to calculate interim rates.

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96 AltaLink has on staff 25 full time equivalents (FTE) in excess of the 220 FTEs that were approved by the Board in the last GTA. AltaLink also proposes to undertake activities that it claims had to be deferred because not all of its requested cost increases were approved in its last GTA. The Board is of the view that until the costs that were disallowed in AltaLink's last GTA can be fully reviewed and assessed, AltaLink should not be allowed to recover any significant amounts of these disallowed costs.

97 In a previous section of this Decision, the Board concluded that 85% of the forecast rate base addition should be used for interim rate making purposes. Consistent with this determination, it follows that a commensurate FTE increase related to operating and maintaining the expanding transmission system should also be recovered during the Interim Term.

98 In addition to the 25 FTE in excess of its complement approved in the last GTA, AltaLink proposes to add a significant amount of FTEs over the Next Year (13 for the 8 months in 2004 and some portion of the 44 FTE addition for 2005). These proposed FTE additions relate to the operations, regulatory and corporate services functional areas.

99 The Board is generally of the view that until the need for all of the applied for FTE increases in each of AltaLink's functional areas can be reviewed and established through the 2004 — 2007 GTA process, it would not be appropriate to allow AltaLink to start recovering through interim rates the full amount of expenses related to AltaLink's significantly increased applied for FTE complement level. However, the Board recognizes that not having sufficient people to operate and maintain the system could potentially expose the system to some risk of failure. The Board will bear this in mind when determining the amount of increased operating expenses that should be recovered through interim rates during the Next Year.

100 The Board recognizes that other factors driving the cost increases such as increased vegetation management may indeed be required over the next few years. While it may be appropriate to allow some of these expenditures to be recovered through the interim rates, the Board is not persuaded that there is an immediate urgency for all of these expenditures to be recovered over the Next Year before they are fully tested.

101 Similarly, the Board considers that it would be appropriate for AltaLink to recover through interim rates, only a minimal amount of expenses related to contract manpower and services, and other general operating expenses such as IT related ones.

102 In summary, the Board is of the view that until AltaLink has the opportunity to justify its operating expense increases in its upcoming 2004 — 2007 GTA proceeding, it would be reasonable to allow only a portion of the applied for increases to be recovered through interim rates during the Interim Term. For all of the reasons discussed above, and particularly the FTE increase related to the expanding transmission system, the Board considers Calgary and FIRM's recommendations to be conservative and believes that, on balance, a more reasonable percentage increase would be in the 70% to 80% range. Therefore, for purposes of establishing interim rates for the Interim Term, the Board will use an overall operating expense increase of $10.5 million and will adjust the applied-for revenue requirements accordingly.

5.6 AltaLink Insurance & Other

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103 AltaLink has forecast a $2.7 million increase in self-insurance reserve and insurance premium fundings, hearing cost funding, and property taxes over the Next Year. The corresponding amount over the Interim Term is $2.8 million.

104 The increase with respect to property taxes is related to the forecast growth in AltaLink's property tax base and gradual increases in mill rates.

105 The increase in the forecast cost of insurance, which account for the majority of the increase revenue requirement in this category, relates to increased coverage and increased premiums. AltaLink has indicated that an increase of $2.5 million per year or $0.2 million per month is necessary in its interim tariff due to increases in insurance expenses. AltaLink has also provided a list of and a discussion of each of the commercial insurance coverage it proposes to have in place.

106 Increased funding of reserve accounts are also proposed. AltaLink has provided details with respect to the functioning of the self-insurance reserve (SIR).

107 For purposes of setting interim rates, the Board considers AltaLink's explanations respecting the increased insurance expense to be reasonable and will therefore allow the requested increase. While the Board is approving this increase in expense on an interim basis it considers AltaLink's proposal to flow actual insurance premiums through the SIR to be an issue that should be debated during the hearing.

108 No increase is expected in property taxes for the 8-month test period in 2004 and AltaLink has forecast no increase in hearing cost expenses for the Interim Term. Therefore the Board considers no increase for these items is necessary for purposes of setting interim rates.

5.7 TransAlta Forecast Revenue Requirement

109 TransAlta forecast increase in revenue requirement over the Next Year is attributable to the areas in the percentages shown in the Table 4 below.

110 *Table 4. TransAlta's Forecast Increases to its Monthly Revenue Requirement for May 1, 2004 to December 31, 2004 and for 2005*

Factors Contributing to TransAlta's Increased Monthly Revenue Requirement	***2004 $ Increase ($ 000)***	***Increase as a % of Current Rate***	***2005 $ Increase ($ 000)***	***Increase as a % of Current Rate***
Revised Debt/equity Ratios and Equity Return	7.2	11.9	9.6	12.8
Increased Rate Base	3.9	6.5	10.0	13.3
Revised Depreciation Rates	8.1	13.5	10.8	14.5
Increased Operations and Maintenance Fee to AltaLink	14.7	24.5	19.0	25.5
Additions to Hearing Cost Reserve Funding	12.5	20.8	8.3	11.2
Other Operating Expense Increases	6.3	10.4	7.1	9.5

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Increased Income Tax due to above changes	7.5	12.4	9.8	13.2
Total	60.2	100.0	74.6	100.0

111 TransAlta explained that the increase in costs was related to:

1. A significant outstanding hearing cost amount (currently in the order of $280,000) from the 2002/2004 proceeding waiting Board approval and additional hearing costs from this proceeding.

2. Significant additions to rate base related mainly to capital maintenance throughout the forecast period that increases the requirement for return, income tax and depreciation.

3. Significant increases in the cost of contracted manpower between 2003/2004 and the balance of 2004 and 2005.

4. An increase in the return on equity and the amount of equity making up rate base to a level TransAlta believes to be prudent.

112 In keeping with their recommendation that AltaLink not be given an interim rate increase, the interveners submitted that no increase should be granted to TransAlta either, as TransAlta's request was based upon a pro-rata share of AltaLink's costs.

113 In recognition of the linkages between the two applications, the Board considers that it would be reasonable to grant TransAlta a similar percentage of its applied for monthly increase. The Board has approved $1.3 million of AltaLink's applied for $3.4 million monthly rate increase, or approximately 40% of the increase requested by AltaLink. Accordingly, the Board will use 40% of TransAlta's requested monthly rate increase to determine TransAlta's interim monthly AESO Charges.

5.8 Board Conclusions on Interim Applications

AltaLink

114 Based on the reasoning in the preceding sections, the Board concludes that it would be appropriate to include $42.8 million of AltaLink's $72.1 million increase in revenue requirement for the Interim Term to determine interim refundable monthly AESO charges.

115 The Board allowed revenue requirement and resulting interim monthly rates for AltaLink for the May 1, 2004 to June 30, 2005 period are summarized in the Table 5 below.

116 *Table 5. Board Approved Revenue Requirement and Interim Monthly Rates for AltaLink for May 1, 2004 to April 30, 2005*

AltaLink Annual Revenue Requirement	***2003/04 Approved ($ Million)***	***Applied For May 1, 2004 to June 30, 2005 ($ Million)***		***Board Approved May 1, 2004 to June 30, 2005 ($ Million)***	
		Increase	***Total***	***Increase***	***Total***

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Total Return	47.5	17.0	64.5	10.8	58.2
Operating Expense	34.6	20.0	54.6	15.4	50.0
Self Insurance Reserve and Insurance Premium Funding	0.5	2.6	3.1	2.5	3.1
Hearing Cost Funding	1.5	0.3	1.8	0.3	1.8
Taxes Other Than Income Tax	12.6	2.4	15.1	2.1	14.7
Miscellaneous Revenue	(5.9)	(1.5)	(7.5)	(1.4)	(7.3)
Depreciation & Amortization	47.8	21.0	68.7	11.0	58.7
Income Taxes	11.5	10.4	22.0	2.1	13.6
Total	*150.1*	72.1	*222.3*	42.8	*192.9*
Monthly Rate	*12.5*	5.2	*15.9*	3.1	*13.8*

117 Note: Totals may not add due to rounding.

118 The monthly rate in Table 5 represents a composite of the rate that would apply from May 1, 2004 to December 31, 2004 and the rate that would apply from January 1, 2005 to June 30, 2005. As such, relative to the allowed Interim Term revenue requirement, the composite monthly rate would over collect revenues in the 2004 period and under collect in the 2005 period. Notwithstanding this, the Board considers that because the rate would be interim and refundable, it would be appropriate to establish a single rate for the Interim Term.

119 Accordingly, the Board approves on an interim refundable basis a monthly rate of $13.8 million for AltaLink, which shall remain in effect from May 1, 2004 to June 30, 2005, or until a final decision of the Board is rendered on the Applicants' 2004-2007 GTAs, or upon further order of the Board.

TransAlta

120 For the reasons above, the Board will determine a single interim rate for TransAlta for the May 1, 2004 to June 30, 2005 period instead of two different rates for the May 1, 2004 to December 31, 2004 and the January 1, 2005 to June 30, 2005 periods. The computation of TransAlta's blended rate for May 1, 2004 to June 30, 2005 is shown in Table 6 below.

121 *Table 6. Board Approved Revenue Requirement and Interim Monthly Rates for TransAlta for May 1, 2004 to June 30, 2005*

		2004 (May 1 to Dec 31)	**2005 (Jan 1 to Jun 30)**	**May 1, 2004 — June 30, 2005**	
				Total	***Rate***
TransAlta Interim Application					
	Currently Approved Monthly Rate	208,667	208,667		
	Requested Monthly Rate Increase	60,208	74,583		
	Total Requested Monthly Increase	*268,875*	*283,250*		
	Requested Revenue Requirement Increase			3,850,500	
	Requested Blended Monthly Rate				*275,036*
Board Approved					
	Currently Approved Monthly Rate	208,667	208,667		

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Approved Monthly Rate Increase (40%)	24,083	29,833		
Total Approved Monthly Increase	*232,750*	*238,500*		
Approved Revenue Requirement			3,293,003	
Approved Blended Monthly Rate				*235,214*

122 Accordingly, the Board approves on an interim refundable basis a monthly rate of $235,214 for TransAlta, which shall remain in effect from May 1, 2004 to June 30, 2005, or until a final decision of the Board is rendered on the Applicants' 2004-2007 GTAs, or upon further order of the Board.

123 The Board's review and exclusion of costs associated with certain contentious areas of the Applicants' untested 2004-2007 GTAs for the purpose of establishing interim refundable rates for the May 1, 2004 to June 30, 2005 period, does not in any way prejudge the final determination of these matters that the Board will make when deciding the Applicants' 2004-2007 GTAs.

6 Order

124 For and subject to the reasons set out in this Decision, IT IS HEREBY ORDERED THAT:

(1) The Interim Transmission Tariffs for AltaLink, in its capacity as General Partner of AltaLink. L.P., and TransAlta shall be as set out in the attached Schedule A and Schedule B and applies on an interim and refundable basis effective May 1, 2004.

(2) The currently approved AltaLink and TransAlta TFO Terms and Conditions, which were finalized in Decision 2004-028, apply on an interim basis effective May 1, 2004.

(3) The Interim Transmission Tariffs and the AltaLink and TransAlta TFO Terms and Conditions of service in (1) and (2) above shall remain in effect for the lesser of the term specified in Schedules A and B, or until a final decision of the Board is rendered on AltaLink and TransAlta's 2004 - 2007 General Tariff Applications, or upon further order of the Board.

APPENDIX A — Altalink Management Ltd., 2004/05 Interim Rate Schedule, Transmission Tariff (Effective May 1, 2004)

Available:	To the Transmission Administrator.
Applicable:	To the Transmission Administrator for the use of AltaLink's transmission facilities commencing May 1, 2004 and ending on June 30, 2005.
Rate:	The Transmission Rate charged to the Transmission Administrator for the use of AltaLink's transmission facilities commencing May 1, 2004 shall be:
	Monthly Charges: $ 13.8 million

APPENDIX B — Transalta Utilities Corporation, 2004/05 Interim Rate Schedule, Transmission Tariff (Effective May 1, 2004)

Available:	To the Transmission Administrator.
Applicable:	To the Transmission Administrator for the use of TransAlta's transmission facilities commencing

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May 1, 2004 and ending June 30, 2005.

Rate: The Transmission Rate charged to the Transmission Administrator for the use of TransAlta's transmission facilities commencing May 1, 2004 shall be:

Monthly Charges: $ 235,214

Footnotes

1 The FIRM Group of Customers is comprised of the Alberta Association of Municipal Districts & Counties, the Alberta Federation of REA's Ltd., Alberta Irrigation Projects Association, Alberta Urban Municipalities Association, the Consumers Coalition of Alberta, Public Institutional Consumers of Alberta (PICA) and the Utilities Consumer Advocate.

2 Decision 2004-028 was issued on March 23, 2004 and finalized AltaLink and TransAlta's rates for May 1, 2002 to April 30, 2004.

3 Includes tax and rate base effects, FIRM argument P. 5

4 Decision 2004-007, Schedule 7.

5 AltaLink, L.P. Report of Finances and Operations May 1,2002 to April 20, 2003, dated March 26, 2004.

6 Joint Argument of AltaLink, Aquila Networks Canada (Alberta) Ltd., EPCOR Distribution Inc. and EPCOR Transmission Inc. dated February 23, 2004, starting at lines 8 page 12 to line 24, page 13.

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2005 CarswellAlta 2281
Alta. E.U.B.

ATCO Gas, Re

2005 CarswellAlta 2281, [2007] A.W.L.D. 2816

ATCO Gas, 2005-2007 General Rate Application Interim Rate Application

B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member

Judgment: August 29, 2005
Docket: 2005-099

Subject: Public

Related Abridgment Classifications

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2005 CarswellAlta 2281, [2007] A.W.L.D. 2816

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered by *B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member*:

ATCO Electric Ltd., Re (2002), 2002 CarswellAlta 1961 (Alta. E.U.B.) — considered

ATCO Gas, Re (2002), 2002 CarswellAlta 2053 (Alta. E.U.B.) — considered

ATCO Gas, Re (2003), 2003 CarswellAlta 2127 (Alta. E.U.B.) — considered

ATCO Gas, Re (2004), 2004 CarswellAlta 2054 (Alta. E.U.B.) — referred to

ATCO Gas, Re (2005), 2005 CarswellAlta 2258 (Alta. E.U.B.) — referred to

ATCO Group, Re (2002), 2002 CarswellAlta 1953 (Alta. E.U.B.) — referred to

Subject:

***B.T. McManus Presiding Member, Gordon J. Miller Member, and Laurie J. Bayda Acting Member*:**

1 Introduction

1 ATCO Gas (AG) filed a General Rate Application (GRA) for the 2005-2007 test period on May 13, 2005. On June 8, 2005, AG filed an application (the Application) with the Board requesting approval for proposed rates on an interim basis. AG proposed that the interim rates would be effective September 1, 2005, and would reflect an increase in revenue from existing 2004 rates in the amount of $9.3 million for ATCO Gas North (AGN). No interim rate increase was requested for ATCO Gas South (AGS).

2 Particulars of the Application

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2 AG provided the following information in support of the Application:

• In the Overview of the GRA, AG indicated that the 2005 revenue shortfall for AGN was $18.5 million. ATCO submitted that this was a substantial shortfall and that the forecast shortfalls for 2006 and 2007 were substantially higher at $26.6 million and $34.5 million respectively. The requested interim increase of $9.3 million represented approximately 50% of the forecast 2005 shortfall and was proposed to be collected between September 1, 2005 — December 31, 2005.

3 AG also proposed that the interim increase should be applied to all customer rates on an across-the-board basis, and provided detailed calculations of the billing determinants and proposed rates for each rate class for AGN customers.

4 AG indicated that, to minimize rate shock and maintain intergenerational equity, it would be in the best interests of customers to implement an interim increase in rates for AGN. AG also indicated that an interim increase in the level proposed would be consistent with the last approved increase for AGN and was in the range of historic approvals for Northwestern Utilities (NUL) and Canadian Western Natural Gas Ltd (CWNG). Since past rate applications involved contentious changes to capital structure and return on common equity that would not be an issue in this proceeding, AG asserted that the request for 50% of the estimated shortfall was reasonable. AG provided excerpts from previous Board Decisions in support of its requested increase and its request that the interim increase be applied across-the-board.

5 By letter dated July 15, 2005, the Board requested that interested parties provide submissions with respect to the Application by July 22, 2005, and that AG provide a response to those submissions by July 29, 2005. However, a submission was received on July 8, 2005 from the Consumer Group (CG) to which AG replied on July 13, 2005. CG filed a response to AG's reply in a letter dated July 15, 2005.

3 Positions of AG and the Interveners

6 The CG disagreed with AG that implementation of the applied for interim rate would minimize rate shock. In their July 15 response letter to AG, CG contended that the difference between $9.3 million and $18.5 million only constituted a 1% difference to customer end bills. As such, CG concluded that rate shock and intergenerational equity should not be considered issues in this instance.

7 CG argued that AGN should not receive an interim rate adjustment. CG claimed that there were significant amounts that AGN included in its Application that had been reduced or denied by the Board in previous proceedings. Additionally, CG stated that there were other amounts that represented unusually large increases over 2004 amounts. In total CG suggested that $19.3 million in reductions should be applied to AGN's forecasted shortfall. Since this amount exceeded AGN's total revenue deficiency, CG asserted that no interim rate adjustment ought to be approved. CG's support for the $19.3 million in reductions is described below.

8 CG noted that in its application AG forecasted a one-time Federal deferred income tax refund for the North. This amount is required to be refunded to customers in accordance with direction set out in Decision 2003-072 [2003 CarswellAlta

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2127 (Alta. E.U.B.)] .[1] CG argued that as no interest was being paid on this amount, it should be used to offset the 2005 forecasted revenue shortfall rather than applied to offset projected expenditures in 2006 as proposed by AG.

9 CG also noted the Board's direction in Decision 2003-072 which directed AG:

> ... to re-evaluate the MRRP [Meter Relocation and Replacement Project] and incorporate in its Refiling, a revised proposal for replacement of meters with underground entries over a 10-year timeframe, and replacement/relocation of meters with aboveground entries on a schedule coincident with the recall program.[2]

10 CG noted that the AG GRA application forecast that the MRRP will cost $30 million per year; an amount greater than the cost of $28 million forecast in the last rate application. For this reason, CG requested that for interim purposes, the MRRP should be limited to $25 million per year. This was the amount approved by the Board for MRRP expenditures for 2004 in Decision 2004-036 [2004 CarswellAlta 2054 (Alta. E.U.B.)][3]

11 CG also argued that AG's forecast expenditures on urban mains replacements was too high at $19.1 million for 2005. CG considered that the Board directed AG in Decision 2003-072:

> ... to reduce the 2004 test year forecast for Urban Mains Replacements to $7.092 million.[4]

12 In its previous forecast, AG budgeted $15.1 million for urban mains replacements in 2004. Therefore, CG submitted that AG's forecast amount for urban mains replacements in 2005 should be reduced to $7 million per year.

13 For the 2005 test year, AG forecast a $5 million increase in movable equipment as compared to 2003 and 2004 actual expenditures. As was noted by CG, the 2005 moveable equipment expenditure forecast was significantly greater than 2006 and 2007 forecast amounts. CG submitted that, for interim purposes, AG's 2005 moveable equipment forecast be reduced by $5 million.

14 In total, CG submitted that the net impact on AG's capital expenditure forecasts pertaining to the above noted items is a reduction of $22 million. The net effect on the revenue requirement of these reductions would be $2.1 million, of which CG argued that $1.1 million should be attributed to AGN.

15 In Decision 2003-072, the Board determined that AG had not established that monthly meter reading was necessary. Therefore, the Board directed AG to revise its forecast to reflect the costs of reading meters on a bi-monthly basis. However, CG noted that AG has continued to provide monthly meter reading and has included forecast monthly meter reading costs in its 2005-2007 GRA. CG stated that in Decision 2003-072, ATCO Gas estimated monthly meter reading expenses at $5.5 million plus capital costs of $577,000. CG argued that none of the costs of monthly meter reading should be included in the interim rates and argued that AGN's interim request should be reduced by $3 million.

16 Also noted by the CG, AG forecasted the addition of 84 full-time employees (FTEs) in 2005. Including labour and benefits expenses, CG noted that the average estimated cost per new FTE was $62,300 per year. Without further testing, CG contended that this amount was front loaded and only the costs of 42 FTEs should be considered for the purpose of interim rates. CG remarked that this would reduce AG's forecast 2005 expenses by $2.5 million, of which CG argued $1.3 million

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ought to be attributed to AGN.

17 CG noted that Account 701 advertising expense was forecast to be $6.0 million in 2005; an increase over the $3.0 million allowed by the Board in Decision 2003-072 for the 2003-2004 test years. CG observed that in its 2003-2004 GRA, AG applied for a similar increase. CG submitted that for interim purposes the Account 701 advertising costs should be limited to $3 million for AG. CG argued that $1.5 million of this amount should be attributed to AGN.

18 In addition, CG remarked that in Decision 2005-039 [2005 CarswellAlta 2258 (Alta. E.U.B.)][5] the Board reduced Customer Communication Costs by $250,000 reflecting the costs associated with the GCRR for which AG was no longer responsible. CG asserted that this amount should also be excluded from interim rates.

19 Furthermore, CG noted that the Board reduced AG's administration costs to reflect the transfer of the retail function to Direct Energy Regulated Services (DERS). CG indicated that AG stated in its latest compliance filing that it had reduced administrative expenses by $1.029 million in the north and by $1.068 million in the south. These amounts reflected savings in administrative costs in the last 7 months of 2004. CG contended that since AG argued that there should not be any reductions in administrative costs as a result of the transfer, it was unlikely that AG would have removed any of these costs from its 2005-2007 GRA. Therefore, CG asserted that for interim purposes, AGN's administrative costs should be reduced by $1.675 million for 2005.

20 CG stated that AG included in its forecast expenses an amount of $500,000 for external legal fees in excess of the Board Scale for 2005, half of which would be attributable to AGN. Since hearing costs in excess of the Board Scale are not allowed for any participants (either companies or interveners), CG argued for a $0.3 million reduction to expenses for AGN interim rates.

21 Similarly, CG submitted that $339,000 for donations included for 2005 should be excluded from both the GRA and the interim rate application. CG argued that historically the Board ruled that donations were not a cost to be borne by customers. As such, CG contended AGN's forecasted expenses be reduced by $0.3 million.

22 CG noted that AG proposed changes to its depreciation study that would result in a net depreciation expense increase of $1.683 million for the 2005 test year. CG asserted that there was no urgent or compelling reason for AG to recover increased depreciation expense caused by changes to service life and net salvage assumptions. CG contended that for interim purposes AGN depreciation expense should be reduced by $0.9 million.

23 CG and the Utilities Consumer Advocate (UCA) noted that AG has forecast an increase of $3 million in ATCO I-Tek charges from 2004 to 2005. The unit prices were based on an MSA that was renewed early in 2005 and included a 3.8% inflation increase for labour. CG and the UCA indicated that the areas relating to Distributed Hardware and Application Service Provider (ASP) applications were forecasted to have the largest increases. Since the Board previously directed ATCO Gas to reduce ATCO I-Tek charges by 7.5% in Decision 2002-069 [2002 CarswellAlta 1953 (Alta. E.U.B.)] ,[6] CG and the UCA contended that ATCO I-Tek charges should be reduced by 10% for interim purposes. The result would be a $0.7 million reduction for AGN in 2005.

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24 CG also submitted that I-Tek Business Services (ITBS) charges ought to be reduced by 11.1%. CG noted that these charges were reduced by the Board in Decision 2002-069 by this amount. The $22.5 million that AG forecast in spending on ITBS was based on a new Master Service Agreement (MSA). CG contended that it was unlikely that the 11.1% reduction ordered by the Board was incorporated in this Application. Therefore, for the purposes of interim rates, CG argued that ITBS charges to ATCO Gas should be reduced by $2.5 million with $1.3 million of that amount being attributable to AGN.

25 CG noted that Industrial Gas Consumers Association of Alberta (IGCAA) submitted evidence in an ATCO Pipelines Application No. 1393613[7] suggesting that costs allocated to unregulated portions of the network, (the Muskeg River Pipeline) have been understated by approximately $1.6 million at the expense of ATCO Pipelines other customers. CG argued that if this evidence was found to be compelling in the ATCO Pipelines proceeding, that it could have a significant impact for AG. CG estimated that charges to AGN could be reduced by as much as $0.6 million for 2005.

26 In addition, ATCO Pipelines was expected to receive $4 million worth of TBO (Transportation By Others) revenues from NOVA Gas Transmission Limited (NGTL). Of this amount, CG contended that $0.4 million would accrue to AGN.

27 Finally, if NGTL's proposed rate design was accepted by the Board, CG claimed that ATCO Pipelines would save 13% over current rates. CG argued that this amount would translate to savings for AGN of $0.15 million.

28 CG maintained that the outcome of the ATCO Pipelines and NGTL proceedings could have a significant impact on the AGN's costs. For this reason, CG submitted that AGN's interim revenue should be reduced by $1.15 million.

29 AG reviewed CG's submission and replied that the focus of an interim rate application should not be to pre-judge contentious issues, but rather to avoid rate shock and provide intergenerational equity. AG stated that an intervener's suggestion of an issue being contentious should not automatically make it so. AG argued that it was for this reason that it only requested 50% of the forecast revenue shortfall as opposed to the full amount. AG noted that it would be unlikely that it would be able to implement adjusted rates based on the outcome of the GRA Decision before March 2003. ATCO Gas asserted that if the full amounts of the shortfall for 2005 and 2006 were approved by the Board, customers would face a significant increase in rates at that time. AG concluded that in order to mitigate any possible rate shock, the Application should be approved as filed.

30 In response to CG's assertion that the forecast federal deferred income tax refund should be repaid in 2005, AG responded that the $6 million refund would almost fully offset $6.9 million of one-time charges for AGN customers that would occur in 2006. AG argued that moving the repayment to 2005 would cause a significant increase in rates for 2006 which may contribute to rate shock.

31 With respect to the proposed changes in depreciation analysis, ATCO Gas noted that CG did not find the amount to be contentious. Rather, AG argued that CG disputed the timing of those amounts. AG submitted that CG was again ignoring the impact of rate on customers and that its request for a $0.9 million reduction was unjustified.

32 AG submitted that it considered it inappropriate for CG to speculate on the outcome of other proceedings that may impact ATCO Pipelines. AG argued that for this reason the $1.1 million reduction sought by CG was unwarranted.

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33 AG submitted that removing the above noted items from CG's analysis decreased CG's proposed reduction from $19.3 to $11.3 million. Therefore, AG noted that, following the reasoning of CG, an interim rate increase of at least $7.2 million should be allowed. An award of such an amount, however, would have to be premised on the assumption that the Board would completely agree with the interveners regarding the contentious issues which AG considered unlikely. AG therefore argued that the Application should be approved as filed.

4 Views of the board

34 AG argued that to mitigate potential rate shock, promote rate stability and maintain intergenerational equity; an interim rate adjustment would be in the best interests of customers. CG identified a number of contentious issues to be debated during the hearing. The Board recognizes that there are significant differences between AG and the interveners regarding the appropriate forecast revenue requirement.

35 With respect to the criteria that the Board should utilize when evaluating the need for an interim rate increase, the Board has considered the arguments of the parties and prior interim rate decisions. In Decision E92036[8] the Public Utilities Board (PUB) indicated at pages 10 and 11:

> The Board considers that an effective approach which could be used by a utility to determine an appropriate level of interim rates is to look at areas which may be contentious and to exclude all or some portion of those amounts from the amount to be collected through interim rates. In this manner the potential of over-collection from interim rates would be minimized which in turn reduces potential fluctuations to customers' rates.

36 In Order E93028[9] the PUB stated at page 14:

> The Board considers that interim rate increases are generally warranted where the forecast revenue deficiency identified for a given period is probable and material. The Board considers it generally appropriate that customers' rates for a period reflect the costs associated with that period in order to maintain intergenerational equity. Furthermore, approving interim rates in a timely manner avoids rate spikes that may otherwise result if recovery of the revenue deficiency is delayed.

37 Further, at page 18 the PUB denied NUL's request to implement an interim rate increase in respect of certain classes only, stating:

> The Board is not persuaded at this time that a need exists to change its long maintained position that interim rates should be based on an existing rate structure and costing methodology....The Board considers that this method least influences the existing Board approved rate structure.

38 In Decision 2002-115 [2002 CarswellAlta 2053 (Alta. E.U.B.)][10] the Board stated at page 10:

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> In the present circumstances, the Board considers that interim rate increases are generally warranted given that the forecast 2003 revenue deficiency is material. An interim rate increase aimed at recovering a portion of any shortfall that is ultimately demonstrated and approved provides for a leveling out of the impact of any final rate increase, thereby promoting rate stability and easing any rate shock to customers at a later date. The Board also considers it appropriate that customers' rates for a given period reflect the costs associated with that period in order to maintain intergenerational equity. While acknowledging the submission of the CG that ATCO has not claimed financial harm or an inability to continue safe utility operations without an interim rate increase, the Board considers it appropriate, given the magnitude of the forecast 2003 revenue deficiencies for AGS and AGN, that some degree of interim rate increase is warranted.

39 Further at page 11 of Decision 2002-115, the Board considered the award granted in the context of previous awards and found the percentage increase granted to be "in line with those awarded by the Board in previous interim rate Decisions."

40 The Board also notes the discussion in Decision 2002-108 [2002 CarswellAlta 1961 (Alta. E.U.B.)][11] of the use of carrying costs as a means of keeping parties whole and thereby potentially avoiding interim rate changes. The Board also discussed the need to consider large forecasted impacts to rates when evaluating a requested interim rate increase that appears at page 12:

> However, if large rate adjustments are forecast, the Board might decide that the need of appropriate price signals to customers is more significant than the need to minimize the number of changes in rates.

41 The foregoing excerpts reference a number of factors that the Board has employed in evaluating an application for an interim rate increase. These factors can be grouped into two categories, those that relate to the quantum of, and need for, the rate increase and those that related to more general public interest considerations.

42 Quantum and need factors are those which relate to the specifics of the requested rate increase and include:

- The identified revenue deficiency should be probable and material
- All or some portion of any contentious items may be excluded from the amount collected
- Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
- Can the applicant continue safe utility operations without the interim adjustment?

43 If all or a portion of the suggested rate increase appears appropriate after a consideration of the quantum and need factors, the Board must assess certain general public interest factors to see if a rate increase is justified, these include:

- Interim rates should promote rate stability and ease rate shock
- Interim adjustments should help to maintain intergenerational equity
- Can interim rate increases be avoided through the use of carrying costs

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- Interim rate increases may be required to provide appropriate price signals to customers
- It may be appropriate to apply the interim rider on an across-the-board basis

44 The Board recognizes that the above listed considerations may be given different weighting depending on the specific circumstances surrounding each application. The Board has considered the above factors in its deliberations.

45 The Board notes AG's comment regarding the impact of revenue shortfalls on AG's financial results for 2005[12] as stated in AG's discussion with the Board and parties in the June 14, 2005 Information Workshop. In this Application, the Board considers that the forecast shortfall of $18.5 million could be considered a material amount if the entire amount had to collected from customers.

46 AG suggested that $9.3 million or approximately 50% of the forecast 2005 revenue shortfall would be a reasonable interim rate adjustment. In determining the reasonableness of the requested amount, the Board notes the number of contentious issues and the amounts of revenue increases related to those issues. The Board has balanced the quantum of contentious revenue related issues with the quantum of the forecast shortfalls and the impact to rates that would be associated with a range of shortfall collection scenarios. While the amount of the requested rate increase would only constitute 2% of current customer bills, the Board considers that by the time the GRA decision is rendered and amended rates have been implemented, AG may have to collect all of the 2005 and some portion of 2006 shortfalls. Given the potential magnitude of these shortfalls, the Board considers it appropriate to award some degree of interim rate adjustment to avoid future rate shock. The Board also considers that applying the interim increase on an equal percentage basis to the energy, fixed and demand charges for all rate classes[13] is a reasonable method of applying the interim increase that is simple and cost effective to apply.

47 The Board considers that an increase in rates, on an interim basis, to generate an amount of $7.0 million in additional revenue in 2005 compared with current rates, will mitigate the risk of future rate shock caused by additional rate increases during 2006, maintain intergenerational equity, ensure rate stability and provide a reasonable level of revenue to the Applicant. The Board considers that this level of increase is sufficient to recognize the possibility of some increase being awarded with respect to rates in 2005 and therefore alleviating the impact of collecting shortfalls during 2006.

48 The Board has prepared Appendix 1 showing the Interim Rates to be applicable to billings on and after September 1, 2005 until replaced by subsequent decisions or orders of the Board.

49 In determining the level of interim rates for AGN, the Board is not making any finding or determination with respect to any of the matters to be considered in the upcoming GRA. The Board recognizes that the evidence before it is untested and that a number of areas of concern identified by the interveners could result in an adjustment to forecasted shortfalls.

5 Order

50 IT IS HEREBY ORDERED THAT:

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(1) Appendix 1, Rider G of this Decision is hereby approved as an additional rider to the current rate schedules, on an interim basis for ATCO Gas North service zone, applicable to billings on and after September 1, 2005 until replaced by subsequent orders of the Board.

Appendix 1

Effective by Decision 2005-099

On consumption September 1, 2005

ATCO GAS NORTH RATE RIDER "G" TO DELIVERY SERVICE RATES

Applicable to the fixed and variable charges in ATCO Gas North DSP Delivery Service Rates 1, 11, 3, 13 and 13b. Effective on all consumption commencing September 1, 2005.

Surcharge to Fixed Charge, Variable Charge and Demand Charge	9.96	

Footnotes

1 Decision 2003-072 — ATCO Gas 2003/2004 General Rate Application, Phase I, dated October 1, 2003

2 Decision 2003-072, p. 81

3 Decision 2004-036 — ATCO Gas 2003/2004 General Rate Application — Compliance Filing, dated April 28, 2004

4 Decision 2003-072, p. 47

5 Decision 2005-039 — ATCO Gas 2003/2004 GRA Impact of the Retail Transfer and ITBS Volume Forecast, dated May 3, 2005

6 Decision 2002-069 — Affiliate Transactions and Code of Conduct Proceeding, Part A: Asset Transfer, Outsourcing Arrangements, and GRA Issues, dated July 26, 2002

7 Muskeg River Pipeline Module

8 Interim Decision E92036, Canadian Western Natural Gas Company Limited, Re: Interim Rates effective April 1, 1992, dated April 2, 1992

9 Order E93028, Northwest Utilities Limited, Re: Interim Rates for 1993, dated March 31, 1993

10 Decision 2002-115, ATCO Gas 2003/2004 General Rate Application Interim Rate Application, dated December 24, 2002

11 Decision 2002-108, ATCO Electric Ltd. 2003 Distribution Tariff and Transmission Facility Owner's Tariff Part A: 2003 Interim DT and TFO Tariff, dated December 11, 2002

12 AG Application letter June 8, 2005 P1

13 Equivalent to the "Across-the-board" basis per AG submission

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2005 CarswellAlta 2281, [2007] A.W.L.D. 2816

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2008 CarswellAlta 2098
Alberta Utilities Commission

ATCO Electric Ltd., Re

2008 CarswellAlta 2098, [2009] A.W.L.D. 902

ATCO Electric Ltd.; 2009 Interim Distribution Tariff and Transmission Facility Owner's Tariff

A. Michaud Acting Commr., B. Lyttle Commr., C.D. Rees V-Chair

Judgment: December 19, 2008
Docket: 2008-134

Counsel: None given

Subject: Public

Related Abridgment Classifications

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2008 CarswellAlta 2098, [2009] A.W.L.D. 902

For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Approval

Table of Authorities

Cases considered:

ATCO Electric Ltd., Re (2005), 2005 CarswellAlta 2284 (Alta. E.U.B.) — considered

ATCO Gas, Re (2005), 2005 CarswellAlta 2281 (Alta. E.U.B.) — referred to

Per Curiam:

1 Introduction

1 On October 31, 2008 ATCO Electric Ltd. (AE) filed an application (the Interim Application) with the Alberta Utilities Commission (AUC or Commission), for approval on an interim refundable basis of the 2009 Interim Distribution Tariff, the 2009 Interim Transmission Facility Owner's Tariff, and amendment to the 2009 Rider B — Balancing Pool Adjustment Rider, effective January 1, 2009.

2 The Notice of Application, issued on November 12, 2008, established the following schedule for the written process which was followed to deal with the Application:

Process Step	***Deadline Date & Time***
Participation Closing Date and Submission of Statements of Intent to Participate	4:00 pm, November 19, 2008
Information Requests to Applicant	4:00 pm, November 20, 2008
Information Responses from Applicant	4:00 pm, November 27, 2008
Argument	4:00 pm, December 2, 2008
Reply Argument	4:00 pm, December 5, 2008

3 The deadlines for Argument and Reply Argument were subsequently extended to December 4, 2008 and December 9, 2008 respectively, due to a temporary filing system disruption.

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4 The AUC received a Statement of Intention to Participate (SIP) from the Utilities Consumer Advocate (UCA). The Commission was the only party to submit Information Requests.

5 To assist with Commission analysis AE was requested to file supplemental rate impact schedules on December 15, 2008 which were based on the UCA's proposal, which is summarized in Section 3 of this Decision.

6 The close of record for this proceeding was December 15, 2008.

2 Background

7 AE's proposed 2009 Interim Tariffs would recover approximately 77% (or $45.7 million) of the Distribution revenue requirement increase and 86% (or $26.2 million) of the Transmission revenue requirement increase requested in the 2009 - 2010 General Tariff Application[1] (GTA).

8 For purposes of the Interim Application AE excluded two items it considered to be potentially contentious. These amounts, which were part of the proposed GTA revenue requirement, related to a management fee and an increase in equity thickness. AE indicated that any difference between the forecast revenues collected from the approved interim and the approved GTA final rates for 2009 would be dispensed through a future Rider G application.

9 To establish distribution rates for the Interim Application, AE proposed to apply the same methodology and application of scaling factors as was filed with the Commission in its 2009 - 2010 GTA. AE indicated that a complete explanation of the cost drivers that supported the proposed revenue requirement increases was available in its 2009-2010 GTA. AE stated that it would be filing a detailed 2010 Phase II Application shortly to address all Phase II related matters.

10 AE also proposed to amend its Rider B — Balancing Pool Adjustment to increase the refund to customers from $5.00/MW.h to $6.50/MWh, effective January 1, 2009, to align with the AESO's proposed Rider F increase.

3 Discussion of Issues

11 The UCA submitted that AE's proposed interim increases based on its requested revenue requirement were excessive and that UCA evidence related to the GTA recommended reductions in a number of areas for consideration by the Commission. These areas included the management fee, inflation, opening rate base balances, rate base additions, numerous O&M areas, corporate aircraft, income tax and the Vancouver Olympics. The UCA suggested that there were more contentious areas than the two identified in AE's Interim Application.

12 The UCA argued that AE's justification[2] in explaining how it met the AUC's two part test, which is summarized in Section 4 of this decision, did not demonstrate any form of financial hardship that it would encounter if the interim application was not approved. Given that a decision on AE's GTA is not anticipated until sometime in the second quarter or early in the third quarter of 2009, the UCA acknowledged that some form of interim increase was justified.

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13 The UCA recommended that no more than 25% of the proposed GTA revenue requirement shortfall should be included in customer rates for the Distribution interim rates, and no more than 50% for the Transmission interim rates. The UCA did not oppose AE's proposed use of a scaling methodology to determine the interim rates. Additionally, the UCA did not oppose AE's proposed future Rider G application treatment for the $22.3 million refund[3] due to AE customers related to the Benchmarking and ATCO I-Tek IT True Up proceeding, provided the appropriate interest was credited to AE customers as part of the carrying charge calculations.

14 AE argued that the UCA proposal for reductions to the interim revenue requirement increases did not provide any explanation of how the proposed reductions provided a stable transition to 2010 distribution rates. AE indicated that it faced significant cost pressures regarding the services it provided and that it required the opportunity to collect the revenue required for providing these services. AE stated that further target revenue requirement reductions would negatively impact its financial position.

4 Commission Findings

15 In Decision 2005-102 [2005 CarswellAlta 2284 (Alta. E.U.B.)],[4] the Alberta Energy and Utilities Board (Board) applied a two-part test to determine the interim TFO tariff requested by AE for 2005. In doing so, the Board specifically considered the principles outlined in Decision 2005-099 [*ATCO Gas, Re*, 2005 CarswellAlta 2281 (Alta. E.U.B.)].[5] The Commission has considered the principles outlined in Decision 2005-099 in arriving at its decision for this proceeding.

16 The factors used in evaluating interim rate increases can be grouped into two categories, namely:

1. Those that relate to the quantum of, and need for, the rate increase

    - Is the identified revenue deficiency probable and material?
    - Can all or some portion of any contentious items be excluded from the amount collected?
    - Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
    - Can the applicant continue safe utility operations without the interim adjustment?

2. Those that relate to more general public interest considerations

    - Do the interim rates promote rate stability and ease rate shock?
    - Do the interim adjustments help maintain intergenerational equity?
    - Can interim rate increases be avoided through the use of carrying costs?
    - Are the interim rate increases required to provide appropriate price signals to customers?
    - Is it appropriate to apply the interim rider on an across-the-board basis?

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17 The considerations forming each of the two categories above may be given different weighting depending on the specific circumstances surrounding each application.

18 The Commission agrees with the comments made by the UCA that AE has provided limited information with respect to the two part test to support its interim tariff request. In particular, the Commission considers that AE has not provided specific evidence to allow examination of the manner in which the principles of financial integrity, financial hardship or continuation of safe utility operations may be affected.

19 Further, the Commission considers that through the use of carrying costs, utilities can be kept whole during the transition from one revenue requirement to another.

20 The Commission notes that the UCA supported some form of interim increase.

21 Notwithstanding the above noted limitations in the evidence submitted by AE to support its request under the two-part test, the Commission acknowledges that a decision on AE's GTA may not be rendered until the second quarter or early in the third quarter of 2009. The Commission is persuaded that some interim rate increase is appropriate to minimize the shortfall for that portion of 2009, and to reduce rate shock and intergenerational inequity.

22 In arriving at its decision respecting what level of interim rate increase would be appropriate, the Commission reviewed both AE's and the UCA's proposals before it.

23 In determining the interim increase amounts the Commission is not making any findings or determinations with respect to any matters to be considered in the current GTA. The Commission notes, however, AE's position regarding the requested 2009 interim rates, that "the transition to final 2010 rates should be as smooth as possible." The Commission considers that increasing rates by the levels proposed by AE does not reflect the principle of gradualism in determining appropriate rates given that it is a reasonable assumption that the final approved rates could be based on an amount that is less than the interim increase proposed by AE, as was suggested by the UCA. In addition, the Commission considers that the level of the interim revenue requirement proposed by AE is a significantly higher dollar amount than in previous interim applications and it therefore warrants examination through the existing GTA process for such factors as changes in economic outlooks before these increases are incorporated as part of rates, including interim rates.

24 The Commission considers that to better provide both gradualism and a transitional rate level, it would be preferable to have an interim increase that reflects an intermediate position between the current rates and the proposed final rates. Based on past practice for interim rate orders in similar circumstances, the Commission has generally maintained current rates or granted 50% of the revenue requirement increase.

25 Given the above considerations, the Commission is persuaded by the UCA's argument. Accordingly the Commission approves 50% of the proposed GTA revenue requirement increase for AE's transmission tariff for 2009, and 25% of the proposed GTA revenue requirement increase for AE's distribution tariff for 2009, effective January 1, 2009, as shown in the table below:

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Table 1. Commission Approved Revenue Requirement (RR) Increases for DT and TFO Tariffs

	AE 2009 GTA Proposed Total RR ($ million)	AE 2009 GTA Proposed RR Increase $ million	AE 2009 Interim Proposed RR Increase ($ million) (% Recovery)[6]	UCA 2009 Proposed Interim RR Increase ($ million) (% Recovery)[7]	Commission Approved RR Increase ($ million) (% Recovery)
DT Tariff	$421.6	$59.5	$45.7 (77%)	$14.9 (25%)	**$14.9 (25%)**
TFO Tariff	$209.2	$30.4	$26.2 (86%)	$15.2 (50%)	**$15.2 (50%)**

Table 2. Percentage Impact of Commission Approved Interim Rates vs. Current Rates for Average Use Customers (based on DT Base Rates and Rider B Components)

Rate Class	August — December 2008 DT Base Rates	Rider B	Total DT Base Rates & Rider B	January 2009 DT Base Rates	Rider B	Total DT Base Rates & Rider B	Impact
		$/month			$/month		
D-11 Residential	52.85	(3.17)	49.68	53.61	(4.12)	49.49	**0%**
D-21 Commercial	262.87	(38.69)	224.18	267.95	(50.22)	217.73	**-3%**
D-25 Irrigation	1,359.69	(63.07)	1,296.62	1,512.69	(82.58)	1,430.11	**10%**
D-26 REA Irrigation	994.85	(63.07)	931.78	1,150.60	(82.58)	1,068.02	**15%**
D-31 Industrial	524.33	(87.25)	437.08	548.86	(113.39)	435.47	**0%**
D-41 Oilfield	343.43	(47.22)	296.21	349.53	(61.41)	288.12	**-3%**
D-51 REA Farm	45.53	(6.68)	38.85	47.29	(8.68)	38.61	**-1%**
D-56 Farm	66.06	(6.68)	59.38	67.54	(8.68)	58.86	**-1%**
D-61 Street Lighting	9.15	(.46)	8.69	9.18	(.60)	8.58	**-1%**
D-63 Private Lighting	12.89	(.46)	12.43	12.95	(.60)	12.35	**-1%**
T-31 Industrial	21,296.55	(5,110.00)	16,186.55	21,670.62	(6,643.00)	15,027.62	**-7%**

26 The above table includes the tariff components which are affected by Commission findings in this Decision. Appendix 2 to this Decision (Rate Impact Schedules) provides a comparison of impacts based on the total tariff, which includes the energy component and Rider G which was only effective from August 1, 2008 to December 31, 2008.

27 With respect to the 2009 interim Distribution Tariff, the Commission notes that the UCA was not opposed to the scaling factor approach to achieve interim distribution rates. The Commission considers that AE's proposed scaling approach is a reasonable way to allocate the interim rate increase. Therefore the Commission approves the scaling factor approach to increase distribution rates by $14.9 million, as contained in Appendix 4 to this Decision (Determination of Adjustment Factors).

28 The Commission also notes AE's proposal to increase the refund associated with Rider B — Balancing Pool Adjustment from $5.00/MWh to $6.50/MWh to align with the AESO's proposed Rider F increase. The Commission approves this request so that AE may flow through the appropriate refund rider to customers. Appendix 3 of this Decision contains the Rider B Balancing Pool Rider Determination.

29 Regarding AE's proposed treatment[8] of the Benchmarking of ATCO IT and CC&B services true-up, the Commission notes the UCA did not oppose AE's Rider G approach, provided that the appropriate amount of interest was credited to AE customers as part of the carrying charge calculations. The Commission finds AE's recommendation to be reasonable. The

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Commission directs AE to true-up the amount related to the Benchmarking of ATCO IT and CC&B services, currently estimated to be $22.3 million that is due to customers, as part of the next Rider G application. Additionally, the Commission directs AE to include the application of interest based on AUC Rule 23: *Rules Respecting Payment of Interest* to be credited to AE customers as part of the carrying charge calculations.

5 Order

30 IT IS HEREBY ORDERED THAT:

(1) ATCO Electric Ltd.'s 2009 Interim Distribution Tariff of $362.1 million shall be increased by $14.9 million to $377.0 million on an interim basis effective January 1, 2009, with use of the scaling factors as applied for by AE to achieve this increase.

(2) ATCO Electric Ltd.'s 2009 Transmission Facility Owner tariff of $178.8 million shall be increased by $15.2 million to $194.0 million on an interim basis effective January 1, 2009. Appendix 5 to this Decision provides the Interim 2009 Transmission Tariff.

(3) ATCO Electric Ltd.'s existing Rider B — Balancing Pool Adjustment Rider shall be increased to a refund of $6.50/MWh to coincide with the AESO Rider F increase, effective January 1, 2009.

APPENDIX 1 — 2009 Interim Distribution Tariff
ATCO ELECTRIC LTD.
2009 INTERIM DISTRIBUTION TARIFF
EFFECTIVE JANUARY 1, 2009

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RESIDENTIAL SERVICE	
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Temporary Adjustment	Rider G
Interim Adjustment	Rider J
Interim RRT Adjustment	Rider Q

Price Schedule D11 Standard Residential Service

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company. Price Schedule D11 is available for use by a single and separate household through a single-phase service at secondary voltage through a single meter. Price Schedule D11 is not applicable for commercial or industrial use.

Price

The charge for service in any one billing period is the sum of the Customer Charge and Energy Charge, determined for each individual Point of Service.

	Customer Charge	***Energy Charge***
Transmission	-	1.59 ¢ / kW.h
Distribution	41.82 ¢ / day	3.93 ¢ / kW.h
Service	26.49 ¢ / day	-
TOTAL PRICE	*68.31 ¢ / day*	*5.52 ¢ / kW.h*

Application

1. *Price Option* - the following price option may apply:

   Idle Service (Option F)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

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Interim RRT Adjustment (Rider Q)

Price Schedule D21 Standard Small General Service

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***		***Energy Charge***
			For the first 200 kW.h per kW of billing demand	**For energy in excess of 200 kW.h per kW of billing demand**
Transmission	-	7.38 ¢/kW/day	0.47 ¢ / kW.h	0.47 ¢ / kW.h
Distribution	-	14.42 ¢/kW/day	2.34 ¢ / kW.h	-
Service	30.79 ¢ / day	-	-	-
TOTAL PRICE	*30.79 ¢ / day*	*321.80 ¢/kW/day*	*32.81 ¢ / kW.h*	*30.47 ¢ / kW.h*

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

(d) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 5 kilowatts.

Application

1. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. *Price Options* - the following price options may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

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REA Distribution Price Credit (Option P)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D22 Standard Small General Service - Energy Only

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, with single or three-phase electric service at secondary voltage. Not applicable for any service in excess of 50 kW.

Price

Charges for service in any one billing period shall be the Energy Charge, determined for each individual Point of Service.

	Energy Charge	
	For the first 50 kW.h per kW of billing demand	**For energy in excess of 50 kW.h per kW of billing demand**
Transmission	0.56 ¢ / kW.h	0.56 ¢ / kW.h
Distribution	16.25 ¢ / kW.h	5.31 ¢ / kW.h
Service	-	-
TOTAL PRICE	*16.81 ¢ / kW.h*	*5.88 ¢ / kW.h*

The billing demand applied to determine the billing energy per block of energy charge for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(d) 5 kilowatts.

The minimum annual charge is 12 times the sum of:

(a) the Service Charge from Price Schedule D21; and

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(b) the Total Demand Charge from Price Schedule D21 multiplied by the higher of the DCD or 5 kW.

Application

1. *Power Factor Correction* - where the power factor at a Point of Service is found to be less than 90%, the Company may require the installation of corrective equipment.

2. *Price Options* - the following price option may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

3. *Price Adjustments* - the following additional charges (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D24 Standard Small General Service Isolated Industrial Areas

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company distribution connected from an isolated industrial areas. Not applicable for any service in excess of 500 kW.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***	***Energy Charge***	
			For the first 200 kW.h per kW of billing demand	**For energy in excess of 200 kW.h per kW of billing demand**
Distribution	-	14.42 ¢/kW/day	2.34 ¢ / kW.h	-
Service	30.79 ¢ / day	-	-	-
TOTAL PRICE	*30.79 ¢ / day*	*14.42 ¢/kW/day*	*2.34 ¢ / kW.h*	-

The billing demand for the Distribution and Service charges shall be the higher of:

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(a) the highest metered demand during the billing period;

(b) 85% of the difference between the highest metered demand in the twelve month period including and ending with the billing period and 150 kW, if this is greater than zero;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 5 kilowatts.

Application

1. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

2. *Price Options* - the following price options may apply:

Idle Service (Option F)

Service for Non-Standard Transformation and Metering Configurations (Option H)

REA Distribution Price Credit (Option P)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D25 Irrigation Pumping Service

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing period during one Season shall be the sum of the Customer Charge, Demand Charge, and Energy Charge, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	6.18 ¢/kW/day	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*16.67 ¢/kW/day*	*0.47 ¢ / kW.h*

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The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;;

(d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746*.

Application

1. *Idle Service* - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.

2. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D26 REA Irrigation Pumping Service

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, between April 1 and October 31 for seasonal irrigation pumping loads of Rural Electrification Association Customers and individual co-operative and colony farms with their own distribution systems. Not applicable for any service in excess of 150 kW.

Price

Charges for service in any one billing period during one Season shall be the sum of the Customer Charge, Demand Charge,

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and Energy Charge, determined for each individual Point of Service.

Customers in the REA O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	1.95 ¢/kW/day	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*12.43 ¢/kW/day*	*0.47 ¢ / kW.h*

Customers outside of the REA O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	10.49 ¢/kW/day	0.47 ¢ / kW.h
Distribution	-	-	-
Service	14.41 ¢ / day	-	-
TOTAL PRICE	*14.41 ¢ / day*	*10.49 ¢/kW/day*	*0.47 ¢ / kW.h*

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) the estimated demand;

(c) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(d) 5 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746*.

REA Specific Charges:

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

The minimum charge for the season shall be 7 times the Service Charge and 7 times the Demand Charge.

Application

1. *Idle Service* - in the event the service remains idle for two consecutive seasons, the Company may remove its facilities, unless the Customer pays the minimum charge for the upcoming season prior to December 31, of the preceding year.

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2. *Power Factor Correction* - where a Customer's power factor is found to be less than 90%, the Company may require the Customer to install corrective equipment.

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D31 Large General Service / Industrial Distribution Connected

Availability

• For System Access Service and Distribution Access Service, single or three-phase distribution connected, for all Points of Service throughout the territory served by the Company. This rate is not applicable for any Small Oilfield and Pumping Power service with yearly average operating demands of less than or equal to 50 kW.

• For distribution connected loads greater than 500 kW, the Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, Energy Charge and Charge for Deficient Power Factor, determined for each individual Point of Service:

	Customer Charge	***Demand Charge***		***Energy Charge***
		For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Transmission	-	11.42 ¢/kW/day	4.02 ¢/kW/day	0.46 ¢ / kW.h
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*27.98 ¢/kW/day*	*25.84 ¢/kW/day*	*0.46 ¢ / kW.h*

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

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The billing demand for the Transmission charges shall be the higher of:

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedules D32 and D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D32 and D33) in the 24-month period.

(f) 50 kilowatts.

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D31 *Base Demand* as specified under the corresponding agreement.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746*.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Price Options* - the following price options may apply:

   Idle Service (Option F)

   Service for Non-Standard Transformation and Metering Configurations (Option H)

   REA Distribution Price Credit (Option P)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

   Interim RRT Adjustment (Rider Q)

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Price Schedule T31 Large General Service / Industrial Transmission Connected

Availability

- For System Access Service, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.
- The Point of Service must be equipped with interval data metering.

Price

Charges for service in any one billing period shall be the sum of the Demand Charge, Energy Charge and charge for Deficient Power Factor, determined for each individual Point of Service.

	Demand Charge		***Energy Charge***
	For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Transmission	Current AESO DTS Rate Schedule less under frequency load shedding credit	Current AESO DTS Rate Schedule less under frequency load shedding credit	Charges per current AESO DTS Rate Schedule
Distribution	8.20 ¢/kW/day	-	-
Service	1.73 ¢/kW/day	-	-
TOTAL PRICE	*9.92 ¢/kW/day + Current AESO DTS Rate Schedule less under frequency load shedding credit*	*Current AESO DTS Rate Schedule less under frequency load shedding credit*	

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any contract opportunity demand delivered and billed under Price Schedule T33);

(b) 85% of the highest metered demand (including any contract opportunity demand delivered and billed under Price Schedule T33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) 50 kilowatts.

The billing demand for the Transmission charge shall be the higher of:

(a) The billing demand charged to ATCO Electric by AESO at a Point of Delivery, that is attributable to the customer at that Point of Delivery;

(b) the highest metered demand during the billing period;

(c) the ratchet level as set out by the AESO at a Point of Delivery, *where (a) through (c) exclude any contracted Opportunity Demand delivered and billed under Price Schedule T33;*

(d) the estimated demand;

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(e) the Transmission Contract Demand (TCD) for Customers served from diversified PODs, or 90% of the TCD for Customers served from dedicated PODs;

(f) 50 kilowatts

The 'highest metered demand' is defined for the purposes of this price schedule, according to the current approved AESO DTS Rate Schedule.

If energy is also taken under Transmission Opportunity Rate (Price Schedule T33), during the billing period, the billing demand will be the Price Schedule T31 *Base Demand* as specified under the corresponding agreement.

Charge for Deficient Power Factor - Power Factor Charges according to the current approved AESO DTS Rate Schedule will apply.

Application

1. *Price Options* - the following price option may apply:

   Service for Non-Standard Transformation and Metering Configurations (Option H)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

Price Schedule D32 Generator Interconnection and Standby Power

Availability

• For Points of Service served by the Company with on-site generating equipment connected to the distribution system, which may be used to supply load at the same site.

• To provide standby power to the on-site load in the event of a forced outage or derate of on-site generating equipment, to provide power for generator startup, and to provide supplemental power if the on-site demand requirements exceed the generator capacity.

• To provide credits to Generators for reduced DTS charges from AESO.

• To charge Generators if the Point of Delivery attracts STS charges from AESO.

• For interconnection of the generator to the distribution system.

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• The Point of Service must be equipped with 4-quadrant interval data metering, for both supply and demand, the cost of which will be in addition to the charges under this rate.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, Energy Charges, Other Charges, Charge for Deficient Power Factor (determined for each individual Point of Service), and Fixed Charges defined below.

	Customer Charge	**For the first 500 kW of billing demand**	***Demand Charge*** **For all billing demand over 500 kW**	***Energy Charge***
Transmission	-	11.42 ¢/kW/day	14.02 ¢/kW/day	0.46 ¢ / kW.h
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*27.98 ¢/kW/day*	*25.84 ¢/kW/day*	*0.46 ¢ / kW.h*

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period (including any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (including any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD).

The billing demand for the Transmission charges shall be the higher of:

(a) The highest metered demand during the billing period (excluding any demand delivered and billed under Price Schedule D33);

(b) 85% of the highest metered demand (excluding any demand delivered and billed under Price Schedule D33) in the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Transmission Contract Demand (TCD);

(e) if any of the above are equal to or greater than 1000 kW, 80% of the highest metered demand (excluding any demand delivered and billed under Price Schedules D33) in the 24-month period including and ending with the current billing period;

If energy is also taken under Transmission Opportunity Rate (Price Schedule D33), during the billing period, the billing demand will be the Price Schedule D32 *Base Demand* as specified under the corresponding agreement.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand* =

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kW Nameplate Rating, or *kW Billing Demand = HP Nameplate × 0.746.*

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest billing kW demand in the same billing period, where billing demand is as defined in this price schedule.

If the Company incurs an increase to the Point-of-Delivery (POD) billing demand with AESO as a result of a standby event of the customer (i.e. the new demand at the POD is coincident with an outage of the generator), then an additional charge may apply, equal to the Transmission Demand Charge for Price Schedule T31, multiplied by the incremental POD demand incurred. This charge will apply for the current billing period, and for the next 11 billing periods.

Capital Recovery Charges:

The cost of the Incremental Interconnection Facilities will be determined as set out in Section 9.6 of the Terms and Conditions for Distribution Service Connections. The total amount will be collected from the customer in accordance with Section 9.8 of the Terms and Conditions for Distribution Service Connections. A contract will be arranged between the customer and the Company, specifying the contract term and the monthly amount, which will be calculated using the Company's Rate of Return, Income Tax and Depreciation in effect at the commencement of the contract term.

The Generating customer will be required to pay all replacement costs for incremental facilities as per Section 9.6 of the Terms and Conditions for Distribution Service Connections.

Incremental Operations and Maintenance Charges:

The minimum monthly incremental Operations and Maintenance charge will be:

(0.01315% × Incremental Interconnection Cost) per day

The Generating customer will be required to pay for switching or isolation as per Section 9.6 of the Terms and Conditions.

Incremental Administration and General Charges:

The minimum monthly incremental Administration and General charge will be:

(0.00432% × Incremental Interconnection Cost) per day

Generator Credits for reduction in Billing Determinants at the Point of Delivery:
*Credit = DTS * (A - B)* *Where:*

A = Monthly Gross Billing Determinants at the POD to which the generator is connected (which will be determined by adding the interval output data metered at the generator to the net interval data metered at the POD).

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B = Monthly Net Billing determinants at the POD to which the generator is connected.

DTS = The charges as per AESO's effective DTS tariff.

The Company will calculate the generator credits on a calendar quarterly basis after all power production information has been provided to the Company in accordance with Section 9.5.4 of the Terms and Conditions for Distribution Service Connections.

Generator Charges for a Point of Delivery:
*Charge = STS * A* *Where:*

A = Monthly *Net* Supply Billing determinants at the POS to which the generator is connected.

STS = The charges as per AESO's effective STS tariff.

Application

1. *Price Options* - the following price options may apply:

   Idle Service (Option F)

   Service for Non-Standard Transformation and Metering Configurations (Option H)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

   Interim RRT Adjustment (Rider Q)

Price Schedule D33 Transmission Opportunity Rate Distribution Connected

Availability

• Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company for loads greater than 1,000 kW.

• Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.

• The Point of Service must be equipped with revenue approved time of use metering. The cost of the time of use

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metering is in addition to the charges in this rate.

• Telemetering is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing period shall be the sum of the following charges determined for each individual Point of Service. The AESO DOS charges will be applied according to the terms of the DOS option selected by the Customer:

	Customer Charges	***Demand Charges*** **For all kW of Opportunity Contract Demand**	***Demand Charges*** **For the peak kW above the Opportunity Contract Demand**	***Energy Charges*** **For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand**	***Energy Charges*** **For all kW.h metered above the Opportunity Contract Demand**
Transmission	Transaction Charge per AESO DOS Rate Schedule	-	Per Price Schedule D32	Per AESO DOS Rate Schedule	Per Price Schedule D32
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-	-
Service	$1.6261 / day	-	0.26 ¢/kW/day	-	-
TOTAL PRICE	*$1.7523 / day + AESO DOS Rate*	*16.56 ¢/kW/day*	*11.82 ¢/kW/day + D32*	*Per AESO DOS Rate Schedule*	*Per Price Schedule D32*

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. *Base Demand* - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule D31 prior to receiving service under this rate (which will be submitted as part of the attached form).

(a) For existing Customers, the Price Schedule D31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

(b) New Customers qualifying for this rate may select the Large General Service/Industrial D31 Base Demand based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

(c) Once established, the Price Schedule D31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. *Applicable Charges* - This rate schedule applies in conjunction with rate D31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. D31 and D33, and D32 should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second and third block

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demand charges. The Service Customer Charge does not apply again as it has already been applied to the base load on Price Schedule D31.

3. *Options* - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. *Notice Period* - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. *Load Curtailment* - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule D31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. *Non-Compliance Charges* - In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. *Price Options* - the following price options may apply:

Service for Non-Standard Transformation and Metering Configurations (Option H)

8. *Price Adjustments* - the following price adjustments may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre - (780) 632-5959.

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Customer Name:	
Date of Request:	
Time of Request:	

1. OPPORTUNITY CONTRACT PERIOD:

Start Date:		**Start Time:**	
End Date:		**End Time:**	
Number of Hours in Contract Period:			**Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE":	DOS 7 Minutes:	
	DOS 1 Hour:	
	DOS Term:	

3. OPPORTUNITY CONTRACT DEMAND: _____ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule D31 Base Demand:		kW
Sum of Demands on all Opportunity Service Contracts:		kW
Total Base Demand:		kW

Confirmation: 1) _____ for ATCO Electric
2) _____ for _____

Graphic 1

Price Schedule T33 Transmission Opportunity Rate Transmission Connected

Availability

• For System Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company that are directly connected to a transmission substation, and do not make any use of distribution facilities owned by ATCO Electric.

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• Available only to Points of Service which are eligible as determined by AESO for Demand Opportunity Service, throughout the territory served by the Company from the Alberta Interconnected System for loads greater than 1,000 kW.

• Available only when AESO determines that there is sufficient transmission capacity. Service on this rate is interruptible for transmission system security reasons at AESO's request.

• The point of service must be equipped with revenue approved time of use metering. The cost of the time of use metering is in addition to the charges in this rate.

• Telemetering is required for all points of service on this rate with demands greater than 2,500 kW, and any associated costs will be in addition to the charges in this rate.

Price

Charges for service in any one billing period shall be the sum of the following charges determined for each individual Point of Service. The current approved AESO DOS charges will be those according to the terms of the DOS option selected by the Customer:

	Transaction Charge	***Demand Charges*** **For all kW of Opportunity Contract Demand**	***Demand Charges*** **For the peak kW above the Opportunity Contract Demand**	***Energy Charges*** **For all kW.h metered above the Base Demand, not exceeding the Opportunity Contract Demand**	***Energy Charges*** **For all kW.h metered above the Opportunity Contract Demand**
Transmission	Per AESO DOS Rate Schedule	-	Per Price Schedule T31	Per AESO DOS Rate Schedule	Per Price Schedule T31
Distribution	-	Per Price Schedule T31	Per Price Schedule T31	-	-
Service	-	Per Price Schedule T31	Per Price Schedule T31	-	-
TOTAL PRICE	*Per AESO DOS Rate Schedule*	*Per Price Schedule T31*	*Per Price Schedule T31*	*Per AESO DOS Rate Schedule*	*Per Price Schedule T31*

The attached form must be completed and submitted to the Company, and serves as an Opportunity Contract which specifies the period and the Opportunity Demand requested by the Customer, as well as the DOS option selected.

The charges according to the AESO DOS Rate Schedule will be the approved charges in effect during the billing period, and will be revised in accordance with AESO's charges as required.

Application

1. *Base Demand* - A Customer qualifying for this rate must establish a Base Demand with the Company on Price Schedule T31 prior to receiving service under this rate.

(a) For existing Customers, the Price Schedule T31 Base Demand will normally be the maximum billing demand in the 12 most recent billing periods.

(b) New Customers qualifying for this rate may select the Large General Service/Industrial T31 Base Demand

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based on forecast loads and economics, provided the Company agrees that the conditions of applicability are satisfied.

(c) Once established, the Price Schedule T31 Base Demand remains fixed for the purposes of billing all future service on this rate.

2. *Applicable Charges* - This rate schedule applies in conjunction with rate T31, in that the first block demand charges apply only to the first 500 kW of the combined demand (i.e. T31 and T33, and T31 again should there be an excursion above contracted opportunity demand), and the remainder of the combined demand is subject to the second block demand charges.

3. *Options* - A Customer requesting service under this rate must select the provisions of one of AESO's DOS Rate Schedules. The Customer is subject to AESO's minimum Opportunity Service charges, attributable to that customer.

4. *Notice Period* - A Customer requesting service under this rate is required to provide notification as prescribed in the AESO tariff in relation to DOS service.

5. *Load Curtailment* - When a load curtailment directive is given, the load at the point of service must not exceed the Price Schedule T31 Base Demand until the Company gives notification that the interruption period is over, at which time consumption of energy may be resumed.

6. *Non-Compliance Charges* - In the event of a load curtailment directive, if the load served under this rate is not curtailed for the entire interruption period, any charges incurred by the Company will be charged to the Point of Service on this rate.

7. *Price Options* - the following price option may apply:

Service for Non-Standard Transformation and Metering Configurations Option H(d).

8. *Price Adjustments* - the following price adjustments may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

This form will be completed and signed by ATCO Electric after a telephone request from a Customer for Transmission Opportunity Service. The form will be faxed to the Customer upon which the Customer will confirm the information with a signature and fax the completed form back to ATCO Electric Control Centre - (780) 632-5959.

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Customer Name:	
Date of Request:	
Time of Request:	

1. OPPORTUNITY CONTRACT PERIOD

Start Date:		**Start Time:**	
End Date:		**End Time:**	
Number of Hours in Contract Period:			**Hours**

2. TRANSMISSION OPPORTUNITY SERVICE OPTION:

AESO "DEMAND OPPORTUNITY SERVICE":	DOS 7 Minutes:	
	DOS 1 Hour:	
	DOS Term:	

3. OPPORTUNITY CONTRACT DEMAND: _____ **kW**

4. BASE DEMAND:

Large General Service/Industrial Price Schedule T31 Base Demand:		kW
Sum of Demands on all Opportunity Service Contracts:		kW
Total Base Demand:		kW

Confirmation: 1) _____ for ATCO Electric
2) _____ for _____

Graphic 2

Price Schedule D34 Large General Service/Industrial Isolated Industrial Areas

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area.

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Price

Charges for service in any one billing period shall be the sum of the Customer Charge, Demand Charge, and Charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***		***Energy Charge***
		For the first 500 kW of billing demand	**For all billing demand over 500 kW**	
Distribution	12.62 ¢/day	16.56 ¢/kW/day	11.56 ¢/kW/day	-
Service	$1.6261 /day	-	0.26 ¢/kW/day	-
TOTAL PRICE	*$1.7523 /day*	*16.56 ¢/kW/day*	*11.82 ¢/kW/day*	-

The billing demand for the Distribution and Service charges shall be the higher of:

(a) The highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 50 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746*.

Charge for Deficient Power Factor - For customer power factor which is less than 90%, an additional charge for deficient power factor of 15.23¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Price Options* - the following price options may apply:

   Idle Service (Option F)

   Service for Non-Standard Transformation and Metering Configurations (Option H)

   REA Distribution Price Credit (Option P)

2. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

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Interim Adjustment (Rider J)

Price Schedule D41 Small Oilfield and Pumping Power

Availability

For System Access Service and Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company. This rate is available only to Points of Service for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters with yearly average operating demand less than or equal to 50 kilowatts.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, Energy Charges and charge for Deficient Power Factor, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	9.69 ¢/kW/day	0.47 ¢ / kW.h
Distribution	40.93 ¢ / day	37.13 ¢/kW/day	-
Service	50.54 ¢ / day	-	-
TOTAL PRICE	*$0.9147 / day*	*46.82 ¢/kW/day*	*0.47 ¢ / kW.h*

The billing demand for the Transmission, Distribution and Service charges shall be the higher of:

(a) the highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) if applicable, the Transmission Contract Demand (TCD) applied to Transmission charges, and/or the Distribution Contract Demand (DCD) applied to Distribution and Service charges;

(e) 4 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746.*

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand, plus a flat rate of $1.47 per kW in lieu of the charge for energy.

The *Metered demand* will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

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Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 35.36¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Demand Metered* - where services are demand metered, the meter will normally be read and reset at least once every two months.

2. *Price Options* - the following price option may apply:

   Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

   Interim RRT Adjustment (Rider Q)

Price Schedule D44 Small Oilfield and Pumping Power Isolated Industrial Areas

Availability

For Distribution Access Service, single or three-phase, for all Points of Service throughout the territory served by the Company from an isolated industrial area, for production energy requirements in the petroleum and natural gas industries including related operations, such as rectifiers, cathodic protection and radio transmitters.

Price

Charges for service in any one billing period shall be the sum of the Customer Charges, Demand Charges, and charge for Deficient Power Factor, determined for each individual Point of Service:

	Customer Charge	***Demand Charge***
Distribution	40.93 ¢ / day	37.13 ¢/kW/day
Service	50.54 ¢ / day	-
TOTAL PRICE	*$0.9147 / day*	*37.13 ¢/kW/day*

The billing demand for the Distribution and Service charges shall be the higher of:

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(a) The highest metered demand during the billing period;

(b) 85% of the highest metered demand during the 12-month period including and ending with the billing period;

(c) the estimated demand;

(d) the Distribution Contract Demand (DCD);

(e) 4 kilowatts.

For non-demand metered services, demand shall be estimated based on equipment nameplate ratings as *kW Billing Demand = kW Nameplate Rating*, or *kW Billing Demand = HP Nameplate × 0.746*.

The 85% ratchet applies only to demand metered loads. The cost of converting an energy meter to a demand meter will be in addition to the charges on this rate.

Estimated Demands - Where it is impractical to meter a point of service, the Company may bill on the basis of estimated maximum demands. In such case, the monthly bill shall be the demand charge above applied to the estimated demand.

The *Metered demand* will be the greater of the registered demand in kW, or 90% of the registered demand in kV.A where a kW reading is not available.

Charge for Deficient Power Factor - where a Customer's power factor is found to be less than 90%, the Company may require such Customers to install corrective equipment. For Customer power factor which is less than 90%, an additional charge for deficient power factor of 35.36¢/kV.A/day will be applied to the difference between the highest metered kV.A demand and 111% of the highest metered kW demand in the same billing period.

Application

1. *Demand Metered* - where services are demand metered, the meter will normally be read and reset at least once every two months.

2. *Price Options* - the following price options may apply:

   Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Special Facilities Charge (Rider E)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

Price Schedule D51 REA Farm Service

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Availability

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to a Rural Electrification Association's distribution system.

Price

- Charges for service in any one billing period are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.
- Please refer to individual REA Tariffs to determine applicable REA charges.

REA Farms in O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	-	8.57 ¢/kV.A/day	-
Service	33.11 ¢ / service / day	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	*C{ 1} ¢ / service/ day*	*13.95 ¢/kV.A/day*	*0.47 ¢ / kW.h*

REA Farms Outside of O & M Pool

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	See REA Tariff	See REA Tariff	-
Service	See REA Tariff	-	-
REA Specific Charges	See REA Tariff	-	-
Total Price	*C{ 1} ¢ / service /day*	*D{ 1} ¢/kV.A/day*	*0.47 ¢ / kW.h*

kV.A capacity for billing purposes will be determined as follows:

(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. 25 kV.A.

REA Specific Charges

Other charges are applied on behalf of the REAs as defined in contracts and are subject to change from time to time.

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These charges include operation and maintenance charges and deposit reserve charges, and are in addition to the charges contained in this price schedule.

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. *Price Option* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Price Schedule D52 REA Farm Service Excluding Wire Services Provider Functions

Availability

• Applicable to any Rural Electrification Association, for whom the Company is not acting as the Wire Services Provider, as defined in the EUA.

• For all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Rural Electrification Association's distribution system.

Price

Charges for service in any one billing period are the sum of the Customer, Demand and Energy charges as indicated below, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	-	-	-
Service	24.78 ¢/service/day	-	-
TOTAL PRICE	*24.78 ¢/service/day*	*5.38 ¢/kV.A/day*	*0.47 ¢ / kW.h*

kV.A capacity for billing purposes will be determined as follows:

(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

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(b) For non-breakered REA farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. 25 kV.A.

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions.

2. *Price Option* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D56 Farm Service

Availability

For System Access Service and Distribution Access Service, for all Points of Service throughout the territory served by the Company, for farming operations which are connected to the Company's distribution system.

Price

Charges for service in any one billing period are the sum of the Customer, Demand, and Energy Charges as indicated below, determined for each individual Point of Service.

	Customer Charge	***Demand Charge***	***Energy Charge***
Transmission	-	5.38 ¢/kV.A/day	0.47 ¢ / kW.h
Distribution	19.84 ¢/service/day	12.39 ¢/kV.A/day	0.47 ¢ / kW.h
Service	33.11 ¢/service/day	-	-
TOTAL PRICE	*52.95 ¢/service/day*	*17.77 ¢/kV.A/day*	*0.94 ¢ / kW.h*

kV.A capacity for billing purposes will be determined as follows:

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(a) For breakered services of 25 kV.A or less, the kV.A capacity will be set by the breaker size as shown below:

Breaker Amperes	25/41	35/50	50/75	75/110	100/150	200
Transformer Capacity in kV.A	3	5	7.5	10	15	25

(b) For non-breakered farm services of 25 kV.A or greater, the kV.A capacity for billing purposes is the greater of:

i. the highest metered kV.A demand during the billing period;

ii. the estimated demand;

iii. the contract demand;

iv. 25 kV.A.

Application

1. *Demand Metering* - when the Company determines, by estimation or measurement, that a 25 kV.A breakered service may be overloaded, the company may require replacement of the breaker with a demand meter and modification of the service facilities in accordance with the Terms and Conditions for Distribution Service Connections.

2. *Price Options* - the following price option may apply:

Idle Service (Option F)

3. *Price Adjustments* - the following price adjustments (riders) may apply:

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Price Schedule D61 Street Lighting Service

Availability

- For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for street lighting.
- Not available for private lighting.

Price

Charges for service in any one billing period are the sum of the Customer Charge and Demand Charge, determined for each individual Point of Service.

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Decorative Lighting (61 A)

- For decorative lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.
- Includes maintenance only.
- Specific contracts may require customers to purchase and maintain inventory of decorative lamps if the customer's lighting fixtures are not the same as the standard used by the company.

	Decorative Lamps	
	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	16.74 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*22.35 ¢/fixture/day*	*0.033¢ /watt/day*

Investment Option (61 B)

- For standard lighting fixtures installed, owned, and maintained by the Company.

	All Lamps	
	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	45.95 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE 51.56	*¢/fixture/day*	*0.033 ¢ /watt/day*

Distribution Investment Option (61 C)

- For customer owned and installed lighting.
- For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.
- The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	All Lamps	
	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	22.09 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*27.70 ¢/fixture/day*	*0.033 ¢ /watt/day*

No Investment Option (61 E)

- Available for new installations only.
- For lighting fixtures installed, owned and maintained by the Company.
- The customer is responsible for the full cost of installation.

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- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	All Lamps	
	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	16.74 ¢/fixture/day	0.017 ¢ /watt/day
Service	5.61 ¢/fixture/day	-
TOTAL PRICE	*22.35 ¢/fixture/day*	*0.033 ¢ /watt/day*

Application

1. *Price Option* - the following price option may apply:

   Idle Service (Option F)

2. *Price Adjustments* — the following price adjustments (riders) may apply:

   Municipal Assessment (Rider A-1)

   Balancing Pool Adjustment (Rider B)

   Temporary Adjustment (Rider G)

   Interim Adjustment (Rider J)

   Interim RRT Adjustment (Rider Q)

Price Schedule D63

Availability

For System Access Service and Distribution Access Service for all Points of Service throughout the territory served by the Company, for sentinel lighting.

Price

Charges for service in any one billing period are the sum of the Customer Charge and Demand Charge determined for each individual Point of Service.

Investment Option (63 A)

For standard sentinel lighting fixtures installed, owned, and maintained by the Company

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	22.56 ¢/fixture/day	0.014 ¢ /watt/day

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Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*35.65 ¢/ fixture/day*	*0.030 ¢ / watt/day*

Summer Village Option (63 B)

- For standard sentinel lighting fixtures installed, owned and maintained by the Company
- For seasonal use only (six month minimum period) by Municipal Corporations in summer villages.
- This portion of the rate is closed.

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	36.37 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*49.46 ¢/fixture/day*	*0.030 ¢ / watt/day*

No Investment Option (63 C)

- Available for new installations only.
- For standard lighting fixtures installed, owned, and maintained by the Company.
- The customer is responsible for the full cost of installation.
- The customer is responsible for the full cost of replacement.
- Includes maintenance only.

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	11.97 ¢/fixture/day	0.004 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*25.06 ¢/fixture/day*	*0.020 ¢ / watt/day*

Metering Option (63 D)

- For standard lighting fixtures installed, owned, and maintained by the Company.
- For service through the meter at the Point of Service.
- This portion of the rate is closed.

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	23.94 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*47.03 ¢/fixture/day*	*0.030 ¢ / watt/day*

Distribution Investment Option (63 E)

- For customer owned and installed lighting.

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• For installation and maintenance of distribution facilities up to, but not including the customer owned conductor serving the light fixtures.

• The Company may require that the Point of Service be metered and served on Price Schedule D21, if the load requirements change over time, or if loads that are not lighting loads are served from the same Point of Service.

	Customer Charge	***Demand Charge***
Transmission	-	0.016 ¢ /watt/day
Distribution	15.66 ¢/fixture/day	0.014 ¢ /watt/day
Service	13.09 ¢/fixture/day	-
TOTAL PRICE	*28.75 ¢/fixture/day*	*0.030 ¢ / watt/day*

Application

1. *Price Adjustments* - the following price adjustments (riders) may apply:

Municipal Assessment (Rider A-1)

Balancing Pool Adjustment (Rider B)

Temporary Adjustment (Rider G)

Interim Adjustment (Rider J)

Interim RRT Adjustment (Rider Q)

Option F Idle Service

Availability

The Idle Service charge will apply to all Price Schedules listed below for Points of Service served by the Company throughout the territory when the Point of Service is temporarily disconnected with the intention of restoring service at a future date.

Price Adjustment

The Idle Service charges shall be:

Price Schedule	***Applicability***	***Idle Service Charge***
D11	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The price schedule monthly Distribution Customer Charge plus the Transmission Customer Charge.
D21—D22	Service outside cities, towns, villages, hamlets, Indian reserves and Metis settlements	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where:—(a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and—(b) Transmission Demand Charge is the price schedule rate minimum
D24—D34—D44	All Points of Service	The sum of the Distribution Demand Charge where the Distribution Demand Charge is the greater of the contract demand or rate minimum.

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D25—D26	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D31—D32—D41	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge where:—(a) Distribution Demand Charge is the greater of the contract demand or rate minimum, and—(b) Transmission Demand Charge is the greater of the contract demand or rate minimum
D33	All Points of Service	Charges based on base demand level established under Price Schedule D31.
T31	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
T33	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).
D51—D52—D56	All Points of Service	The sum of the Distribution Customer charge and the Distribution and Transmission Demand Charges applicable to a 3 kV.A service.
D61	All Points of Service	The sum of the Distribution Demand Charge plus the Transmission Demand Charge
D63	Does not apply (no charges apply when Point of Service is placed on idle).	Does not apply (no charges apply when Point of Service is placed on idle).

Application

1. If the Customer's Point of Service is reconnected within 12 months of disconnection, the minimum monthly charge for each month of disconnection will be applied to the Point of Service.

2. For further information on idle services, refer to Terms and Conditions 14.1 — Disconnection and Idle Service.

The Retailer will be responsible for any costs that the Company incurs from AESO as a result of a point of service going idle. If the point of service is not enrolled with a Retailer, the costs incurred from AESO will be charged directly to the Customer.

Option H Service for Non-Standard Transformation and Metering configurations

Availability

• For Points of Service throughout the territory served by the Company under Price Schedule D21, D22, D31, T31, D32 where metering and / or delivery voltage are non-standard.

• Standard service for distribution connected customers is delivered and metered at the utilization voltage. When delivery or metering is necessary at other voltages, for the convenience of either the customer or the Company, bills for service will be adjusted as outlined below in (a) to (c).

• Standard service for transmission connected customers is delivered to the customer and metered at the substation voltage. When delivery is required at lower voltages, bills for service will be adjusted as outlined below in (d). Section (b) may also apply to transmission connected customers.

Price Adjustment

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(a) If the point of delivery and metering is on the primary side (25 kV) of a transformer (including cases where one-point service is required by the customer for more than a single utilization voltage or point of use), and the customer owns or rents the necessary transformer(s), a *discount of 2.88 ¢/kW/day* of billing demand will be applied. This adjustment does not apply o customers connected directly to the transmission system who are exempt from the Distribution Charge on the applicable rate.

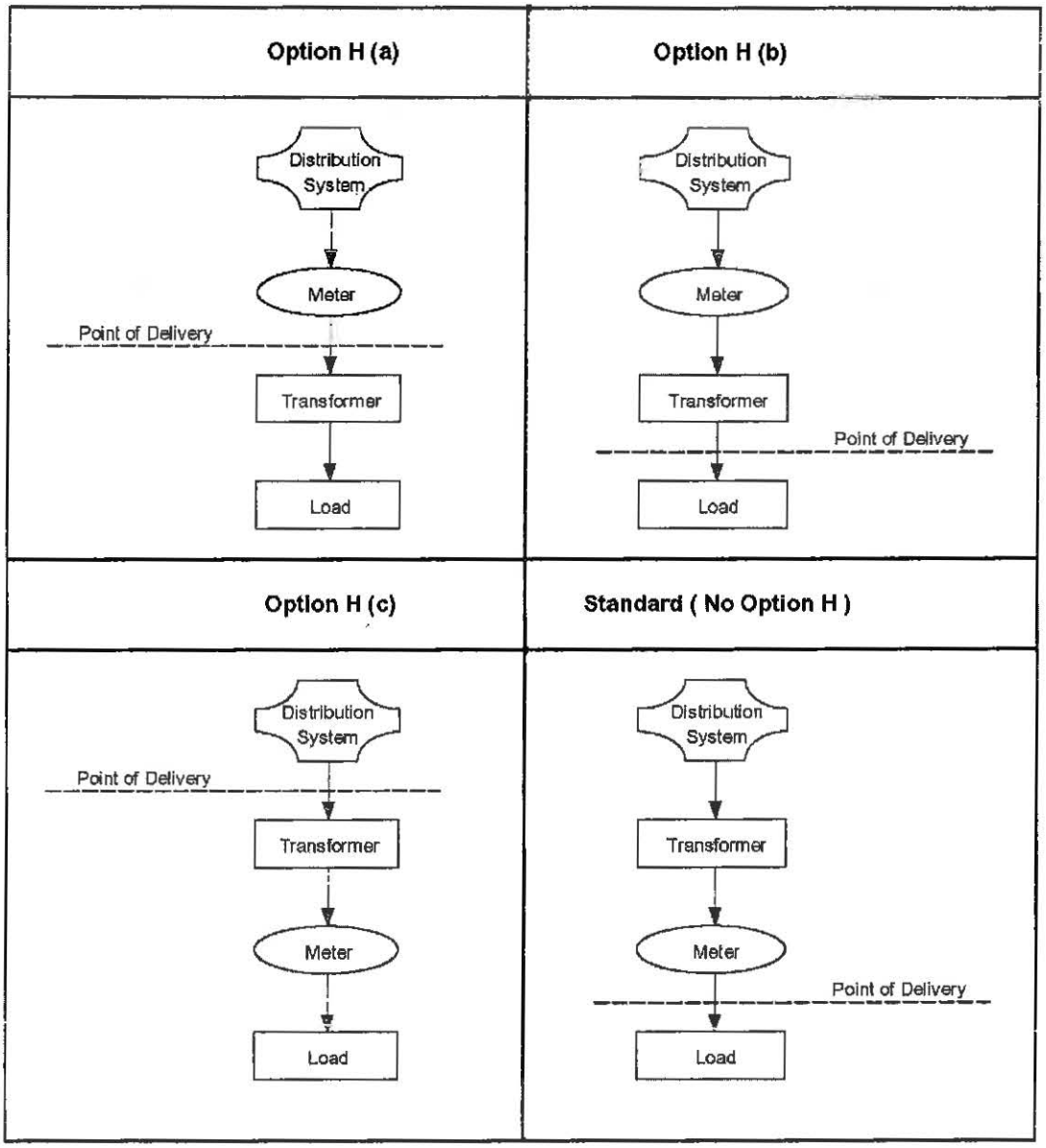
(b) If primary or higher voltage delivery metering is desirable for the convenience of the Company, or to improve accessibility, etc., *demand and energy measurements will be reduced by 1%* so as to approximate secondary voltage delivery conditions.

(c) If primary or higher voltage delivery is made to customer owned transformers, but metering is at secondary or utilization voltage for the Company's convenience, *demand and energy measurements will be increased by 1%* so as to approximate primary or transmission voltage delivery conditions and *a discount, as specified in (a)* shall apply.

(d) Customers who are connected directly to the transmission system, but take service from the low side of a transformer (with primary side 25kV), and do not own or rent any necessary transformer(s), and are exempt from the Distribution Charge on the applicable rate, a *surcharge of 2.88 ¢/kW/day* of billing demand will apply.

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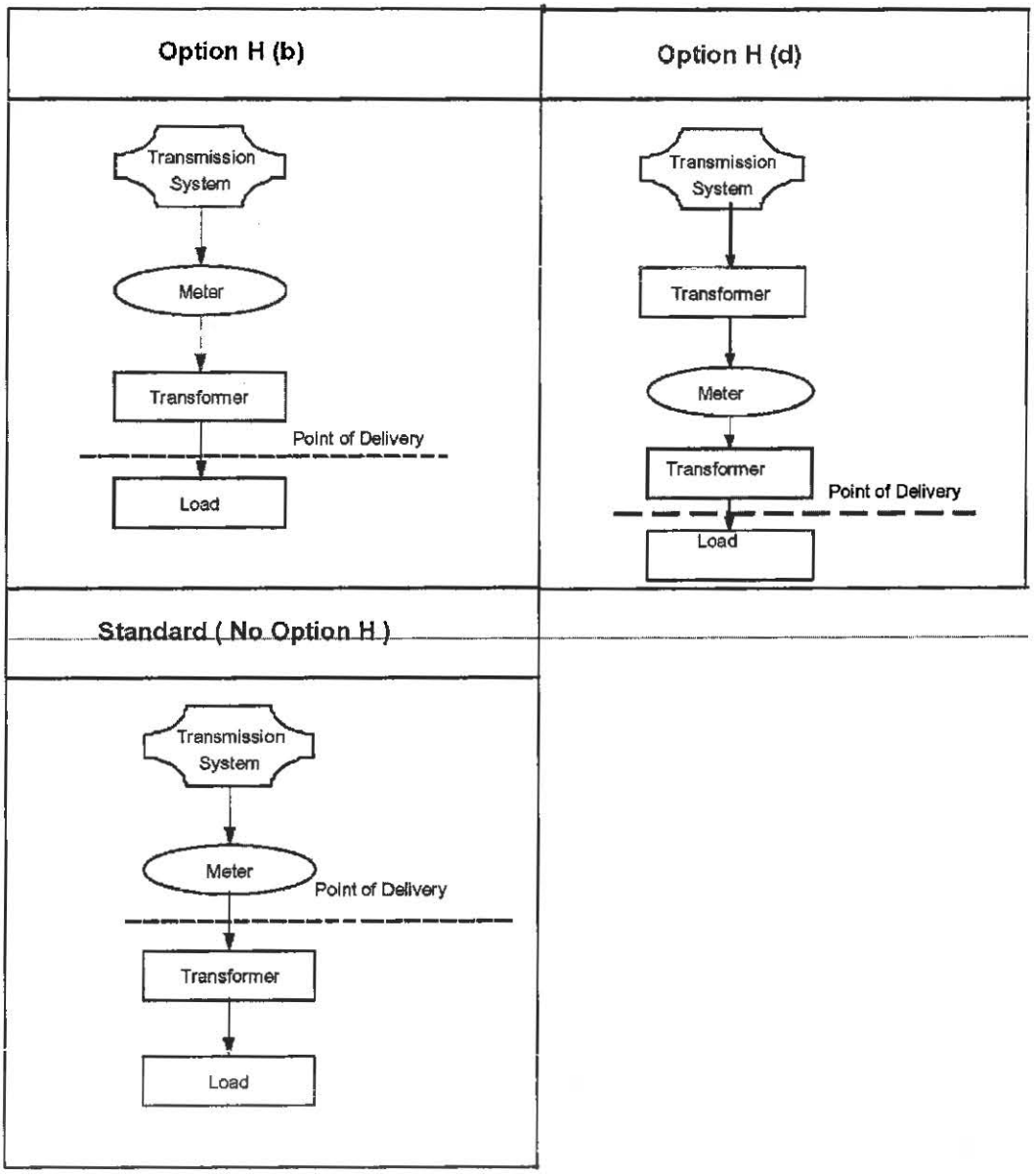
Schematic of Metering and Transformation Configurations for Option H Definitions
(Distribution Connected Customers)



Graphic 3

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Schematic of Metering and Transformation Configurations for Option H Definitions
(Transmission Connected Customers)



Graphic 4

Option P REA Distribution Price Credit

Availability

For all Pooled O&M REA Farm Points of Service throughout the territory served by the Company, served under Price Schedule D21 or Price Schedule D31.

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Price Adjustment

Standard Small General Service Price Schedule D21

For REA farm Points of Service electing to take service under Small General Service Price Schedule D21, a credit adjustment of 42% will be applied to the base bill.

Large General Service / Industrial Price Schedule D31

For REA farm Points of Service electing to take service under Large General Service / Industrial Price Schedule D31, a credit adjustment of 28% will be applied to the base bill.

Rider A-1 Municipal Assessment

Availability

- Applicable throughout the territory served by the Company to electric service within the municipalities identified in Table 2.
- The following are exempt from the surcharge:

(a) Farm customers (Price Schedules D51, D52 and D56)

(b) Irrigation Pumping customers (Price Schedule D25 and D26)

(c) Customers within Indian Reservations not listed in Table 2

(d) Special Facilities Charge (Rider E) customers

Price Adjustment

- The Company pays to a municipality each year or month, in accordance with the franchise agreement between the Company and the municipality, a percent of the gross revenue, or wires revenue, of the Company derived from the sale or delivery of electricity to the consumers in the municipality.
- The percentage of gross revenue (franchise fee and/or tax), or wires revenue, to be paid by the Company to its franchised municipalities is given by category number in Table 1. The municipalities, and their category numbers, are listed in Table 2. For Category 7 the municipalities and percentages of yearly wires revenue are listed in Table 3. For Category 8 the municipalities and percentages of monthly wires revenue are listed in Table 4.
- For all categories except Category 8, an estimated surcharge will be added to each customer's bill within a municipality in order to recover the above payments. Adjustments will be made once each year for any difference between the estimated surcharge collected and the actual surcharge required.
- For Category 8, the percentages listed in Table 4 will be applied to the monthly billing. The amount billed will be paid to the municipality in accordance with the franchise agreement between the Company and the municipality.

Table 1 — Percent of Gross Revenue by Category

CATEGORY 1	2% of the first $100,000 of gross revenue;—3% of the next $200,000 of gross revenue;—4% of

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	the next $200,000 of gross revenue;—5% of gross revenue in excess of $500,000.
CATEGORY 5	1.0% of the first $100,000 of gross revenue;—1.5% of the next $200,000 of gross revenue;—2.0% of the next $200,000 of gross revenue;—2.0% of gross revenue in excess of $500,000.
CATEGORY 6	An amount equal to taxes assessed pursuant to the Municipal Government Act Chap. M-26. 1.
CATEGORY 7	A percentage of the wires revenue of a municipality as listed in Table 3.
CATEGORY 8	A percentage of monthly wires revenue of a municipality as listed in Table 4.

Table 2 — Category Numbers of Municipalities

Alliance 8+6	Empress 8+6	Jasper Nat'l Park 5	Sexsmith 7
Andrew 8+6	Fairview 8+6	Kinuso 8+6	Slave Lake 8+6
Beaverlodge 7	Falher 8+6	Kitscoty 7+6	Smoky Lake 8+6
Berwyn 8+6	Forestburg 8+6	Linden 8+6	Spirit River 8+6
Big Valley 8+6	Fort McMurray 7	Lloydminster 8+6	St Paul 8+6
Bonnyville 8+6	Fox Creek 8+6	Manning 7	Stettler 7+6
Botha 7	Gadsby 8+6	Mannville 8+6	Swan Hills 8+6
Carbon 7	Galahad 7	Marwayne 8+6	Three Hills 8+6
Castor 8+6	Girouxville 7	McLennan 7	Trochu 8+6
Cereal 7	Glendon 8+6	Minburn 6	Two Hills 8+6
Cold Lake 8+6	Grande Cache 8+6	Morrin 7	Valleyview 8+6
Consort 8+6	Grande Prairie 8+6	Mundare 6	Vegreville 6
Coronation 8+6	Grimshaw 7	Munson 7+6	Vermilion 8+6
Delburne 8+6	Halkirk 8+6	Myrnam 6	Veteran 8+6
Delia 8+6	Hanna 8+6	Nampa 7	Vilna 8+6
Derwent 6	Heisler 8+6	Oyen 7	Waskatenau 8+6
Dewberry 8+6	High Level 8+6	Paradise Valley 8+6	Wembley 7
Donalda 8+6	High Prairie 7	Peace River 8+6	Willingdon 8+6
Donnelly 7	Hines Creek 7	Radway (County 7) 7	Youngstown 7+6
Drumheller 8+6	Hythe 7	Rainbow Lake 8+6	
Elk Point 8+6	Innisfree 7	Rosalind 8+6	
Elnora 8+6	ID Jasper 7	Rycroft 7	

Table 2 — Category Numbers of Municipalities

Category 6 also applies to the following non-franchised municipalities:

Bonnyville Beach	County No. 27 Minburn	M.D. of Big Lake No. 125
Horseshoe Bay	County No. 29 Flagstaff	M.D. of Smoky R. No. 130
Lavoy	County No. 30 Lamont	M.D. of East Peace No. 131
Pelican Narrows	County No. 89 Lakeland	M.D. of Spirit River No. 133
Rochon Sands	M.D. of Badlands No. 07	M.D. of Peace No. 135
Wanham	M.D. of Greenview No. 16	M.D. of Fairview No. 136
Warspite	M.D. of Opportunity No. 17	I.D. No. 12 & ID No. 24
Whitesands	M.D. of Wood Buffalo No. 18	Allison Bay B219
County No. 01 Grande Pr.	M.D. of Birch Hills No. 19	Fort McMurray Band B352
County No. 06 Stettler	M.D. of Saddle Hills No. 20	Peavine N172
County No. 07 Thorhild	M.D. of Clear Hills No. 21	Gift Lake N173
County No. 13 Smoky Lake	M.D. of Northern Lights No. 22	East Prairie N174
County No. 16 Wheatland	M.D. of Mackenzie No. 23	Elizabeth N187
County No. 18 Paintearth	M.D. of Acadia No. 34	Fishing Lake N188
County No. 19 St. Paul	M.D. of Starland No. 47	Paddle Prairie N221
County No. 21 Two Hills	M.D. of Kneehill No. 48	Special Areas
County No. 22 Camrose	M.D. of Bonnyville No. 87	Sturgeon Lake I.R. #154
County No. 23 Red Deer	M.D. of Bonnyville Annexed No. 88	Whitefish Lake Band B924
County No. 24 Vermilion R.	M.D. of Lesser Slave River No. 124	

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*Move to Category 8+6, with the new Franchise Agreement

Table 3 — Original Style Franchise Agreement (Percent of Wires Revenue by Municipality - Category 7)

Beaverlodge	7.20%	High Prairie	7.80%	Oyen	7.75
Botha	4.50%	Hines Creek	6.50%	Radway (County 7)	3.00%
Carbon	3.50%	Hythe	7.25%	Rycroft	4.30%
Cereal	5.00%	Jasper (ID)	7.50%	Sexsmith	8.20%
Donnelly	5.00%	Kitscoty	5.00%	Stettler	7.50%
Fort McMurray	7.60%	Manning	7.50%	Wembley	6.70%
Fox Creek	6.30%	McLennan	8.25%	Youngstown	4.00%
Galahad	6.75%	Morrin	6.00%		
Girouxville	7.00%	Munson	3.00%		
Grimshaw	7.50%	Nampa	5.00%		

Table 4 — New Style Franchise Agreement (Percent of Monthly Wires Revenue by Municipality Paid in addition to other taxes — Category 8)

Alliance	6.00%	Forestburg	1.00%	Peace River	5.00%
Andrew	2.00%	Fox Creek	4.50%	Rainbow Lake	7.75%
Berwyn	1.75%	Gadsby	5.00%	Rosalind	0.50%
Big Valley	1.00%	Glendon	1.50%	Slave Lake	7.10%
Bonnyville	6.80%	Grande Cache	4.60%	Smoky Lake	3.25%
Castor	5.00%	Grande Prairie	7.75%	Spirit River	4.50%
Cold Lake	4.25%	Halkirk	1.00%	St Paul	7.00%
Consort	3.50%	Hanna	3.50%	Swan Hills	4.00%
Coronation	3.75%	High Level	6.50%	Three Hills	5.00%
Delia	0.50%	High Prairie	6.25%	Trochu	3.50%
Delburne	1.50%	Innisfree	1.50%	Two Hills	2.75%
Derwent	6.00%	Kinuso	3.50%	Valleyview	5.25%
Donalda	1.50%	Linden	4.00%	Vegreville	5.00%
Drumheller	9.00%	Lloydminster	10.50%	Vermilion	3.50%
Elk Point	3.60%	Mannville	2.50%	Veteran	3.00%
Elnora	1.00%	Marwayne	2.30%	Vilna	4.00%
Empress	2.00%	Minburn	1.00%	Willingdon	2.00%
Fairview	6.00%	Myrnam	2.00%		
Falher	6.25%	Paradise Valley	2.00%		

Rider E Special Facilities Charge

Availability

Applicable to facilities constructed by the Company on customer owned or leased property, as requested by the customer.

Price

The Facilities charge will be set out in a contract, negotiated between the customer and the Company, and will recover the revenue requirement of the applicable facilities. The revenue requirement will be calculated on a rate base of net book value and will include Return, Income Tax, Depreciation, and Operations and Maintenance costs.

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Application

- Facility charges will normally be billed monthly. Monthly charges are subject to change as new facilities are added or currently installed facilities are retired.

- For facilities shared among more than one customer, a separate contract will be established for each customer making use of the facilities.

- Facilities constructed under Rider E are owned and maintained by the Company.

Rider B Balancing Pool Adjustment

Availability

- This Rider B is designed to flow through a Balancing Pool Refund from the Alberta Electric System Operator (AESO).

- Applicable to all customers with the exception of customers served on Price Schedule D24, Price Schedule D34, and Price Schedule D44, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2009.

- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	***Charge (¢/kW.h) "+" = Charge "-" = Refund***
D11 Residential	-0.687
D21 Small General Service	-0.688
D22 Small General Service — Energy Only	-0.688
D25 Irrigation Pumping Service	-0.707
D26 REA Irrigation Pumping Service	-0.707
D31 Large General Service/Industrial — Distribution Connected	-0.681
T31 Large General Service/Industrial — Transmission Connected	Flow through
D32 Generator Interconnection and Standby Power	-0.681
D33 Transmission Opportunity Rate — Distribution Connected	-0.681
T33 Transmission Opportunity Rate — Transmission Connected	Flow through
D41 Small Oilfield and Pumping Power	-0.701
D51 REA Farm Service	-0.692
D52 REA Farm Service — Excluding Wires Service Provider	-0.692
D56 Farm Service	-0.692
D61 Street Lighting Service	-0.687
D63 Private Lighting Service	-0.686

Note: Rider B does not apply to Rider A-1, Rider E, Rider G, Rider J, and Rider Q.

Rider G Temporary Adjustment

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Availability

- This Rider G is designed to true-up 2005 Rider G and dispense of new deferral balances.

- Applicable to all customers, at points of service, throughout the territory served by the Company for energy consumption effective January 1, 2009.

- The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Applicable Distribution Tariff Price Schedule	***Charge (¢/kW.h) "+" = Charge "-" = Refund***
D11 Residential	0.000
D21 Small General Service	0.000
D22 Small General Service — Energy Only	0.000
D25 Irrigation Pumping Service	0.000
D26 REA Irrigation Pumping Service	0.000
D31 Large General Service/Industrial — Distribution Connected < 2MW	0.000
D31 Large General Service/Industrial — Distribution Connected > 2MW	0.000
T31 Large General Service/Industrial — Transmission Connected < 2MW	0.000
T31 Large General Service/Industrial — Transmission Connected > 2MW	0.000
D32 Generator Interconnection and Standby Power < 2 MW	0.000
D32 Generator Interconnection and Standby Power > 2 MW	0.000
D33 Transmission Opportunity Rate — Distribution Connected	0.000
T33 Transmission Opportunity Rate — Transmission Connected	0.000
D41 Small Oilfield and Pumping Power	0.000
D51 REA Farm Service	0.000
D52 REA Farm Service — Excluding Wires Service Provider	0.000
D56 Farm Service	0.000
D61 Street Lighting Service	0.000
D63 Private Lighting Service	0.000

Note: Rider G does not apply to Rider A-1, Rider E, Rider J, and Rider Q.

Rider J Interim Adjustment

Availability

Applies to all electric service throughout the territory served by the Company when a charge or refund is approved by the AEUB.

Rider Q RRT Adjustment

Availability

- Rider Q is designed to true-up outstanding 2003 and 2004 Non-Energy Regulated Rate Tariff (RRT) matters.

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• The Company's applicable charges under the following Price Schedules will be adjusted by the amounts noted below:

Price

This Rider will apply on energy consumption effective January 1, 2009.

Regulated Rate	***Applicable Distribution Tariff Price Schedule***	***Charge (¢/kW.h) "+" = Charge "-" = Refund***
E1	D11 Residential	0.000
E2	D21, D22 Small General Service	0.000
E3	D31, T31, D32 Large General Service/Industrial & Generator Interconnection	0.000
E4	D41 Small Oilfield and Pumping Power	0.000
E51	D51, D52 REA Farm Service	0.000
E56	D56 Farm Service	0.000
E6	D61, D63 Lighting Service	0.000
E7	D25, D26 Irrigation Pumping Service	0.000

Note: Rider Q does not apply to Rider A-1, Rider E, Rider J and Rider G.

APPENDIX 2 — Rate Impact Schedules

ATCO Electric 2009 Interim Tariff Application

Summary of Rate Impact to Typical Bills (Distribution Tariff Base Rates - Without Retail Energy Purchases)

	January 1, 2008					***August 1, 2008***					***January 1, 2009***				
Rate Class	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***	***DT Base Rates***	***Rider G***	***Rider Q***	***Rider B***	***Net***
D11 Residential—600 kWh	$52.85	$0.00	$0.00	-$3.17	$49.68	$52.85	-$0.67	$0.00	-$3.17	$49.01	$53.61	$0.00	$0.00	-$4.12	$49.49
D21 Commercial—20 kW; 7300 kWh	$262.87	$0.00	$0.00	-$38.69	$224.18	$262.87	-$27.81	$0.00	-$38.69	$196.37	$267.95	$0.00	$0.00	-$50.22	$217.72
D31 Industrial—50 kW; 16,650 kWh	$524.33	$0.00	$0.00	-$87.25	$437.08	$524.33	-$63.44	$0.00	-$87.25	$373.64	$548.86	$0.00	$0.00	-$113.39	$435.47
D41 Oilfield—20 kW; 8,760 kWh	$343.43	$0.00	$0.00	-$47.22	$296.21	$343.43	-$45.55	$0.00	-$47.22	$250.66	$349.53	$0.00	$0.00	-$61.41	$288.13
D51 REA Pooled—7	$45.53	$0.00	$0.00	-$6.68	$38.85	$45.53	$1.18	$0.00	-$6.68	$40.03	$47.29	$0.00	$0.00	-$8.68	$38.60

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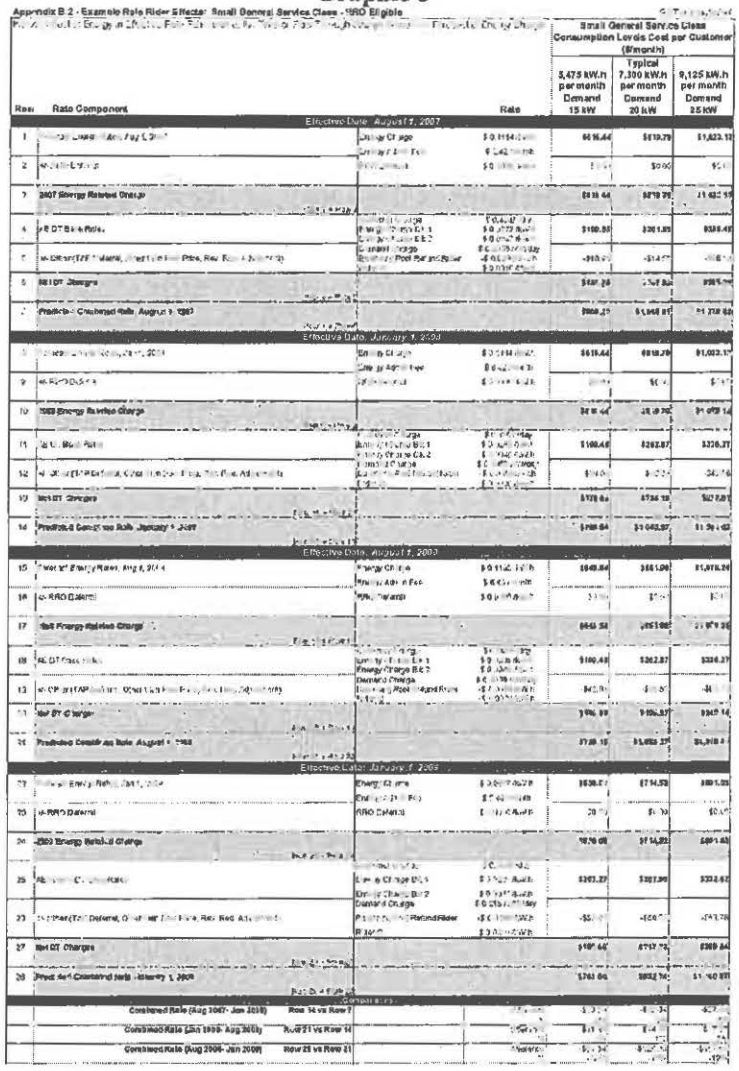
.5 kVA; 1,255 kWh															
D56 Farm—7.5 kVA; 1,255 kWh	$66.06	$0.00	$0.00	-$6.68	$59.38	$66.06	-$5.50	$0.00	-$6.68	$53.88	$67.54	$0.00	$0.00	-$8.68	$58.85
D61 Street Lights—250 Watts	$9.15	$0.00	$0.00	-$0.46	$8.68	$9.15	-$2.93	$0.00	-$0.46	$5.76	$9.18	$0.00	$0.00	-$0.60	$8.58
D63 Private Lights—250 Watts	$12.89	$0.00	$0.00	-$0.46	$12.43	$12.89	-$3.23	$0.00	-$0.46	$9.20	$12.95	$0.00	$0.00	-$0.60	$12.34
T31 Industrial —2 MW 1,022 MWh	$19,041.87	$0.00	$0.00	-$5,110.00	$13,931.87	$21,296.55	-$5,110.00	$0.00	-$5,110.00	$11,076.55	$21,670.62	$0.00	$0.00	-$6,643.00	$15,027.62


Appendix B.1 - Example Rate Rider Effects: Residential Class - RRO Eligible

Row	Rate Component	Rate	Residential Class Consumption Levels Cost per Customer ($/month) 300 kW.h per month	Typical 600 kW.h per month	1,200 kW.h per month
	Effective Date: August 1, 2007				
1	Regulated Energy Rates Aug 1, 2007	Energy Charge $0.06[illegible]/kWh Energy Adjustment Fac -0.93 cents/kWh	$29.83	$59.27	$148.14
2	+/- RRO Deferral	RRO Deferral $0.00[illegible]/kWh	$0.00	$0.00	$0.00
3	2007 Energy Related Charge		$29.83	$59.27	$148.14
4	AE DT Base Rates	Customer Charge $0.16427/day Energy Charge $.03853/kWh	$34.83	$62.97	$85.23
5	+/- Other (TAP Deferral, Other than Post-[illegible] Reg Adjustments)	Balancing Pool Refund Rider -$0.00[illegible]/kWh	$-4.15	$-7.51	$-10.19
6	Net DT Charges		$63.82	$115.46	$156.58
7	Predicted Combined Rate, August 1, 2007		$79.48	$143.73	$194.97
	Effective Date: January 1, 2008				
8	Regulated Energy Rates Jan 1, 2008	Energy Charge $.06[illegible]/kWh Energy Adjustment Fac -0.93 cents/kWh	$29.83	$53.27	$148.14
9	+/- RRO Deferral	RRO Deferral $.00000/kWh	$0.00	$0.00	$0.00
10	2008 Energy Related Charge		$29.83	$53.27	$148.14
11	AE DT Base Rates	Customer Charge $0.16427/day Energy Charge $.03853/kWh	$34.83	$62.97	$85.23
12	+/- Other (TAP Deferral, Other than Post-[illegible] Reg Adjustments)	Balancing Pool Refund Rider -$0.00[illegible]/kWh Rider [illegible]	$-4.15	$-7.51	$-10.19
13	Net DT Charges		$64.51	$116.73	$158.18
14	Predicted Combined Rate, January 1, 2008		$93.68	$169.99	$306.32
	Effective Date: August 1, 2008				
15	Regulated Energy Rates Aug 1, 2008	Energy Charge $0.11402/kWh Energy Adjustment Fac -0.93 cents/kWh	$43.84	$77.73	$147.91
16	+/- RRO Deferral	RRO Deferral $.00000/kWh	$0.00	$0.00	$0.00
17	2008 Energy Related Charge		$43.84	$77.73	$147.91
18	AE DT Base Rates	Customer Charge $0.16427/day Energy Charge $.03853/kWh	$39.74	$62.98	$85.07
19	+/- Other (TAP Deferral, Other than Post-[illegible] Reg Adjustments)	Balancing Pool Refund Rider -$.00[illegible]/kWh	$-21.97	$-31.64	$-37.64
20	Net DT Charges		$61.62	$109.07	$194.34
21	Predicted Combined Rate, August 1, 2008		$97.62	$173.00	$342.25
	Effective Date: January 1, 2009				
22	Regulated Energy Rates Jan 1, 2009	Energy Charge $.06[illegible]/kWh Energy Adjustment Fac -0.93 cents/kWh	$27.00	$48.16	$134.36
23	+/- RRO Deferral	RRO Deferral $.00000/kWh	$0.00	$0.00	$0.00
24	2009 Energy Related Charge		$27.00	$48.16	$134.36
25	AE Fixed DT Base Rates	Customer Charge $0.16427/day Energy Charge $.03853/kWh	$27.83	$49.61	$69.73
26	+/- Other (TAP Deferral, Other than Post-[illegible] Reg Adjustments)	Balancing Pool Refund Rider -$.00[illegible]/kWh Rider [illegible]	$-3.06	$-4.12	$-5.24
27	Net DT Charges		$24.77	$45.49	$64.49
28	Predicted Combined Rate, January 1, 2009		$51.77	$93.65	$198.85
	Comparisons				
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7		-$14.42	-$26.26	-$41.20
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14		$3.94	$3.01	$35.93
	Combined Rate (Aug 2008- Jan 2009) Row 28 vs Row 21		-$45.85	-$79.35	-$143.40

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Graphic 5

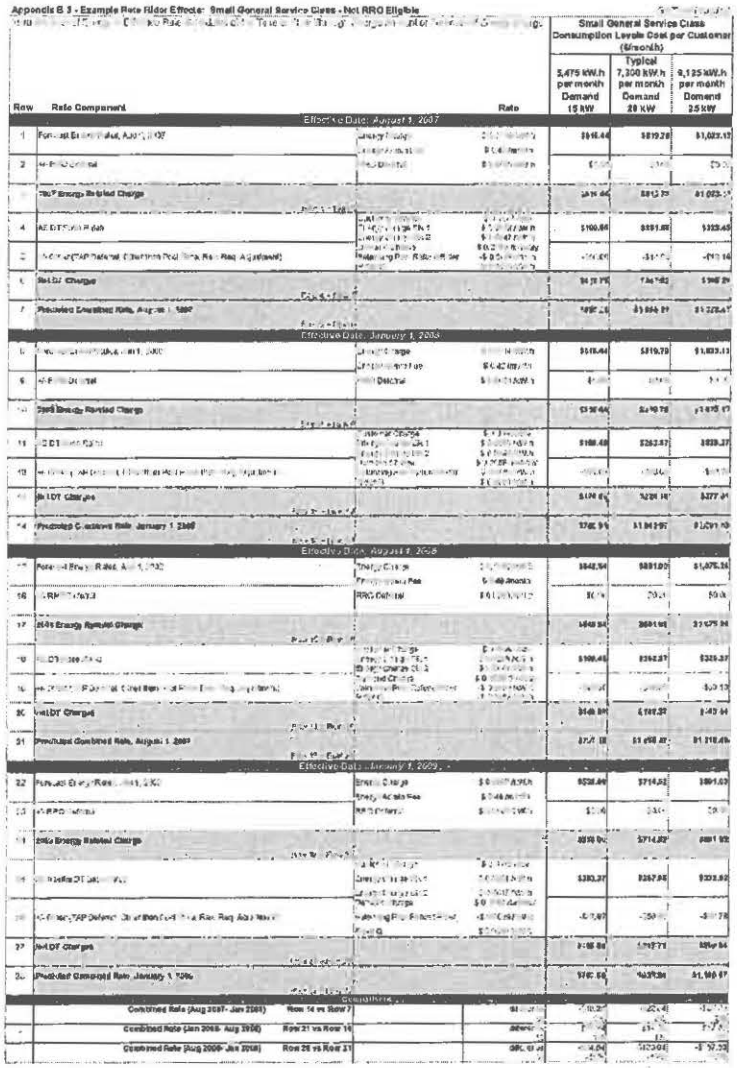


Appendix B 2 - Example Rate Rider Effects: Small General Service Class - RRO Eligible

Row	Rate Component		Rate	Small General Service Class Consumption Levels Cost per Customer (\$/month) 5,475 kW.h per month Demand 15 kW	Typical 7,300 kW.h per month Demand 20 kW	9,125 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007					
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
7	2007 Energy Related Charge			[illegible]	[illegible]	[illegible]
8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	[illegible]			[illegible]	[illegible]	[illegible]
11	Predicted Combined Rate August 1, 2007			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
14	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy Related Charge			[illegible]	[illegible]	[illegible]
18	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	[illegible]			[illegible]	[illegible]	[illegible]
21	Predicted Combined Rate August 1, 2008			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge			[illegible]	[illegible]	[illegible]
25	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	2009 DT Charges			[illegible]	[illegible]	[illegible]
28	Predicted Combined Rate January 1, 2009			[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7		[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14		[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21		[illegible]	[illegible]	[illegible]

Graphic 6

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Appendix B 3 - Example Rate Rider Effects: Small General Service Class - Not RRO Eligible

Row	Rate Component	Rate	Small General Service Class Consumption Levels Cost per Customer ($/month) 5,475 kW.h per month Demand 15 kW	Typical 7,300 kW.h per month Demand 20 kW	9,125 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007				
1					
2					
4					
5					
6					
7					
	Effective Date: January 1, 2008				
8					
9					
11					
12					
14					
	Effective Date: August 1, 2008				
16					
17					
19					
20					
22					
23					
25					
26					
28					
	Effective Date: January 1, 2009				
29					
30					
32					
33					
35					
36					
38					
39					
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7			
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14			
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21			

Graphic 7

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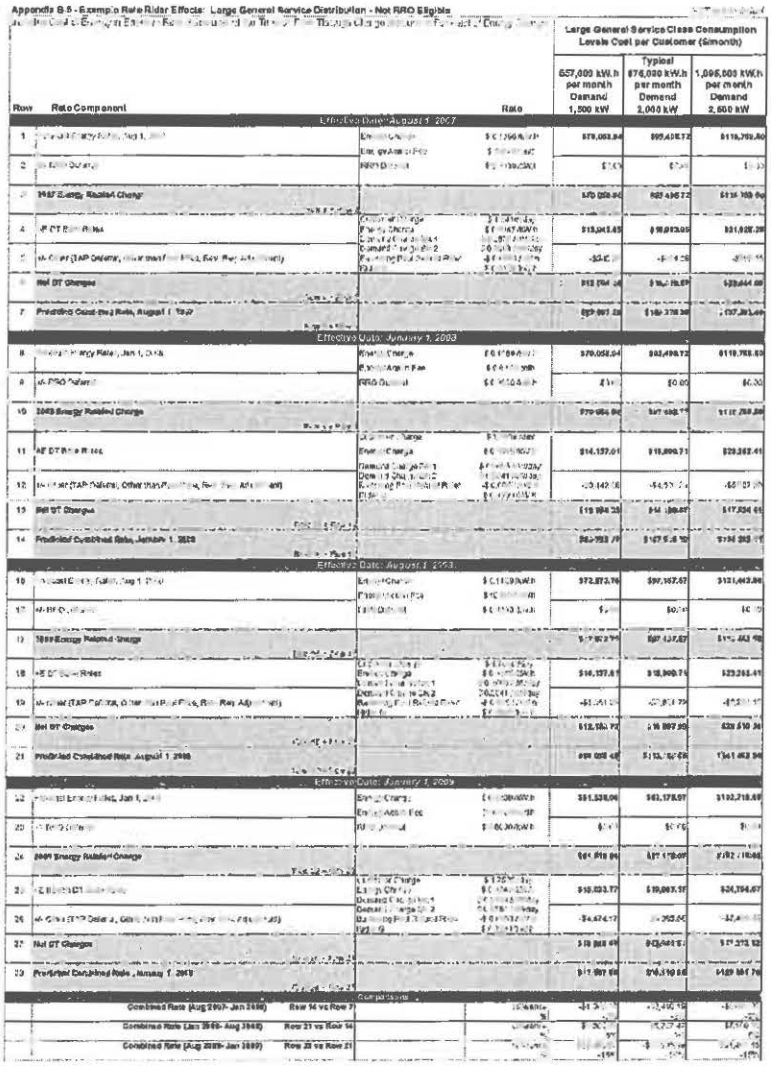


Appendix B.4 - Example Rate Rider Effects: Large General Service Distribution - RRO Eligible

Row	Rate Component	Rate	Large General Service Class Consumption Levels Cost per Customer ($/month): 12,200 kW.h per month Demand 50 kW	Typical 18,830 kW.h per month Demand 50 kW	20,808 kW.h per month Demand 59 kW
	Effective Date: August 1, 2007				
1	[illegible]	[illegible]	$1,310.36	$1,784.82	$2,227.36
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	2007 Energy Related Charge		$1,700.79	$1,784.82	$2,227.36
4	AEDT Rate Rider	[illegible]	$475.84	$497.59	$565.28
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	Net DT Charges		$475.84	$497.59	$565.28
7	Predicted Combined Rate August 1, 2007		$1,700.79	$2,282.40	$2,792.64
	Effective Date: January 1, 2008				
8	[illegible]	[illegible]	$1,310.36	$1,784.82	$2,227.36
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	2008 Energy Related Charge		$1,930.10	$1,784.82	$2,227.36
11	AEDT Rate Rider	[illegible]	$882.74	$934.33	$1,044.77
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	Net DT Charges		$882.74	$934.33	$1,044.77
14	Predicted Combined Rate January 1, 2008		$1,930.10	$2,281.80	$2,822.40
	Effective Date: August 1, 2008				
15	[illegible]	[illegible]	$1,381.33	$1,854.78	$2,314.87
16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	2008 Energy Related Charge		$1,381.33	$1,854.78	$2,314.87
18	AEDT Rate Rider	[illegible]	$893.74	$894.33	$894.77
19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	Net DT Charges		$893.74	$897.94	$949.83
21	Predicted Combined Rate August 1, 2008		$2,183.46	$2,976.68	$3,741.58
	Effective Date: January 1, 2009				
22	[illegible]	[illegible]	$1,381.84	$1,856.90	$2,307.84
23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	2009 Energy Related Charge		$1,381.84	$1,856.90	$2,307.84
25	[illegible]	[illegible]	$839.39	$840.56	$843.59
26	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	Net DT Charges		$839.31	$839.47	$879.17
28	Predicted Combined Rate January 1, 2009		$2,180.15	$2,694.37	$3,186.75
	Rate Impacts				
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7		[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14		[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009) Row 28 vs Row 21		[illegible]	[illegible]	[illegible]

Graphic 8

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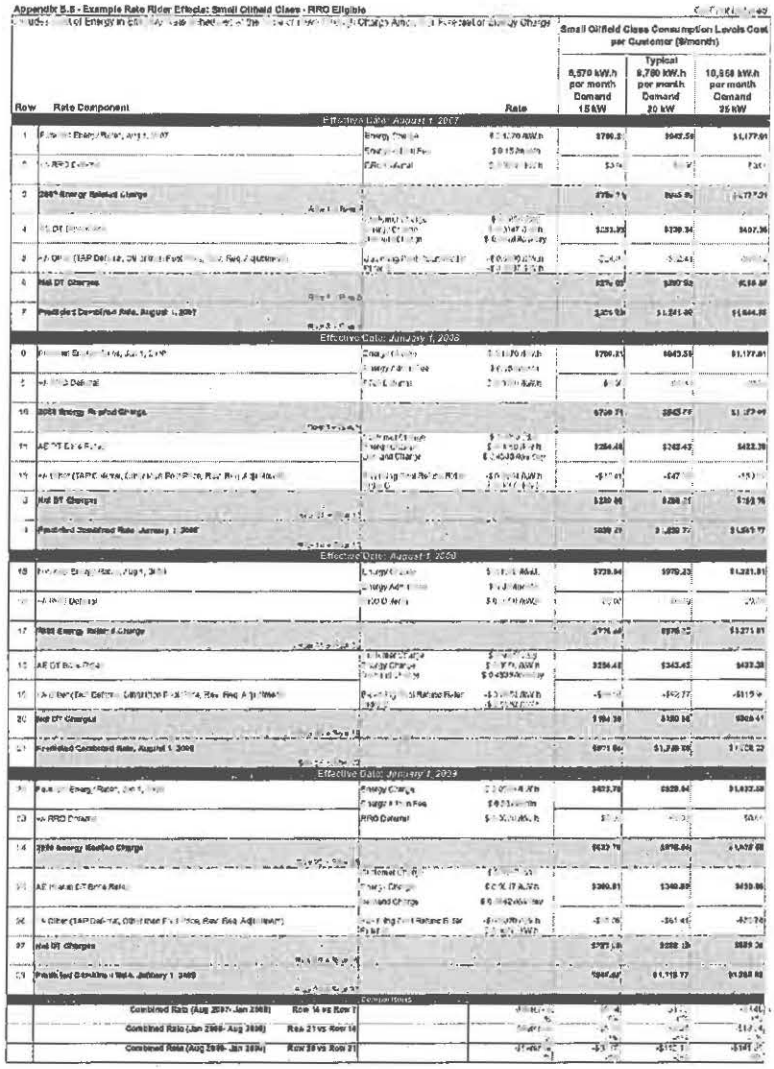


Appendix B-5 - Example Rate Rider Effects: Large General Service Distribution - Not RRO Eligible

Row	Rate Component	Rate	Large General Service Class Consumption Levels Cost per Customer ($/month) 657,000 kW.h per month Demand 1,500 kW	Typical 876,000 kW.h per month Demand 2,000 kW	1,095,000 kW.h per month Demand 2,500 kW
	Effective Date: August 1, 2007				
1	[illegible]	[illegible]	$79,063.84	$95,436.72	$111,809.60
2	[illegible]	[illegible]	$0.00	$0.00	$0.00
3	1st Energy Related Charge		$79,063.84	$95,436.72	$111,809.60
4	AE DT Base Rates	[illegible]	$13,241.63	$18,013.05	$22,784.47
5	[illegible]	[illegible]	-$3,42[illegible]	-$4,[illegible]	-$5,[illegible]
6	Net DT Charges		$12,[illegible]	$16,[illegible]	$20,[illegible]
7	Predicted Combined Rate, August 1, 2007		$91,[illegible]	$111,[illegible]	$132,[illegible]
	Effective Date: January 1, 2008				
8	[illegible]	[illegible]	$79,058.84	$95,436.72	$111,809.60
9	[illegible]	[illegible]	$0.00	$0.00	$0.00
10	2008 Energy Related Charge		$79,058.84	$95,436.72	$111,809.60
11	AE DT Base Rates	[illegible]	$14,157.01	$19,000.71	$23,844.41
12	[illegible]	[illegible]	-$3,142.[illegible]	-$4,[illegible]	-$5,[illegible]
13	Net DT Charges		$11,[illegible]	$14,[illegible]	$17,[illegible]
14	Predicted Combined Rate, January 1, 2008		$90,[illegible]	$110,[illegible]	$129,[illegible]
	Effective Date: August 1, 2008				
15	[illegible]	[illegible]	$72,872.76	$97,167.67	$121,462.59
16	[illegible]	[illegible]	$0.00	$0.00	$0.00
17	2008 Energy Related Charge		$72,872.76	$97,167.67	$121,462.59
18	AE DT Base Rates	[illegible]	$14,157.01	$18,900.71	$23,844.41
19	[illegible]	[illegible]	-$3,[illegible]	-$4,[illegible]	-$5,[illegible]
20	Net DT Charges		$10,[illegible]	$13,[illegible]	$16,[illegible]
21	Predicted Combined Rate, August 1, 2008		$83,[illegible]	$110,[illegible]	$138,[illegible]
	Effective Date: January 1, 2009				
22	[illegible]	[illegible]	$81,538.06	$[illegible]	$122,[illegible]
23	[illegible]	[illegible]	$0.00	$0.00	$0.00
24	2009 Energy Related Charge		$81,[illegible]	$[illegible]	$122,[illegible]
25	[illegible]	[illegible]	$10,823.77	$[illegible]	$[illegible]
26	[illegible]	[illegible]	-$4,[illegible]	-$[illegible]	-$[illegible]
27	Net DT Charges		$[illegible]	$[illegible]	$[illegible]
28	Predicted Combined Rate, January 1, 2009		$[illegible]	$[illegible]	$[illegible]
	Comparisons				
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7	[illegible]	-$1,[illegible]	-$[illegible]	-$[illegible]
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14	[illegible]	$[illegible]	$[illegible]	$[illegible]
	Combined Rate (Aug 2008- Jan 2009) Row 28 vs Row 21	[illegible]	[illegible]	$[illegible]	[illegible]

Graphic 9

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Appendix B.5 - Example Rate Rider Effects: Small Oilfield Class - RRO Eligible

Row	Rate Component	Rate	Small Oilfield Class Consumption Levels Cost per Customer ($/month)		
			6,570 kW.h per month Demand 15 kW	Typical 9,780 kW.h per month Demand 20 kW	10,368 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007				
1	[illegible] Energy Rider, Aug 1, 07	Energy Charge [illegible] ¢/kW.h	$786.3	$943.56	$1,177.01
		Energy Adj Fac [illegible] $/kW.h			
2	[illegible] RRO Deferral	RRO Deferral [illegible] ¢/kW.h	$34	[illegible]	[illegible]
3	2007 Energy Related Charge		$786.34	$943.56	$1,177.01
4	AE DT [illegible]	Distribution Charge [illegible] ¢/kW.h Energy Charge [illegible] ¢/kW.h Demand Charge $ [illegible] /kW/day	$253.72	$339.34	$407.36
5	+/- Other (TAP Deferral, DN 2007-[illegible] Fixed [illegible] Rev Req Adjustment	Distribution Tariff Rate [illegible] ¢/kW.h DTOC [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
6	Net DT Charges		$274.02	$280.92	$0.00
7	Prohibited Combined Rate, August 1, 2007		$1,314.08	$1,561.80	$1,884.38
	Effective Date: January 1, 2008				
8	[illegible] Energy Rider, Jan 1, 08	Energy Charge [illegible] ¢/kW.h Energy Adj Fac [illegible] $/kW.h	$786.34	$943.56	$1,177.01
9	+/- RRO Deferral	RRO Deferral [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
10	2008 Energy Related Charge		$786.34	$943.56	$1,177.01
11	AE DT Electric	Distribution Charge [illegible] ¢/kW.h Energy Charge [illegible] ¢/kW.h Demand Charge $ [illegible] /kW/day	$264.48	$343.43	$422.38
12	+/- Other (TAP Deferral, DN 2007-[illegible] Fixed [illegible] Rev Req Adjustment	Distribution Tariff Rate [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
13	Net DT Charges		$259.98	$288.21	$162.76
14	Prohibited Combined Rate, January 1, 2008		$1,039.29	$1,220.77	$1,324.77
	Effective Date: August 1, 2008				
15	[illegible] Energy Rider, Aug 1, 08	Energy Charge [illegible] ¢/kW.h Energy Adj Fac [illegible] $/kW.h	$729.94	$970.23	$1,221.81
16	+/- RRO Deferral	RRO Deferral [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
17	2008 Energy Rider 8 Charge		$776.46	$976.72	$1,271.81
18	AE DT Electric	Distribution Charge [illegible] ¢/kW.h Energy Charge [illegible] ¢/kW.h Demand Charge $ [illegible] /kW/day	$264.48	$343.43	$422.38
19	+/- Other (TAP Deferral, DN 2007-[illegible] Fixed [illegible] Rev Req Adjustment	Distribution Tariff Rate [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
20	Net DT Charges		$184.38	$180.94	$208.41
21	Prohibited Combined Rate, August 1, 2008		$971.80	$1,139.59	$1,128.22
	Effective Date: January 1, 2009				
22	[illegible] Energy Rider, Jan 1, 09	Energy Charge [illegible] ¢/kW.h Energy Adj Fac [illegible] $/kW.h	$453.78	$629.64	$1,022.58
23	+/- RRO Deferral	RRO Deferral [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
24	2009 Energy Rider Charge		$632.78	$878.64	$1,429.58
25	AE Rural DT Electric	Distribution Charge [illegible] ¢/kW.h Energy Charge [illegible] ¢/kW.h Demand Charge $ [illegible] /kW/day	$360.81	$340.89	$450.86
26	+/- Other (TAP Deferral, DN 2007-[illegible] Fixed [illegible] Rev Req Adjustment	Distribution Tariff Rate [illegible] ¢/kW.h	$ [illegible]	[illegible]	[illegible]
27	Net DT Charges		$787.19	$288.19	$689.26
28	Prohibited Combined Rate, January 1, 2009		$1,041.87	$1,119.77	$1,268.82
	Comparisons				
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7		[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14		[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009) Row 28 vs Row 21		$71.87	$-121.1	$-159.4

Graphic 10

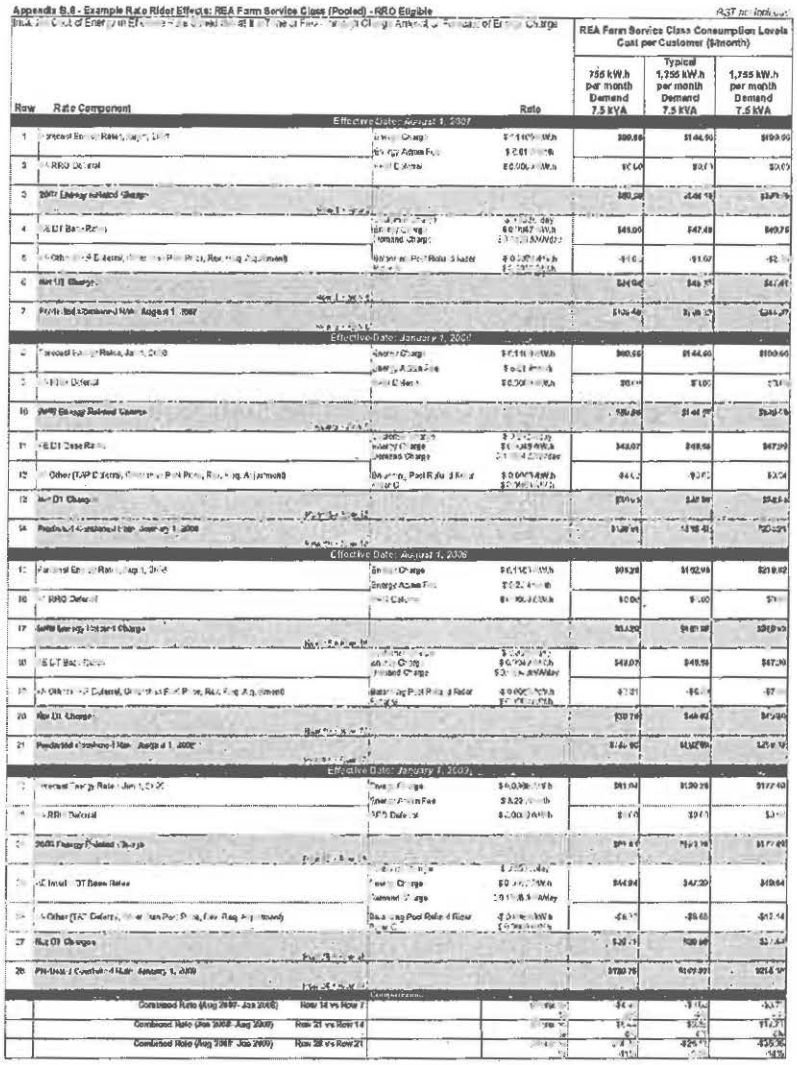
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Row	Rate Component		Rate	Small Oilfield Class Consumption Levels Cost per Customer ($/month)		
				6,570 kW.h per month Demand 15 kW	Typical 8,760 kW.h per month Demand 20 kW	10,950 kW.h per month Demand 25 kW
	Effective Date: August 1, 2007					
1	[illegible] Energy Rider, Aug 1, 2007	Energy Charge	$0.10705/kW.h	$780.21	$949.14	$1,117.81
2	+/- RPO Deferral	Energy Adjustment Fee	28.15/month			
		RPO Deferral	$0.00130/kW.h	[illegible]	[illegible]	[illegible]
3	Total Energy-Related Charge			$808.21	$977.14	$1,145.81
	Rate 1 + Rate [illegible]					
4	GEDT Base Rate	Customer Charge	$0.32/day	$243.33	$536.34	$449.16
		Energy Charge	$0.01340/kW.h			
		Demand Charge	$7.43/kW/day			
5	+/- Other (TAP Deferral, Other than [illegible] Rate Rider, Rate Rider Adjustment)	Balancing Pool Refund Rate Rider G	-$0.00[illegible]/kW.h	-$3.51	-4.39	-[illegible]
6	Net DT Charges			$239.82	$531.95	$444.84
	Rate [illegible] + Rate [illegible]					
7	Provisional Non-Loss Rate August 1, 2007			$1,048.03	$1,508.09	$1,590.65
	Rate [illegible] + Rate [illegible]					
	Effective Date: January 1, 2008					
8	Provisional Energy Rates, Jan 1, 2008	Energy Charge	$0.10705/kW.h	$780.21	$949.14	$1,117.81
		Energy Adjustment Fee	28.15/month			
9	+/- RPO Deferral	RPO Deferral	$0.00130/kW.h	[illegible]	[illegible]	[illegible]
10	Total Energy-Related Charge			$808.21	$977.14	$1,145.81
	Rate [illegible] + Rate [illegible]					
11	GEDT Base Rate	Customer Charge	$0.32/day	$243.33	$536.34	$449.16
		Energy Charge	$0.01340/kW.h			
		Demand Charge	$7.43/kW/day			
12	+/- Other (TAP Deferral, Other than [illegible] Rate Rider, Rate Rider Adjustment)	Balancing Pool Refund Rate Rider G	-$0.00[illegible]/kW.h	-$3.51	-4.39	-[illegible]
13	Net DT Charges			$239.82	$531.95	$444.84
	Rate [illegible] + Rate [illegible]					
14	Provisional Combined Rate January 1, 2008			$1,048.03	$1,508.09	$1,590.65
	Rate [illegible] + Rate [illegible]					
	Effective Date: August 1, 2008					
15	Provisional Energy Rates, Aug 1, 2008	Energy Charge	$0.11[illegible]/kW.h	$[illegible]	$[illegible]	$[illegible]
		Energy Adjustment Fee	28.15/month			
16	+/- RPO Deferral	RPO Deferral	$0.00[illegible]/kW.h	[illegible]	[illegible]	[illegible]
17	Total Energy-Related Charge			$[illegible]	$[illegible]	$[illegible]
	Rate [illegible] + Rate [illegible]					
18	GEDT Base Rate	Customer Charge	$[illegible]/day	$[illegible]	$[illegible]	$[illegible]
		Energy Charge	$[illegible]/kW.h			
		Demand Charge	$[illegible]/kW/day			
19	+/- Other (TAP Deferral, Other than [illegible] Rate Rider, Rate Rider Adjustment)	Balancing Pool Refund Rate Rider G	-$[illegible]/kW.h	-[illegible]	-[illegible]	-[illegible]
20	Net DT Charges			$[illegible]	$[illegible]	$[illegible]
	Rate [illegible] + Rate [illegible]					
21	Provisional Combined Rate August 1, 2008			$[illegible]	$[illegible]	$[illegible]
	Rate [illegible] + Rate [illegible]					
	Effective Date: January 1, 2009					
22	Provisional Energy Rates, Jan 1, 2009	Energy Charge	$0.[illegible]/kW.h	$[illegible]	$[illegible]	$[illegible]
		Energy Adjustment Fee	28.15/month			
23	+/- RPO Deferral	RPO Deferral	$-0.[illegible]/kW.h	[illegible]	[illegible]	[illegible]
24	Total Energy-Related Charge			$[illegible]	$[illegible]	$[illegible]
	Rate [illegible] + Rate [illegible]					
25	GEDT Base Rate	Customer Charge	$[illegible]/day	$[illegible]	$[illegible]	$[illegible]
		Energy Charge	$[illegible]/kW.h			
		Demand Charge	$[illegible]/kW/day			
26	+/- Other (TAP Deferral, Other than [illegible] Rate Rider, Rate Rider Adjustment)	Balancing Pool Refund Rate Rider G	-$[illegible]/kW.h	-[illegible]	-[illegible]	-[illegible]
27	Net DT Charges			$[illegible]	$[illegible]	$[illegible]
	Rate [illegible] + Rate [illegible]					
28	Provisional Combined Rate January 1, 2009			$[illegible]	$[illegible]	$[illegible]
				Comparisons		
	Combined Rate (Aug 2007- Jun 2008)	Row 14 vs Row 7	difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Jun 2008- Aug 2008)	Row 21 vs Row 14	difference	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	difference	[illegible]	[illegible]	[illegible]

Graphic 11

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Appendix B.8 - Example Rate Rider Effects: REA Farm Service Class (Pooled) - RRO Eligible

REA Farm Service Class Consumption Levels Cost per Customer ($/month)

Row	Rate Component	Rate	755 kW.h per month Demand 7.5 kVA	Typical 1,255 kW.h per month Demand 7.5 kVA	1,755 kW.h per month Demand 7.5 kVA
	Effective Date: August 1, 2007				
1	Forecast Energy Rate, Aug 1, 2007	Energy Charge $0.11[illegible]/kW.h Energy Admin Fee $0.01 /month	$88.86	$144.90	$200.93
2	ATRRO Deferral	$0.000[illegible]/kW.h	$0.08	$0.13	$0.19
3	2007 Energy Related Charge		$80.28	$130.91	$181.54
4	REDT Base Rates	Energy Charge $0.[illegible]/kW.h Demand Charge $3.[illegible]/kW/day	$45.00	$47.48	$49.75
5	Other (TAP Deferral, Other Non-Pool Rate, Rate Rdg Adjustment)	Balancing Pool Rate Rider $0.00[illegible]/kW.h	-$1.02	-$1.67	-$2.31
6	Non DT Charge		$43.98	$45.81	$47.44
7	Pro-forma Combined Rate August 1, 2007		$156.40	$219.23	$281.07
	Effective Date: January 1, 2008				
8	Forecast Energy Rate, Jan 1, 2008	Energy Charge $0.11[illegible]/kW.h Energy Admin Fee $0.01 /month	$88.86	$144.90	$200.93
9	ATRRO Deferral	$0.00[illegible]/kW.h	$0.08	$0.13	$0.19
10	2007 Energy Related Charge		$80.28	$130.91	$181.54
11	REDT Base Rates	Energy Charge $0.[illegible]/kW.h Demand Charge $3.[illegible]/kW/day	$45.07	$46.56	$47.99
12	Other (TAP Deferral, Other Non-Pool Rate, Rate Rdg Adjustment)	Balancing Pool Rate Rider $0.00[illegible]/kW.h	-$1.02	-$1.67	-$2.31
13	Non DT Charge		$43.98	$45.81	$47.44
14	Pro-forma Combined Rate January 1, 2008		$156.40	$219.23	$281.07
	Effective Date: August 1, 2008				
15	Forecast Energy Rate, Aug 1, 2008	Energy Charge $0.11[illegible]/kW.h Energy Admin Fee $0.01 /month	$88.86	$144.90	$200.93
16	ATRRO Deferral	$0.00[illegible]/kW.h	$0.08	$0.13	$0.19
17	2008 Energy Related Charge		$80.28	$130.91	$181.54
18	REDT Base Rates	Energy Charge $0.[illegible]/kW.h Demand Charge $3.[illegible]/kW/day	$45.07	$46.56	$47.99
19	Other (TAP Deferral, Other Non-Pool Rate, Rate Rdg Adjustment)	Balancing Pool Rate Rider $0.00[illegible]/kW.h	-$1.02	-$1.67	-$2.31
20	Non DT Charge		$43.98	$45.81	$47.44
21	Pro-forma Combined Rate August 1, 2008		$156.40	$219.23	$281.07
	Effective Date: January 1, 2009				
22	Forecast Energy Rate, Jan 1, 2009	Energy Charge $0.09[illegible]/kW.h Energy Admin Fee $0.01 /month	$80.64	$130.28	$177.93
23	ATRRO Deferral	$0.00[illegible]/kW.h	$0.08	$0.13	$0.19
24	2008 Energy Related Charge		$80.28	$130.91	$181.54
25	REDT Base Rates	Energy Charge $0.[illegible]/kW.h Demand Charge $3.[illegible]/kW/day	$44.94	$47.20	$49.64
26	Other (TAP Deferral, Other Non-Pool Rate, Rate Rdg Adjustment)	Balancing Pool Rate Rider $0.00[illegible]/kW.h	-$1.02	-$1.67	-$2.31
27	Non DT Charge		$43.98	$45.81	$47.44
28	Pro-forma Combined Rate January 1, 2009		$156.40	$219.23	$281.07
	Comparisons				
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	$0.00	$0.00	$0.00
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	$0.00	$0.00	$0.00
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	$0.00	$0.00	$0.00

Graphic 12

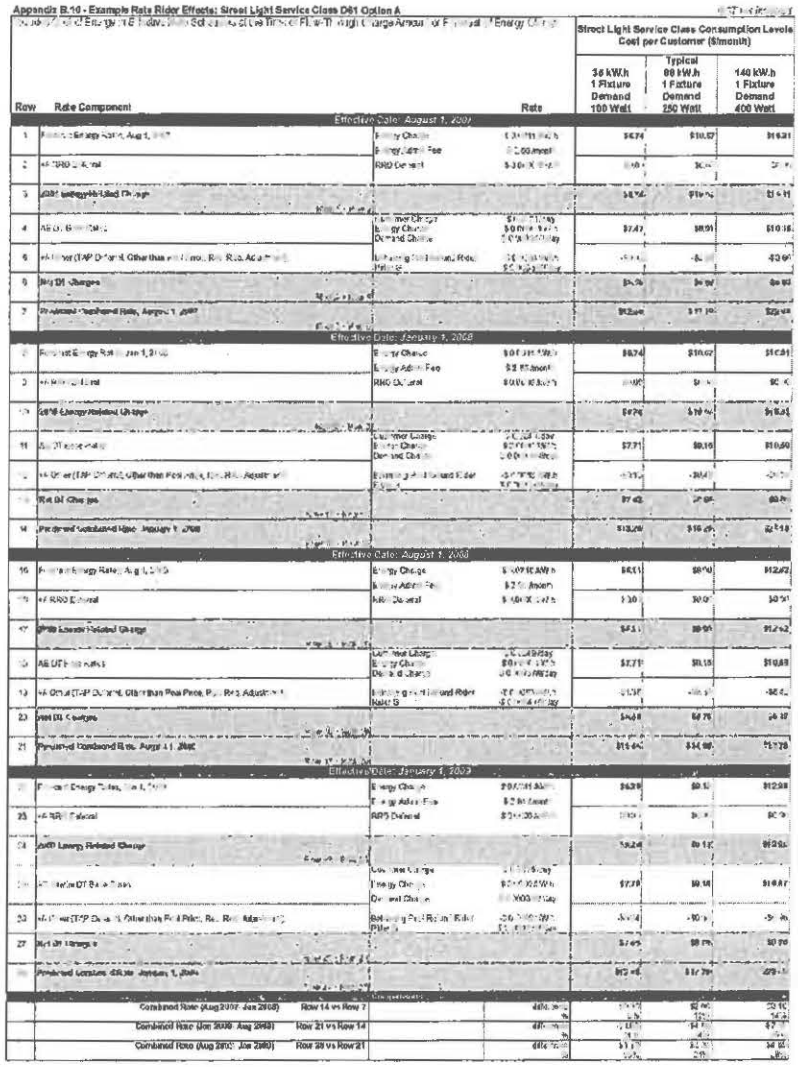
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Appendix B 9 - Example Rate Rider Effects: Farm Service Class - RRO Eligible

Row	Rate Component		Rate	RFA Farm Service Class Consumption Levels Cost per Customer ($/month) 755 kW.h per month Demand 7.5 kVA	Typical 1,255 kW.h per month Demand 7.5 kVA	1,755 kW.h per month Demand 7.5 kVA
	Effective Date: August 1, 2007					
1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
2	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
3	[illegible]			[illegible]	[illegible]	[illegible]
4	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	[illegible]			[illegible]	[illegible]	[illegible]
7	[illegible]			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2008					
8	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
9	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
10	[illegible]			[illegible]	[illegible]	[illegible]
11	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
12	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
13	[illegible]			[illegible]	[illegible]	[illegible]
14	[illegible]			[illegible]	[illegible]	[illegible]
	Effective Date: August 1, 2008					
15	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
16	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
17	[illegible]			[illegible]	[illegible]	[illegible]
18	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
19	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	[illegible]			[illegible]	[illegible]	[illegible]
21	[illegible]			[illegible]	[illegible]	[illegible]
	Effective Date: January 1, 2009					
22	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
23	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
24	[illegible]			[illegible]	[illegible]	[illegible]
25	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
26	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
27	[illegible]			[illegible]	[illegible]	[illegible]
28	[illegible]			[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 13

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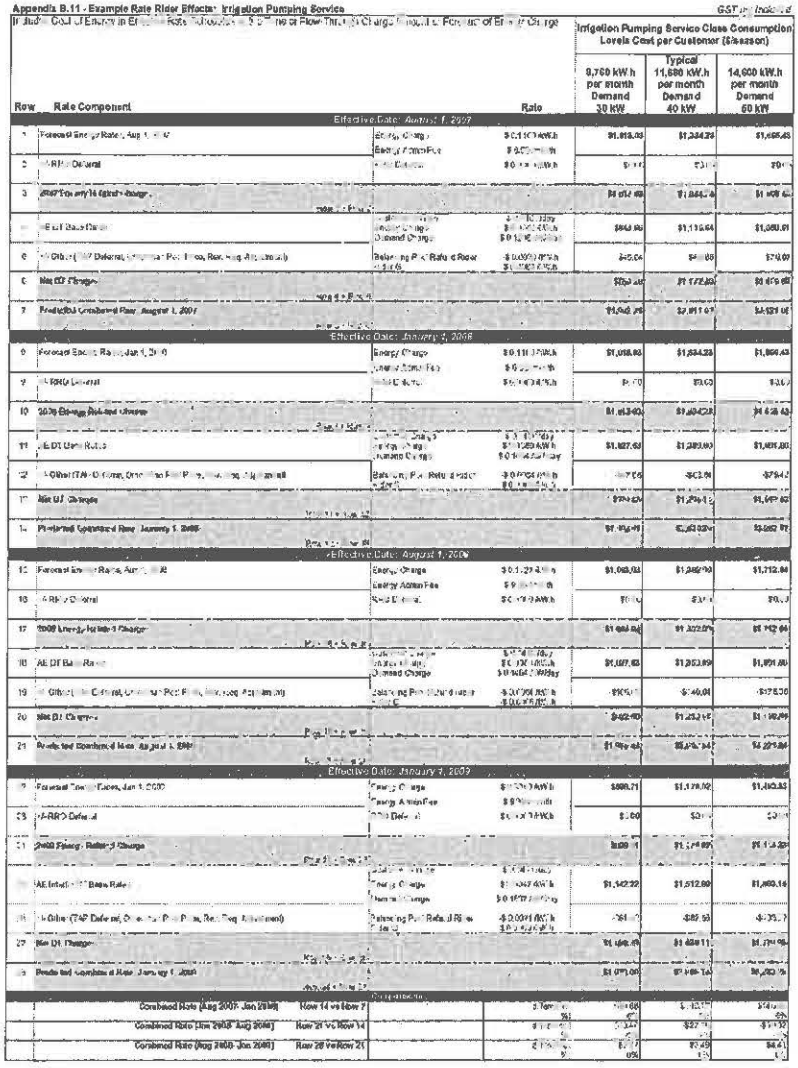


Appendix B.10 - Example Rate Rider Effects: Street Light Service Class D61 Option A

Row	Rate Component	Rate	Street Light Service Class Consumption Levels Cost per Customer ($/month) 36 kW.h 1 Fixture Demand 100 Watt	Typical 69 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	Effective Date: August 1, 2007				
1			$4.74	$10.57	$19.31
2					
3			$4.74	$10.57	$19.31
4			$7.47	$8.91	$10.16
5					-$2.99
6			$9.36	$9.36	$9.36
7			$12.83	$11.10	$22.54
	Effective Date: January 1, 2008				
8			$4.74	$10.57	$19.31
9					
10			$4.74	$10.57	$19.31
11			$7.71	$9.15	$10.60
12					
13			$7.42	$7.42	$7.42
14			$12.16	$16.99	$29.73
	Effective Date: August 1, 2008				
15			$4.61	$9.94	$18.72
16					
17			$4.61	$9.94	$18.72
18			$7.71	$9.15	$10.60
19					
20			$9.48	$9.76	$10.10
21			$13.64	$14.98	$19.78
	Effective Date: January 1, 2009				
22			$4.39	$9.51	$17.98
23					
24			$4.24	$9.16	$16.94
25			$7.19	$8.38	$9.57
26					
27			$9.48	$9.76	$10.10
28			$12.91	$13.79	$29.11
	Combined Rate (Aug 2007- Jan 2008) Row 14 vs Row 7				
	Combined Rate (Jan 2008- Aug 2008) Row 21 vs Row 14				
	Combined Rate (Aug 2007- Jan 2009) Row 28 vs Row 21				

Graphic 14

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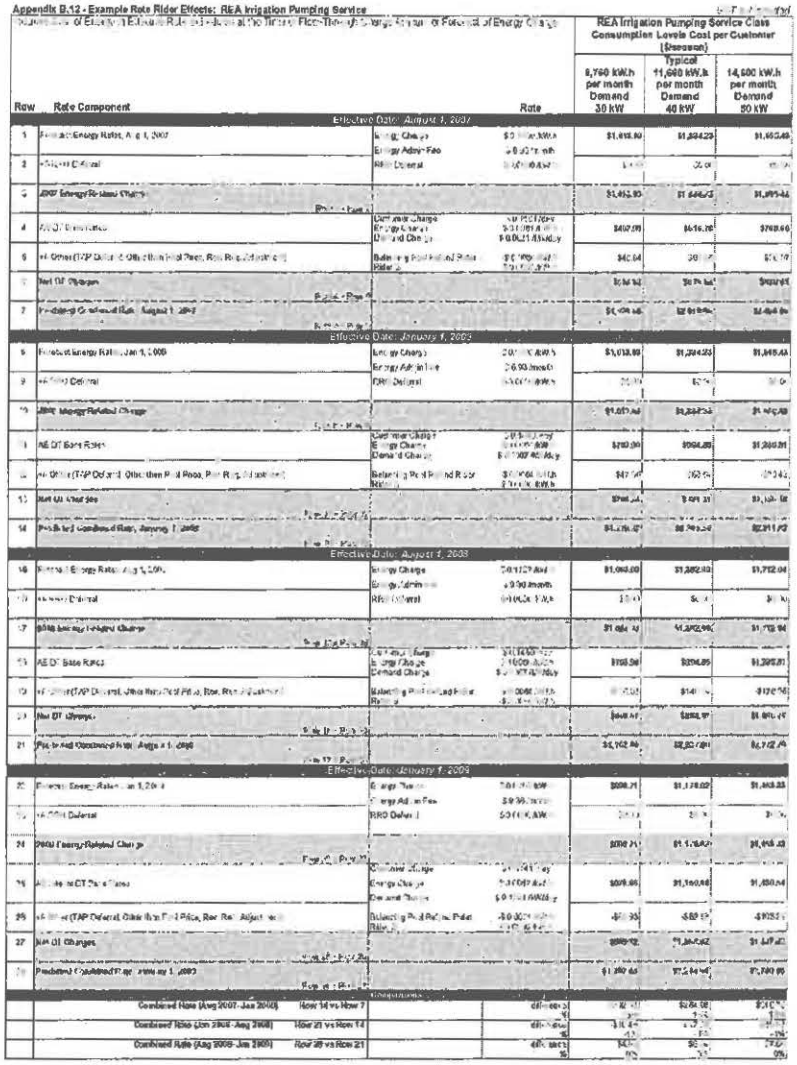


Appendix B.11 - Example Rate Rider Effects: Irrigation Pumping Service — GST Included

Row	Rate Component	Rate	Irrigation Pumping Service Class Consumption Levels Cost per Customer ($/season) 9,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 50 kW
	Effective Date: August 1, 2007				
1	Forecast Energy Rates, Aug 1, 2007	Energy Charge $0.0[illegible]/kWh; Energy Admin Fee $0.[illegible]/kWh	$1,018.03	$1,284.28	$1,695.43
2	4-RRO Deferral	$0.[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
3	2007 Energy Related Charge		$[illegible]	$[illegible]	$[illegible]
[illegible]	AESO Basic Rate	Energy Charge $0.[illegible]/kWh; Demand Charge $0.[illegible]/kW/day	$[illegible]	$1,113.64	$1,680.01
6	4-Other (TAP Deferral, Customer Post Rate, Rate Reg Adjustment)	Balancing Pool Refund Rider $0.0[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
6	Net DI Charges		$[illegible]	$1,172.60	$1,676.66
7	Projected Combined Rate, August 1, 2007		$[illegible]	$2,911.07	$3,921.05
	Effective Date: January 1, 2008				
8	Forecast Energy Rates, Jan 1, 2008	Energy Charge $0.1[illegible]/kWh; Energy Admin Fee $0.[illegible]/kWh	$1,058.93	$1,334.28	$1,896.43
9	4-RRO Deferral	$0.[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
10	2008 Energy Related Charge		$1,[illegible]	$1,[illegible]	$1,[illegible]
11	AESO Basic Rates	Energy Charge $0.[illegible]/kWh; Demand Charge $0.[illegible]/kW/day	$1,027.63	$1,283.90	$1,801.80
12	4-Other (TAP Deferral, Customer Post Rate, Rate Reg Adjustment)	Balancing Pool Refund Rider $0.0[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
13	Net DI Charges		$[illegible]	$1,[illegible]	$1,[illegible]
14	Projected Combined Rate, January 1, 2008		$[illegible]	$[illegible]	$[illegible]
	Effective Date: August 1, 2008				
15	Forecast Energy Rates, Aug 1, 2008	Energy Charge $0.1[illegible]/kWh; Energy Admin Fee $0.[illegible]/kWh	$1,068.03	$1,345.90	$1,912.84
16	4-RRO Deferral	$0.[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
17	2008 Energy Related Charge		$1,[illegible]	$1,[illegible]	$1,[illegible]
18	AESO DT Basic Rates	Energy Charge $0.[illegible]/kWh; Demand Charge $0.[illegible]/kW/day	$1,027.63	$1,283.90	$1,801.80
19	4-Other (TAP Deferral, Customer Post Rate, Rate Reg Adjustment)	Balancing Pool Refund Rider $0.0[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
20	Net DI Charges		$[illegible]	$1,[illegible]	$1,[illegible]
21	Projected Combined Rate August 1, 2008		$[illegible]	$[illegible]	$[illegible]
	Effective Date: January 1, 2009				
22	Forecast Energy Rates, Jan 1, 2009	Energy Charge $0.[illegible]/kWh; Energy Admin Fee $0.[illegible]/kWh	$888.71	$1,119.92	$1,593.53
23	4-RRO Deferral	$0.[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
24	2009 Energy Related Charge		$[illegible]	$1,[illegible]	$1,[illegible]
[illegible]	AESO Basic Rate	Energy Charge $0.[illegible]/kWh; Demand Charge $0.[illegible]/kW/day	$1,142.22	$1,512.80	$1,869.16
25	4-Other (TAP Deferral, Customer Post Rate, Rate Reg Adjustment)	Balancing Pool Refund Rider $0.0[illegible]/kWh	$[illegible]	$[illegible]	$[illegible]
27	Net DI Charges		$[illegible]	$1,[illegible]	$1,[illegible]
28	Projected Combined Rate January 1, 2009		$[illegible]	$[illegible]	$[illegible]
	Comparisons				
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7	$[illegible] [illegible]%	$[illegible] [illegible]%	$[illegible] [illegible]%
	Combined Rate (Jan 2008- Aug 2008)	Row 21 vs Row 14	$[illegible] [illegible]%	$[illegible] [illegible]%	$[illegible] [illegible]%
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21	$[illegible] [illegible]%	$[illegible] [illegible]%	$[illegible] [illegible]%

Graphic 15

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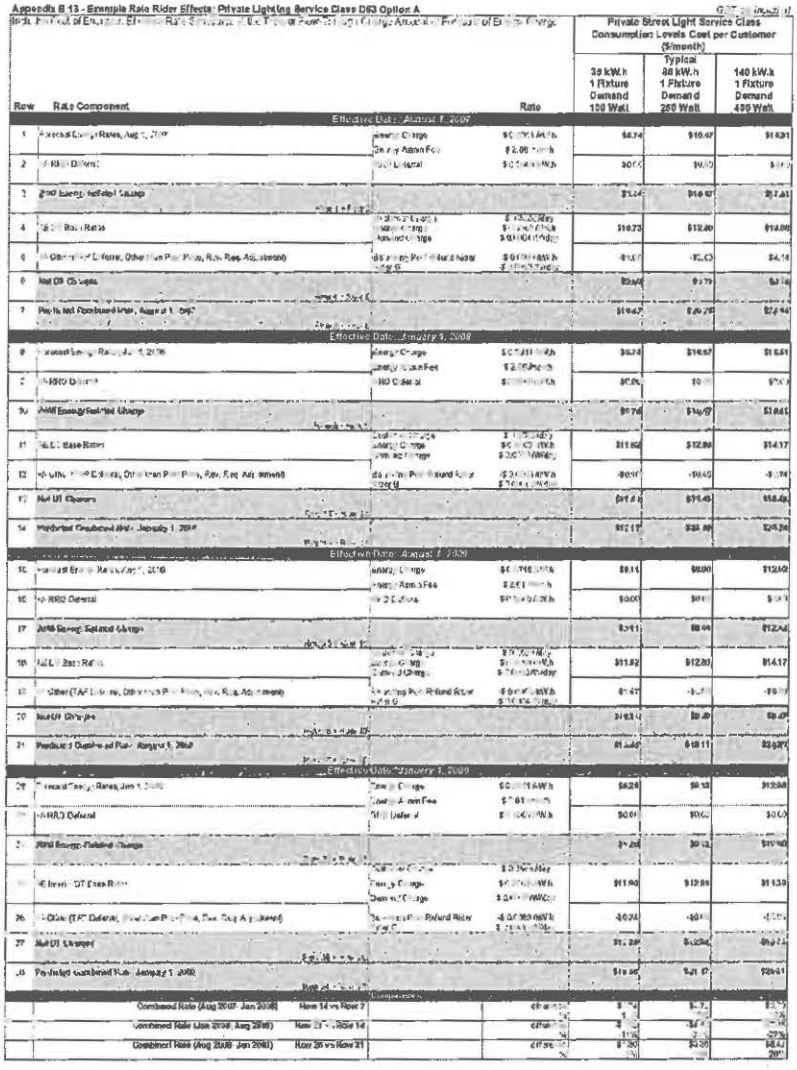


Appendix B.12 - Example Rate Rider Effects: REA Irrigation Pumping Service

Row	Rate Component	Rate	REA Irrigation Pumping Service Class Consumption Levels Cost per Customer (Season) — 8,760 kW.h per month Demand 30 kW	Typical 11,680 kW.h per month Demand 40 kW	14,600 kW.h per month Demand 50 kW
	Effective Date: August 1, 2007				
1	Energy Rates, Aug 1, 2007	Energy Charge Energy Adm Fee	$0.[illegible]/kW.h $ 0.[illegible]/month	$1,[illegible]	$1,[illegible]	$1,[illegible]
2	RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]
3	2007 Energy-Related Charge			$1,[illegible]	$1,[illegible]	$1,[illegible]
4	AESO Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.[illegible]/month $ 0.[illegible]/kW.h $ 0.[illegible]/kW/day	$[illegible]	$[illegible]	$[illegible]
5	Other (TAP Deferral, Other Non-Bypassable Fees, Rate Rider, Adjustment)	Balancing Pool Refund & Rate Rider	$ 0.[illegible]/kW.h [illegible]%	$[illegible]	$[illegible]	$[illegible]
6	Net DT Charges			$[illegible]	$[illegible]	$[illegible]
7	Predicted Combined Rate, August 1, 2007			$[illegible]	$[illegible]	$[illegible]
	Effective Date: January 1, 2009				
8	Energy Rates, Jan 1, 2009	Energy Charge Energy Adm Fee	[illegible]/kW.h $ 0.00/month	$1,[illegible]	$1,[illegible]	$1,[illegible]
9	RRO Deferral	RRO Deferral	[illegible]	[illegible]	[illegible]
10	2009 Energy-Related Charge			$1,[illegible]	$1,[illegible]	$1,[illegible]
11	AESO Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.[illegible]/day [illegible]/kW.h $ 0.[illegible]/kW/day	$[illegible]	$[illegible]	$[illegible]
12	Other (TAP Deferral, Other Non-Bypassable Fees, Rate Rider, Adjustment)	Balancing Pool Refund & Rate Rider	$ 0.[illegible]/kW.h [illegible]%	$[illegible]	$[illegible]	$[illegible]
13	Net DT Charges			$[illegible]	$[illegible]	$[illegible]
14	Predicted Combined Rate, January 1, 2009			$[illegible]	$[illegible]	$[illegible]
	Effective Date: August 1, 2008				
15	Energy Rates, Aug 1, 2008	Energy Charge Energy Adm Fee	[illegible]/kW.h $ 0.00/month	$1,[illegible]	$1,[illegible]	$1,[illegible]
16	RRO Deferral	RRO Deferral	[illegible]/kW.h	[illegible]	[illegible]
17	2008 Energy-Related Charge			$1,[illegible]	$1,[illegible]	$1,[illegible]
18	AESO Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.[illegible]/day [illegible]/kW.h $ 0.[illegible]/kW/day	$[illegible]	$[illegible]	$[illegible]
19	Other (TAP Deferral, Other Non-Bypassable Fees, Rate Rider, Adjustment)	Balancing Pool Refund & Rate Rider	$ 0.[illegible]/kW.h [illegible]%	$[illegible]	$[illegible]	$[illegible]
20	Net DT Charges			$[illegible]	$[illegible]	$[illegible]
21	Predicted Combined Rate, August 1, 2008			$[illegible]	$[illegible]	$[illegible]
	Effective Date: January 1, 2009				
22	Energy Rates, Jan 1, 2009	Energy Charge Energy Adm Fee	[illegible]/kW.h $ 0.00/month	$[illegible]	$1,[illegible]	$1,[illegible]
23	RRO Deferral	RRO Deferral	[illegible]/kW.h	[illegible]	[illegible]
24	2009 Energy-Related Charge			$[illegible]	$1,[illegible]	$1,[illegible]
25	AESO Base Rates	Customer Charge Energy Charge Demand Charge	$ 0.[illegible]/day [illegible]/kW.h $ 0.[illegible]/kW/day	$[illegible]	$1,[illegible]	$1,[illegible]
26	Other (TAP Deferral, Other Non-Bypassable Fees, Rate Rider, Adjustment)	Balancing Pool Refund & Rate Rider	$ 0.[illegible]/kW.h [illegible]%	$[illegible]	$[illegible]	$[illegible]
27	Net DT Charges			$[illegible]	$1,[illegible]	$1,[illegible]
28	Predicted Combined Rate, January 1, 2009			$1,[illegible]	$1,[illegible]	$1,[illegible]
	Comparisons					
	Combined Rate (Aug 2007-Jan 2008)	Row 14 vs Row 7	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Jan 2008-Aug 2008)	Row 21 vs Row 14	[illegible]	[illegible]	[illegible]	[illegible]
	Combined Rate (Aug 2008-Jan 2009)	Row 28 vs Row 21	[illegible]	[illegible]	[illegible]	[illegible]

Graphic 16

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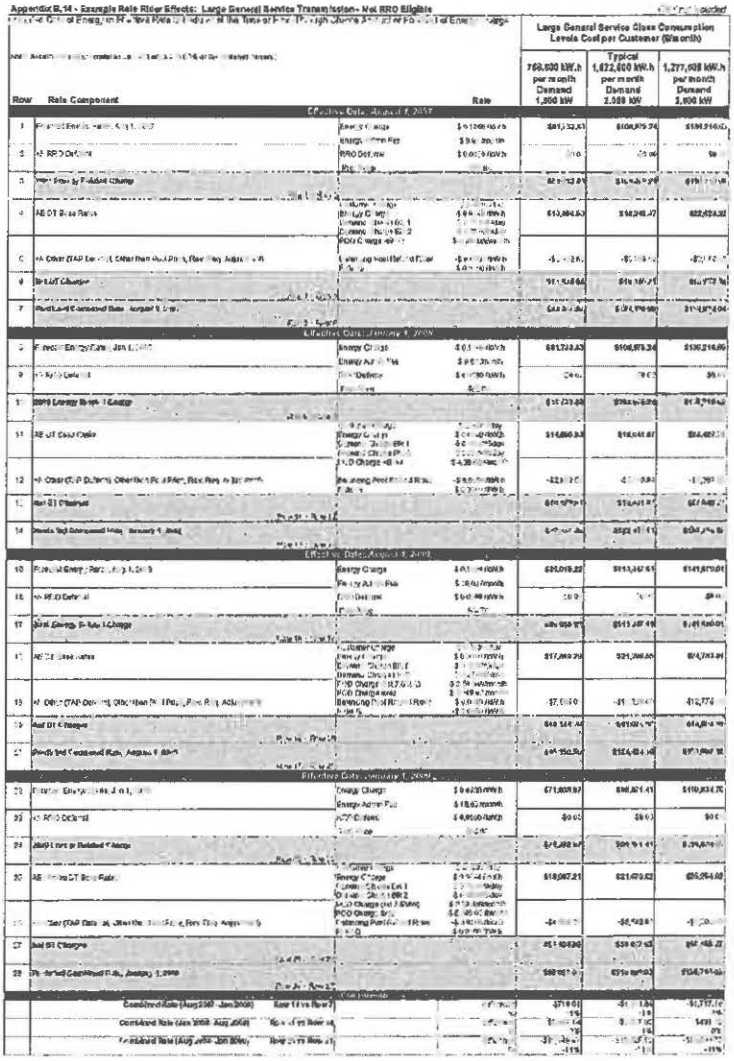


Appendix B 13 - Example Rate Rider Effects: Private Lighting Service Class D63 Option A

Row	Rate Component	Rate	Private Street Light Service Class Consumption Levels Cost per Customer ($/month)		
			38 kW.h 1 Fixture Demand 100 Watt	Typical 88 kW.h 1 Fixture Demand 250 Watt	140 kW.h 1 Fixture Demand 400 Watt
	Effective Date: August 1, 2007				
1	Approved Energy Rates, Aug 1, 2007	Energy Charge Energy Admin Fee	$0.[illegible]/kWh $2.05 /month	$8.74	$10.47	$14.31
2	AARO Deferral	AARO Deferral	$0.[illegible]/kWh	$0.00	$0.00	$0.00
3	2007 Energy Related Charge			$1.24	$1.67	$2.41
4	DSTS Base Rate	Energy Charge Admin Charge Administration	$ [illegible]/day $ [illegible]/kWh $0.00104/kWh	$10.73	$12.80	$14.06
5	Other (TAF Deferral, Other Non Pass Thru, Rev Req Adjustment)	65 Energy Pass Through Refund Rider Energy	$ 0.00[illegible]/kWh $ [illegible]/kWh	-$1.07	-$1.43	-$4.14
6	Net DT Charges			$9.90	$11.79	$8.14
7	Previous last Combined Rate, August 1, 2007			$19.67	$24.26	$27.94
	Effective Date: January 1, 2008					
8	Proposed Energy Rates, Jan 1, 2008	Energy Charge Energy Admin Fee	$ [illegible]/kWh $2.05/month	$8.74	$10.47	$14.31
9	AARO Deferral	AARO Deferral	$ [illegible]/kWh	$0.00	$0.00	$0.00
10	2008 Energy Related Charge			$1.76	$2.37	$3.24
11	DSTS Base Rates	Energy Charge Admin Charge	$ [illegible]/kWh $ [illegible]/kWh $ 0.00104/kWh	$11.82	$12.80	$14.17
12	Other (TAF Deferral, Other Non Pass Thru, Rev Req Adjustment)	65 Energy Pass Through Refund Rider Energy	-$ 0.00[illegible]/kWh $ [illegible]/kWh	-$1.07	-$1.43	-$4.14
13	Net DT Charges			$11.51	$13.43	$13.43
14	Projected Combined Rate - January 1, 2008			$32.17	$38.89	$45.36
	Effective Date: August 1, 2008					
15	Proposed Energy Rates, Aug 1, 2008	Energy Charge Energy Admin Fee	$ [illegible]/kWh $2.61 /month	$8.11	$9.80	$12.40
16	AARO Deferral	AARO Deferral	$ [illegible]/kWh	$0.00	$0.00	$0.00
17	2008 Energy Related Charge			$1.11	$1.44	$2.44
18	DSTS Base Rates	Energy Charge Admin Charge	$ [illegible]/kWh $ [illegible]/kWh $ 0.00104/kWh	$11.82	$12.80	$14.17
19	Other (TAF Deferral, Other Non Pass Thru, Rev Req Adjustment)	65 Energy Pass Through Refund Rider Energy	-$ 0.00[illegible]/kWh $ [illegible]/kWh	-$1.07	-$1.43	-$4.14
20	Net DT Charges			$11.86	$12.81	$12.47
21	Projected Combined Rate - August 1, 2008			$31.08	$36.11	$39.37
	Effective Date: January 1, 2009					
22	Proposed Energy Rates, Jan 1, 2009	Energy Charge Energy Admin Fee	$ [illegible]/kWh $7.61 /month	$8.28	$9.13	$12.08
23	AARO Deferral	AARO Deferral	$ [illegible]/kWh	$0.00	$0.00	$0.00
24	2009 Energy Related Charge			$1.26	$1.72	$2.60
25	DSTS Base Rates	Energy Charge Admin Charge	$ 0.00/day $ [illegible]/kWh $ 0.00104/kWh	$11.90	$12.88	$14.30
26	Other (TAF Deferral, Other Non Pass Thru, Rev Req Adjustment)	65 Energy Pass Through Refund Rider Energy	-$ 0.00169/kWh $ [illegible]/kWh	-$0.24	-$0.33	-$0.54
27	Net DT Charges			$11.66	$12.55	$13.76
28	Projected combined Rate - January 1, 2009			$31.20	$35.40	$42.91
	Combined Rate (Aug 2007- Jan 2008)	Row 14 vs Row 7		$ [illegible]	$ [illegible]	$ [illegible]
	Combined Rate (Jan 2008- Aug 2008)	Row 21 - Row 14		$ [illegible]	$ [illegible]	$ [illegible]
	Combined Rate (Aug 2008- Jan 2009)	Row 28 vs Row 21		$ [illegible]	$ [illegible]	$ [illegible]

Graphic 17

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Graphic 18
ATCO ELECTRIC
ATCO ELECTRIC 2009 DISTRIBUTION INTERIM TARIFF APPLICATION
Energy Rates Used in Appendix B-1 to B-14

	Admin. Charges Fixed ($ / Day)	Cost of Energy October 2008 ($ / kWh)
D11	0.265	0.09701
D21	0.282	0.09672
D31	0.601	0.09379
T31	0.601	0.09379
D41	0.296	0.09358
D51	0.274	0.09645
D56	0.274	0.09645
D25	0.312	0.09497
D61	0.087	0.07405
D63	0.087	0.07405
D26	0.312	0.09497

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Rates used are the RRO Rates as posted on Direct Energy Regulated Services website Oct 6/2008) These rates are used for the January 1, 2009 scenarios (less Rider).

APPENDIX 3 — Rider B — Balancing Pool Rider Determination

Rider B - 2009 Balancing Pool Rider Determination

Rate Class	*A* *Proposed 2009 AESO Rider F (¢/kW.h)*	*B* *Distribution Losses Note 1 (%)*	*C=A*(1+B)* *Proposed 2009 ATCO Electric Rider B (¢/kW.h)*
D11	0.650	5.66%	0.687
D21/D22	0.650	5.90%	0.688
D25/D26	0.650	8.77%	0.707
D31/D32/D33	0.650	4.79%	0.681
T31/T33	0.650		flow through
D41	0.650	7.86%	0.701
D51/D52	0.650	6.49%	0.692
D56	0.650	6.49%	0.692
D61	0.650	5.69%	0.687
D63	0.650	5.53%	0.686

Note 1: Distribution losses obtained from ATCO Electric's approved 2008 DTA (Section 10 Load Research EDLA Model).

APPENDIX 4 — Determination of Adjustment Factors

Table 1 Scaling Factor Determination All Revenue in $'000's

Year	*Column No.*	*Scenario*	*(A)* *Trans Demand Revenue*	*(B)* *Trans Energy Revenue*	*(C)* *T31 Trans Demand Revenue*	*(D)* *T31 Trans Energy Revenue*	*(E)* *Dist Revenue*	*Power Factor*	*Total*
Before Scaling									
		12 mo. 2008 final rates	57,459	52,946	14,619	7,352	214,585	4,286	351,247
		Adj for D11	9,435	(9,435)					
2009		Adj for D61	(101)	101					
		Adj for D63	(16)	16					
	(1)	Total	66,777	43,627	14,619	7,352	214,585	4,286	351,247
	(2)	Target	81,323	41,440	14,619	7,352	213,180	4,286	362,200
	(3)	Scaling Factor	*1.217830*	*0.949866*	*1.000*	*1.000*	*0.993451*	*1.000*	*1.031*
After Scaling									
2009		12 mo. 2008 final rates after scaling	69,943	52,820	14,619	7,352	213,180	4,286	362,200
		Adj for D11	11,491	(11,491)					
		Adj for	(96)	96					

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	D61 Adj for D63	(15)	15					
(4)	Total	81,323	41,440	14,619	7,352	213,180	4,286	362,200

Table 2 Breakdown of Transmission Rate All Revenue in $'000's
Based on 2008 Refiling Application

	Demand Related Portion	*Energy Related Portion*	*Total Trans Revenue*
D11	9,435	5,023	14,458
D61	155	101	256
D63	26	16	42

Factored Future Costs for 2009				*(F) Scaling Factor*
D11	11,491	4,771	16,262	*1.125*
D61	189	96	284	*1.112*
D63	31	15	47	*1.114*

Table Summary

Table 1, Row 1 sets out the forecast revenue for 2009 based on ATCO Electric's final approved 2008 DT. The revenues are split out by the transmission component in Column (A) and Column (B), which relates to recovery of costs under the distribution rates associated with transmission access - by demand and energy. An adjustment to revenues (between Demand and Energy components) for D11, D61, and D63 was made to align it with the allocation of costs based on ATCO Electric's Phase II transmission cost of service study. Column (C) and (D) relate to demand and energy revenue associated with direct connect transmission customers, and Column (E) relates to the revenue required to collect costs specifically associated with the distribution and service functions by all classes. Rider A1 has been excluded from this calculation. Row (2) sets out the revenue requirement for 2009, or the "target" revenue in which the rates are designed to achieve. In order to get the forecast revenue equal to the forecast revenue requirement, the distribution and transmission components of the distribution rates will be adjusted by the scaling factor in Row (3). This applies to all rate classes.

However, for rates D11, D61, and D63 — since these rates recover total transmission revenue under only one component (demand or energy) while the costs are incurred under both demand and energy, the scaling factor is iterated against the weighted average of the demand and energy related costs until the revenue equals the costs recovered under the rate. Revenue adjustments are made for these components in Table 1 to ensure that revenue is reflected in the manner in which they are recovered. For example, D11 collects $14.5M in transmission revenue of which, $9.4M is associated with demand related costs.

Since ATCO Electric now flows through the AESO rates to direct connect transmission customers, there is no requirement to adjust the transmission demand and energy revenue in Column (C) and (D).

The total revenue after the scaling factor is applied is set out in Row (4), Table 1.

APPENDIX 5 — 2009 Interim Transmission Tariff

EFFECTIVE: 2009-01-01
SUPERSEDES: 2008-01-01

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2009 RATE SCHEDULE
INTERIM TRANSMISSION TARIFF

AVAILABLE:	To the Transmission Administrator
APPLICABLE:	To the Transmission Administrator for use of the Company's transmission facility for the 2009 calendar year.
RATE:	Interim Charges to the Transmission Administrator for the 2009 calendar year shall be:
Annual Tariff:	$194,000,000
Monthly Charges:	$16,166,667

Footnotes

[1] ATCO Electric Ltd. 2009-2010 General Tariff Application (Application No. 1578371, Proceeding ID. 86)

[2] Application, Section 2.1 — AE's Proposed Target Revenue Requirement: Two-Part Test

[3] Information Response to AUC-AE-1

[4] Decision 2005-102 — ATCO Electric Ltd. 2005 Interim Transmission Facility Owner Tariff (Application 1407551) (Released: September 7, 2005)

[5] Decision 2005-099 — ATCO Gas 2005-2007 General Rate Application Interim Rate Application (Application 1404168) (Released: August 29, 2005)

[6] Application, Table 3 — Proposed Increases to 2009 Revenue Requirements for 2009 Interim Rates, Page 6

[7] UCA Argument, December 2, 2008

[8] Information Response to AUC-AE-1

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AUC
Alberta Utilities Commission

ENMAX Power Corporation

2015 Interim Distribution and Transmission Tariff Application

November 12, 2014

The Alberta Utilities Commission
Decision 2014-311: ENMAX Power Corporation
2015 Interim Distribution and Transmission Tariff Application
Application No. 1610874
Proceeding No. 3433

November 12, 2014

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The Alberta Utilities Commission

Calgary, Alberta

Decision 2014-311
ENMAX Power Corporation **Application No. 1610874**
2015 Interim Distribution and Transmission Tariff Application **Proceeding No. 3433**

1 Introduction

1. On September 25, 2014, ENMAX Power Corporation (EPC) submitted an application (application) to the Alberta Utilities Commission (AUC or Commission), pursuant to sections 37, 102, 119 and 124(2) of the *Electric Utilities Act*, SA 2003, c. E-5.1, applying for the following:

(i) Approval to implement 2015 distribution access service (distribution) rates on an interim basis, as described in Section 3 of the application,[1] calculated in Appendix 1[2] and set out in the rate schedules provided in Appendix 2,[3] effective January 1, 2015.

(ii) Approval to implement 2015 transmission rates on an interim basis, as described in Section 4 of the application, calculated in Appendix 3[4] and set out in the rate schedules provided in Appendix 4,[5] effective January 1, 2015.

2. On September 29, 2014, the Commission issued a notice of application advising interested parties to file a statement of intent to participate (SIP) to the Commission no later than October 9, 2014. In the SIPs, parties were asked to indicate whether they supported or objected to the application, provide reasons for their positions and comment on the need for further process and the supporting rationale.

3. The following parties registered in the proceeding by the specified deadline:

- FortisAlberta Inc.
- ATCO Electric Ltd.
- Alberta Electric System Operator (AESO)
- EPCOR Distribution & Transmission Inc.

4. None of the above-listed parties objected to the application or requested further process.

5. On October 21, 2014, the Commission issued a process letter classifying the proceeding as a *notice-only process* proceeding and advising that the Commission had two questions for EPC. On October 22, 2014, EPC filed its responses to the Commission's questions.[6]

[1] Exhibit No. 3, application.
[2] Exhibit No. 5, application, Appendix 1.
[3] Exhibit No. 6, application, Appendix 2.
[4] Exhibit No. 7, application, Appendix 3.
[5] Exhibit No. 8, application, Appendix 4.
[6] Exhibit No. 14.01, Commission process letter; Exhibit No. 15.01, Commission information request; Exhibit No. 16.01, EPC responses to information request.

6. The Commission considers that the record for this proceeding closed on October 22, 2014.

7. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Details of the application

8. On July 24, 2013, EPC filed an application with the AUC requesting approval of EPC's 2014 Phase I Distribution Tariff Application (DTA) and 2014-2015 Transmission General Tariff Application (GTA) (collectively Proceeding No. 2739).[7] According to EPC, even if a decision for Proceeding No. 2739 is issued in December 2014, given the likely timing of a compliance filing, it is unlikely that final 2014 rates will be approved before the end of 2014, and therefore final 2014 rates will not be available to be used as the basis of interim 2015 rates by January 1, 2015.[8]

9. EPC's current distribution and transmission tariffs were approved on an interim basis in Decision 2013-436[9] and have been in place on an interim basis since January 1, 2014. If existing 2014 interim rates continue for 2015, EPC forecasted a total revenue shortfall of $10.229 million for distribution and $14.260 million for transmission.[10]

10. EPC stated that the shortfall amount is significant. To reduce the impact of the rate increase that will be required when the final 2015 distribution and transmission rates are implemented, EPC requested approval of interim distribution and transmission rates to be effective January 1, 2015 and continuing until such time as the AUC approves revised interim or final 2015 distribution and transmission rates. EPC advised that, once matters in Proceeding No. 2739 have been decided by the Commission, EPC will make the required adjustments or applications to set final 2015 distribution and transmission rates.[11]

2.1 Distribution

11. EPC submitted that its forecast distribution revenue for 2015, included in Appendix 1 to the application, is $192.571 million based on current interim distribution rates. EPC's forecast distribution revenue requirement is $202.800 million, as determined by escalating the 2014 DTA revenue requirement by the placeholder performance-based regulation (PBR) formula described in Section 3 of the application. Consequently, if the 2014 DTA is approved as applied for, and no

[7] Application for Approval of 2014 Phase I Distribution Tariff Application and 2014-2015 Transmission General Tariff Application, Exhibit No. 3, Application 1609784, Proceeding No. 2739.
[8] Exhibit No. 3, application, paragraph 2.
[9] Decision 2013-436: ENMAX Power Corporation, 2014 Interim Distribution and Transmission Tariff Application, Application No. 1610012, Proceeding ID No. 2886, December 11, 2013.
[10] Exhibit No. 3, application, paragraph 4.
[11] Exhibit No. 3, application, paragraphs 3 and 20.

interim rate adjustment is made effective January 1, 2015, there will be a distribution revenue shortfall of $10.229 million from January 1, 2015 to December 31, 2015.[12]

12. In order to calculate its distribution revenue shortfall calculations, EPC adopted the PBR formula established in Decision 2012-237 (first generation PBR) for other utilities to adjust their distribution base rates on an annual basis:[13]

$$R_t = \underbrace{BR_{t-1} * (1+ (I-X))}_{\text{Base rates } (BR_t)}$$

Where:

R_t = Upcoming year's rates for each class

BR_{t-1} = Current year's base rates for each class

I = Inflation Factor ("I factor")

X = Productivity Factor ("X factor")

13. For its 2015 interim rate calculations, EPC adopted the first generation PBR formula using EPC's proposed 2014 DTA revenue requirement as BR_{t-1}.[14]

14. EPC requested the following first generation PBR placeholders for interim distribution rate setting purposes only:

(i) I factor placeholder of 2.93%, where the I factor placeholder is calculated the same as the first generation PBR I factor approved in Decision 2012-237, using the Alberta Average Weekly Earnings ("AWE") from July 2012 to June 2014 with a weighting of 55%, and the Alberta Consumer Price Index ("CPI") from July 2012 to June 2014 with a weighting of 45%. The Statistics Canada data for each index showing the placeholder I factor calculation is provided in Appendix 1, Schedule 1.2; and

(ii) X factor placeholder of 1.16%, where the X factor placeholder is the same as the first generation PBR X factor of 1.16% approved in Decision 2012-237.[15]

15. In response to a Commission information request, EPC revised the data used in calculating the I factor and calculated a new 2015 I factor of 2.65 per cent. EPC also provided revised 2015 interim distribution rate calculations and tariffs.[16]

---

[12] Exhibit No. 3, application, paragraph 12; Appendix 1, schedules 1.1 and 1.5; 2014 Phase I DTA and 2014-2015 Transmission GTA; Exhibit No. 106.6, Schedule 12-1, Retail Sales of $310.888 (Line 21) less the cost of Sales of $111.615 million (Line 9), Application No. 1609784, Proceeding ID No. 2719.

[13] Exhibit No. 3, application, paragraph 6; Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012, at paragraph 963.

[14] Exhibit No. 3, application, paragraph 7.

[15] Exhibit No. 3, application, paragraph 8.

16. EPC noted that its proposal to use first generation PBR placeholders is for convenience, and does not necessarily mean that it will propose these factors in its forthcoming second generation PBR application, or that it accepts these factors would be reasonable for the same. EPC submitted that the use of first generation PBR placeholders is reasonable and conservative for the purposes of determining 2015 interim distribution rates.[17]

17. EPC's distribution rates would require an increase of 5.31 per cent to collect the forecast 2015 distribution revenue requirement of $202.800 million. However, EPC's proposed interim rate adjustment will result in an increase to distribution rates of 3.19 per cent, which will enable EPC to recover 60 per cent of its revenue shortfall and collect $198.710 million in 2015 distribution revenue. This will reduce the forecast 2015 distribution revenue shortfall from $10.229 million to $4.090 million.[18]

18. EPC also proposed that the requested interim distribution base rate increase of 3.19 per cent be applied to all rate classes on an across-the-board basis, therefore maintaining the currently approved rate structure based on EPC's last approved Phase II cost of service study.[19]

19. Subsequent to receiving a decision in Proceeding No. 2739, EPC plans to file for approval of a capital tracker, or K factor, in 2015 as part of the second generation PBR application or as a separate filing. While EPC did not propose a K factor placeholder in the application, EPC indicated that it will request approval to adjust the 2015 interim distribution base rates subsequent to the filing of its capital tracker application.[20]

20. In the application, EPC referred to its 2015 billing determinant forecast:

> EPC's forecast 2015 Distribution revenue is $192.571 million if the existing 2014 interim Distribution rates are continued in 2015 without an adjustment, based on the 2015 billing determinant forecast.[21]

21. In response to a Commission information request on the 2015 billing determinant forecast, EPC:

- confirmed that the forecast is a new forecast that has not been previously approved by the Commission
- explained that the forecast is based on the same methodology used in EPC's 2014 DTA but with updated historical data and key economic indicators
- submitted that it considers the forecast to be interim and will be including the forecast for full testing in its forthcoming PBR application[22]

---

16 Exhibit No. 16.01, AUC-EPC-1; Exhibit No. 16.02, Appendix 1, revised 2015 interim distribution rate calculations; Exhibit No. 16.03, Appendix 2, revised 2015 interim distribution tariffs.
17 Exhibit No. 3, application, paragraphs 9 and 10.
18 Exhibit No. 3, application, paragraphs 13 to 15.
19 Exhibit No. 3, application, paragraph 16.
20 Exhibit No. 3, application, paragraph 17.
21 Exhibit No. 3, application, paragraph 12.
22 Exhibit No. 16.01, AUC-EPC-2.

2.2 Transmission

22. EPC submitted that its forecast transmission revenue for 2015, included in Appendix 3 to the application, is $61.708 million based on current interim transmission rates. EPC's forecast transmission revenue requirement for 2015 is $75.968 million, as applied for in its 2014-2015 transmission GTA. Consequently, if the 2014-2015 GTA is approved as applied for and no interim rate adjustment is made effective January 1, 2015, there will be a transmission revenue shortfall for 2015 of $14.260 million from January 1, 2015 to December 31, 2015.[23]

23. EPC's transmission revenue requirement would require an increase of 23.11 per cent to collect the forecast 2015 transmission revenue requirement of $75.968 million, as applied for in its 2014-2015 GTA. However, EPC requested approval of an interim increase to its existing transmission revenue requirement of 13.87 per cent, which will allow EPC to recover 60 per cent of its revenue shortfall. The proposed adjustment would result in 2015 transmission revenue of $70.264 million, reducing the forecast 2015 transmission revenue shortfall from $14.260 million to $5.704 million.[24]

2.3 Test to support interim tariff applications

24. In the application, as justification for its interim rates, EPC relied on the two-part test that was originally used by the Commission's predecessor, the Alberta Energy and Utilities Board, in evaluating interim rate applications, and has since been used by the Commission. The two-part test is as follows:

> The first part of the test relates to quantum and need, and includes the following considerations:
>
> i. Is the identified revenue deficiency probable and material?
> ii. Can all or some portion of any contentious items be excluded from the amount collected?
> iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
> iv. Can the applicant continue safe utility operations without the interim adjustment?
>
> The second part of the test relates to the public interest and includes the following considerations:
>
> i. Will the interim rates promote rate stability and ease rate shock?
> ii. Will the interim adjustments help to maintain intergenerational equity?
> iii. Can the interim rate increases be avoided through the use of carrying costs?
> iv. Are the interim rate increases required to provide appropriate price signals to customers?
> v. Is it appropriate to apply the interim rider on an across-the-board basis?[25]

3 Issues and Commission findings

25. When evaluating the merits of an interim rate application, the Commission applies the above-stated test. It weighs the potential benefits of rate stability and minimization of rate shock and intergenerational inequity that might result on approval of final rates against the costs that

[23] Exhibit No. 3, application, paragraph 19; 2014 Phase I DTA and 2014-2015 Transmission GTA, Exhibit No. 124, Application No 1609784, Proceeding ID No. 2719; Appendix 3, Schedule 3.1.
[24] Exhibit No. 3, application, paragraphs 21 to 23.
[25] Exhibit No. 3, application, paragraphs 24-25.

underpin the interim rate increase, whether they be contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations.

26. The above-listed considerations in the two-part test may be given different weighting depending on the specific circumstances of each application. The Commission has evaluated the application with these considerations in mind.

27. The Commission has reviewed the transmission and distribution revenue shortfall calculations included in appendices 1 and 3 of the application, including the revised I factor calculations, and is satisfied that they are accurate.

28. In respect of the 2015 billing determinant forecast, the Commission accepts EPC's explanation and is satisfied that the forecast, using previously approved methodologies and updated historical data and key economic indicators, is sufficient for the purposes of 2015 interim distribution rates based on 60 per cent of EPC's applied-for 2014 DTA. The 2015 billing determinant forecast will be tested in EPC's upcoming PBR proceeding. The Commission will make a determination at that time on the reasonableness of the forecast.

29. The Commission considers that the forecast distribution revenue shortfall of $10.229 million and transmission revenue shortfall of $14.260 million, amounting to a total revenue deficiency of $24.289 million, is a material amount if the entire amount had to be collected from customers.

30. The Commission is also cognizant of the financial hardship that such a material deficiency could have on EPC, as it stated in its application, "[t]hese deficiencies will reduce cash flow, which will in turn require increased short-term borrowing. Long-term borrowing may also be impacted, if the existing rates will be in place for the majority of 2015."[26]

31. The Commission also notes EPC's arguments that it has experienced load growth and system infrastructure expansion over the formula-based ratemaking (FBR) term of 2007 to 2013, while revenues were decoupled from costs. Consequently, EPC submitted that its distribution rate base grew significantly, and the cost of providing service has increased beyond the difference between the approved FBR inflation and productivity factors.[27]

32. To understand the impact of EPC's proposed interim rate increases on typical customer bills, the Commission has reviewed the bill comparison submitted by EPC.[28] The Commission has used the bill comparison information to prepare Table 1 below which illustrates that the interim rate increase will promote rate stability for customers.

[26] Exhibit No. 3, application, paragraph 31.
[27] Exhibit No. 3, application, paragraph 27.
[28] Exhibit No. 5, application, Appendix 1, Schedule 1.8.

Table 1. Bill impacts

	Total charges		
Rate Class	Without interim rates	With interim rates	
	2015 PBR base rates January 1, 2015 (per cent)	2015 interim rates January 1, 2015 (per cent)	2015 PBR base rates January 1, 2015 (per cent)
Residential rate D100	4.0	0.6	1.6
Small commercial rate D200	2.9	0.4	1.2
Medium commercial rate D300	3.7	0.6	1.5
Large commercial - secondary rate D310	2.3	0.4	0.9
Large commercial - primary rate D410	1.0	0.2	0.4

33. Given the magnitude of the potential revenue shortfall and resultant financial impact to EPC and rate shock to customers' bills as demonstrated in Table 1 above, the Commission considers that some degree of interim rate adjustment should be made. The Commission is aware that the financial hardship to EPC could be mitigated by the award of carrying costs; however, it will not mitigate the risk of potential rate shock to customers. The Commission finds that approval of an interim increase to EPC's distribution rates will provide a gradual and stable transition to EPC's final 2015 distribution rates.

34. The Commission recognizes that while EPC's transmission tariff initially only applies to a single customer, the AESO, the increases to EPC's transmission tariff will flow-through to EPC's customers by way of EPC's system access service (SAS) rates and transmission access charge (TAC) deferral account riders. Consequently, the Commission accepts EPC's submission that "the proposed interim Transmission rates will help levelize the transmission Tariff throughout 2015, reducing the magnitude of the increase once final 2015 Transmission rates are approved"[29] and finds that, given the magnitude of the potential shortfall, an interim increase to its transmission rates will enable a more gradual transition to final 2015 transmission rates.

35. To better provide for both a gradual increase and a transitional rate level, the Commission considers that it is preferable to have an interim increase that reflects an intermediate position between the current rates and the proposed final rates. The Commission notes that for the period from January 1, 2014 to August 1, 2014, EPC estimated a distribution revenue shortfall of $20.175 million and a transmission revenue shortfall of $11.748 million.[30] The Commission approved EPC's request to collect 60 per cent of EPC's shortfall, reducing the forecasted shortfall to $8.069 million of revenue for distribution and $4.699 million of revenue for transmission.

36. In determining the reasonableness of the requested amount, the Commission notes that it received no objection from interveners on this application and accepts EPC's submission that a collection of 60 per cent of both its forecast distribution and transmission revenue deficiencies is

[29] Exhibit No. 3, application, paragraph 40.
[30] Decision 2013-436, paragraphs 7 and 11.

sufficient to account for any potentially contentious elements of EPC's 2014 DTA and 2014-2015 GTA. The Commission recognizes that the combined shortfall of $24.489 million is approximately $7.5 million lower than the combined shortfall than requested in EPC's 2014 Interim Distribution and Transmission Tariff Application. The Commission finds that as the proposed rate increases are requested on an interim basis, rates will be trued up once the final 2015 rates for distribution and transmission are approved.

37. The Commission also considers that applying the interim distribution rate increase to all rate classes on an across-the-board basis continues to be a reasonable method that is simple and cost effective to apply, and preserves the currently approved rate structure based on EPC's last approved Phase II cost of service study.

38. Accordingly, the Commission finds that the collection of 60 per cent achieves a reasonable balance in recognition of rate stability and minimization of rate shock that might result on approval of final rates against the costs that underpin the interim rate increase, contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations. Consequently, the Commission approves the interim distribution and transmission rates as filed in this application effective January 1, 2015. The Commission approves:

- A 3.19 per cent interim increase to the distribution revenue requirement which represents 60 per cent of the 5.31 per cent applied for shortfall in the interim distribution revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $10.229 million to $4.090 million; and

- An interim increase to the interim transmission revenue requirement of 13.87 per cent which represents 60 per cent of the 23.11 per cent applied for shortfall in the interim transmission revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $14.260 million to $5.704 million.

39. In determining the level of interim rates for EPC, the Commission is not making any finding or determination with respect to any of the matters in EPC's 2014 DTA and 2014-2015 GTA, which is currently pending before the Commission.

40. The Commission has attached appendices 2 and 3 to this decision showing the interim distribution and transmission rates to be applicable on and after January 1, 2015, until replaced by subsequent decisions or orders of the Commission.

4 Order

41. It is hereby ordered that:

(1) The interim distribution tariff rates schedules attached as Appendix 2 to this decision are approved on an interim basis effective January 1, 2015.

(2) The interim transmission tariff attached as Appendix 3 to this decision is approved on an interim basis effective January 1, 2015.

Dated on November 12, 2014.

The Alberta Utilities Commission

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ENMAX Power Corporation (EPC) T. Carle R. Lottermoser
ATCO Electric Ltd. (AE) B. Yee L. Kerckhof
Alberta Electric System Operator (AESO) J. Martin R. Sharma
EPCOR Distribution & Transmission Inc. (EPCOR) J. Baraniecki G. Zurek N. Lamers
FortisAlberta Inc. (Fortis) T. Dalgleish J. Croteau M. Stroh J. Walsh

The Alberta Utilities Commission Commission Panel B. Lyttle, Commission Member Commission Staff G. Bentivegna (Commission counsel) P. Howard C. Runge J. Graham

Appendix 2 – Interim distribution tariff

(return to text)

Appendix 2 - Interim distribution tariff

(consists of 18 pages)

Appendix 3 – Interim transmission tariff

(return to text)



Appendix 3 - Interim transmission tariff

(consists of 1 page)



ENMAX POWER CORPORATION ("EPC")

DISTRIBUTION TARIFF

RATE SCHEDULE

RATES IN EFFECT AS OF JANUARY 1, 2015

EPC DISTRIBUTION TARIFF RATE SCHEDULE

Rate Code	Rate Description	Page
D100	Distribution Tariff Residential	4
D200	Distribution Tariff Small Commercial	6
D300	Distribution Tariff Medium Commercial	8
D310	Distribution Tariff Large Commercial – Secondary	11
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D700	Distribution Tariff Transmission Connected	20

DISTRIBUTION TARIFF

RESIDENTIAL

RATE CODE D100

Rate Schedule for the provision of Electricity Services to residential Customers of a Retailer.

ELIGIBILITY

1. Sites which use Electricity Services for domestic purposes in separate and permanently metered single family dwelling units with each unit either metered separately or incorporated into a common building with other units.
2. As a single phase or three phase wire service supplied at a standard voltage normally available.
3. Sites eligible under 1 and 2 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.427587
System Usage Charge	per kWh	$0.008896
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.019463

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. No more than one additional unit of living quarters within a single family dwelling, such as a basement suite equipped with cooking facilities, may be provided Electricity Services through one Meter under Rate Code D100. If the dwelling contains more than one additional self-contained unit of living quarters, a Commercial Rate will apply unless a separate Meter is installed for each unit.

   All new construction in R2 or higher density areas shall have a separate Meter for each suite, or alternatively the Electricity Services may be invoiced at the appropriate commercial rate.

2. If a Residential Site has a garage with a separate meter, the garage will be assigned a commercial rate.

3. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

SMALL COMMERCIAL

RATE CODE D200

Rate Schedule for the provision of Electricity Services to small commercial Customers of a Retailer.

ELIGIBILITY

1. Commercial Sites where the Energy consumption is less than 5,000 kWh per month (includes all unmetered services that are not Rate Code D500).

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.979551
System Usage Charge	per kWh	$0.007632
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.015905

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Temporary Construction/Service

   Construction and rental costs for necessary transformers and equipment required for any temporary Electricity Services (whether single or three phase, or

whether served from an overhead or underground source), shall be payable by the Customer to EPC in advance and based on an EPC estimate. Construction costs include costs associated with:

(a) up and down labour;

(b) unsalvageable material;

(c) vehicles; and

(d) equipment.

2. Temporary Connection Service

Where applied-for Connection Services are to be used for temporary purposes only, the Customer will pay EPC, in advance of the installation:

(a) EPC's total cost of installation and removal of the Facilities required for the temporary service; and

(b) the cost of unsalvageable material.

3. Unmetered Services

For unmetered services where individual energy consumption is small and easily predicted, estimated consumption will be based on equipment nameplate rating and operational patterns.

4. If a Site that qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

MEDIUM COMMERCIAL

RATE CODE D300

Rate Schedule for the provision of Electricity Services to medium commercial Customers of a Retailer.

ELIGIBILITY

1. For Sites whose Energy consumption is equal to or greater than 5,000 kWh per month for at least six of the last 12 invoice periods, provided a peak demand greater than 150 kVA was not registered twice in the previous 365 days.

2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$5.539776
Facilities Charge	per day per kVA of Billing Demand	$0.037608
System Usage Charge	per kWh	$0.004081
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.118081
Variable Charge	per kWh	$0.004047

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period;

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period; and

(c) "Contract Demand" is the kVA contracted for by the Customer.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Non-Standard Residential "Bulk-Metering".

2. Bulk Metering is the metering of multiple-unit residential occupancies under one corporate identity, (e.g., town housing, apartments, mobile home parks). Where bulk-metering exists, the Customer shall not re-sell electricity, but may include electricity as part of the rental charge and not separate therefrom.

3. Includes Medium Commercial Sites served at primary voltage that existed prior to November 2004 rate class changes.

4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

5. D300 Primary Voltage Service Customers

    a. For locations or buildings that receive primary voltage service, there will be a transformation credit of $1.335496 per day applied to the Service Charge, and a transformation credit of $0.009234 per day per kVA of Billing Demand applied to the Facilities Charge.

    b. The transformation credit is applicable only to D300 sites receiving primary voltage service prior to January 1, 2009.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - SECONDARY

RATE CODE D310

Rate Schedule for the provision of Electricity Services to large commercial (secondary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that registered a monthly peak demand greater than 150 kVA twice in the previous 365 days and served at secondary voltage.

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$16.089680
Facilities Charge	per day per kVA of Billing Demand	$0.098202
System Usage Charge On Peak	per kWh	$0.006604
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138805
Variable Charge On Peak	per kWh	$0.004574
Variable Charge Off Peak	per kWh	$0.003573

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer.

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all service supplied under this Tariff.

OTHER

If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - PRIMARY

RATE CODE D410

Rate Schedule for the provision of Electricity Services to large commercial (primary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that are served at primary voltage.
2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Facilities Charge	per day per kVA of Billing Demand	$0.013834
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138700
Variable Charge On Peak	per kWh	$0.004512
Variable Charge Off Peak	per kWh	$0.003525

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer,

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. The Customer is responsible for supplying all transformers whether owned by Customer or rented.
2. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.
3. Multi-Sites
   a) For Customers that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged based on Rate Code D410.
   b) For Customers that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged based on Rate Code D410 provided the service connections are:
      i) positioned on adjacent and contiguous locations;
      ii) not separated by private or public property or right-of-way; and
      iii) operated as one single unit.
4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

STREETLIGHTS

RATE CODE D500

Rate Schedule for the provision of Electricity Services to Customers of a Retailer.

ELIGIBILITY

For all photo cell controlled lighting services including all streetlights, traffic sign lighting, roadway lighting and lane rental lighting. Services with photo cell controlled lighting will not be eligible for a Meter.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
System Usage Charge	per kWh	$0.017490
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.016804

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE DISTRIBUTED GENERATION

RATE CODE D600

Rate Schedule for the provision of Electricity Services to Sites with on-site generation with a minimum export capacity of 1,000 kVA.

ELIGIBILITY

1. For services with on-site generation connected in parallel with the EPC Electric Distribution System with a minimum export capacity of 1,000 kVA.
2. For Electricity Services that are served at primary voltage.
3. For sites equipped with bi-directional interval recording metering.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Dedicated Facilities Charge	per day	customer specific
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs/Credits	$	Flow through

1. The customer specific Dedicated Facilities Charge daily amount will be determined as follows:

   Dedicated Facilities Charge = ((DFA + GA) x (CRF + OMA))/365 days.

Where:

a) DFA = current cost of dedicated feeder assets

b) GA = general assets associated with DFA and equal to 10.8% of DFA

c) CRF = Capital Recovery Percentage Factor based on EPC's weighted cost of capital and approved depreciation rate.

d) OMA = Operation, maintenance and administration factor equal to 3.1% of DFA.

The customer specific Dedicated Facilities Charge daily amount will be outlined in the Interconnection Agreement which will also include the term of the Agreement and an annual inflation adjustment.

2. The System Usage Charge will be determined using the net of the energy inflow and energy outflow at the Meter(s). System Usage Charge will be waived for sites that only have dedicated facilities and do not use the EPC primary feeder system.

3. "On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition), "Off Peak" is all Energy consumption not consumed in On Peak hours.

4. Flow-Through of ISO Costs/Credits will be determined by applying the ISO DTS rate (and any applicable riders) to the difference between the POD billing determinants with and without the site(s) billing determinants.

5. An initial fee will be charged for the incremental cost of bi-directional meter(s).

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of EPC form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

5. The Customer is responsible for supplying all transformers whether owned by customer or rented.

6. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.

7. Multi-Site Locations

   c) For locations or buildings that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged on Rate Code D600.

   d) For locations that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged on Rate Code D600.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

TRANSMISSION CONNECTED

RATE CODE D700

Rate Schedule for the provision of Distribution Access Service to Customers of a Retailer that are connected directly to EPC Facilities at a transmission voltage.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs	$	Flow through

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

TRANSMISSION RATE SCHEDULE

EFFECTIVE JANUARY 1, 2015

ENMAX POWER CORPORATION
RATE SCHEDULE
INTERIM 2015 TRANSMISSION TARIFF

ELIGIBILITY

To the Alberta Electric System Operator for use of ENMAX Power Corporation's Transmission facilities for the period

RATE

The Transmission tariff charged to the Alberta Electric System Operator is:

Monthly Charge:	$5,855,318.18

TERMS AND CONDITIONS

The terms and conditions of ENMAX Power Corporation form part of this rate schedule and apply to service supplied under this tariff.

2011 CarswellMan 390
Manitoba Public Utilities Commission

Manitoba Hydro, Re

2011 CarswellMan 390

The Public Utilities Act, Re

Interim Rates for Manitoba Hydro Effective April 1, 2011

Graham Lane Chair, Robert Mayer V-Chair

Judgment: March 30, 2011
Docket: 40/11

Counsel: None given

Subject: Public

Related Abridgment Classifications
For all relevant Canadian Abridgment Classifications refer to highest level of case via History.

Headnote

Public law --- Public utilities — Operation of utility — Rates — Fairness and impartiality

Public law --- Public utilities — Operation of utility — Rates — Miscellaneous

Table of Authorities

Cases considered by *Graham Lane Chair*:

Bell Canada v. Canadian Radio-Television & Telecommunications Commission (1989), 38 Admin. L.R. 1, [1989] 1 S.C.R. 1722, 60 D.L.R. (4th) 682, 97 N.R. 15, 1989 CarswellNat 586, 1989 CarswellNat 697 (S.C.C.) — considered

Statutes considered:

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Public Utilities Board Act, R.S.M. 1987, c. P280
s. 27 — referred to

s. 44 — referred to

s. 48 — referred to

s. 58 — referred to

***Graham Lane Chair*:**

1.0 Executive Summary

1 By this Order, the Public Utilities Board (Board), which heard submissions on March 9, 2011 from Manitoba Hydro (MH or Hydro) and Interveners as to whether the Board should approve a further interim electricity rate increase, approves an average 2.0 % interim rate increase, to be effective April 1, 2011.

2 The increase is to be applied to the energy rate across all customer classes with the exception of Area and Roadway Lighting which will not receive any interim rate increase at this time. As well, in applying this interim rate increase to the Residential Class, MH is to apply the Residential rate increase to eliminate the inversion and then keep the two energy block rates equal.

3 The Board is satisfied that a further interim rate adjustment is required ahead of an expected fall conclusion of MH's General Rate Application (GRA). This latest interim rate increase is expected to increase MH's annual revenue by approximately $22 million, while the interim increase implemented April 1, 2010 is estimated to have increased MH's annual revenue by approximately $33 million. Combined, the two interim rate increases should increase MH's annual revenue for the Utility's 2011/12 fiscal year by approximately $55 million.

4 The evidence before the Board, as of March 9, 2011, provides *prima facie* support for the granting of an interim rate increase as of April 1, 2011, although the increase approved herein is of 2.0%, that less than the 2.9% sought by MH.

5 From the evidence adduced to date, there is a reasonable basis for being concerned that MH's projected string of 3.5% annual rate increases (from 2012 through, to and including, 2021), and the interim increases granted in this General Rate Application (which collectively accumulate to an approximate 45% rate increase for consumers between 2011 and 2021) may, when finalized, be insufficient in light of MH's major capital development plans (which includes the construction of Wuskwatim, Keeyask and Conawapa Generating Stations and Bipole III transmission line). However, the GRA hearing is far from over, with much more evidence and testimony to be heard and considered.

6 The Board concludes, also on an interim basis, that MH's current ratepayers should share in the risks surrounding MH's

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major development plans with future generations of ratepayers, with the sharing of the risks to take place through higher rates to the current generation of ratepayers.

7 The Board's major concerns revolve around the Utility's Preferred Development Plan for MH's self described "decade of investment". The Plan, which includes the completion of Wuskwatim and the construction of Bipole III, Keeyask Generating Station and Conawapa Generating Station, was conceived some time ago.

8 However, since MH formulated its Preferred Development Plan, MH's future domestic load forecasts have been significantly reduced (pushing back the date new generation is required to meet domestic demand); the term sheets entered into by MH and its American counterparties have yet to be converted into firm contracts; short-term and spot export sales prices have fallen dramatically (to 2.3 cents per kilowatt on average for the past two years); and, there is a risk that if the present development plan is implemented sharper rate increases may be required of the Utility's Manitoba consumers than MH currently projects.

9 Following the conclusion of the GRA hearing, the Board intends to finalize all of its interim rate decisions related to MH; parties are aware that rates set on an interim basis may be confirmed or varied.

2.0 Background

10 On December 1, 2009 MH filed a GRA seeking 'across-the-board' 2.9% rate increases to be effective both on April 1, 2010 and April 1, 2011. On December 10 and 22, 2009 and March 12, 2010, the Board held Pre-hearing Conferences (PHC) to identify Interveners for participation in the GRA public process; whether and how to incorporate a review of MH's risks and risk management into the GRA process; and, to establish a timetable for the orderly exchange of evidence (to lead up to public hearings that, eventually, began in January 2011).

11 The Board granted Intervener status to Consumers' Association of Canada (Manitoba) Inc. and Manitoba Society of Seniors (CAC/MSOS); Manitoba Industrial Power Users Group (MIPUG); Manitoba Keewatinowi Okimakanak, Inc. (MKO); Resource Conservation Manitoba and Time to Respect Earth's Ecosystems (RCM/TREE); City of Winnipeg (City); and, Southern Chiefs Organization (SCO), collectively referred to as the "Interveners".

12 While the Board rejected an Application for intervener status from a former consultant to MH (the 'New York Consultant'/'NYC'), who made serious allegations of mismanagement and risk involving the Utility, the Board provided a role for the NYC. NYC's public document (setting out the NYC's allegations) was distributed to Interveners, placed on the public record and responded to by KPMG in a review engaged by MH.

13 At the PHCs in December 2009, when various timetables were discussed, it became clear that there was no agreement on the timetable that would facilitate the potential for final April 1, 2010 rate adjustments, should any be ordered by the Board.

14 Subsequently, the Board accepted a recommendation by RCM/TREE, supported by MH, that MH's rate increase

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request for April 1, 2010 be considered on an interim basis, pending finalization subsequent to the completion of the GRA process.

15 Accordingly, the Board held an Interim Rate Consideration Hearing on January 19, 2010, where the Board heard submissions from MH and Interveners as to whether interim rate adjustments should be made effective April 1, 2010, pending completion of the GRA hearing process. The Board subsequently granted interim rate increases effective April 1, 2010.

16 The Board also determined in 2010 that the oral evidentiary public hearing (a major component of the GRA proceeding) would consider, among other issues, MH's risks and risk management; revenue requirement; the cost of service study (a comparison of assigned revenues and costs employed in the consideration of whether rates are fair and reasonable); and, MH's general rate design.

17 The initial plan was for the hearing to begin in the summer of 2010, with a conclusion expected for the fall of that year. However, as a result of a number of events and factors, the major factor being the extensive range and complex nature of the issues to be considered, the oral hearing did not begin until early January 2011, and is now not anticipated to conclude (with a final GRA order) until the fall of this year, 2011.

18 With the revised expectation that the GRA would not conclude until long after April 1, 2011, and noting that MH has projected a rate increase which the Utility has factored into its long-term plans, the Board sought submissions from Interveners and MH with respect to possibly approving a further interim rate adjustment, that to take effect April 1, 2011. Submissions were received from MH and Interveners on March 9, 2011.

3.0 Intervener Positions

19 CAC/MSOS opposed interim rate increases effective April 1, 2011.

20 This Intervener submitted that in considering the setting an interim rate, the Board should consider regulatory precedent for the fixing of "just and reasonable" rates, citing *Bell Canada v. Canadian Radio-Television & Telecommunications Commission*, [1989] 1 S.C.R. 1722 (S.C.C.) paragraph 57, which states:

> ....The very purpose of interim rates is to allay the prospect of financial instability which can be caused by the duration of proceedings before a regulatory tribunal. In fact in this case the respondent asked for and was granted interim rate increases on the basis of serious apprehended financial difficulties. The added flexibility provided by the power to make interim orders is meant to foster financial stability throughout the regulatory proceeding. The power to revisit the period during which interim rates were in force is a necessary corollary of this power without which interim orders made in emergency situations may cause irreparable harm and subvert the fundamental purpose of ensuring that rates are just and reasonable.

21 CAC/MSOS noted that the underlying purpose of interim rates, always in the context of just and reasonable rates, is to foster financial stability for a utility throughout a regulatory process, so as to protect the utility against serious apprehended

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financial difficulties that could flow from an extended duration of a regulatory process.

22 Holding that there was no serious apprehended financial difficulty in the case of MH, CAC/MSOS opposed an April 1, 2011 interim rate increase while acknowledging that the Board has the regulatory discretion to grant an interim rate increase.

23 CAC/MSOS held that such discretion should only be exercised in circumstances where current rates are not just and reasonable, and recommended that in deliberating on whether to set interim rates the Board consider criteria based both upon case law and the Board's decision in Order 18/10:

- First, has the Board concluded that a lengthy delay in the regulatory proceeding is likely to take place?
- Secondly, has the tribunal reached the conclusion that there is an unusual financial need such that either a rate increase is necessary to allay the prospect of financial instability or address serious apprehended financial difficulties, which can be caused by the duration of the proceeding?; and
- Third, has the Corporation established a prima facie basis that the proposed interim rate is just and reasonable?

24 CAC/MSOS opined that MH's current financial condition is much improved from the Utility's prior forecasts, noting that MH's GRA is based on the financial forecasts of IFF-09-1, which indicated that MH would need an additional $33 million of revenue from domestic customers in 2010/11 and a cumulative additional $69 million for 2011/12. CAC/MSOS observed that MH's actual net income for 2009/10 was $39 million higher than MH's projection in its IFF-09 forecast.

25 In addition, CAC/MSOS noted that MH's updated forecasts for 2010/11 and 2011/12 (represented in the projections of IFF10) reflect an anticipated material improvement in MH's expectations for both net income and retained earnings for the two years (with retained earnings now projected to be $93 million higher than that forecast in IFF 09).

26 CAC/MSOS suggested that even if the 2.9% increase for April 1, 2011 sought by MH was not implemented, MH would still be materially better off (as measured by the level of projected retained earnings) as at March 31, 2012 than the Utility had originally forecast. Accordingly, CAC/MSOS submitted that MH's materially improved financial results neither support a conclusion of a state of financial instability nor that of a serious apprehended financial difficulty (to arise from a delay of the Board approving another rate increase for the Utility following the close of evidence).

27 CAC/MSOS further noted that MH's OM&A expenditures have risen materially over the years, and suggested that there was insufficient evidence to suggest effective cost management by the Utility. For CAC/MSOS, Hydro's improved financial position arises from rate increases and subpar forecasting.

28 CAC/MSOS also submitted that it would be premature for the Board, by approving an interim rate increase as of April 1, 2011, to partially pre-fund the Utility's Preferred Development Plan (particularly until there is greater certainty that the Utility's plan will unfold as planned). For CAC/MSOS, based on the record of the proceeding to-date, it is still unclear whether the export sales term sheets will become firm contracts, and even whether the construction of Keeyask Generating Station will prove to be an appropriate action and proceed.

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29 CAC/MSOS underlined its view of uncertainty associated with MH's Preferred Development Plan, listing three concerns drawn from the evidence of Mr. Rose of ICF (a witness engaged by the Utility), those being (a) natural gas prices and forecast prices are significantly (38-49%) lower than was the case in 2009 when the IFF-O9 was developed; (b) forecasts of the value of carbon emission allowances (expected by MH to assist the pricing of its exports) have been significantly downgraded — both in terms of the time frame within the value would be established and as to the likely magnitude of the assumed positive effect for Hydro's export pricing (the forecast carbon value now 40% to 60% lower than previously forecast); and, (c) the number of anticipated coal plant retirements in the MISO area — MH's export market, are now expected to be fewer than before.

30 CAC/MSOS observed that there is a significant amount of evidence yet to be provided in the hearing, including from the Independent Experts engaged by the Board and from Intervener witnesses.

31 CAC/MSOS, having fundamental issues with MH's GRA and holding that their issues have yet been fully tested, opined that it would be imprudent for the Board to make a directional judgment at this time, ahead of evidence yet to come. CAC/MSOS also contended that MH had failed to comply with Directive 4 of Board Order 32/09, which directed that an overall analysis of the risks faced by MH be carried out. CAC/MSOS noted that KPMG's study did not provide the comprehensive risk analysis requested by the Board.

32 CAC/MSOS further held that there would be a material risk that MH would draw the wrong inference from another interim rate approval, and that the granting of a 2.9% interim rate increase could be interpreted by the Utility as the Board approving its scenarios (as set out in IFF09 and IFF10), which incorporate its Preferred Development Plan, even though MH failed to comply with Directive 4 of Order 32/09.

33 CAC/MSOS also submitted that the sought interim rate increase should not be granted because Manitoba consumers are vulnerable, facing economic and employment uncertainty, citing that electricity and other cost increases are increasing pressure on household budgets, while wage settlements have not kept pace with inflation. CAC/MSOS further observed that MH's rate increases over the last seven years have exceeded the general rate of inflation, and suggested that the flow of rate increases should be "slowed".

34 CAC/MSOS concluded that the Board rejecting or moderating MH's proposed 2.9% interim rate increase would provide welcome relief to vulnerable consumers, and provide an opportunity for a more "sober" consideration of the issues, while sending a "message" to MH that it is not enough to rely on subpar forecasts and domestic rate increases to meet the Utility's projected future financial obligations.

4.0 MIPUG

35 MIPUG joined CAC/MSOS in opposing the granting of interim rate increases as of April 1, 2011.

36 MIPUG noted that while, in support of its interim rate request, MH had cited BC Hydro's high rate increases proposals, MH had not "featured" Hydro-Quebec's action of requesting a zero percent increase at this time.

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37 MIPUG stated that the Board has, to-date, only heard "one side of the story" and opined that a balanced view of the Utility's circumstances have yet to be presented, with, to this point in the proceeding, only Hydro's view and Hydro's evidence tested, and that only somewhat tested as cross-examination of Hydro's panel by Interveners has yet to occur. MIPUG also noted that none of the Interveners have had the opportunity of having their witnesses testify.

38 With respect to KPMG's risk review (KPMG's panel of witnesses was cross-examined by both the Board and Interveners), MIPUG noted that the review failed to quantify MH's risks (as sought by the Board in Order 32/09) and submitted that further rate increases should be halted until such time that there is sufficient evidence on the quantum and probability of MH's risks.

39 Also, MIPUG noted that the Board may be missing critical information that may reside in alternative IFF scenarios not provided by MH, and that identification and examination of alternative scenarios are required before a further interim rate increase is approved.

40 Noting the Board's reluctance for retroactive rate changes, MIPUG also submitted that the establishing of an across the board interim rate increase could create continued inequity for some classes - especially those with Revenue to Cost Ratios outside the Zone of Reasonableness.

41 MIPUG also submitted that a "special test" has to be met in considering whether to establish interim rates, and referenced *The Public Utilities Board Act*, particularly Sections 44, 27 and 48, the latter which states:

> The Board shall not make an order involving any outlay, loss, or deprivation to any owner of a public utility, or to any person without due notice and full opportunity to all parties concerned to produce evidence, and be heard at a public hearing of the Board, except in the case of urgency...

42 MIPUG also cited court cases that it submitted supported is position that an interim rate increase should not be granted. In particular, MIPUG relied on a *Bell Canada* case (also cited by CAC/MSOS), and set out the criteria used by the CRTC in considering interim rate adjustments, that being:

> The Commission considers that, as a rule, general rate increases should only be granted following the full public process contemplated by Part III of its Telecommunications Rules of Procedure. In the absence of such a process, general rate increases should not in the Commission's view be granted, even on an interim basis, except where special circumstances can be demonstrated. Such circumstances would include lengthy delays in dealing with an application that could result in a serious deterioration in the financial condition of an applicant absent a general interim increase.

43 MIPUG also referred to an Alberta Utilities Commission (AUC) decision dealing with interim rates. MIPUG reported that in AUC Order 2002-115, the Commission set out the factors to be considered in evaluating the merits of a proposed interim rate increase:

> These factors can be grouped into two categories, those that relate to the quantum of, and need for, the rate increase and those that relate to more general public interest considerations.

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44 The quantum and need factors cited by AUC, as reported by MIPUG, included: (a) that the identified revenue deficiency should be probable and material; (b) a response to the question of whether the interim increase was required to either preserve the financial integrity of the applicant or to avoid financial hardship for the applicant; (c) a response to the question whether the applicant could continue safe utility operations without the interim adjustment; and, (d) recognition that contentious costs could be excluded from the revenue requirement to be met.

45 MIPUG suggested that if all or a portion of the suggested rate increase appears appropriate after consideration of the above listed factors, the Board must then assess certain general public interest factors to see if a rate increase is justified, including the following: (a) whether Interim rates would promote rate stability and ease rate shock; (b) whether interim rate adjustments would help maintain intergenerational equity; (c) whether an interim rate increase was required to provide appropriate price signals to consumers; (d) whether deferring costs from being taken into account in determining revenue requirements should be considered to avoid interim rate increases; and, (e) whether, if an interim rate increase is to be approved, it is appropriate to do so on an across-the-board basis.

46 MIPUG suggested that the above considerations could be given different weighting depending on the specific circumstances, and held that in applying the above factors by MIPUG, MH does not meet the requirements for an interim rate increase.

47 MIPUG noted the following factors as not supporting MH having an urgent need for an interim rate increase: (a) MH's forecast electricity operations net income for 2010/11 and 2011/12 have increased from the $78 million and $87 million set out in IFF-09 to $149 million and $125 million in IFF-10; (b) MH's forecast electricity operations retained earnings for 2010/11 and 2001/12 has increased from the $2.261 billion and $2.331 billion forecast in IFF-09 to $2.354 billion and $2,279 billion in IFF-10; (c) MH's quarterly report for the three months ending December 31, 2010 indicates that export revenues for the first nine months of 2010 /11 were higher in both absolute dollar terms and average revenue per unit sold compared to the first nine months of 2009/10; (d) MH's IFF-10 forecast has short-term and long-term debt rates lower than that forecast in IFF-09; and, (e) MH's indicates water levels and water storage through December 2010 is both higher than was the case 2009, and well above average.

48 With respect to "Public Interest" factors, MIPUG noted that domestic consumers have been subject to a series of rate increases exceeding inflation over the past several years and, for MIPUG, current economic conditions considered from a public interest perspective suggest that ratepayers should not be burdened with an additional interim rate increase.

5.0 RCM/TREE

49 In addition to its oral submission of March 9, 2011, RCM/TREE provided a written submission supporting MH's request for an interim rate increase. This Intervener maintained that the Board has the legal jurisdiction and wide discretion, derived from statute, to make interim rate adjustments based on the facts before it.

50 RCM/TREE urged that a long-term view on rates be adopted, and advocated steady annual rate increases be implemented. The Intervener noted that MH's annual export revenues and net income levels are volatile because of water flows and varying export prices, and, by taking a long-term view, rate increases would not be a "start/stop" process based on the "fortunes" of the previous year.

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51 RCM/TREE envisions regular incremental increases, this to smooth the impact of meeting the higher capital costs of such new generation that is required for Manitoba growth. RCM/TREE submits that "skipping" an annual rate increase would not only deprive MH of needed additional income (during the Utility's "decade of investment"), but result in negative revenue impacts into the future by setting a lower baseline for future rate increases.

52 RCM/TREE also perceives MH's risks as asymmetrical, with the downside of revenue expectations during adverse conditions being more severe than variations to the positive side during favourable conditions, and recommended that rates be sufficient to allow for MH to create and maintain sufficient retained earnings to withstand future negative events.

53 RCM/TREE noted that its witnesses have yet to testify, and anticipated that one of its witnesses would make recommendations related to rate design. RCM/TREE suggested that the Board approve an interim increase now and adjust rate design and address cost allocation issues with the final Order. For RCM/TREE, if an interim rate increase were granted but the final Order failed to address cost of service and rate design issues, the result would perpetuate what the Intervener holds to be a suboptimal rate design.

54 With respect to any future Energy Intensive Industry Rate proposal (on two occasions, MH has submitted an application only to later withdraw it), RCM/TREE requested that it be included in the consultation process.

6.0 SCO

55 SCO submitted a written brief that requested that in any revision of rates, the quantum of the increase be set aside and earmarked for all Manitoba First Nations. The purpose of such segregation and designation of funds would be, in SCO's view, to offset any compensation required to be paid to First Nations as a result of the "negligent operations" of MH's projects and facilities. Any rate increase should, in SCO's view, be set-aside until an environmental assessment on MH's projects takes place and is concluded.

7.0 MH's Submissions

56 MH requested the Board approve an 'across all rate classes' interim rate increase of 2.9%, with the exception of the Area and Roadway Lighting class, effective April 1, 2011. For MH, the implications of a later implementation date would be that MH would either forego needed revenue or that a higher future rate increase will be required. For the Utility, any delay in the implementation of the sought-after rate increase will result in more pressure driving up the magnitude of a future rate increase.

57 MH noted that its proposal was modest compared to a recent application made by BC Hydro, which applied for a rate increase of 9.73% for each of the next three years (a cumulative increase of over 32% for fiscal years 2012 to 2014). MH stated that its long-term rate strategy involves regular and modest incremental rate increases; with the Utility holding that a 2.9% rate increase as of April 1, 2011 would be consistent with that goal. MH advised that it is mindful of the interest of its ratepayers and promotes gradualism in its rate applications.

58 MH submits that Intervener suggestions that MH must first demonstrate urgency or a serious apprehension of financial

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difficulties as a prerequisite for an interim rate increase are erroneous. MH maintained that there is nothing in legislation requiring a state of urgency or requiring MH to be in financial difficulty for the Board to approve an interim rate increase, noting that the Board has never accepted such a premise.

Term Sheets

59 With respect to the Utility's term sheets [with Minnesota Power (MP) and Wisconsin Public Service, (WPS)]; MH stated negotiations are continuing with significant progress taking place. MH held that both American customers remain strongly committed to proceeding with the proposed transactions and that a major factor delaying completion of the negotiations is defining required American transmission facilities, their associated costs, and the allocation of such costs.

60 MH indicated that transmission discussions have been undertaken with the CapX Group (Minnesota transmission-owning utilities), and, at the request of CapX, the new Manitoba-US major interconnection was identified in the fall of 2010 for inclusion in MISO's transmission expansion plan as a major regional transmission project (with the goal of it becoming an approved project in the 2012 MISO transmission expansion plan — if approved the cost of the transmission is to be "socialized", i.e. shared by all utilities within the MISO region).

61 MH reported that MISO filed (having received approval from FERC in December 2010) a modification of the MISO Transmission Tariff to include multi-valued projects (MVPs) that allow for cost regionalization of major regional transmission projects. If the MH transmission interconnection is approved as a MVP in the 2012 MISO transmission expansion plan, MH reported that would allow MP and WPS to conclude contract negotiations with MH such as to meet the revised and now current in-service dates for new MH generation.

Risk

62 In response to Interveners' claims that MH did not comply with risk related directives of Board Order 32/09, and with respect to assertions of Interveners that the KPMG report did not address Order 32/09, MH noted that there were very unique circumstances surrounding the commissioning of the KPMG report, and, that to suggest that the Board has not been provided with the "full picture" of the risks faced by the Corporation is, from MH's perspective, inaccurate.

63 MH reported that it has filed its full corporate risk management report, which identifies all of the major risks faced by the Corporation, and the ICF report. MH further cited the fact that the Board commissioned Independent Experts to produce a risk related report, with a wide scope. MH also noted that in addition, extensive interrogatories (IRs) have been filed and responded to, related to risk.

Load Forecast

64 MH observed (citing the economic downturn) that there have been significant reductions in its forecasts of the future load of industrial customers, claiming that the forecast reductions in industrial load will be significantly offset by expected increases in the remaining domestic load, in particular with respect to residential loads.

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65 MH also stated that the forecast industrial load growth reductions, indicated to be in the order of a fifteen year delay in reaching previously forecast future loads, would have little impact on forecast future domestic revenues because of the differences in unit prices within the different customer rate classes (the average industrial rate is about 3.7¢/kW.h, the residential rate is close to 7¢/kW.h).

Energy Intensive Rate Application

66 MH stated that the economic downturn also drove it's decision to defer filing a new application for an Energy Intensive Industrial Rate (EIIR) — the concept of EIIR is that large additional loads from industrial customers, billed now at an average rate of below 4 cents a kW.h, could result in "lost" incremental revenues as that same power could be sold on export to American counterparties at higher prices. (With the average export price now below 4 cents and with short-term or spot export sales as low as 1 cent, the premise behind the EIIR was challenged.)

67 MH reported having met with MIPUG and individual large customers on topics related to new industrial rates for new or additional loads. MH stated that numerous meetings were held throughout the spring, summer, and fall of 2010, culminating in a November 2, 2010 workshop presentation to which all MIPUG members were invited.

68 MH reported that a further workshop is planned for March 16, 2011, and this meeting would broaden consultation to include remaining customers served at voltages between 30 kV and 100 kV. MH further advised that its future consultations would include RCM/TREE, CAC/MSOS and the government.

69 Upon completion of stakeholder consultation, MH indicated it plans to file a new EIIR Application with Board.

OM&A

70 MH stated that there are various "uncontrollable" business cost drivers that have contributed to the Utility's OM&A expense increases that, the Corporation acknowledges, have exceeded the rate of inflation.

71 These "higher than inflation" expenses include increased maintenance costs due to aging infrastructure, higher environmental and regulatory requirements, costs related to customer additions and new facilities, higher pension costs (the result of investment fund performance and low interest rates), higher material and commodity prices, and higher employee costs (due to additional resource requirements and competitive wage pressures).

72 MH indicated it had taken steps to constrain the rate of increase in OM&A costs, including a hiring freeze (excepting for trainees and specific key personnel hires), limiting out-of-province travel and other measures. MH advised that the measures taken had been effective in reducing the year-over-year change in OM&A expenses in 2010/11, when compared to 2009/10. For the ten-month period ended December 31, 2010, MH reported that its restraint measures had avoided $16 million in costs.

International Financial Reporting Standards (IFRS)

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73 MH stated that the forecasts of IFF-10 reflect the most likely impacts of the expected and required conversion to IFRS accounting standards. The likely required changes include a reduction to capitalizing overheads (with a corresponding increase to operating costs) and an expected "write-off" to retained earnings of amounts previously capitalized or deferred (the latter including Demand Side Management ('DSM'), energy efficiency expenditures) but no longer allowed such treatment.

74 The adoption of IFRS will, according to MH, result in changes to the timing of the recognition of certain costs in MH's current operating accounts, and MH indicated that some mechanism may be required to defer recognition of these costs for rate setting purposes. In this regard, MH indicated that it would provide the PUB with alternatives to consider.

Debt to Equity Ratio

75 MH believes that its debt to equity ratio and the 25% equity ratio target continue to be important financial metrics to be considered in rate setting, particularly given planned future capital expenditures.

76 MH responded to questions raised by the Board as to whether Accumulated Other Comprehensive Income (AOCI) and Contributions In Aid of Construction (CIAC) should continue to be included in the determination of equity for use in calculating the debt to equity ratio.

77 MH stated that in as much as AOCI is a component of equity, in accordance with Generally Accepted Accounting Principles (GAAP), it is appropriate to include the balance as part of equity and as a component in the debt-equity calculation, noting that AOCI primarily reflects unrealized gains or losses associated with the translation of MH's U.S. dollar (United States currency, USD) debt. MH asserted that the translation of the USD denominated debt into Canadian dollar equivalents at each balance sheet date is important, and the result is the best indication of what that debt represents in Canadian currency at that point in time. (MH's exports sales to American counterparties are priced in USD, and if and as the Canadian dollar appreciates relative to the American dollar, the value of the exports in Canadian dollars decreases, offsetting over time currency gains that have and or may arise with respect to USD debt.)

78 MH further noted that rating agencies Standard & Poors and Moody's both accept AOCI as a component of equity for use in debt to equity calculations, and that, as well, both BC Hydro and Hydro Quebec include AOCI in their debt to equity determinations.

79 MH asserted that Contributions in Aid of Construction (CIAC) should continue to be included as an element of equity, to be taken into account in the determination of the debt to equity ratio, as it represents non-refundable contributions provided by customers towards service extension costs (CIAC amounts are non-refundable, are amortized into income at the same rate as the corresponding assets are depreciated, and do not represent liabilities of the Corporation.).

80 For MH, since the equity ratio measures the portion of the Corporation's assets that are not funded by debt, the inclusion of CIAC in equity conforms with the purpose of the equity ratio calculation.

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81 Nonetheless, MH advised that the debt to equity ratio at January 31, 2011 was 74/26, and that if AOCI were excluded from that calculation the ratio would change to 76/24, and, if CIAC was also excluded, the ratio would change to 78/22.

Pensions

82 With respect to the pension deficit (pension obligations less pension assets), MH stated that its pension fund investments have recovered since the economic and market downturn of 2008/09, and that the impact of the negative returns on pension investments in that fiscal year have been partially offset by positive returns since. As of March 31, 2010, MH reported an overall deficit obligation deficit of $89 million, and that it expected the deficit to decrease further by March 31, 2011.

83 MH further stated that the Civil Service Superannuation Board has considered seeking increases to both employer and employee pension contributions, but that no changes have yet been made by government.

84 MH further indicated that the International Accounting Standards Board (IASB) has issued an exposure draft, which, if approved, will require all pension gains or losses to be recorded directly into AOCI. As a result of the current level of deferred actuarial losses on the pension plan, the application of these accounting changes will have, according to MH, a relatively small negative impact on the Utility's debt to equity ratio in the short-term, with the effects expected to be fully offset in future periods due to either improved asset values, higher interest rates and/or future amortization of losses.

Upside vs. Downside Risk

85 With respect to the Board's questions as to: (a) whether there is appropriate sharing of risks between this generation and future generations of electricity ratepayers?; (b) is MH speculating (the word was not employed in a negative sense) on behalf of current ratepayers with the outcomes to be realized by future generations of ratepayers?; (c) as to how symmetrical the Utility's downside risk is in comparison to its upside risk?; and, (d) is it possible that higher rate increases may be required than forecasted in the future?

86 MH stated that answers to these questions are complex, and that the future is far from certain. That said, for the Utility to do nothing is not an option. For Hydro, the nature of its business demands that decisions be made far in advance of new supply requirements coming on-stream, this in order to provide for the continuance of the supply of energy needed to meet the requirements of the Province.

87 MH advised that it has been informed by the Minister Responsible for MH that it is the Government's intention to assign responsibility to an independent body to carry out a Needs and Justification assessment of MH's proposed major new generation projects, which, presumably, would include a review of alternate development approaches. MH indicated that it is confident that this upcoming review process will address any and all questions related to the "upside and downside" risks of development.

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Forecasting

88 With respect to concerns raised by CAC/MSOS related to MH's forecasts, MH acknowledged they are just that — forecasts, and that forecasts represent a view of the future based on "known" information. MH advised it cannot control conditions that will actually occur and which will cause variations to forecasts.

89 For MH, the one thing known with certainty is that actual results will be different from forecast.

MH's Conclusion

90 MH concluded its submission by repeating its request for an interim rate increase of 2.9% across all customer classes with the exception of Area and Roadway Lighting, to take effect April 1, 2011,

8.0 Board Findings

91 The Board acknowledges that the GRA hearing is far from over and that important new evidence and witness testimony is yet to come. As well, the Board further acknowledges that Interveners have yet to have the opportunity to cross-examine the MH panel or the witnesses that they, and the Board, have engaged. Finally, the Board acknowledges that its preference is to have concluded a GRA proceeding before approving rate changes.

92 This hearing is unique in the Board's regulatory history, and not only with respect to interim grid rate Orders awaiting finalization, along with an interim diesel rate decision, but also with respect to the complexities of the issues; the importance of the potential outcomes for ratepayers, the Utility and the Province; and, as well, this proceeding's length, scope, cost and public profile.

93 MH filed its GRA December 1, 2009, and in the normal course of events the hearing would have taken place and been concluded with a final rate order issued well before the summer of 2010.

94 Circumstances resulted in a lengthy delay in the commencement of the oral hearing, and while the importance of the matters before the Board have also contributed to the lengthy process, the facts are that MH has indicated plans to spend in the range of $20 billion in a "decade of investment", a plan that requires a need for massive new borrowings and, as it would appear, a decade of higher than inflation rate increases. MH projects that during the decade of investment it will seek annual rate increases of 3.5% each year, accumulating in the range of 45% in the 'decade of investment'.

95 CAC/MSOS is correct in noting that from 2004 on, MH's rates have increased by considerably more than the rate of inflation. However, it is also useful to take into account that before 2004, MH rates, other than industrial rates which actually fell, remained frozen for approximately a decade. It is also useful to note that since 2004, the Utility has had to confront a drought, which led to a loss in one fiscal year in excess of $400 million, a credit crisis and major global recession (which contributed to a reduction in demand and a fall in export prices), and with what some observers have portrayed as a "game

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changer"- new production techniques that have led to major new reserves of natural gas and plunging and now low natural gas prices (which has also contributed to lower export prices).

96 It has not been an uneventful decade for MH, and it would seem the next decade will be as equally challenging. MH plans a "decade of investment" and, ahead of new Manitoba domestic demand, the construction of major new generation and transmission assets to support the entering into major new export sales contracts with American counterparties, contracts yet to be finalized and which will involve both commitments and risks.

97 In the end, the results of MH's actions are of considerable significance to not only Manitoba and the Utility's customers, but to the overall Manitoba economy. If the new investments planned by MH do not generate the export revenues MH's expects, or if the costs of its planned investments exceed their current forecasts and are not able to be fully recovered by the now forecast domestic rates and export sales revenue then domestic rates will have to rise higher, and perhaps faster, than the levels now predicted by MH.

98 Contract and construction risks are not the only risks faced by MH. Already long identified by the Board and the Utility are risks including equipment failure, drought, currency fluctuations, interest and finance cost increases, market disruptions, load forecast variances, etc. etc.

99 For MH to be able to borrow at reasonable financial terms, the billions of dollars required to complete MH's plans for its decade of investment (billions of dollars to be guaranteed by the Province — MH borrowings may, if as projected, represent 50% or more of the Province's overall debt), lenders have to be confident with the Utility's plans and have assurances with respect to the future balances to arise out of Utility revenues and expenditures. So, the state of the capital structure of the Utility, now and into the future, is a very important matter.

100 While the GRA hearing is not over, with much evidence, testimony, cross-examination and final argument yet to come, the Board is cognizant of aspects of the Utility's financial circumstances and indications as to the revenue requirements for the future.

101 The Board has had regulatory responsibilities related to MH for many years, and is familiar with its practices, plans, forecasts and, to a significant yet limited degree, risks. In response to Interveners' views as to the ability of the Board to approve an interim rate increase and that approving an across-the-board interim increase could disadvantage certain classes, the Board finds:

a) that it has the necessary jurisdiction — urgency is not a required condition; and

b) the Board's comments in previous rate orders, which have advised that cost attribution is but one factor in the Board's determination of just and reasonable rates, stand.

102 Unlike the circumstances of the April 1, 2010 interim rate increase, the GRA is now well underway and while considerable evidence remains to be provided and tested, sufficient evidence is already on the record to justify the Board's consideration of granting another interim rate increase. MH has filed an extensive GRA (including its latest published annual report and financial forecasts), and thousands of interrogatories have been posed and responded to (involving MH, the Board,

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Interveners and expert witnesses).

103 As well, MH's witnesses from two consultancies engaged by MH (ICF and KPMG), have submitted briefs, testified and been cross-examined, and while Board Counsel had yet to complete the cross-examination of MH's panel of internal witnesses as at the date submissions were received on the question of an interim rate increase (and ahead of Interveners cross-examining the MH witness panel), a panel that includes MH's Senior Vice President and Chief Financial Officer, a considerable portion of the Board's cross-examination had been undertaken by March 9, 2011.

104 As to the evidence of witnesses engaged by Interveners and the Independent Experts engaged by the Board, reports have been filed, although the witnesses have yet to testify and be cross-examined.

105 Accordingly, having considered filings and submissions to and including March 9, 2011, the Board finds that the evidence received and considered to-date, supplemented by the submissions of the parties provided on March 9, 2011, provide *prima facie* justification for an interim 2.0% average rate increase, effective April 1, 2011.

106 The increase is to be applied to the energy portion across all rate classes, exempting the Area and Roadway Lighting class. MH is to apply the Residential rate increase to the first energy block rate, to eliminate the inversion and then keep the two energy block rates equal, effective April 1, 2011.

107 With respect to Area and Roadway Lighting (ARL), while the Board will again exempt the class from an interim rate increase to be applied to other classes of customers, it puts the ARL class on notice that further exemptions are far from assured. The Board will careful assess the revenue to cost ratio and other factors that apply to rate setting in determining the relative positioning of the ARL class' rates.

108 With respect to Residential rates, when the inverted rate was established, circumstances were different than what they are now. Natural gas prices were very high, so high that there was a risk that property owners would consider switching their heating source from natural gas to electricity and MH has yet to reflect consideration of home heating loads in its rate design.

109 There are rate design issues still to be considered with possible revision in the Board's final GRA Order.

110 In the remainder of the GRA Hearing and in its deliberations following closing argument, the Board will reassess its view on inverted rates for residential properties, particularly for those where gas heat is not an option.

111 With respect to rate differentiation between classes and overall rate design matters, MH's plans for massive capital spending and the Utility's projections of a series of annual rate increases of 3.5% extending over a decade, allows the Board ample opportunity to adjust the rates of individual customer classes if it deems such adjustments are necessary.

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112 A major component of this GRA is the identification and review of risks faced by MH, and how such risks should be reflected in consumer rates, and in what quantum and time. MH has testified that while current circumstances and results are important, the Utility's long-term prospects, with its planned new generating stations expected to have service lives of up to one hundred years, need to be taken into account.

113 MH's major capital expenditure development plans include the completion of Wuskwatim Generating Station (which, although originally forecast to cost $900 million, is now expected to cost $1.6 billion), the construction of Bipole III (MH indicates the proposed new transmission line and converter stations are required for reliability purposes — though also required if major new generating stations are built), and the construction of Keeyask Generating Station and then Conawapa Generating Station. MH's current long-term financial projections involve the expenditure in excess of $17 billion, to be funded by debt and projected accumulated net income.

114 If MH's major capital plan is implemented, the Utility's assets and loans will more than double over the period of approximately ten years. The major new assets to be constructed, three generating stations (the first, Wuskwatim, to be in service by the end of fiscal 2011/12) and Bipole III, will come at costs very much higher than the cost of generation stations and transmission facilities built in decades past.

115 With the construction of these assets, the cost per kWh of overall sold electricity will rise significantly, with the marginal cost being a multiple of the historical and present average cost.

116 MH's comparatively low rates for Manitoba consumers (the comparison being other Canadian and American electric utilities) are founded in large part on the relatively low undepreciated capital costs of the Utility's pre-2010 generation and transmission assets, for which annual amortization costs are very low and the original loans have either been fully paid off or considerably paid down, resulting in relatively low finance expenses. The last major generation station to come into service was Limestone, basically twenty years ago.

117 Another factor providing for low rates is MH's ongoing deferral and capitalization of expenditures incurred related to its construction development plans. Every year, approximately 1/3rd of MH's OM&A expenditures are capitalized or deferred, meaning these expenditures are neither considered current period costs nor taken into account in rate setting.

118 To avoid future deficits, the evidence suggests that if the Utility's present capital expenditure development plan is implemented, both domestic rates and export sales prices will have to rise significantly. As developments are completed and new assets put into service, expenditures previously capitalized or deferred, including those carried within Construction Work in Progress on the Utility's Balance Sheet, begin being recorded in the annual income statements as 'costs'. These costs include amortization of "capital" costs as well as the financial costs (interest and the Province's guarantee fee) and any operating costs associated with operating the then in-service asset.

119 A component of MH's currently projected future rate increases relate to the expectation of ongoing general economic price inflation, the other major component being the inclusion in annual "booked" costs, the costs noted above (again: amortization, financial and operating associated with new generation and transmission assets after they come into service).

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120 Another issue that plays, or may play, a significant role in the forecast of future rate increases is the Utility's debt to equity ratio, a financial test considered to be important by lenders, the Utility, the Board and Interveners. For a considerable period of time, the accepted target for the ratio is 75% debt to 25% equity. As developments proceed and expenditures are incurred, whether expensed in the period or deferred or capitalized, debt generally increases, placing downward pressure on the equity ratio. While it has been generally accepted that the target ratio is unlikely to be maintained through a development phase, when major expenditures are being incurred but the asset or assets being constructed are not yet in service and are, for the time period of development, non-performing assets, the target and the Utility's present actual ratio is still considered important and plays a role in rate setting.

121 The Board notes that circumstances have changed significantly, not only since the Utility's capital expenditure plans were formed as represented in IFF-09 and prior IFFs, but since MH filed its GRA and since the April 1, 2010 interim rate increase was implemented.

122 The changed circumstances include:

a) An increased awareness of the causes of and implications of "much" lower than expected natural gas prices (the implementation of new production methods has allowed for the economic extraction of natural gas from shale deposits, and the gas in the deposits discovered to-date has dramatically increased North American reserves — with this new supply source, the market price of natural gas has disconnected from its historical relationship to the price of oil and fallen to levels not seen for a decade or more);

b) Much reduced prices and bountiful supplies of natural gas has reduced the marginal cost of production of electricity from natural gas. With MH's major American export customers employing gas generation to meet peak demand, and, more recently, also base demand, the low natural gas prices are also driving down the prices MH has been receiving from its American export counterparties for non-firm short-term and spot export sales;

c) As indicated, MH's short-term and spot sales prices of electricity to American counterparties have fallen sharply, bringing the average price received for exported electricity to below 4 cents per kWh (short-term and spot sales have come at a price as low as 1 cent per kWh. and MH is unable to provide assurances that prices will "recover" in the near future);

d) With firm (contracted) export sales, at average prices less than 6 cents per kWh, remaining at volumes well within the capacity of MH's current hydro-electric generation, MH has confirmed that Wuskwatim's initial generation, which will come at an "all-in" price of 10 cents per kWh is unlikely to recover, at least initially, more than 3 cents per kWh. In short, Wuskwatim's initial generation is expected to produce losses rather than to contribute to net income;

e) As suggested from the Wuskwatim experience, the estimated construction costs for MH's planned major new assets (Bipole III's cost estimates are the subject of discussion, if not controversy, while the forecasts for the construction costs of Keeyask and Conawapa have increased substantially), affecting the price required by MH to make profitable export sales from or through the use of these new generating and transmission assets;

f) It would appear that the cost of Bipole III, mandated by the government to be constructed on the west side of the Province, has risen considerably from the initial estimate of $2.2 Billion — the Board understands that a large component of the anticipated increase in cost has to do with the required converter stations);

g) The Canadian dollar has strengthened against the American dollar, while this development reduced the cost of historical debt financed in U.S. dollars, and resulted in major "unrealized gains" on foreign exchange for MH with respect to U.S. denominated debt outstanding, it also has negative implications for the Canadian dollar value of exports to the United States, as those exports are priced in American dollars;

h) Political developments in the United States, and the decision of the Canadian government to follow "carbon"

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developments in America, has reduced the probability and/or quantum of a "carbon premium' being placed on MH's exports of "clean" hydro-electric electricity to the United States (again, if a carbon premium does come about, it is likely to come at a lower value and later date for that premium, than previously anticipated);

i) The risk of inflation is increasing, globally, including in Canada, and with inflation one would expect, eventually, higher interest rates;

j) Delays in the conversion of MH's term sheets with Minnesota Power and Wisconsin Public Service into binding contracts, leading to the "in service" date of Keeyask and Conawapa being delayed a year — the in-service date for Bipole III was previously set back five years, it is now expected to be in service in MH's 2017/18 fiscal year;

k) The Board has approved new interim rates for four isolated northern communities provided electricity by means of diesel generation, and, in doing so, has directed the absorption in MH's general accounts of the accumulated deficit on past diesel generation operations; indicated an intention to reduce the "tail block" rate for service to the communities over the next several years; and recommended that the grid be extended to the communities; and

l) The recession followed by a major pulp and paper company's closure, the announced closures of one mining company's smelter, and the announced planned closure of another smelter and a refiner in Northern Manitoba have contributed to reduced domestic load forecasts, resulting in delays in the requirement for Keeyask and/or Conawapa in service dates for domestic load requirements. MH has advised that it has already spent $400 million on its Keeyask Generation Station project, which is carried on the Utility's balance sheet as an asset — within the category 'construction work in progress', and that Hydro's ongoing present level of expenditures on its overall major development plans approximate $1 million a day, with that level of daily expenditure expected to rise considerably as the plans mature and further work is undertaken.

123 All of these expenditures are classified as "assets" (generally construction in progress) on the Utility's balance sheet, and the value of those assets going forward depends on the conversion of MH's term sheets with American counterparties into firm contracts containing adequate volumes, profitable pricing and other significant terms; a favourable outcome at an expected Needs and Justification Review (yet to be conducted), and the development of transmission in the United States, funded by either MH's American counterparties or the utilities of the region acting in concert.

124 While MH has indicated that economic conditions have improved in both Manitoba and in the MISO market overall, it has also reported, as indicated above, that a) its domestic load forecasts for future years have been scaled back, b) MH has withdrawn its application for Energy Intensive Industry Rates (EIIR), though the Utility has indicated continued consultations with industrial customers and a plan to make a new application at some point in the future, c) the term sheets entered into with MH's major American counterparties have been extended (MH has testified that negotiations are "going well" and the Utility anticipates the conditions required for successful sales will be met), and, d) that the Utility's projected "in service" dates for the two major generation projects, Keeyask and Conawapa, have been delayed a year.

125 Furthermore, and as indicated above, the Utility's forecasts for the costs of what it portrays as its "decade of investment" have increased significantly, with new higher cost forecasts for Keeyask and Conawapa and serious outstanding questions as to the expected cost of Bipole III (MH's current forecast for the construction of Bipole III is $2.2 billion, though other "unofficial" estimates, yet to be tested and/or confirmed by external experts engaged by MH, have ranged to $4.1 billion).

126 Until the GRA unfolds further, the Board sees MH's current GRA filings and evidence in a similar light to the Utility's prior interim rate request and Board Order 18/10 (which provided for a 2.9% interim rate increase, 2.8% when the exemption of Area and Roadway Lighting is taken into account, as of April 1, 2010): that is, replete with issues and concerns

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with numerous risk factors.

127 These risk factors include drought; changes in accounting standards, IFRS; illiquid equity — MH's balance sheet includes intangible assets, deferred and capitalized costs that may be subject to adjustment or expensing under IFRS; extensive capital plans — with rising cost estimates; decreased short-term and spot export sales prices; term sheets that are subject to renegotiation, to mention but a few.

128 The Board is not, at least yet, comfortable with either the Utility's methodology of determining its debt:equity ratio, which is one of the cornerstones of MH's alleged financial strength, or that the established target of 75:25 is adequate when the plans made would, if implemented, more than double the Utility's assets and debt obligations.

129 The Board notes that the present and forecast debt:equity ratio, agreed by MH as being important to credit rating agencies and lenders, also involves the inclusion of Accumulated Other Comprehensive Income (formed by unrealized gains on foreign exchange — debt outstanding in American currency). Those "gains" may well be "offset" by reduced export sales, as export prices are also in U.S. dollars.

130 Furthermore, MH has testified that if intangible assets, rate regulated assets and contributions in aid of construction were deducted from its equity, its debt:equity ratio would increase from the present 75:25 to approximately 80:20.

131 As well, the Board has concerns with the present circumstances of the term sheets; the ongoing spending of a million dollars a day based on the premise adequate firm export contracts will be developed; and whether intergenerational equity is represented in current rates, where current ratepayers are, in a sense, engaged in plans that involve risk, with the "cost" of those risks deferred to another generation of ratepayers.

132 With respect to the funds spent to-date and ongoing spending on the planned Keeyask generating station, those funds will be eventually "recovered" only if Keeyask is built and the export contracts that provide for its "advancement" (of its in service date) are adequate to avoid period losses. That said, the evidence to-date suggests that if built Keeyask may be expected to generate $500 million per year in costs but, as its entire output will, at first, expect to be exported, as domestic load growth is not expected to require Keeyask for well past its expected in service date, export sales revenue may develop only $300 million per year for at least the initial years, leaving $200 million to be met by domestic revenues.

133 A similar situation appears to apply to Conawapa, where the currently expected annual cost, once it is in service, is $700 million while MH currently forecasts only $550 million of revenue, leaving a further $150 million of annual deficit in the initial years to be, presumably, covered by domestic revenue.

134 As to Bipole III, dependent upon what the final cost to construct is, these costs will also need to be recovered from additional revenue. If the cost ends up in the range of $2 billion, the annual initial additional costs to be absorbed by additional revenue appears to be in the range of $200 million; if the cost is in the order of $4 billion, then the annual cost in the initial years will be in the $400 million range.

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135 Clearly, the long anticipated "Needs and Justification" review is required. Neither a date for that review has yet been set, nor an agency assigned to undertake that responsibility.

136 Such a review may require the commitment of MH's American export counterparties to new firm contracts and the building of new transmission in the United States to connect to MH's transmission at the border — the cost of the new American transmission may be $2 billion.

137 Again, the Board is concerned with meeting the need for intergenerational equity, with MH taking risks on behalf of current ratepayers that could contribute to higher rates (in comparison with inflation) rather than lower rates for future generations.

138 The Board is of the view that other development plans need to be considered as well as MH's present preferred development plan. While MH has assured the Board that its Preferred Development Plan will be implemented only if it proves out to be economically feasible, and that other development plans have been considered — such as building Conawapa but not Keeyask, or deferring both projects and constructing a combined cycle natural gas generation station in southern Manitoba — such alternative scenarios have not been fully tested.

139 One of the yardsticks by which various development scenarios should be tested is the implications for domestic rates. It is possible that MH's preferred development approach will not prove out to be the most optimal approach for its domestic customers; many of them lower income and many of them using electricity to heat their homes.

140 Looking out a decade, the Board notes that MH's forecasts assume 3.5% annual rate increases, commencing with April 2012, those projected increases being approximately twice the expected rate of inflation.

141 Based on the evidence before the Board at this stage in the Hearing, the Board is not "comfortable" or confident that MH's estimated series of annual 3.5% rate increases, although basically twice the rate of inflation, would recover the costs and meet the Utility's revenue requirements into the future, if the present development plan is implemented.

142 In the very short-term, MH has advised that it does not expect to achieve its most recent forecast net income for fiscal 2011, despite continuing good water conditions (above average), the shortfall largely attributable to lower than expected export sales prices for MH's short term and spot export market sales. In closing, while the Board appreciates that MH's revenues and expenses have not yet been fully tested, and that the GRA process, now underway, will afford the Board and Interveners the full opportunity to do so, there is more than enough evidence and "concern" to justify a further 2.0% interim increase. To avoid this interim increase would only increase the risk that a larger rate increase will be required after the hearing is concluded, providing the risk of rate shock for consumers.

143 As to the delays in concluding this hearing, the timing of the GRA process has been significantly extended from the usual duration of past experience, primarily due to the increased attention now being paid to MH's risks, that the result of a whistleblower's allegations and the resultant Board's review of MH's risk and risk management issues.

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144 The concerns of the Board with respect to MH's risks go back at least to 2004, and have last been fully enumerated in a number of Orders, including Orders 32/09 and 116/08. Despite the Board's focus on risks and directions to MH to file independent reports reviewing and quantifying its risks, MH has moved slowly, initially withholding risk reports received from their former NYC consultant, and failing to undertake the full risk review sought by the Board through MH's engagement of KPMG.

145 The extended timelines of the ongoing GRA is not an effort to deliberately delay 'just and reasonable rate increases'. The extended timeline is necessary to ensure all issues are properly explored, thereby, it is hoped, protecting the public interest in the long-term.

146 When the most important "commercial" asset of the Province, MH, is planning to, largely through debt (that debt to be guaranteed by the Province and likely represent more than 50% of the overall debt of the Province), engage in a "decade of investment" involving commitments to export customers that, in themselves, involve risk, setting rates so as to achieve just and reasonable rates for not only this generation of customers but also the ones that will follow is very important.

147 The Board considers it highly likely that public hearings will carry over at least into the summer of 2011, thereby delaying a final decision, not only with respect to the interim rates that took effect April 1, 2010 but also the further rate increases sought by MH for April 1, 2011.

148 Even without having the benefit of the full GRA, the Board does not accept the premise that ratepayers would be better off with delaying a further "relatively modest" (compared to future forecasts) increase on April 1 of this year.

149 This Board has repeatedly indicated that the financial health of the Utility is a factor to be considered in the Board's deliberations as to setting rates that are in the public interest. To the credit of all Interveners, they too value and support rates to sustain a financially solid Utility.

150 While the GRA is far from completed, the Board has sufficient information to see the increasing significance and importance of domestic (Manitoba) revenue, and the Utility's reliance on rate increases to support annual net income results and its overall capital structure.

151 That said, the interests of consumers are another factor that the Board must, and does, take into consideration in assessing the public interest. The economic conditions of the past year, and now, consist of trying times and challenges for consumers. That weighs heavy on the mind of the Board, which still awaits evidence in this hearing on measures and viable options towards addressing the particular payment and energy efficiency problems of lower income consumers.

152 While financial challenges lie ahead for MH, with its ambitious capital plans, those challenges and issues need to be reviewed taking into account the long-term and such a review has yet to be held. Yet, and despite prior Board Directives, MH has not pursued the required review of its capital plans and export intentions, all of which impact domestic rates. At this point in time, the Board is not confident that MH's preferred and forecast capital expenditure plans for the "decade of investment" represent the approach most likely to ensure the lowest rates possible for domestic Manitoba customers.

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153 And, if the further interim rate increase to be granted as of April 1, 2011 was to be deferred until the conclusion of the GRA, the rate increase required to recover the additional revenues would mathematically need to be higher to recover the additional revenues in the remaining months of MH's fiscal year 2011/12. The Board has previously stated its disapproval of "retroactive" rates or rate riders.

154 By this interim rate approval, the Board is protecting the short-term financial status of MH with the maintenance of adequate retained earnings. Examining MH's financial forecasts clearly disclose that domestic rate increases are required to keep MH producing annual net income results, without those regular increases, the forecasts suggests a string of annual deficits, even before the coming into service of major new generation and transmission assets, that with further rate implications.

155 After hearing all of the evidence and submissions in the GRA, the Parties to the hearing and ratepayers generally may be assured that if the Board concludes that the facts do not justify the imposition of the rate increases provided on an interim basis, the Board will adjust rates downward in the final GRA Order. Any amount collected found to be in excess of the rate in the final Order may be refunded/credited back to domestic customers, this to ensure consumers are protected in the longer term.

156 Interim increases to rates do not bind the Board, in any way, in making its final GRA rulings and directives. MH still bears the onus in its GRA to show that interim rate increases are just and reasonable.

157 The Board expects all Interveners to collectively explore and test fully all rate increase issues through the remainder of the GRA, together with all cost of service and rate design issues. The interim rate adjustments are to have no prejudicial affect on the ability of Interveners to argue, at the conclusion of the GRA hearing, that the rate increases and/or rate design, quite different from that awarded, ought to be approved by the Board in its final rate Order(s).

158 MH is to file Rate Schedules to conform with the directions of this Order.

159 Board decisions may be appealed in accordance with the provisions of Section 58 of The Public Utilities Board Act, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure (Rules). The Board's Rules may be viewed on the Board's website at www.pub.gov.mb.ca.

9.0 It Is Therefore Ordered That:

160

1. Manitoba Hydro's request for a 2.9% average rate increase, for all domestic customer classes (except Area and Roadway Lighting) served by MH, effective April 1, 2011, BE AND IS HEREBY DENIED;

2. Manitoba Hydro is to implement a 2.0% average and interim rate increase for all domestic customer classes (except Area and Roadway Lighting) through an increase to the energy portion of consumer rates, and, with respect to Residential rates, the rate increase is to be applied to the first energy block rate to eliminate the inversion and, then, keep

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the two energy blocks equal;

3. Manitoba Hydro is to provide the Public Utilities Board with revised interim Rate Schedules for all electricity consumed on and after April 1, 2011, together with Proof of Revenues, prepared in accordance with the directives in this Order;

4. This Order shall remain interim until confirmed, varied or otherwise dealt with by further Order of the Board.

End of Document

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New Brunswick | Newfoundland and Labrador | Nova Scotia | Prince Edward Island

February 18, 2015

VIA COURIER and ELECTRONIC MAIL

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

Attention: Ms. G. Cheryl Blundon
Board Secretary

Dear Ms. Blundon:

RE: Newfoundland and Labrador Hydro's Application for 2015 Interim Rates for March 1, 2015

Enclosed are the original and twelve (12) copies of Vale's Written Submissions in respect of the above-noted Application.

We have provided a copy of this correspondence together with enclosures to all concerned parties.

We trust you will find the enclosed satisfactory.

Yours faithfully,

Thomas J. O'Reilly, Q.C.

TJOR/js
Encl.

c.c. Geoffrey P. Young, Senior Legal Counsel, Newfoundland & Labrador Hydro
Gerard Hayes, Senior Legal Counsel, Newfoundland Power
Thomas J. Johnson, O'Dea Earle
Paul Coxworthy, Stewart McKelvey
Edward M. Hearn, Q.C., Miller & Hearn
Senwung Luk, Olthuis, Leer, Townshend LLP
Yvonne Jones, MP Labrador
Genevieve M. Dawson, Benson Buffett

Thomas J. O'Reilly, Q.C. | Partner
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Suite 1000 Scotia Centre 235 Water Street St. John's NL A1C 1B6

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

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro, pursuant to Sections 70 and 75 of the *Act*, for the approval of customer electricity rates, rules and regulations on an interim basis to become effective March 1, 2015 (the "2015 Interim Rates Application").

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

WRITTEN SUBMISSIONS OF VALE NEWFOUNDLAND & LABRADOR LIMITED

The following are the submissions of Vale Newfoundland and Labrador Limited ("Vale") in relation to Newfoundland and Labrador Hydro's ("Hydro") Application before the Board seeking an Order for interim rates for, among others, Island Industrial Customers effective March 1, 2015. Vale's submissions will address the following issues:

i) The Industrial Customer interim rates requested by Hydro;

ii) Hydro's proposed recovery of the $6.8 million balance in the Industrial Customer RSP Fuel Component from the Industrial Customer's portion of the RSP Load Variation Component and the Industrial Customer RSP Surplus;

iii) The phase-in of industrial customer rates; and

iv) Costs.

Issue i): Interim Rates

Vale accepts that Hydro requires some form of interim rate relief subject to Hydro demonstrating through evidence filed as part of Hydro's Amended 2013 General Rate Application (the "GRA") that the interim rates reasonably reflect the Cost of Service. Without interim rates, there is a significant risk that the current rates will not be sufficient for Hydro to recover its cost of service. A discrepancy between current rates and cost of service will result in a revenue deficiency being created in 2015 by Hydro's 2015 customers that Hydro will seek to recover from its 2016 (and future year) customers. If the Island Industrial Customer Class were to remain stable over time, this would not by an issue. However, the makeup of the Island Industrial Customer Class is changing radically over time with (a) Vale ramping up into production in a manner that will make it Hydro's largest industrial customer within a short period of time and (b) to the best of Vale's knowledge, Teck Resources, which is benefiting from current rates, closing its operations in 2015. As such, if present day deficiencies are recovered from future customers, there will inevitably be intergeneration inequity in that the changing dynamic within the Island Industrial Customer Group:

i) will result in a customer responsible for contributing a small percentage to the accumulating deficiency repaying the largest percentage of that deficiency; and
ii) could result in an industrial customer that benefited from the rates that created the deficiency ceasing operations before its portion of the deficiency is repaid through a rate rider.

For the reasons stated, Vale submits that Hydro should be granted interim rates to reduce the potential for intergenerational inequity created by changes within the Island Industrial Customer Group. As the evidence supports Hydro's submission that a revenue deficiency is accumulating, fairness dictates that an Order for interim rates should become effective at the earliest possible date. As discussed in detail in response to TIR-CA-NLH-0001, maintaining generational equity is one of the factors demonstrating a need for interim rates.

Vale also supports Hydro's proposed method of calculating interim rates by adjusting the forecast cost of No. 6 fuel to $65.63 per barrel from the 2015 test year cost of $93.32 per barrel. This adjustment has the benefit of reducing the potential for rate shock and ensures that interim rates are based on the most up to date data on fuel cost.

<u>Issue ii): Recovery of the $6.8 Million Balance in the IC RSP Fuel Component</u>

In its application, Hydro has proposed recovery of the $6.8 million balance in the Industrial Customer's RSP Fuel Component by:

i) dividing the current balance on the RSP Load Variation Component ($37.6 million) based on energy ratio allocation and applying the Industrial Customer's portion ($2.1 million) to reduce the balance in the Industrial Customer's RSP Fuel Component to $4.7 million; and

ii) taking the remaining $4.7 million balance in the Industrial Customer's RSP Fuel Component from the Industrial Customer RSP Surplus ($10.9 million) with the

remaining balance of the Industrial Customer RSP Surplus being used to phase in Industrial Customer rates.

Vale supports Hydro's proposed method for recovery of the $6.8 million balance in the Industrial Customer's RSP Fuel Component. By using current RSP balances owing to customers to offset balances currently owing to Hydro, Hydro reduces or eliminates the potential for intergeneration inequity created by the use of future rate riders to recover past balances. Vale submits that the use of future rate riders to collect balances owing to the utility should be a measure of last resort and only approved in limited circumstances.

Issue iii): Phase in of Industrial Customer Rates

Hydro has provided two alternatives for the use of the Industrial Customer Surplus to phase in Industrial Customer rates. Under the first alternative, the Industrial Customer Surplus would be used to offset 85% of industrial customer base rates (which include firm energy charges, demand charges and specifically assigned charges) increases from March 1, 2015 to December 31, 2015 and 60% of base rate increases from January 1, 2016 to September 1, 2016. Under the second alternative, the Industrial Customer Surplus would be used to offset a flat 73% of base rate increases from March 1, 2015 to September 1, 2016. Hydro has recommended that the Board accept the first alternative on the basis that it limits the maximum impact of any one rate change to approximately 10%.

Vale submits that alternative two is preferable to alternative one as it reduces the number of rate changes experienced by industrial customers over an 18 month period from three (under alternative one) to two. The increased rate stability provided by alternative two is preferable for industrial customer's budgeting purposes. The only downside to alternative two is that the maximum rate impact increases from 10.2% under scenario one to 12.7% under scenario two [see Table 2, page 9 of Hydro's Evidence]. Vale submits that the difference in rate impact is marginal and is offset by the benefit of the increased rate stability that results from alternative two.

Issue iv): Costs

Vale requests that the Board award Vale its costs on the within Application on the same basis as any award of costs made in favor of the Consumer Advocate and/or the Industrial Customer Group. An award of costs in favor of Vale is justified based on the fact that:

i) Vale's energy consumption is steadily increasing with time and, when Vale's Long Harbour processing facility completes production ramp up, Vale will be the single largest industrial customer of Hydro. As such, Vale had a significant interest in participating in the within Application; and

ii) Vale's interests in the within Application are discreet from the interests of the Industrial Customer Group.

The within Application was made necessary by the complexity of and delays in the general rate application process as a result of the fact that Hydro elected to allow

seven years between GRAs. For this reason, Vale submits that all or a significant percentage of the costs of the within Application should be borne by Hydro and should not form part of Hydro's rate base.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 18th day of February, 2015.

COX & PALMER

Per: _____
Thomas J. O'Reilly, Q.C.

TO: The Board of Commissioners of Public Utilities
Suite E210, Prince Charles Building
120 Torbay Road
P. O. Box 21040
St. John's, NL A1A 5B2
Attention: Board Secretary

TO: Newfoundland & Labrador Hydro
500 Columbus Drive
P. O. Box 12400
St. John's, NL A1B 4K7
Attention: Geoffrey P. Young
Senior Legal Counsel

TO: Newfoundland Power
55 Kenmount Road
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TO: House of Commons
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Attention: Yvonne Jones, MP Labrador

TO: Genevieve M. Dawson
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February 25, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - 2015 Interim Rates Application

Enclosed please find the original plus 12 copies of Newfoundland and Labrador Hydro's reply to parties' submissions with regard to the above noted application.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Senwung Luk – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn
Genevieve M. Dawson – Benson Buffett

SUBMISSION AND REPLY OF

NEWFOUNDLAND AND LABRADOR HYDRO

2015 Interim Rates Application

February 25, 2015

newfoundland labrador hydro
a nalcor energy company

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

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro, pursuant to Sections 70 and 75 of the *Act,* for the approval of customer electricity rates, rules and regulations on an interim basis to become effective March 1, 2015 (the 2015 Interim Rates Application).

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

SUBMISSION AND REPLY OF NEWFOUNDLAND AND LABRADOR HYDRO

The following is Newfoundland and Labrador Hydro's (Hydro) submission and its reply to the parties' submissions with regard to the above-noted application.

1.0 Application Background

On July 30, 2013, Hydro filed its General Rate Application (GRA) seeking approval of rates for January 1, 2014, based on a 2013 Test Year, in accordance with a government directive. Hydro subsequently filed two applications for interim relief recognizing that delayed rate implementation would deprive Hydro of the opportunity to earn a just and reasonable return on rate base for 2014. Both of these applications were denied. On June 6, 2014, Hydro notified the Board of Commissioners of Public Utilities (the Board) and the Parties that it would be filing an amended GRA in the fall of 2014 based on updated financial information. It became apparent to Hydro that because of changes in its forecast costs since filing the 2013 GRA, the prudent course of action was to update the evidence in its 2013 GRA to derive rates based upon 2015 forecast costs. The stipulation in the Order in Council which required the use of a 2013 Test Year for the GRA was rescinded effective October 30, 2014.

On November 10, 2014, Hydro filed its Amended General Rate Application (the Amended Application) with the Board. In its Amended Application, Hydro requested that the proposed customer rates be approved on an interim basis in advance of completing the GRA. Hydro also proposed revised Rate Stabilization Plan (RSP) Rules to become effective on an interim basis on January 1, 2015 to permit the continued phase in of the Island Industrial Customer (IIC) rates.

On November 28, 2014, Hydro filed an application requesting approval of the deferral and recovery of $45.9 million in revenue deficiency for 2014. The creation of a deferral account to address Hydro's 2014 revenue deficiency of $45.9 million was approved by the Board. In addition, Hydro's application regarding increased capacity-related supply costs of $9.6 million, dated October 8, 2014, was approved for deferral by the Board.

On December 24, 2014, Hydro was directed by the Board to file a comprehensive and complete interim rates application for rates to be charged effective March 1, 2015. In accordance with this direction from the Board, Hydro filed its 2015 Interim Rates Application on January 28, 2015, for an interim order from the Board as to rates to be charged to Hydro's IIC, Newfoundland Power (NP) and Hydro's Rural Customers, as well as changes to the RSP Rules to implement the phase in of changes to the IIC rates.

Since Hydro filed its Amended Application on November 10, 2014, the forecast cost of No. 6 fuel at Holyrood has decreased materially. Hydro's Amended Application was based upon an average No. 6 fuel of $93.32 per barrel while the most recent fuel forecast provided by PIRA indicates an average fuel cost of $65.63 per barrel for 2015. Based upon the 2015 Test Year forecast, the revised fuel cost reduces Hydro's 2015 Test Year Cost of Service by approximately $73 million. As such, the proposed increase to customer rates in 2015, as requested in Hydro's Amended Application, is no longer supported by the 2014 fuel cost forecast. Given the change in No. 6 fuel price was material, Hydro subsequently reflected the 2015 fuel cost reduction in this 2015 Interim Rates Application. In its written

submission dated February 18, 2015, Vale has indicated that it supports the adjustment of the fuel forecast of No. 6 fuel as this adjustment has the benefit of reducing the potential for rate shock and also ensures that interim rates are based on the most up to date information. Hydro also notes that none of the intervenors have submitted that they disagree with Hydro's adjustment of the forecast fuel cost of No. 6 fuel.

As stated in Hydro's letter to the Board dated February 17, 2015, Hydro wishes to clarify that it is its submission and intent that all of this evidence (the evidence filed with the Amended Application and the evidence and information filed with the 2015 Interim Rates Application) is properly before the Board and may be considered by it for its present purposes of considering the application for an interim order. The evidence that accompanied the Amended Application forms the foundation for the evidence filed with the application for an interim order. The evidence filed with the application for an interim order supplements and, for the limited purpose of the application for interim rates, modifies the Amended Application evidence with respect to the fuel cost change and the effects that flow from it.

2.0 Hydro's Interim Rate Application Proposals

Hydro's response to TIR-PUB-NLH-001 provides a detailed explanation of each proposal that has been changed in the 2015 Interim Rates Application from the Amended Application, and the customer impacts of Hydro's 2015 Interim Rates Application.

3.0 Regulatory Practice and Board Authority

Hydro respectfully submits that there is legal precedent in this province to support the Board's broad discretion in approving rates, tolls, and charges for utilities. Further, Hydro submits that such decisions should be based on generally accepted sound public utility practice.

As stated by Green J.A., as he then was, in *Reference Re Section 101 of the Public Utilities Act (Nfld)* (1998), 164 Nfld & PEIR 60 (NLCA) (the *Stated Case,* at tab 1) at para 13:

> [13]…The Board is a creature of statute and its jurisdiction and powers to deal with matters before it , and the manner of dealing with such matters, must be found, expressly or impliedly, within the statutes conferring jurisdiction on and governing the operation of the Board.

This was confirmed and restated by the Newfoundland and Labrador Court of Appeal in *Newfoundland and Labrador Hydro v. Newfoundland and Labrador (Board of Commissioners of Public Utilities)*, 2012 NLCA 38 (the *RSP Appeal,* at tab 2) at paragraph 53. In describing the Board's jurisdiction and powers, the Court of Appeal in that decision stated:

> [54] The Board's jurisdiction and powers are governed by the PUB Act and the Electrical Power Control Act, 1994, SNL 1994 c. E-5.1 ("EPC Act"). The PUB Act confers on the Board the power for "the general supervision of all public utilities". Specifically the Board has sole authority to approve the rates charged by public utilities – ss. 70(1) and 71 – and the power to approve interim rates unilaterally – s. 75. The breadth of the Board's authority over rates is illustrated by s. 76 which confers the right to rescind or alter rates, s. 82 which confers the right to investigate a rate, where the Board believes that it is unreasonable or unjustly discriminatory, and ss. 84-87 which authorize the Board, following a formal complaint, to investigate and to cancel rates and void contracts where rates are found to be unjust, unreasonable, insufficient or unjustly discriminatory.
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> [55] In considering the extent of the Board's powers under the PUB Act reference must be made to s. 118 which states:
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> > 118.(1) This Act shall be interpreted and construed liberally in order to accomplish its purposes, and where a specific power or authority is given the board by this Act, the enumeration of it shall not be held to exclude or impair a power or authority otherwise in this Act conferred on the board.
> >
> > (2) The board created has, in addition to the powers specified in this Act, all additional, implied and incidental powers which may be appropriate or necessary to carry out all the powers specified in this Act.
>
> …..

> [56] The EPC Act states the electrical power policy of the province in s. 3. It obligates the Board to implement that policy as it carries out its duties and exercises its powers under the PUB Act and in so doing s. 4 requires the Board to apply tests which are consistent with "generally accepted sound public utility practice".

It is clear from the sections of the *Public Utilities Act*, the *Electrical Power Control Act* (EPCA) and the court decisions referenced above, that in interpreting and applying the acts, a literal and technocratic interpretation should be avoided *"in favour of an interpretation which will advance the underlying purpose of the legislation, as well as the power policy of the province and be consistent with generally accepted sound public utility practice."*[1]

The Court of Appeal in the *RSP Appeal,* then went on to identify generally accepted principles of sound public utility practice applicable to the interpretation of the *Public Utilities Act* and the ECPA. At paragraph 57 (tab 2), relying on the *Stated Case,* the Court of Appeal stated:

> [57] In the Stated Case Green J.A. stated some of the general principles applicable to the interpretation of the PUB Act and EPC Act as follows:
>
> > [36] …
> >
> > 1. The Act (PUB Act) should be given a broad and liberal interpretation to achieve its purposes as well as the implementation of the power policy of the province;
> >
> > 2. The Board has a broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the purposes of the legislation and to implement provincial power policy;
> >
> > 3. The failure to identify a specific statutory power in the Board to undertake a particular impugned action does not mean that the jurisdiction of the Board is thereby circumscribed; so long as the contemplated action can be said to be "appropriate or necessary" to carry out an identified statutory power and can be broadly said to

[1] *Reference Re Section 101 of the Public Utilities Act (Nfld)* (1998), 164 Nfld & PEIR 60 (NLCA) at para 18 (the *Stated Case*, tab 1).

advance the purposes and policies of the legislation, the Board will generally be regarded as having such an implied or incidental power;

4. In carrying out its functions under the Act, the Board is circumscribed by the requirement to balance the interests, as identified in the legislation, of the utility against those of the consuming public;

5. The setting of a "just and reasonable" rate of return is of fundamental importance to the utility and must always be an important focus of the Board's deliberations; however, the "entitlement" of the utility to a just and reasonable rate of return does not guarantee it that level of return. The "entitlement" is to have the Board address that issue and to make its best prospective estimate, based on its full consideration of all available evidence, for the purpose of setting rates, tolls and charges;

6. The Board has jurisdiction, which will not generally be interfered with on judicial review, to make a determination of what is a just and reasonable rate of return within a "zone of reasonableness" and in so doing is not constrained in its choice of applicable methodologies, so long as they can be rationally justified in accordance with sound utility practice and are not inconsistent with the achievement of the purposes and policies of the legislation.

[58] Though the Stated Case concerned a utility's rate of return, the principles stated above, including those in sub-paragraphs 5 and 6, apply in a similar manner to the determination of rates for a utility's customers.

3.1 Jurisdiction to award Interim Rates

Section 75 of the *Public Utilities Act* provides that the Board has jurisdiction to make an order with respect to interim rates. Section 75 reads as follows:

Interim order

75. (1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.

(2) The schedule of rates, tolls and charges approved under subsection (1) are the only lawful rates, tolls and charges of the public utility until a final order is made by the board under section 70.

(3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be

(a) refunded to the customers of the public utility; or

(b) placed in a reserve fund for the purpose that may be approved by the board.

This authority was recognized by the Board in a recital in Order No. P.U.41(2006):

> Whereas section 75 of the Act provides that the Board may make an interim order unilaterally and without public hearing or notice, approving with or without modification a schedule of rates, tolls and charges submitted by a public utility upon the terms and conditions that it may decide;[2]

This authority was also confirmed by the Newfoundland and Labrador Court of Appeal in the *RSP Appeal,* with reference to a decision of the Supreme Court of Canada. At paragraph 61 (tab 2) of its decision, the Court of Appeal stated:

> [61] The power of the Board to authorize interim rates is granted in s. 75 of the PUB Act. That section allows the board to set rates expeditiously without full evidence and submissions, such rates being subject to review and possible modification in the final order of the Board, as is expressly provided for in subsections 75(2) and (3). Depending on the nature of the final order of the board it may have a retroactive or retrospective effect. In Bell Canada 1989, Gonthier J. stated:
>
> > The statutory scheme established by the Railway Act and the National Transportation Act is such that one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order. I hasten to add that the words "further directions" do not have any magical, retrospective content. Under the Railway Act and the National

[2] Order No. P.U.41(2006), at page 4, at lines 17 to 20

> Transportation Act, final orders are subject to "further [prospective] directions" as well. It is the interim nature of the order which makes it subject to further retrospective directions.
>
> (p. 1752)
>
> …The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits. As was stated in obiter in Re Eurocan Pulp & Paper Co. and British Columbia Energy Commission (1978), 87 D.L.R. (3d) 727 (B.C.C.A.), with respect to a similar though not identical legislative scheme, the power to make interim orders effectively implies the power to make orders effective from the date of the beginning of the proceedings. In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return yielded by the interim rates and the rate of return allowed in the final decision for the period during which they are in effect so as to achieve just and reasonable rates throughout that period.
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> (p. 1761)

3.2 Alberta Utilities Commission Interim Rates Test

The Consumer Advocate, IIC Group, NP, and Vale all agree that the Board has the jurisdiction to award interim rates. While the Board has this jurisdiction, there is no defined test in Newfoundland and Labrador to determine what Hydro must prove in order to achieve interim rates. The Consumer Advocate, in its submission, proposes that the "*Board apply the interim rates test used by the Alberta Utilities Commission.*"[3] Hydro agrees with the submission of the Consumer Advocate.

[3] Consumer Advocate's written submission, dated February 18, 2015, at page 2.

NP indicated in its written submission in this matter that it does not disagree with the test proposed by the Consumer Advocate. Further, NP highlighted the application of the Alberta Utilities Commission (AUC) test in their submission, referring to a December 19, 2008 decision regarding interim rates for ATCO Electric. As noted in the Consumer Advocate's submission, NP's own interim rates application dated November 20, 2009 would not have passed this test, nor did NP attempt to apply the AUC test from the ATCO decision in its interim rates application. In Hydro's response to TIR-CA-NLH-001, Hydro submitted that its interim rates application meets the requirements of this two-part test.

As noted in the Consumer Advocate's submission and in TIR-CA-NLH-001, the AUC has established a two-part test applicable to interim rate applications. This test was confirmed and used to evaluate the interim rates application of ENMAX Power Corporation (EPC).[4] The test, as set out in Decision 2014-311, includes two parts. The first part of the test relates to quantum and need, and includes the following considerations:

i. Is the identified revenue deficiency probable and material?
ii. Can all or some portion of any contentious items be excluded from the amount collected?
iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
iv. Can the applicant continue safe utility operations without the interim adjustment?

The second part of the test relates to the public interest and includes the following considerations:

i. Will the interim rates promote rate stability and ease rate shock?

[4] "Enmax Power Corporation; 2015 Interim Distribution and Transmission Tariff Application" dated November 12, 2014 http://www.auc.ab.ca/applications/decisions/Decisions/2014/2014-311.pdf. (tab 3)

ii. Will the interim adjustments help to maintain intergenerational equity?

iii. Can the interim rate increases be avoided through the use of carrying costs?

iv. Are the interim rate increases required to provide appropriate price signals to customers?

v. v. Is it appropriate to apply the interim rider on an across the board basis?

EPC originally filed an application with the AUC requesting approval of EPC's 2014 Phase 1 Distribution Tariff Application (DTA) and 2014-2015 Transmission General Tariff Application (GTA). However, as it was unlikely that final 2014 rates would be approved by the end of 2014, resulting in a forecasted revenue shortfall to EPC of $10.229 million for distribution and $14.260 million for transmission, the EPC brought an application for approval of interim rates that would permit it to recover 60% of its forecast revenue shortfall.

In considering EPC's interim application, the AUC applied the test and stated that:

> When evaluating the merits of an interim rate application, the AUB applies the above-stated test. It weighs the potential benefits of rate stability and minimization of rate shock and intergenerational inequity that might result on approval of final rates against the costs that underpin the interim rate increase, whether they be contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations.[5]

As explained in detail in Hydro's response to TIR-CA-NLH-001, Hydro submits that its 2015 Interim Rates Application meets the two-part test established by the AUC for consideration of interim rate adjustments. Hydro states that:

- It has shown that the net income deficiency for 2015 is both probable and material;

[5] Enmax Power Corporation; 2015 Interim Distribution and Transmission Tariff Application Decision 2014-311 at paragraph 25 (tab 3).

- Approval of the proposed interim rates will provide an approximate 70**%** recovery of the 2015 forecast net income deficiency if implemented on March 1, 2015 and a recovery of slightly below 60% if implemented April 1, 2015. A 60% recovery of the 2015 forecast net income deficiency provides a forecast net income for 2015 of approximately $5.2 million;

- It is not appropriate to make further adjustments to reduce 2015 Test Year revenue requirement for the purpose of establishing interim rates. If upon final testing of 2015 costs, the Board determines that 2015 cost adjustments are required, then these amounts would be applied to reduce the 2015 net income deficiency to be recovered through customer rates in future years;

- The proposed interim rates will add rate stability for 2015, enable the phase-in of Island IC rates with materially lower customer impacts and help mitigate intergenerational equity concerns caused by delayed rate implementation. Delayed implementation of Hydro's 2015 base rates will further increase net income deficiency proposed for recovery from customers upon establishment of final customer rates; and

- Approval of Hydro's 2015 Interim Rates Application provides a reasonable balance of the interests of both the utility and its customers.

Hydro agrees with the Consumer Advocate's submission on this point:

> It is clear that given these circumstances, Hydro requires an interim rate increase and its application passes Part 1 of the interim rates test. Hydro also shows that with respect to Part 2 of the interim rates test, its proposed interim rates will promote rate stability, ease rate shock, help to maintain inter-generational equity, and improve price signals to consumers. The Consumer Advocate submits that Hydro's 2015 Interim Rates Application meets the requirements set out in the two-part interim rates test. The key consideration in the assessment of this Application is the impact on the

> electricity consumers in the Province. The Consumer Advocate does not see how electricity consumers can possibly benefit from Hydro's continuing financial deterioration.[6]

As required by the EPCA, and confirmed by the Newfoundland and Labrador Court of Appeal, in exercising its duties under the *Public Utilities Act*, the Board is required to follow generally accepted sound public utility practice. Hydro disagrees with the Board's assessment that "approval of interim relief in advance of the conclusion of a general rate application is an extraordinary measure which must be fully justified in the circumstances."[7] Hydro submits that the awarding of interim rates to provide revenue to a utility in advance of concluding a GRA is common in other jurisdictions[8] and is considered a generally accepted sound public utility practice, as noted above and in the evidence to the Amended Application and the evidence to the 2015 Interim Rates Application.

As is discussed at greater length below, there is nothing in the *Public Utilities Act* or in the decision of the other Canadian utility regulators that suggests that an application for an interim order ought to be denied on the basis that the evidence upon which it is grounded has not been tested. Moreover, there is nothing in section 75 of the *Public Utilities Act* to support the Board's characterization of interim rates as being an extraordinary measure and the regulatory and judicial jurisprudence make it clear that interim orders are part of the normal and common remedial measures to address circumstances such as those which Hydro finds itself in at present.

In a May 1, 2014 decision of the Manitoba Public Utilities Board concerning an application made by Manitoba Hydro, that Board was dealing with an application for interim rates that was made months in advance of an anticipated general rate application. The Manitoba

[6] Consumer Advocate's written submission, dated February 18, 2015, at page 5.
[7] Order No. P.U. 39(2014) and reiterated in Order No. P.U. 58(2014).
[8] The evidence of Mr. Larry Brockman filed with the Board on February 24, 2014 regarding the RSP Surplus disposition includes a number of instances where rate increases were implemented on an interim basis. Canadian jurisdictions include Saskatchewan, New Brunswick and FortisBC in British Columbia. In the United States, rate increases were implemented on an interim basis in Alaska, Connecticut, Delaware, Hawaii, Kentucky, Louisiana, Michigan, Minnesota, Montana, North Dakota and South Dakota.

Board dealt with the application on the basis of the *prima facie* case that was before it, based upon untested forecast information. The Board stated: "The Board agrees with Manitoba Hydro's rebuttal submission that urgency is not a necessary precondition for an interim rate increase."[9]

3.3 Impact of Interim Rates on Final Rates

Hydro submits that under section 75 of the *Public Utilities Act*, the implementation of interim rates is not final and can be adjusted by the Board, as necessary, upon final determination of the GRA. Indeed, if after review of the Amended Application and the testing of Hydro's costs, it is determined that the interim rates approved by the Board were too high and resulted in Hydro earning excess revenues, subsection 75(3) of the *Public Utilities Act* permits the Board to order that customers receive a refund or place the monies in a fund for a purpose approved by the Board.

> 75(3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be
>
> (a) refunded to the customers of the public utility; or
>
> (b) placed in a reserve fund for the purpose that may be approved by the board.

As submitted above, section 75 of the *Public Utilities Act* gives broad powers to the Board to make an interim order approving the rates, tolls and charges to Hydro's customers, until a final order of the Board is made. Subsection 75(3) empowers the Board to deal with any excess revenue that may be earned by Hydro, not only by refunding it, but also by placing it in a reserve fund "for the purpose that may be approved by the board."[10] As provided by the Court of Appeal in the *RSP Appeal* decision:

[9] Interim Order in respect of Manitoba Hydro's Application for Interim Rates Effective May 1, 2014, Order No. 49/14, at page 17 (tab 4).

[10] *RSP Appeal* at paragraphs 128-129 (tab 2).

> [129] Subsection 75(3) provides, in broad terms, that the Board may order that excess revenue earned pursuant to an interim order be dealt with, not only by refunding it to the customers of the public utility concerned, but also by placing it in a reserve fund "for the purpose that may be approved by the board." This provides considerable flexibility to the Board to dispose of excess revenue earned as a result of an interim order, that is not confirmed in the final order, in a variety of ways that may or may not involve the customers of the utility who contributed to the excess benefiting directly through a refund. As was noted in the *Stated Case*, "[t]he Board has a broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the purposes of the legislation and to implement provincial power policy" (paragraph 36, item 2). In so doing, the Board must "balance the interests, as identified in the legislation, of the utility against those of the consuming public" (paragraph 36, item 4).[11]

As noted in Hydro's response to TIR-CA-NLH-007, the Board has previously adjusted interim rates after the fact. In Order No. P.U. 1(2006), the Board approved interim rates for AUR Resources Inc. In Order No. P.U. 7(2007), the Board awarded rates for AUR Resources Inc. that were different from the interim order and approved a refund or credit to AUR Resources Inc. for the difference between the approved final rates and those approved in the interim order.

The 'truing up' of interim rates against final rates is also a common occurrence in other jurisdictions. In Decision 2014-311 noted above, in awarding EPC's interim rates, the AUC stated that:

> The Commission finds that as the proposed rate increases are requested on an interim basis, rates will be trued up once the final 2015 rates for distribution and transmission are approved.[12]

[11] *RSP Appeal* at paragraph 129 (tab 2).
[12] Enmax Power Corporation, Decision 2014-311 at paragraph 36 (tab 3).

Further, in paragraph 39 of Decision 2014-311, the AUC stated:

> In determining the level of interim rates for EPC, the Commission is not making any finding or determination with respect to any of the matters in EPC's 2014 DTC and 2014-2015 GTA, which is currently pending before the Commission.

Hydro submits that the awarding of interim rates pursuant to this application does not derogate from the jurisdiction of the Board to award final rates, which are different from the interim rates, upon final testing of 2015 costs, in Hydro's GRA. This position is supported by the Consumer Advocate in his submission:

> *Therefore, the Board has jurisdiction to approve interim rates, and if the review of the Amended 2013 General Rate Application determines that the interim rates have resulted in Hydro earning excess revenues, to refund revenues to customers.*[13]

4.0 Reasonableness of Rates

NP does not oppose interim rates for Hydro *per se.* However, NP asserts that the proposed interim rates are not "*consistent with the reasonableness requirement of the EPCA.*"[14] Hydro disagrees with this statement. At paragraph 56 of the *RSP Appeal*, the Court of Appeal states:

> The EPC Act states the electrical power of the province in S. 3. It obligates the Board to implement that policy as it carries out its duties and exercises its powers under the PUB Act and in so doing s.4 requires the Board to apply tests which are consistent with "generally accepted sound public utility practice".[15]

As referenced above section 3.0 of this submission, at paragraph 57, the Court of Appeal refers to its decision in *Reference Re Section 101 of the Public Utilities Act,* in which it

[13] Consumer Advocate's written submission dated February 18, 2015, at page 2.
[14] NP's written submission dated February 18, 2015, page 1.
[15] *RSP Appeal* (tab 2).

identified some of the general principles applicable to the interpretation of the *Public Utilities Act* and the EPCA. Two notable principles for the purpose of the current matter are 5 and 6 of paragraph 57.

> [57] … 5. The setting of a "just and reasonable" rate of return is of fundamental importance to the utility and must always be an important focus of the Board's deliberations; however, the "entitlement" of the utility to a just and reasonable rate of return does not guarantee it that level of return. **The "entitlement" is to have the Board address that issue and to make its best prospective estimate, based upon the full consideration of all available evidence, for the purpose of setting rates, tolls and charges.**
>
> 6. The Board has jurisdiction,…, to determine what is a just and reasonable rate of return within a "zone of reasonableness" and in doing so **is not constrained in its choice of applicable methodologies, so long as they can be rationally justified in accordance with sound utility practice** and are not inconsistent with the achievement of the purposes and policies of the legislation. [emphasis added.]

Continuing in its decision, the Court of Appeal stated that although the *Stated Case* concerned a utility's rate of return, "*the principles stated above, including those in sub-paragraphs 5 and 6, apply in a similar manner to the determination of rates for a utility's customers".*[16]

As explained above in section 3.1 of this submission, paragraph 61 of the Court Appeal's decision in the *RSP Appeal* addresses the Board's authority to set interim rates and relies on the Supreme Court of Canada's decision in *Bell Canada 1989*, in which Gonthier J. stated that the determination of the justness and reasonableness of rates cannot be resolved as to interim rates until the final decision of the Board is rendered.

> In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return allowed in the final decision for the period during which they are in effect so

[16] *Stated Case*, Paragraph 58, (tab 1).

as to achieve just and reasonable rates throughout that period.[17](emphasis added)

The Board's powers to award interim rates allows it to set rates "*to make its best prospective estimate, based upon the full consideration of all available evidence, for the purpose of setting rates, tolls and charges".*[18] The Board *"is not constrained in its choice of applicable methodologies, so long as they can be rationally justified in accordance with sound utility practice".*[19] When the final costs are approved, the Board can remedy any discrepancy *between* the rate of return allowed in the interim rates and the final decision so ***as to achieve just and reasonable rates*** throughout that period.

The evidence before the Board in this hearing shows:

- Hydro has not increased base rates since 2007;
- Hydro's net income was $209,000 in 2013;
- As at the end of the third quarter 2014, Hydro was forecasting a net loss of approximately $27 million under existing rates. Audited year-end results are not yet available;
- The Board approved a $45.9 million cost deferral in 2014 to provide an opportunity to earn a reasonable return in 2014, however, the cost deferral remains subject to testing by the Board;
- Under existing rates Hydro is forecasting a net loss of $68 million for 2015;

[17] *RSP Appeal*, at paragraph 61 (tab 2).
[18] *RSP Appeal*, at paragraph 57.
[19] RSP Appeal, at paragraph 57.

- If proposed rates are implemented for the remainder of 2015, Hydro forecasts a net income of $5.2 million for 2015 based upon a rate implementation date of April 1, 2015 (net income deficiency of $28 million); and

- Further delay in implementation or adjustment to the proposed rates will further increase the cost deferral of current costs to be recovered through future rates creating intergenerational equity concerns.

The current circumstances demonstrate that full consideration of the available evidence justifies approval of the proposed interim rates as soon as possible.

As set out in section 3 of this submission, the Board has the jurisdiction to award interim rates and to make adjustments to remedy any discrepancy between the rate of return allowed in the final decision for the period during which interim rates were in effect so **as to achieve just and reasonable rates.** An example of when the Board has adjusted rates to ensure rates were reasonable is provided in Hydro's response to TIR-CA-NLH-007. On November 10, 1997, pursuant to section 82 of the *Public Utilities Act*, the Board commenced, on its own motion, an investigation and subsequent hearing into the cost of capital reflected in the rates of NP. The commencement of a hearing effectively made NP's rates interim effective January 1, 1998. In Order No. P.U. 16(1998-1999), the Board approved interim rate adjustments to the rates that were in effect for the period January 1, 1998 to August 31, 1998 and refunds were issued to customers to reflect the reduced cost of capital approved in the Board's order. The Board conducted a further review of the reasonableness of the adjusted interim rates in NP's 1998 fall hearing, however, upon final review, determined that no further adjustment was required.

Hydro reiterates its submission that the Board "*has broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the*

purposes of the legislation and to implement provincial power policy."[20] In so doing, the Board must *"balance the interests, as identified in the legislation, of the utility against those of the consuming public."* [21]

5.0 2015 Tested Costs and Inclusion of Contentious Costs

Hydro submits that both the Consumer Advocate and Vale are supportive of Hydro's 2015 Interim Rate Application and are satisfied with the evidence provided to support its application. The IIC Group were also supportive of the interim rates, with the exception of the specifically assigned charge for one of their customers.

5.1 Untested Costs

In its written submission to the Board, NP takes issue with Hydro's proposal to use untested costs to determine interim rates. NP states on page two of their submission:

> The 2015 interim rates application appears to assume that Hydro's assertion of a forecast loss for 2015 provides, in and of itself, sufficient justification for the Board to approve interim rates for Hydro's customers, ***which are based on untested costs***.
>
> …..
>
> Hydro asserts that a forecast 2015 loss provides sufficient regulatory justification for the Board's approval of the rates requested by Hydro in the 2015 interim rates application. ***This is not consistent with regulatory practice in this province or Canada generally***. (emphasis added).

Hydro submits that these statements are inconsistent with the regulatory decisions which are relied upon by NP in its own submission, and that approval of interim rates based upon forecast untested costs is, in fact, quite common in regulatory jurisdictions across Canada.

[20] *The Stated Case,* at paragraph 36, item 2, (tab 1).
[21] *The Stated Case,* at paragraph 36, item 4, (tab 1).

A number of examples of approval of untested costs, found in authorities cited in NP's February 18, 2015 submission in this matter are as follows:

- Appendix A – AltaLink Management Ltd. and TransAlta Utilities Corporation, 2004-2005 Interim Transmission Tariff

At electronic page 12 of the NP submission (paragraph 23 of the AltaLink Management Ltd. Interim rates decision) the AUC noted the intervenor's position and stated *"Calgary submitted that there were numerous areas of contention in AltaLink's 2004-2007 GTA filing and that* ***these areas remain untested****. In Calgary's view, amounts pertaining to contentious issues should be excluded in whole or in part."* (emphasis added).

Hydro notes that interim rates were indeed approved by the AUC based on these untested costs.

- Appendix B – ATCO Gas, 2005-2007 General Rate Application Interim Rate Application

At electronic page 37 of the NP submission (at paragraph 49 of the Alberta Energy and Utility Board decision) the Board stated *"In determining the level of interim rates for AGN, the Board is not making any finding or determination with respect to any of the matters to be considered in the upcoming GRA.* ***The Board recognizes that the evidence before it is untested*** *and that a number of areas of concern identified by the interveners could result in an adjustment to forecasted shortfalls."* (emphasis added).

Hydro notes that interim rates were approved based on these untested costs.

- Appendix C – ATCO Electric Ltd.; 2009 Interim Distribution Tariff and Transmission Facility Owner's Tariff

At electronic page 44 of the NP submission, (at paragraph 18 of the AUC decision), the AUC stated *"The Commission agrees with the comments made by the UCA that **AE has provided limited information with respect to the two part test to support its interim tariff request. In particular, the Commission considers that AE has not provided specific evidence to allow examination** of the manner in which the principles of financial integrity, financial hardship or continuation of safe utility operations may be affected."* (emphasis added).

Hydro notes that interim rates were approved based on this limited evidence.

- Appendix D – ENMAX Power Corporation 2015 Interim Distribution and Transmission Tariff Application

At electronic page 115 of the NP submission (at paragraph 28 of the AUC decision), the AUC stated *"In respect of the 2015 billing determinant forecast, the Commission accepts EPC's explanation and **is satisfied that the forecast, using previously approved methodologies and updated historical data and key economic indicators, is sufficient for the purposes of 2015 interim distribution rates** based on 60 per cent of EPC's applied-for 2014 DTA. The 2015 billing determinant forecast will be tested in EPC's upcoming PBR proceeding. The Commission will make a determination at that time on the reasonableness of the forecast."* (emphasis added).

Hydro notes that interim rates were approved based on this untested forecast.

- Appendix E – Interim Rates for Manitoba Hydro Effective April1, 2011

At electronic page 147 of the NP submission, (at paragraph 31 of the Manitoba PUC decision) the PUC stated, *"CAC/MSOS, having fundamental issues with MH's GRA and **holding that their issues have yet been fully tested**, opined that it would be imprudent for*

the Board to make a directional judgment at this time, ahead of evidence yet to come." (emphasis added)

Further, at electronic pages 156-157 of the NP submission (at paragraph 102 of the decision) the PUC stated, *"Unlike the circumstances of the April 1, 2010 interim rate increase, the GRA is now well underway and* ***while considerable evidence remains to be provided and tested****, sufficient evidence is already on the record to justify the Board's consideration of granting another interim rate increase. MH has filed an extensive GRA (including its latest published annual report and financial forecasts), and thousands of interrogatories have been posed and responded to (involving MH, the Board, Interveners and expert witnesses)."* (emphasis added).

Hydro notes that interim rates were approved based on this untested evidence.

In addition to the aforementioned cases submitted by NP, there is an additional, more recent, decision from the Manitoba Public Utilities Board (Order No. 49/14, tab 4) where the Board approved an application by Manitoba Hydro for interim rates even though no GRA had been filed and one was not planned to be filed for a number of months. The information relied upon by the Board was filed by the applicant on March 7, 2014. A decision on the application was rendered by the Board on May 5, 2014 even though no GRA was planned to be filed by the applicant until the autumn of 2014. The Board considered the positions of the parties and ruled on the matter as follows (at pages 16-17 of the decision):

> **4.0 Board Findings**
> **Test for Granting Interim Rates**
> The Board notes that Manitoba Hydro plans to file a General Rate Application in the fall of 2014, which Application would likely be heard in a public hearing in the spring of 2015. Accordingly, a General Rate Application would likely only be decided towards the end of the Corporation's 2014/15 fiscal year. Interim rate orders are intended to relieve Manitoba Hydro from the

deleterious effects caused by the length of a regular regulatory proceeding. The questions to be determined by this Board are whether it would be just and reasonable to grant interim rates, and whether Manitoba Hydro would suffer a deleterious effect in the absence of an interim rate increase. For the reasons set out below, the Board considers it to be in the public interest to approve an interim rate increase, albeit at a level lower than requested by Manitoba Hydro.

Manitoba Hydro's Financial Position

According to Manitoba Hydro, the energy future in Manitoba will require significant annual rate increases regardless of which source of additional new generation is pursued, and regardless of which decision will be reached in the NFAT Review currently underway. All possible development plans presented in the NFAT Review require rate increases. As such, the Board and Manitoba Hydro customers cannot assume that in the absence of the Preferred Development Plan being approved, rate increases can be avoided. This requires the Board to take into account the need for rate stability and the avoidance of rate shock.

The Board notes that Manitoba Hydro's Interim Application for a 3.95% rate increase is consistent with the Preferred Development Plan that involves the construction of both Keeyask and Conawapa Generating Stations. The outcome of the NFAT Review will be known prior to the filing of Manitoba Hydro's next General Rate Application, and a full General Rate Application is needed to examine the magnitude of additional rate increases.

Nonetheless, the Board is satisfied on a *prima facie* basis, that an interim rate increase is required. Reliability of Manitoba Hydro's infrastructure is paramount, and the Board accepts that investments in the maintenance and replacement of existing infrastructure is required.

Electricity export price forecasts have decreased over successive forecasts, resulting in less projected export revenue to help offset the requirement for domestic rate increases.

The Wuskwatim Generating Station is now 'in service' and has resulted in an additional domestic revenue requirement to be carried by domestic customers as those additional costs are not paid from export revenues.

Lastly, and despite the Board's comments in Order 43/13 with respect to the need for Manitoba Hydro to contain OM&A costs, those OM&A expenses are projected to increase above the rate of inflation in 2014/15.

The Board agrees with Manitoba Hydro's rebuttal submission that urgency is not a necessary precondition for an interim rate increase. However, it is

> appropriate to consider Manitoba Hydro's current financial condition in light of favourable recent financial results and the fact that a General Rate Application will be filed this Fall. The Board has determined that an interim rate increase of 2.00%, approximating the annual rate of inflation, is sufficient at this time to meet the needs of Manitoba Hydro. Whether or not an additional rate increase is required is an issue to be left to the General Rate Application, by which time actual financial results for the 2013/14 fiscal year will also be available.

Hydro notes that, if anything, the Manitoba Public Utilities Board Act (an excerpt of which is reproduced and provided at tab 5) is more general and less specific and clear as to the intent of the Manitoba legislature to empower its Board the power to grant interim orders in these kinds of circumstances. The interim order provision from the Manitoba statute reads:

> **Interim order**
>
> 47(2) The board may, instead of making an order final in the first instance, make an interim order and reserve further directions, either for an adjourned hearing of the matter, or for further application.

The statutory provision empowering this Board on interim orders bears repeating here for comparison:

> **Interim order**
>
> 75. (1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.
>
> (2) The schedule of rates, tolls and charges approved under subsection (1) are the only lawful rates, tolls and charges of the public utility until a final order is made by the board under section 70.
>
> (3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be
>
> (a) refunded to the customers of the public utility; or
>
> (b) placed in a reserve fund for the purpose that may be approved by the board.

While the above case law examples indicate a consistent practice of approved interim rates based on untested costs in Canada, in its written submission to the Board, NP appears to submit that interim rates in this province should be based only on tested costs. On page two of their submission dated February 18, 2015 NP states *"The Board has historically used tested costs to establish rates, even interim rates. The use of tested costs ensures that the rates are reasonable. The costs which are included in the rates proposed in the general rate application have never been tested."* Hydro submits that Hydro's existing interim rates were set based upon 2007 tested forecast costs and are demonstrably not, at this time, reasonable rates. Hydro has provided a complete filing of evidence and has responded to in excess of 1400 Requests for Information in the GRA. In accordance with the tests used by other regulators, Hydro submits that this constitutes strong *prima facie* evidence of a revenue shortfall.

As noted in the examples provided in NPs own submission, the concept of using non-tested costs for interim rates is common in other jurisdictions in Canada. Further, the Board's authority to set rates without tested evidence was confirmed by the Newfoundland and Labrador Court of Appeal in the *RSP Appeal*. At paragraph 61 of its decision, the Court of Appeal stated:

> [61] The power of the Board to authorize interim rates is granted in s. 75 of the PUB Act. **That section allows the board to set rates expeditiously without full evidence** and submissions, such rates being subject to review and possible modification in the final order of the Board, as is expressly provided for in subsections 75(2) and (3). (emphasis added)

Therefore, Hydro submits that approval of interim rates based on untested costs and a forecast loss is consistent with regulatory practice in Canada, generally, and as noted in the cases above, including those cases provided in NP's submission to the Board and those other authorities noted in this submission. These cases signify that this approach is based on generally accepted sound public utility practice, and that there is legal precedent in this province to support the Board's ability to approve interim rates based upon untested costs.

Moreover, this Province's Court of Appeal has endorsed and clarified this power of the Board.

5.2 Inclusion of Contentious Costs

NP contends that Hydro's 2015 base rate includes costs and return that are not reasonable for interim recovery and that the return on items subject to the prudence review by the Board should not be included.

NP submits that partial recovery of a forecast utility revenue deficiency in interim rates may be appropriate in certain circumstances and in doing so relies upon the view expressed by the Newfoundland and Labrador Court of Appeal that the language contained in section 3 of the EPCA emphasizes the need for tempering each of the utility's and its customers economic interests. While Hydro agrees with the view as expressed by the Court of Appeal, Hydro respectfully submits that NP is overlooking the fact that the EPCA and the *Public Utilities Act* work together to provide jurisdiction and powers to the Board. Pursuant to section 75 of the *Public Utilities Act*, the Board does have the authority to grant interim rates and to later provide a refund to customers if upon final testing of Hydro's costs it is determined that revenues earned as a result of the interim rates were too high.

The Consumer Advocate does not take issue with the inclusion of contentious items in Hydro's 2015 base rate. As is stated in the Consumer Advocate's submission, the fact that Hydro is seeking implementation as of March 1, 2015 means that Hydro will not recover 100% of its revenue deficiency. Referring to Hydro's response to TIR-CA-NLH-003, the Consumer Advocate states that "*the revenues from proposed 2015 interim rates effective March 1, 2015 would be less that the 2015 revenue requirement even if all 2015 costs subject to the Board's prudency review were disallowed*."[22] Further, as submitted by the Consumer Advocate, there "*are ample opportunities for the Board to claw back any excess*

[22] Consumer Advocate's written submission, dated February 18, 2015, at page 5, footnote 4.

revenues that might accumulate to Hydro under the 2015 Interim Rates Application."[23] Hydro submits that a reasonable process to follow would be in accordance with Hydro's response to TIR-PUB-NLH-003.

6.0 Level of Recovery of Interim Rates

NP suggests in its submission that Hydro's 2015 Interim Rate Application will provide for 100% recovery of Hydro's 2015 revenue requirement on an annualized basis. Hydro disagrees with this assertion and submits that it is specious. Hydro has requested interim rates effective March 1, 2015. As of this date it is not possible for Hydro to achieve annualized (i.e. 12 months of) interim rates in 2015.

Table 1

Scenario ($000's)	2015 Net Income	Variance from January 1, 2015 Implementation	Effective Annual 2015 Recovery
Interim Rates, January 1, 2015	33.9	-	100%
Interim Rates, January 1, 2015 100% of Prudency Costs Removed	21.2	(12.7)	81%
Interim Rates, March 1, 2015 [1]	**14.0**	**(19.9)**	**71%**
Interim Rates, April 1, 2015	5.2	(28.7)	58%
2015 Net Income: Current Rates	(34.6)	(68.5)	0%

[1] Hydro's proposal

As shown in Table 1, Hydro's proposal for implementation of interim rates on March 1, 2015 has an effective annual rate increase of providing recovery of approximately 70% of the forecast 2015 net income deficiency. Hydro's application proposes two months of existing rates and ten months of interim rates in 2015. Delayed interim rate implementation decreases Hydro's effective annual return, as lower existing rates remain in effect for the first two months of the calendar year where energy demand and revenue are typically at

[23] Consumer Advocate's written submission, dated February 18, 2015 at page 6.

their highest. On an annualized basis, this proposed delayed implementation of interim rates to March 1, 2015 is no different in result than implementing rates effective January 1, 2015 to provide recovery of 70% of the 2015 forecast net income deficiency.

As noted on page 5 of NP's submission "*In their consideration of interim rates, the AUC does not automatically provide a utility with full recovery of a proposed revenue requirement increase. For example, the AUC has granted only a portion of the revenue requirement increase proposed in the principal rate case where such an approach seemed reasonable."* Hydro accepts that this approach appears to be common Canadian regulatory practice, however, this is not always the case.

On November 24, 2014, FortisBC received approval for 100% recovery of their applied for interim rate increase of 3.5% "*on an interim and refundable basis pending the outcome of the annual review of 2015 rates.*"[24] Hydro submits that the proposed increase in Hydro's interim rates application is conservative when compared to FortisBC's recent 100% recovery reflected in its approved interim rates, given that the effective annual revenue requirement increase proposed by Hydro is only 70%.

As provided for in Hydro's response to TIR-CA-NLH-001, if interim rates are made effective March 1, 2015, Hydro will recover 70% of its forecast net income deficiency for 2015. If rates are not made effective until April 1, 2015, Hydro will recover only 60% of the forecast net income deficiency. Approval of the proposed interim rates effective March 1, 2015 or later, does not provide recovery of the financial impact of delayed rate implementation beyond January 1, 2015. As such, Hydro is not seeking recovery of 100% of its 2015 net income deficiency in the interim rates proposed to become effective on March 1, 2015.

[24] Order Number G-182-14 of the British Columbia Utilities Commission. *FortisBC Inc. ~ Multi-Year Performance Based Ratemaking Plan for the years 2014 through 2019 Order G-139-14 Amended Financial Schedules Compliance Filing and Request for Approval of 2014 Permanent Rates and 2015 Interim Rates*, (tab 6). FortisBC applied for, and obtained approval of, a 3.5% interim refundable rate increase effective January 1, 2015.

The Consumer Advocate's submission states that regulatory boards that allow interim rate increases often cap the amount at a percentage of the additional revenue needed to provide the utility with a reasonable rate of return. The two cases provided by the Consumer Advocate notes that the AUC limited the interim rates awarded to 60% of the utilities required increase in revenue. According to the Consumer Advocate's submission, Hydro's is requesting 78.5% of its revenue deficiency for 2015 as the proposed rates would not become effective until March 1, 2015, as opposed to January 1, 2015. As Hydro is not seeking 100% recovery of its required revenue for 2015, the Consumer Advocate supports Hydro's 2015 Interim Rates Application, as proposed, subject to a full review of Hydro's costs during the GRA.

Hydro submits that, as stated above in section 3.2 of this submission, if upon final testing of Hydro's costs in the GRA the Board determines that Hydro has received more revenues than it requires, subsection 75(3) of the *Public Utilities Act* provides considerable flexibility to the Board to dispose of any excess revenue earned by Hydro as a result of an interim order, that is not confirmed in the final order, in a variety of ways.[25]

7.0 Phase in of IIC Rates

Order in Council OC2013-089 and OC2013-090, direct that IIC rates are to be phased in over a three year period with funding for this phase in to be drawn from the IIC RSP Surplus.

In a submission dated December 10, 2014, the IIC Group submitted that the impacts of the rate proposals reflected in the Amended Application constitute "rate shock". Current IIC rates do not include a fuel rider. As such, their rates do not recover the increased cost of Holyrood fuel since the 2007 Test Year. The proposed average base rate increase for IIC for the 2015 Test Year, based upon the fuel cost forecast used in the Amended Application and with no phase-in approach, is 39.2%. Using an updated Holyrood fuel price of $65.63 per barrel reduces the proposed base rate increase to 18.1%. The IIC Group submission of

[25] *RSP Appeal at* paragraph 129. (tab 2)

December 18, 2014 expressed concern with the customer impacts in the Amended Application. To mitigate the customer rate impacts, the IIC Group proposed that the Board consider: (i) disposition of the credit balance in the RSP load variation component; and (ii) using a lower No. 6 fuel price in establishing revenue requirement for the purpose of establishing interim rates.

As set out in the evidence to the 2015 Interim Rates Application, Hydro considered two alternatives to phasing in IIC rates and proposed that the Board accept alternative 1 on the basis that it would limit the maximum impact of any single base rate change to the IIC to approximately 10%. In its written submission, Vale submits that the Board should accept the second alternative proposed by Hydro "*as it reduces the number of rate changes experienced by industrial customers over an 18 month period from three (under alternative one) to two. The increased rate stability provided by alternative two is preferable for industrial customer's budgeting purposes.*"[26] Hydro considers either approach acceptable.

The Consumer Advocate has indicated in its written submission that Hydro's proposal to phase in IIC rates is not in compliance with OC2013-89. Hydro disagrees with this assessment and submits that the proposed phase-in approaches, either alternative one or two, are in compliance with OC2013-089. The OC dictates that the rates should be phased in over a three year period and conclude by August 31, 2016. Hydro submits its proposed approach to the phasing in of IIC will have started and concluded within the three year period specified by the OC and is therefore compliant with OC2013-89.

7.1 CBPP Specifically Assigned Charge

In its February 23, 2015 submission, the IIC Group indicated that its specifically assigned charge comprised 0.4% of its power bill in 2011 and if the interim rates are approved as applied for, will comprise almost 25% of CBPP's power bill. Hydro wishes to point out that these figures must be seen in their proper context. Hydro has invested significant funds in

[26] Vales's written submission dated February 18, 2015, at page 5.

the plant dedicated to serve this customer since that time – the plant's value used for allocating this amount is nearly ten times higher than it was then primarily due to replacements of aged equipment. From the perspective of understanding the proportion of the bill that fixed plant has to the demand and energy components of the bill, it should also be understood that CBPP's load is approximately one-seventh what it was in 2001. In Hydro's view, the level of increase arising from this component of this customer's rate should not be singled out for differential treatment for the purposes of the proposed interim order.

8.0 RSP Load Variation Component

The 2014 year end credit balance in the RSP load variation component is approximately $35.5 million. Pursuant to Order No. P.U. 29(2013), this component has been segregated with disposition between the IIC and NP to be determined in the GRA. In this 2015 Interim Rates Application, Hydro is proposing that the Board approve the disposition of the 2014 year-end load variation balance using the energy ratio allocation approach that was proposed in the Amended Application. The approval of this proposal would result in $2.1 million being allocated to the IIC, reducing the 2014 year-end IIC RSP balance from $6.8 million to $4.7 million. The remainder of the $35.5 million segregated RSP load variation balance would flow through the RSP for disposition to retail customers which will enable continuation of the existing RSP recovery rider of (0.551) cents per kWh until June 3, 2016, without resulting in a large balance owing from NP customers.

The Consumer Advocate disagrees with Hydro's proposal that $2.1 million from the balance of the load variation component of the RSP that has accumulated since September 1, 2013. The IIC Group and Vale support the use of the load variation component to reduce customer rate impacts of implementing the proposed interim rates. Hydro submits that the disposition of the RSP load variation component as proposed by Hydro reduces customer rates impacts and supports the principle of intergenerational equity in phasing in the IIC rates. As submitted by Vale in its written submission, "*By using current RSP balances owing*

to customers to offset balances currently owing to Hydro, Hydro reduces or eliminates the potential for intergenerational inequity created by the use of future rate riders to recovery past balances."

9.0 July 1, 2015 RSP Update

Each July, the RSP fuel rider is updated to reflect forecast fuel costs for the following 12 months and the RSP recovery adjustment is updated to reflect balances that have accumulated as a result of variances from forecast fuel costs and RSP recovery over the previous 12 months. The implementation of interim base rates effective March 1, 2015 which reflects updated fuel costs for 2015 removes the RSP fuel rider that has been in effect since July 1, 2014. Implementation of revised retail rates on March 1, 2015, which reflect both the disposition of the balance in the RSP segregated load variation component and the updated fuel forecast, avoids the necessity for a July 1, 2015 rate change. Hydro sees no additional benefit in providing a further fuel cost update to become effective July 1, 2015 and proposes that the July 1, 2015 NP RSP update be suspended.

As explained in Hydro's response to TIR-PUB-NLH-001, the implementation of new base rates to IIC requires modifications to the values used in the operation of the RSP for the period that interim rates are in effect. To avoid any implications on NP's customers of the interim changes to the RSP rules, Hydro is proposing that there be no RSP rate adjustment for 2015.

The Consumer Advocate, in its written submission, supports "*Hydro's proposal that there be no RSP rate adjustment for Newfoundland Power customers in July 2015*."[27] Hydro notes that NP made no submission on this point.

[27] Consumer Advocate's written submission, dated February 18, 2015, page 8.

10.0 Intergenerational Equity

As stated by Hydro in its response to TIR-CA-NLH-001, if its 2015 Interim Rates Application is not approved, there is substantial risk that customer rates for 2015 will not reflect the costs associated with providing service for that period. Rates charged in 2014, and now potentially in 2015, will not accurately reflect the costs of service provided in those periods. Denying Hydro's application will further increase the 2015 net income deficiency and place an increased burden on future customers to fund recovery of costs. [28]

Vale's submission also highlights the intergenerational equity concerns if interim rates are not awarded. The composition of the IIC class is changing radically with Vale ramping up production which will make it Hydro's largest IIC within a short period of time and with Teck Resources anticipating to close operations in 2015, while benefiting from current rates. As stated by Vale in its written submission,

> [I]f present day deficiencies are recovered from future customers, there will inevitably be intergeneration inequity in that the changing dynamic within the Island Industrial Customer Group:
>
> i) Will result in a customer responsible for contributing a small percentage to the accumulating deficiency repaying the largest percentage of that deficiency; and
>
> ii) Could result in an industrial customer that benefited from the rates that created the deficiency ceasing operations before its portion of the deficiency is repaid through a rate rider.[29]

As further stated by Vale in its written submission, as the "*evidence supports Hydro's submission that a revenue deficiency is accumulating, fairness dictates that an Order for interim rates should become effective at the earliest possible date. As discussed in detail in response to TIR-CA-NLH-001, maintaining generational equity is one of the factors demonstrating a need for interim rates*."[30] Hydro agrees with Vale's views on intergenerational equity for the IIC class.

[28] Also see page 6 to the Evidence of Hydro's 2015 Interim Rates Application.
[29] Vale's written submission, dated February 18, 2015, page 2.
[30] Vale's written submission, dated February 18, 2015, page 3, lines 3 to 7.

While NP's submission did not address intergenerational equity, Hydro submits that this issue is material to NP customers and should be an area of concern for NP. As noted in section 1 of this submission, late in 2014 the Board approved $55.5 million in costs for deferral ($45.9 2014 Net Income Deficiency and $9.6 million in Additional Capacity-Related Supply Costs). As sales to NP comprise the majority of Hydro's regulated income,[31] the majority of these costs, if approved for recovery, will be borne by NP customers.

If interim rates are not implemented and final rates take effect on December 1, 2015, Hydro's 2015 net income deficiency would be approximately $61.0 million.[32] This, combined with the above mentioned 2014 deferrals, represents a potential of $116.5 million to be recovered from future customers.

The magnitude of these deferred costs is the main driver for Hydro's intergenerational equity concerns for all customers, particularly those of NP. Keeping 2007 base rates in effect for the majority of 2015 will effectively require 2016 customers (and beyond) to subsidize the service provided to 2015 customers, as the rates charged in 2015 will not reflect the costs associated the service provided in that period.

Intergenerational equity is typically an area of concern for NP. As noted in Hydro's response to TIR-CA-NLH-001, NP's evidence on the 2011 Sale of Joint Use Support Structures application[33] states *"As time passes, the makeup and usage of a customer group changes. Therefore, the longer the period that costs are deferred, the more serious the breach of the intergenerational equity principle… cost deficiencies should be recovered over as short a period as is reasonable, so the customer group that eventually pays for the costs is similar to the one benefiting from the costs."* Hydro submits this issue is particularly relevant with

[31] Page 17 of Nalcor's 2013 Annual Report, sales to NP comprised 82.4% of Hydro's 2013 Regulated Revenue.
[32] Please see TIR-CA-NLH-001, Page 4 of 12, Lines 3 to 6.
[33] Newfoundland Power, Sale of Joint Use Support Structures, Consent #2, the Report of J.T. Browne Consulting, Appendix 3, Page 4 of 4.

respect to its 2015 Interim Rates Application. While NP has chosen not to address this issue with respect to Hydro's interim rates application and its impact on their customers, it is clear that NP is familiar with the concept of intergenerational equity and its application in their own proceedings.

In addition to the intergenerational equity evidence submitted by NP for an application of their own, NPs submission on Hydro's interim rates dated February 18, 2015, (at electronic page 35, paragraph 36) contains the interim rates decision for ATCO Gas which reads

> *The Board considers that interim rate increases are generally warranted where the forecast revenue deficiency identified for a given period is probable and material.* ***The Board considers it generally appropriate that customers' rates for a period reflect the costs associated with that period in order to maintain intergenerational equity.*** (emphasis added)

Hydro respectfully submits that the greater the delay with respect to Hydro's 2015 base rate implementation, interim or otherwise, the greater the concern with intergenerational equity for all customers.

11.0 Implementation of Interim Rates

The IIC Group and Vale do not oppose the implementation of interim rates as of March 1, 2015.

While retail rates may not practicably be implemented by March 1, 2015, Hydro submits that it is an option for the Board to consider that the Utility Rate change be implemented effective March 1, 2015. Newfoundland Power could then propose a flow-through approach to its retail customers. The Consumer Advocate recommends that the Board direct NP to implement interim rates promptly to ensure that its customers receive the rate reduction in a timely manner. As stated by Hydro in its response to TIR-CA-NLH-008, based upon the implementation period required as a result of Hydro's 2006 GRA, the process to

revise customer rates to reflect a new Utility rate can proceed quickly if NP starts the implementation process early and proceeds efficiently.

12.0 Submission

Hydro submits that the evidence supports the approval of the 2015 Interim Application proposals. Therefore, Hydro requests an interim Order pursuant to Section 75 of the Act, approving:

(i) the schedule of rates, tolls and charges set out in Schedule 1 to this 2015 Interim Rates Application to be effective on and after March 1, 2015, or as soon as is practical, until superseded by a final order of the Board; and

(ii) changes to the RSP rules to implement the phase-in of changes to the IIC rates and to remove the requirement for the RSP rate adjustment to NP scheduled for July 1, 2015.

If the Board finds that there is inadequate time for NP to implement the necessary changes to effect the retail rate proposals effective March 1, 2015, the Board could approve the wholesale rate proposed by Hydro to be effective March 1, 2015, with delayed implementation of the retail rates to be effective April 1, 2015.

All of which is respectfully submitted.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 25th day of February, 2015.

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Docket: 96/141

98 190 006

IN THE SUPREME COURT OF NEWFOUNDLAND
COURT OF APPEAL

IN THE MATTER OF Section 101 of the *Public Utilities Act*, R.S.N. 1990, c. P-47

AND IN THE MATTER OF a case stated by the Board of Commissioners of Public Utilities to the Court of Appeal for its hearing consideration and opinion on questions of law affecting the jurisdiction of the Board of Commissioners of Public Utilities

Coram: O'Neill, Cameron and Green, JJ.A.

Reference Heard: March 11 & 12, 1997
Opinion Rendered: June 15, 1998

Opinion delivered by Green, J.A.
Concurred in by Cameron, J.A.
Dissenting Opinion in part by O'Neill, J.A.

Counsel for the Board of Commissioners of Public Utilities: V. Randell J. Earle, Q.C.
Counsel for Nfld. Light & Power Co. Ltd.: Ian F. Kelly , Q.C.
Counsel for the Consumer Advocate: Mark Kennedy

Opinion of Green, J.A.:

[1] The Board of Commissioners of Public Utilities has stated a case for the opinion of this Court, pursuant to s. 101 of the **Public Utilities Act**[1]. The questions posed concern the jurisdiction and powers of the Board as they affect the approach of the Board to the determination of a "just and reasonable return" on the rate base of a utility, as well as related matters.

The Stated Case in Context

[2] The Board is the statutory body which has the authority and duty for the "general supervision of all public utilities" in Newfoundland and Labrador and in the course of exercising that supervisory role has general authority to "make all necessary examinations and inquiries and keep itself informed as to the compliance by public utilities with the law" and, as well, it has the right "to obtain from a public utility all information necessary to enable the Board to fulfil its duties"[2].

[3] One of the Board's primary functions with respect to electrical utilities is the regulation and approval of rates, tolls and charges[3]. In so doing, the Board must take account of the statutory requirement that the utility is entitled to earn annually a "just and reasonable return" as determined by the Board on the rate base as fixed and determined by the Board.[4] The process essentially involves the fixing and determining of the appropriate rate base, the determination of a "just and reasonable return" on that rate base and then the approval of a schedule of rates, tolls and charges that would be appropriate to generate the revenue which, in the Board's estimation, would be necessary to provide the determined rate of return. Once rates, tolls and charges are set by the Board they continue to apply until altered under the Act, as a result of a reapplication by the utility for an

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[1]R.S.N. 1990, c. P-47 as amended (hereinafter the "Act")

[2]**Act**, s. 16

[3]**Act**, s. 70

[4]**Act**, s. 80

increase, a complaint by the public or an order for a reexamination initiated by the Board itself.

[4] It is important to remember, however, that in addition to its periodic adjudicative role which itself involves a large measure of policy implementation in arriving at its decisions, the Board has, because of its duty of "general supervision of all public utilities", an ongoing supervisory role of the activities of the utility between hearings as well, which is facilitated by statutory requirements for periodic reporting of financial information to the Board.

[5] In 1991 the Board made Orders[5] determining a just and reasonable return for Newfoundland Light and Power Co. Ltd.[6] and approving a schedule of rates, tolls and charges based on estimated revenue requirements necessary to cover operating expenses and to provide that level of return. The essential features of the 1991 order determining the just and reasonable rate of return were that:

(a) The just and reasonable return was determined to be between a stated range (10.6% - 11.19%) of the company's average rate base;

(b) The rate base was determined on the basis of a hypothetical test year (1992);

(c) The Board determined that the just and reasonable return, as defined, would provide an opportunity to NLP to earn a rate of return on common equity between a certain stated range (13% to 13.5%);

(d) The schedule of rates, tolls and charges was determined applying a rate of return equal to the mid-point between the stated range of returns on rate base;

(e) The Board ordered that a particular capital structure of NLP be adopted and continue to be the basis of NLP's financial plan.

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[5]Board Orders P.U.6 (1991) and P.U.7 (1991)

[6]Hereinafter, "NLP"

[6] The Board had previously adopted a policy allowing NLP to retain earnings above the allowed range of return on rate base, provided those earnings were within the allowed range of rates of return on common equity. Where the earnings exceeded the allowed rate of return on common equity, the Board, in purported exercise of its statutory powers to regulate NLP's accounting procedures, as well as other powers, required NLP to set up a reserve account in which these excess earnings would be held and dealt with in accordance with subsequent direction by the Board.

[7] In April of 1996, NLP petitioned the Board for another order fixing and determining a new rate base, determining a just and reasonable return and approving a revised schedule of rates, tolls and charges, amongst other matters. One of the parties represented at the hearing was the "Consumer Advocate", who was appointed[7] by the Government of Newfoundland and Labrador to represent the interests of domestic and general service consumers in respect of the rate hearing.

[8] During the years between the making of the 1991 orders and the 1996 hearing, NLP had filed annual returns with the Board, as required by s-s. 59(2) of the Act, which indicated that in the years 1991, 1992 and 1993 the company's rate of return on rate base was in excess of the range determined in the 1991 Order. However, as calculated by NLP, the rate of return on common equity was always within the range that had been stipulated by the Board. The rates of return on rate base and on common equity were calculated based on actual expenses and on the actual capital structure of NLP.

[9] In its periodic reports to the Board, NLP disclosed that its actual advertising costs in 1992 exceeded the amounts projected to the Board as a forecast for 1992 which had been approved as reasonable and prudent by the Board in its 1991 Order in the course of fixing and determining the rate base.

[10] During the course of the 1996 hearing, certain submissions were made to the Board respecting, amongst other things,

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[7]Pursuant to s. 117 of the Act. See OC 96-226; OC 96-236

(a) whether NLP should be regarded as having earned revenue in excess of its allowed range of rate of return where its rate of return on common equity was nevertheless within the stated allowable range;

(b) whether the manner of calculation of excess revenue and the proposed manner of the disposition of any excess was permitted;

(c) whether NLP could and should be required to alter its capital structure so as to obtain its capital requirements in a manner other than the way in which it was presently doing;

(d) whether the Board could and should take account, in setting future rates, of past expenditures which were in excess of amounts deemed reasonable and prudent at the time of a previous hearing.

[11] Questions arose as to the jurisdiction and power of the Board to entertain and act on the sorts of submissions that were made. This prompted the Board to state the current case to this Court. NLP and the Consumer Advocate were granted standing to appear and be heard at the hearing.

The Specific Questions

[12] The Stated Case poses for consideration by this Court the following questions:

(1) Does the Board have jurisdiction pursuant to the Act to set and fix the return which a public utility may earn annually upon:

(i) the rate base as fixed and determined by the Board for each type of service applied by the public utility; and/or

(ii) the investment which the Board has determined has been made in the public utility by the holders of common shares.

(2) Does the Board have jurisdiction to set the rates of return referred to in Question (1) as a range of permissible rates of return.

(3) Should a public utility earn annually a rate of return which is in excess of the rate of return determined by the Board to be just and reasonable, either on:

(i) the base rate as fixed and determined by the Board for each type of service applied by the public utility; or

(ii) the investment, which the Board has determined, has been made in the public utility by holders of common shares,

does the Board have jurisdiction to:

(i) require the public utility to use the excess earnings to reduce revenue requirements for the succeeding year; or

(ii) require the public utility to place the excess earnings in a reserve fund for the purpose of adjusting rates, tolls and charges of the public utility at a future date, or

(iii) require the public utility to rebate the excess earnings to customers of the public utility.

(4) Does the Board have jurisdiction to order that the rates, tolls and charges of a public utility shall be approved taking into account earnings in excess of a just and reasonable return upon,

(i) the rate base as fixed and determined by the Board for each type of service applied by the public utility, or

(ii) the investment, which the Board has determined, has been made in the public utility by the holders of common shares,

in prior years.

(5) Does the fact that the Board has advised the public utility that it is permitted to retain earnings in excess of the rate of return determined by the Board to be a just and reasonable return, upon the rate base as fixed and determined by the Board for each type of service supplied by the public utility, but not in excess of the return determined by the Board to be a just and reasonable return upon the investment which the Board has determined has been made in the public utility by the holders of common

shares, affect the jurisdiction of the Board to approve rates, tolls and charges on the basis queried in Question (4).

(6) Does the Board have jurisdiction to order the rates, tolls and charges of the public utility shall be approved taking into account the amount of expenses previously incurred by the public utility which the Board may now consider inappropriate to be allowed as reasonable and prudent and properly chargeable to operating account notwithstanding that such classes of expenses were allowed as reasonable and prudent and properly chargeable to operating account.

(7) Does the Board have jurisdiction to require a public utility to maintain:

(i) a ratio; or

(ii) a ratio within a stated range of ratios

of equity and debt, as the means of obtaining the capital requirements of the public utility.

(8) Does the Board, upon an application pursuant to Section 91 or otherwise, have the jurisdiction to require a public utility to obtain its capital requirements by the issue of specific financial instruments, whether common shares, preferred shares, stocks, bonds, debentures or evidence of indebtedness payable in more than one year.

Although the questions are stated above as they appear in the Stated Case filed with the Court, there are several obvious typographical errors in the language used. This was recognized by the participants in references to the questions in their written arguments. In particular "supplied" was at times substituted for the word "applied" in questions 1(i), 3(i) and 4(i) and "base rate" in Question 3(i) was replaced by "rate base." In addition, the phrase "In the event that a public utility should ..." at the beginning of Question 3 was used at times in the written submissions in preference to the phrase "Should a public utility ..." Nothing turns on these informal changes. They do, however, make the import of the questions clearer and I will interpret the questions in that light.

The Legislative Framework

[13] The answers to the questions which have been posed must, of course, be given taking account of the legislative framework within which the Board operates. The Board is a creature of statute and its jurisdiction and powers to deal with matters brought before it, and the manner of dealing with such matters, must be found, either expressly or impliedly, within the statutes conferring jurisdiction on and governing the operation of the Board.

[14] While a number of specific provisions of the Act and related legislation will have to be referred to in the course of this opinion, certain legislative provisions, which are central to this analysis, can be conveniently set forth here:

Public Utilities Act

58. The board may prescribe the form of all books, accounts, papers and records to be kept by a public utility and a public utility shall keep its books, accounts, papers and records and make its returns in the manner and form prescribed by the board and comply with all directions of the board relating to those books, accounts, papers, records and returns.

69.(1) A public utility, if so ordered by the board, shall, out of earnings, set aside all money required and carry it in a depreciation account.

(2) The depreciation account shall not, without the consent of the board, be spent otherwise than for replacements, new constructions, extensions or additions to the property of the company.

(3) The board may by order require a public utility to create and maintain a reserve fund for a purpose which the board thinks appropriate, including the improvement of the public utility's status as a borrower or seeker of funds for necessary maintenance or expansion of its operations.

(4) The board, in a case where it has made an order which has the effect of increasing a public utility's revenues, may require the public utility to refrain from distributing as dividends until further order the whole or a part of the extra revenue which is in the board's opinion attributable to the order.

(5) An order under this section shall be made only after hearing the public utility concerned.

70.(1) A public utility shall not charge, demand, collect or receive compensation for a service performed by it whether for the public or under contract until the public utility has first submitted for the approval of the board a schedule of rates, tolls and charges and has obtained the approval of the board and the schedule of rates, tolls and charges so approved shall be filed with the board and shall be the only lawful rates, tolls and charges of the public utility, until altered, reduced or modified as provided in this Act.

75.(1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.

(2) The schedule of rates, tolls and charges approved under subsection (1) are the only lawful rates, tolls and charges of the public utility until a final order is made by the board under section 70.

(3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be

(a) refunded to the customers of the public utility; or

(b) placed in a reserve fund for the purpose that may be approved by the board.

76. The board may upon notice to the public utility and after hearing as provided in this Act, by order rescind, alter or amend an order fixing rates, tolls, charges or schedules, or other order made by the board, and certified copies of the order shall be served and take effect as provided in this Act for original orders.

78.(1) Except as otherwise provided in this Act, the board may fix and determine a separate rate base for each kind of service provided or supplied to the public by a public utility, and may revise the base.

(2) In fixing a rate base the board may, in addition to the value of the property and assets as determined under section 64, include

.....

(h) other fair and reasonable expenses which

(i) the board thinks appropriate and basic to the public utility's operation, and

(ii) has, with the approval of the board, been charged to capital account,

but the expenses shall be allowed only to the extent not amortized in previous years.

80.(1) A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility but where the board by order requires a public utility to set aside annually a sum for or towards an amortization fund or other special reserve in respect of a service supplied, and does not in the order or in a subsequent order authorize the sum or a part of it to be charged as an operating expense in connection with the service, the sum or part of it shall be deducted from the amount which otherwise under this section the public utility would be entitled to earn in respect of the service, and the net earnings from the service shall be reduced accordingly.

(2) The return shall be in addition to those expenses that the board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the board according to this Act and the rules and regulations of the board.

(3) Reasonable payments each year to former employees of a public utility who have retired and are receiving payments of supplemental income from the public utility are expenses that the board may allow as reasonable and prudent and properly chargeable to the operating account of the public utility.

(4) The board may use estimates of the rate base and the revenues and expenses of a public utility.

84.(1) Upon a complaint made to the board against a public utility by an incorporated municipal body or the Newfoundland and Labrador Federation of Municipalities or by 5 persons, firms or corporations, that the rates, tolls, charges or schedules are unreasonable or unjustly discriminatory or that a regulation, measurement, practice or act affecting or relating to the operation of a public utility is unreasonable, insufficient or unjustly discriminatory or that the service is

inadequate or unobtainable, the board shall proceed, with or without notice, to make the investigation that it considers necessary or expedient.

(2) The board may order the rates, tolls, charges or schedules reduced, modified or altered, and make other orders as to the reduction, modification or change of the regulation, measurement, practice or acts that the case may require, and may order on the terms and subject to the conditions that are just that the public utility provide reasonably adequate service and facilities and make extensions that may be required, but an order shall not be made or entered by the board without a public hearing or inquiry.

87.(1) Where upon an investigation the rates, tolls, charges or schedules are found to be unjust, unreasonable, insufficient or unjustly discriminatory, or to be preferential or in violation of this Act, the board has power to cancel those rates, tolls, charges or schedules and declare void all contracts or agreements, either oral or written, dealing with them upon and after a day named by the board, and to determine and by order substitute those rates, tolls or schedules that are reasonable.

91.(1) A public utility shall not issue shares, which for the purposes of this section shall include preferred shares, stocks, bonds, debentures or evidence of indebtedness payable in more than 1 year from the date of issue, except as provided in subsection (2) until it has obtained approval from the board for the proposed issue; ...

.....

(3) After hearing the application and where satisfied that the proposed issue by a public utility of its shares, stocks, bonds, debentures or other evidence of indebtedness is to be made in accordance with law and for a purpose approved by the board, it is the duty of the board to make an order approving the proposed issue to the amount that it considers appropriate, and also to prescribe the purpose to which the issue or the proceeds of the issue are applied.

.....

(5) Without first obtaining the approval of the board,

(a) a public utility shall not make a material alteration in the characteristics of its stocks or shares, or its bonds, debentures, securities, or other evidence of indebtedness as those

characteristics are described by the board in granting its approval of the issue; ...

Electrical Power Control Act, 1994[8]

3. It is declared to be the policy of the province that

(a) the rates to be charged, either generally or under specific contracts, for the supply of power within the province

(i) should be reasonable and not unjustly discriminatory,

(ii) should be established, wherever practicable, based on forecast costs for that supply of power for 1 or more years,

(iii) should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world, and

.....

(b) all sources and facilities for the production, transmission and distribution of power in the province should be managed and operated in a manner

(i) that would result in the most efficient production, transmission and distribution of power,

(ii) that would result in consumers in the province having equitable access to an adequate supply of power,

(iii) that would result in power being delivered to consumers in the province at the lowest possible cost consistent with reliable service, ...

.....

[8]S.N. 1994, c. E-51, as amended (hereinafter, the "EPC Act")

> 4. In carrying out its duties and exercising its powers under this Act or under the *Public Utilities Act*, the public utilities board shall implement the power policy declared in section 3, and in doing so shall apply tests which are consistent with generally accepted sound public utility practice.

Approach to Interpretation

[15] The Court was not referred to any decisions in this or other jurisdictions which directly addressed, let alone answered, the specific types of questions which have been posed. To answer the questions, therefore, it is necessary to develop a theoretical frame of reference within the context of the general language of the existing legislation so as to determine the approach to be taken to its application in concrete situations.

[16] It is necessary to examine the specific legislative provisions in the larger regulatory context and against the background of the purposes of the legislation and the general principles which have been developed as part of regulatory practice[9]. This approach follows from s. 118 of the Act which provides:

> 118.(1) This Act shall be interpreted and construed liberally in order to accomplish its purposes, and where a specific power or authority is given the board by this Act, the enumeration of it shall not be held to exclude or impair a power or authority otherwise in this Act conferred on the board.
>
> (2) The Board created has, in addition to the power specified in this Act, all additional implied and incidental powers which may be appropriate or necessary to carry out the powers specified in this Act.
>
> (3) A substantial compliance with the requirements of this Act is sufficient to give effect to all the rules, orders, acts and regulations of the Board, and they shall not be declared inoperative, illegal or void for an omission of a technical nature.

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[9] I acknowledge a large indebtedness to the following sources for much of the information referred to herein about general regulatory principles and practice in North America: Charles F. Phillips, Jr. **The Regulation of Public Utilities** (Arlington: Public Utilities Reports Inc., 1993); A.J. deGrandpré, "Fair Returns for Utilities-Concept or Reality?" (1970), 16 McGill L.J. 19; A.B. Jackson, "The Determination of the Fair Return for Public Utilities" (1964), 7 Canadian Public Administration 343.

[17] In addition, the EPC Act[10], provides that the Board, in carrying out its duties and exercising its powers under the **Public Utilities Act** must implement the power policy of the province, as declared in s. 3 of the Act, and in so doing must "apply tests which are consistent with generally accepted sound public utility practice".

[18] It follows from these provisions that a literal and technocratic interpretation and application of the provisions of the Act is to be avoided, in favour of an interpretation which will advance the underlying purpose of the legislation[11], as well as the power policy of the province and be consistent with generally accepted sound public utility practice.

[19] In answering the questions posed, therefore, it is necessary to identify generally accepted principles of sound public utility practice and to give to the legislation an interpretation which follows those principles and advances the stated legislative policy of the Province.

[20] The trade off for the regulation by the state of the rates, tolls and charges of monopolistic utilities in the interests of consumers is the statutory recognition that the utility should be entitled to earn a fair return for its efforts. Although differing in details, the regulatory statutory regimes existing throughout North America can, as a generalization, be said to be broadly similar in approach[12], although in recent

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[10] s. 4

[11] See **Bell Canada v. Canada (CRTC)** [1989] 1 S.C.R. 1722 (hereinafter referred to as the "Bell Rebate case") where Gonthier, J. in response to an argument that a regulatory board did not have a particular power because it was not expressly provided for in the legislation stated at p. 1758: "This approach to the interpretation of statutes conferring regulatory authority over rates and tariffs is only the expansion of the wider rule that the Court must not stifle the legislator's intention by reason only that a power has not been explicitly provided for."

[12] "Nearly all the boards and commissions in the United States and Canada that regulate public utility rates do so on the basis of allowing a public utility a 'return' on the 'value' of the public utility property. The return that must be allowed is usually referred to as the 'fair return' ..." per Jackson, op.cit. fn.9, p. 343. See also **Re Union Gas Ltd. and Ontario Energy Board et al** (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.) per Anderson, J. at page 710: "By way of general observation ... there are substantial similarities between the situation here and in the United

years the regulatory schemes and their coverage are being affected more and more by the trends towards deregulation.

[21] The regulatory body in question (in Newfoundland, the Board of Commissioners of Public Utilities) is generally charged with balancing the competing interests of consumers and the investors in the utility[13]. As deGrandpré[14] observed:

> This involves the Board attempting to make sure that, in the consumers' interests, the service provided is adequate and provided at just and reasonable rates and, for the utility and its investors, that those rates provide a sufficient income.

[22] This balancing of interests is found in the province's stated power policy in s. 3 of the **EPC Act** where, emphasizing the interests of the utility, it is declared that the rates charged for the power should provide sufficient revenue to the utility to enable it to earn a just and reasonable return "so that it is able to achieve and maintain a sound credit rating in the financial markets of the world"[15] while at the same time declaring that the rates should be "reasonable"[16] and that the utilities' facilities should be managed and operated in a manner that would result in power

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States, and authorities of courts in the United States are frequently referred to and considered..."

[13]**Federal Power Commission et al v. Hope Natural Gas Co.** 320 U.S. 591 (1944), per Douglas J. at page 603: "The rate-making process under the Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests"; **Northwestern Utilities Limited v. City of Edmonton** [1929] S.C.R. 186, per Lamont, J. at pages 192-193: "The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer on the one hand, and which, on the other hand, would secure to the company a fair return for the capital invested".

[14]deGrandpré, op.cit. fn. 9, p. 20. See also **Re Union Gas Ltd. and Ontario Energy Board et al** (1983), 1 D.L.R. (4th) 698 (Ont. Div. Ct.) per Anderson, J. at page 710: "... it is the function of the [Board] to balance the interest of the [utility] in earning the highest possible return on the operation of its enterprise (a monopoly) with the conflicting interests of its customers to be served as cheaply as possible". See also **Bell Canada v. Canada (CRTC)** [1989] 1 S.C.R. 1722 per Gonthier, J. at p. 1748.

[15]**EPC Act**, s. 3(a)(iii)

[16]**EPC Act**, s. 3(a)(i)

being delivered to consumers "at the lowest possible cost consistent with reliable service"[17]. This policy finds legislative expression in the regulatory mechanisms of the Act itself, which provides that a utility must provide service and facilities which are "reasonably safe and adequate and just and reasonable"[18] and prohibits a utility from charging rates, tolls and charges unless they have been approved by the Board[19] while at the same time stating as a general principle that the utility is entitled to earn annually a just and reasonable return on its rate base[20].

[23] This statutory entitlement of the utility to earn a "just and reasonable" return is the linguistic touchstone for the balancing exercise. This phrase emphasizes the fairness aspect, both to the utility, in earning sufficient revenues to make its continued investment worthwhile and to maintain its credit rating in financial markets, and to the consumer, in obtaining adequate service at reasonable rates. It also emphasizes the need for a tempering of each interest group's economic imperative by consideration of the interests of the other.

[24] Having said that, the entitlement of the utility to a fair return on its investment is always regarded as of fundamental importance[21]. In the United States, controls which fail to allow a fair return have the potential of running afoul of constitutional strictures against confiscation of property without due compensation. While the same constitutional concerns may not be present in Canada, the case law has at times nevertheless referred to the entitlement to a fair

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[17]**EPC Act**, s. 3(b)(iii)

[18]**Act**, s. 37(1)

[19]**Act**, s. 70(1). Although, unlike the legislation of some other jurisdictions, s. 70 does not expressly state that the rates approved by the Board must be "reasonable" or "just and reasonable", that standard is nevertheless imported into the approval process by virtue of the **EPC Act**, s. 3(a)(i) which declares the policy of the province to be that rates must be "reasonable".

[20]**Act**, s. 80(1)

[21]**British Columbia Electric Railway Co. Ltd. v. Public Utilities Commission of British Columbia et al** [1960] S.C.R. 837, per Locke, J. at page 848: "The obligation to approve rates which will produce the fair return to which the utility has been found entitled is, in my opinion, absolute..."

return as a "common law right"[22] which should be read into the legislation even where it is not specifically expressed.

[25] There is no uniform methodology employed in the regulatory jurisdictions in North America for the determination of a just and reasonable rate of return[23]. What recurs, however, is a theme that the process is not an exact science and depends on a variety of factors necessary to balance the competing interests involved. Rate setting is essentially a prospective exercise where determinations are made on the basis of estimates and information that will not necessarily remain static.

[26] Most jurisdictions adopt a "multiple factor" approach. The **Bluefield Waterworks** case[24] in the United States emphasized early on that the determination of a fair rate of return

> ... depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts.[25]

[27] Statements such as "the company will be allowed as large a return on the capital invested in the enterprise ... as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise"[26] often occur. For the

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[22]Ibid., per Locke, J. at pages 845, 847.

[23]Ibid., per Locke, J. at page 848: "I do not think it is possible to define what constitutes a fair return upon the property of utilities in a manner applicable to all cases ...".This observation was adopted and followed by this Court in **Newfoundland Light and Power Co. v. P.U.C. (Bd.)** (1987), 25 Admin. L.R. 180 (NFCA) at page 193.

[24]**Bluefield Waterworks and Improvement Co. v. Public Service Commission of West Virginia et al,** 262 U.S. 679 (1923). (This case has often been referred and relied upon in subsequent decisions in the United States and Canada, including in this Court. See **Newfoundland Light & Power Co. v. P.U.C. (Bd.)** supra, fn. 23 at page 193.)

[25]Ibid., page 692.

[26]**Northwestern Utilities Ltd. v. City of Edmonton** [1929] S.C.R. 186, per Lamont, J. at page 193.

rationale for such statements one need look no further than the provincial policy, stated in paragraph 3(a)(iii) of the **EPC Act** that the utility must be "able to achieve and maintain a sound credit rating in the financial markets of the world" so as to be able to raise the money necessary for the proper performance of its functions. To achieve such a goal of attracting capital, factors such as comparisons with other comparable enterprises, the respective costs of debt and equity, the capital breakdown between debt and equity and general economic conditions, amongst other things, are considered.

[28] In **Federal Power Commission v. Hope Natural Gas Co.**[27], another landmark United States case, the court emphasized that it is the "end result of the process which has to be judged as to whether the rate is "just and reasonable". As a result, in the words of deGrandpré:

> In stating that the end result was the only point of consideration, whatever the means of arriving thereat, the court opened the door to a wide variety of ways and means to arrive at a proper calculation of returns. In effect, it left the valuation of rate bases to the Commission's or Court's discretion.[28]

DeGrandpré's conclusion, based on his survey of North American regulatory regimes, is later stated as follows:

> The constantly changing economic conditions are perhaps a good reason why there should be no stringent rules for determining a rate of return. As was often stated, the process is one which calls for common sense, good judgment and a proper appreciation of all surrounding factors.[29]

[29] This approach is also reflected in the decision of this Court in **Newfoundland Light & Power Co. v. P.U.C. (Bd.)** where O'Neill, J.A., speaking for the Court in rejecting an argument that the Board of Commissioners of Public Utilities had exceeded its jurisdiction in determining a just and reasonable rate of

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[27]320 U.S. 591 (1944)

[28]deGrandpré op.cit. fn. 9, page 28

[29]Ibid., page 37

return by not adopting a particular methodology (a "comparable earnings" test), stated:

> ... it is within the discretion of the Board, having heard all the evidence and giving consideration to the various tests which may be used, to make its ruling on the basis of what in the Board's opinion will give to the applicant a just and reasonable return and permit it to maintain a sound financial credit rating.[30]

The Board therefore has a broad discretion to adopt appropriate methodologies for the calculation of allowable rates of return. So long as the methodologies chosen are not inconsistent with generally accepted sound public utility practice and the purposes and policies of the Act, and can be supported by the available opinion evidence, the determination of what constitutes a just and reasonable return in a given case will generally be within the province of the Board and will not normally be interfered with[31]. The jurisdiction of the Board must therefore be defined to enable that process to occur.

[30] Because setting the rate of return is not an exact science no matter what methodology is chosen, because the viewpoint is essentially prospective, it has been recognized that there is a "zone of reasonableness" within which a rate of return chosen by the Board should be regarded as just and reasonable. This has been expressed by the United States Supreme Court in the following language:

> Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. It allows a substantial spread between what is unreasonable because too low and what is unreasonable because too high[32].

This notion has also at times been recognized in Canada[33].

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[30]supra, fn. 23 at page 194

[31]Ibid. page 194

[32]**Montana-Dakota Co. v. Public Service Co.**, 341 U.S. 246 (1951), per Jackson, J. at page 251

[33]**Re The Bell Telephone Company of Canada** (1966), 56 B.T.C. 535 at page 731: "We are ... not persuaded that reasonableness can, in practical terms, be expressed as a fixed point from which there can be no deviation. We therefore propose to use a range of percentage

[31] This leads to another point: because the setting of the rate of return is based on projections, one cannot be sure that the rate of return will be achieved in practice. Although the utility is "entitled" by s. 80 of the Act to have the Board determine a just and reasonable rate of return based on appropriate predictive techniques and methodologies, it is not "entitled", in the sense of being guaranteed, to that rate of return[34]. The utility therefore takes the risk that its chosen management techniques and the future economic climate may not yield its expected success. Although some of the activities of the utility are regulated within the framework of the statutory objectives, the utility nevertheless remains subject to business risks and the effects of management decisions. To that extent, the financial risks associated with the operation of the utility, just as in the case of any private business, are to be born by the investors in the enterprise, not the consumer of the service.

[32] The corollary of this position is that the utility must be accorded a degree of managerial flexibility in decision-making in order to be able to minimize the risks to which it must respond. Thus, it is often said that the powers of the Board must be regulative and corrective, but not managerial, and they do not therefore contemplate a retroactive adjustment of the actions of management.

[33] This leads to the general principle of non-retroactivity which prevents a utility from recovering expenses incurred in the past out of current rates. The utility must live with the decisions it makes and the economic vicissitudes that occur.[35]

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earnings on total average capitalization."

[34]**Federal Power Commission v. Hope Natural Gas Co.** Supra fn. 13 per Douglas, J. at page 603

[35]In **Re Northwestern Utilities Ltd. et al and City of Edmonton** (1978), 89 D.L.R. (3d) 161 (SCC), Estey, J. stated at p. 164: "The statutory pattern is founded on the concept of the establishment of rates in futuro ... [T]he Board must act prospectively and may not award rates which will recover expenses incurred in the past and not recovered under the rates established for past periods." [Of course, such an approach assumes that without such rates, the utility will continue to be economically viable. If poor management leads to losses that threaten the very continued existence of the utility, the Board may well have to set future rates at a level that will

[34] By the same token, it is sometimes argued that the occurrence of the reverse situation, of the utility doing better than expected, should mean that the utility should be able to reap the advantage of better and more efficient management techniques and favourable economic conditions and keep any surplus. The concern for the consumer interest is often put forward as a brake on this idea, however. The requirement that the consumer receive power "at the lowest possible cost"[36] consistent with the utility's requirement of earning a just and reasonable return for its purposes means, it is often argued, that the regulator ought to have power to ensure that excessive returns are somehow accounted and compensated for.

[35] Another factor that is referred to in the cases is the recognition that the capital structure of the utility will often have a bearing on the total cost of capital and this will therefore be important where the determination of the rate base depends on the total debt and equity capital requirements. DeGrandpré observes that "the reasonableness of the ratio of debt to equity is a question of fact left to the appreciation of the Board or Court"[37]. Thus, issues such as whether the Board can dictate to the utility a particular mix of debt and equity or, for the purpose of setting the rate of return, do so on the basis of a notional blend of capital requirements if the actual blend is not in accordance with what the Board feels is optimal to ensure a fair return as well as low rates, tolls and charges, often surface. Indeed, this issue is presented in this case.

[36] Having conducted this brief survey, I will now attempt to state some general principles to be used in the interpretation and application of the local legislation:

1. The Act should be given a broad and liberal interpretation to achieve its purposes as well as the implementation of the power policy of the province;

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enable the utility to remain operative so as to ensure continued service to customers. This is an unlikely scenario in view of the close monitoring that the Board should exercise between rate hearings.]

[36] **EPC Act**, s. 3(1)(b)(iii)

[37] deGrandpré op.cit. fn. 9, page 26

2. The Board has a broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the purposes of the legislation and to implement provincial power policy;

3. The failure to identify a specific statutory power in the Board to undertake a particular impugned action does not mean that the jurisdiction of the Board is thereby circumscribed; so long as the contemplated action can be said to be "appropriate or necessary" to carry out an identified statutory power and can be broadly said to advance the purposes and policies of the legislation, the Board will generally be regarded as having such an implied or incidental power;

4. In carrying out its functions under the Act, the Board is circumscribed by the requirement to balance the interests, as identified in the legislation, of the utility against those of the consuming public;

5. The setting of a "just and reasonable" rate of return is of fundamental importance to the utility and must always be an important focus of the Board's deliberations; however, the "entitlement" of the utility to a just and reasonable rate of return does not guarantee it that level of return. The "entitlement" is to have the Board address that issue and to make its best prospective estimate, based on its full consideration of all available evidence, for the purpose of setting rates, tolls and charges.

6. The Board has jurisdiction, which will not generally be interfered with on judicial review, to make a determination of what is a just and reasonable rate of return within a "zone of reasonableness" and in so doing is not constrained in its choice of applicable methodologies, so long as they can be rationally justified in accordance with sound utility practice and are not inconsistent with the achievement of the purposes and policies of the legislation.

[37] It is now necessary to consider each of the specific questions that have been posed. In approaching them, it is worth remembering that the questions have been posed in the abstract and ask for answers to broadly-identified issues of jurisdiction. The case is not an appeal and there can be no findings of fact made by this Court in arriving at its conclusions. The information provided by the

Board as to past hearings was given as background only so as to assist the Court in better understanding the scope and potential importance of the questions. While the answers given may provide guidance with respect to specific issues that have arisen in hearings in the past, they cannot be taken as an adjudication of those issues in the specific factual context in which they arose.

Question No. 1

> (1) **Does the Board have jurisdiction pursuant to the Act to set and fix the return which a public utility may earn annually upon:**
>
> (i) **the rate base as fixed and determined by the Board for each type of service applied by the public utility; and/or**
>
> (ii) **the investment which the Board has determined has been made in the public utility by the holders of common shares.**

[38] It will become apparent from the ensuing discussion that a number of the questions posed on this stated case are interrelated in the sense that the answer to some of them will provide a strong impetus for a particular response in others. This is particularly evident in Question 1.

[39] The answer to Question 1 in fact involves a consideration of two sub-issues. The first relates to the legal significance of a determination by the Board on a given application of the just and reasonable return to which the utility is entitled. The second sub-issue, which is affected by the decision on the first, relates to the powers of the Board to make determinations with respect to the rate of return on a utility's common equity portion of its capital structure.

(a) The Legal Significance of a "Determination"

[40] It is to be noted that Question 1 asks whether the Board has jurisdiction to "set and fix" the utility's return whereas s-s. 80(1) of the Act speaks in terms of the utility being entitled to earn a return as "determined" by the Board. The use of this differing terminology in the question, as explained by counsel for the Board at the hearing, was designed deliberately to raise the issue as to whether the Board may, by determining the level of return, be said to be prescribing that level as an upper limit to the level of earnings to which the utility may be entitled and thereby

exercise certain powers with respect to disposition of any excess that may in fact be earned. This issue becomes more focused when Question 3 is considered. The answer to that question will, to some extent, be influenced by the power which the Board can be said to have under s. 80 with respect to the setting of a level of return.

[41] It is obvious, of course, that in the process of approving rates, tolls and charges under s-s. 70(1) the Board must determine what is a just and reasonable return on the utility's rate base in order to determine the level of revenue needed by the utility[38]. This flows from the utility's "entitlement" in s-s. 80(1) to earn that level of return. The determination of a just and reasonable return on rate base is therefore an essential component in the series of calculations which the Board must undertake in the process of approving rates, tolls and charges.

[42] If the determination of a just and reasonable return is merely a step in the process of approving rates, tolls and charges under s-s. 70(1), that is, if it is only an intermediate calculation necessary to arrive at the final result of consumer rate approval, the "determination" of a just and reasonable level of return will have no independent legal significance, in the sense of prescribing the limit of the utility's return for other purposes of the Board's functions.

[43] On the other hand, if the determination of a just and reasonable level of return has, as it were, an independent life of its own, in the sense of it not being a mere intermediate calculation but can be "set and fixed", in the sense of being prescribed, it could, for example, be used to support an argument that a utility is not entitled to earn in excess of a just and reasonable return. As indicated, this impacts directly on Question 3. While counsel for NLP suggested that there may be other mechanisms available to deal with excess earnings (by means of the use of a designated excess revenue reserve fund), that would not require the derivation of such a power from s. 80, counsel for the Board and the Consumer Advocate both indicated that they were concerned about the legal basis for the derivation of the operation of an excess revenue account from other parts of the legislation, such

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[38] "The fixing of tolls and tariffs that are just and reasonable necessarily involves the regulation of the revenues of the regulated entity": per Gonthier, J. in **Bell Canada v. Canada (CRTC)** supra, fn. 11 at page 1747

as the administrative and supervisory power of the Board to regulate a utility's accounts. It is appropriate therefore that this matter be addressed.

[44] The issue boils down to this: If the power to "determine" the return encompasses the notion of fixing, in the sense of prescribing the limits of entitlement, one would be able to derive from s-s. 80(1) a power in the Board to say to the utility that it may earn that level of return and no more. If not, the power to determine would simply be part of a calculation that leads to consumer rate setting with no independent existence or significance for regulatory practice generally.

[45] **Black's Law Dictionary**[39] explains "determine" in part as follows:

> To bring to a conclusion, to settle by authoritative sentence, to decide. ... To adjudicate on an issue presented ...
>
> To estimate ...
>
> To decide, and analogous to "adopt" or "accept" ...

[46] The **Concise Oxford Dictionary**[40] defines the word in pertinent part as:

> 1. v.t. & i. settle, decide, (dispute, person's fate ...), come to a conclusion, give decision, be the decisive factor in regard to ...; ascertain precisely, fix; ...
>
> 3. v.t. & i. (esp. Law) bring or come to an end.
>
> 4. v.t. limit in scope, define; fix (date) beforehand.

[47] For what limited value these definitions can have in this context, it would appear that the primary meaning of the word determine, with its emphasis on coming to a final decision and amounting to a decisive factor as well as the notion of ascertaining something precisely and "fixing", encompasses something more than a mere calculation in a broader process.

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[39] 4th ed. rev., 1968

[40] J.B. Sykes (ed), 7th ed.

[48] Having said that, it is to be noted that s-s. 80(1) is structured in such a way that its emphasis is on the entitlement of the utility to a just and reasonable return, as determined by the Board, rather than involving the express conferral on the Board of a power to prescribe the level of return. The structure of the subsection could be said to be directed towards establishing a minimum base line of entitlement without saying anything expressly about the power of the Board to create a cap. To put the matter beyond doubt, the insertion of the words "and no more" after the language entitling the utility to a just and reasonable return would certainly have clearly indicated a prescriptive power in the Board, if that had been intended. Furthermore, although the return is referred to as being "determined" by the Board, the subsection goes on to indicate that the return so determined is applied to the rate base "as fixed and determined" by the Board. On a strict linguistic analysis alone, the use of the word "fixed" in conjunction with "determined" in one place would imply that its absence in the other was deliberate.

[49] Notwithstanding these matters, I am not satisfied that a linguistic analysis of the subsection can provide the answer in this case. Even a cursory perusal of the remaining provisions of the Act indicates that there is no uniform terminology chosen to describe the various decision-making functions in which the Board may engage. For example, the Act provides that the Board may "inquire into and determine"[41] the valuation of a utility's assets and may "determine"[42] those values in accordance with a number of stated rules. It may "ascertain and determine"[43] what are proper and adequate rates of depreciation of classes of utility property. Its role with respect to the utility's rates, tolls and charges is one of "approval"[44].

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[41] s. 64(1)

[42] s. 64(2)

[43] s. 68(4)

[44] s. 70(1). This provision makes the scheme administered by the Board a "positive approval scheme" (requiring advance approval of rates as being reasonable) rather than a "negative disallowance scheme" (permitting the utility to set its own rates subject to user objection, which would only then trigger a review into reasonableness), as those terms were explained by Gonthier, J. in the **Bell Rebate** case, supra, fn. 11 at p. 1758.

Indeed, if there is any decision of the Board which is contemplated as having operative legal effect and to amount to a "fixing" of the utility's rates, tolls and charges from which the utility may not deviate, it is the "approval" contemplated in this regard; yet the word "fix" does not appear. In another context, the Board may "fix and determine"[45] a separate rate base for each kind of service supplied by a utility; yet when describing what is to be included in the calculation of rate base, the reference to "determine" is dropped and it is simply described as "fixing a rate base"[46]. Finally, the term "approval" surfaces again in the context of the power of the Board to authorize new stock issues of the utility[47].

[50] To resolve this conundrum, resulting from inconsistency in terminology, resort must be had to the purposes of and policies underlying the legislation as mandated in s-s. 118 of the Act as well as s. 4 of the **EPC Act**. As indicated previously,[48] the Board is required, in carrying out its functions under the Act, to balance the interests, as identified in the legislation, of the utility against those of the consuming public. The notion of a "just and reasonable return" in s-s. 80(1) is the benchmark against which fairness to the utility and the consumer is to be measured. It is pivotal in the balancing exercise. The interests of the consuming public in obtaining power at the lowest possible cost consistent with reliable service[49] must accommodate the utility's interest in being afforded the opportunity to earn a fair rate of return for its efforts. In the methodology adopted by the Board, the approval of appropriate rates, tolls and charges necessarily factors the just and reasonable return, and only that level of return, into that calculation. Otherwise, the interests of the consumer would not be protected in obtaining power at the lowest possible cost. It is therefore inherent in the process that in determining a just and reasonable return for the utility, the utility should have the opportunity of earning that return but, other things being equal, should not expect to earn any more. Accordingly, determining the just and reasonable return

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[45] s. 78(1)

[46] s. 78(2)

[47] s. 91(1), (3)

[48] supra, paragraphs [21] -[23]

[49] **EPC Act**, s. 3(b)(iii)

necessarily involving prescribing the return and in that sense can be said to amount to "setting and fixing" the rate of return.

[51] It follows from this that the use of the word "determine" can, in the context of the use of that and other terminology in the Act, encompass something more than the notion of mere calculation and extends to the idea of prescribing, or fixing, a level of return in the nature of a legal decision which can bind and have effect on the utility for other purposes related to the Act.

(b) <u>The Power to Set and Fix the Level of Return on Common Equity</u>

[52] In order to determine the just and reasonable return on rate base to which the utility is entitled by s-s. 80(1), the Board must first determine the cost to the utility of the various components of its sources of funds. The costs associated with long term debt and preference shares are generally static over the period covered by a particular rate hearing. Accordingly, they are often described as "embedded costs". The rate of return necessary to be earned on rate base to cover the cost of debt and preference shares can therefore usually be easily determined based on the interest rates or dividend rates applicable to such instruments. In the case of common equity, however, the cost to the utility of this source of funds depends upon a number of factors, especially current market conditions which, by nature, can be volatile.

[53] At a rate hearing, therefore, the Board usually faces a greater difficulty in determining the component of rate of return on common equity than on the other sources of funds because their embedded costs are usually well defined.

[54] Since the rate base is financed by a combination of debt, preference shares and common equity, the rate of return on which is different for each component, the overall rate of return on rate base is calculated as a weighted average of the rates of return on the various individual components.[50]

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[50]See, e.g., Board Order P.U.6 (1991), page 72

[55] As a generalization, it is sometimes said that the cost of common equity is often higher than that of debt[51]. The rate of return on common equity may therefore be expressed as a percentage which is higher than the overall rate of return on the full rate base because the higher equity cost will be weighted downwards by the rates for the other components.

[56] The issue raised by Question 1(ii) is whether the Board may set and fix the rate of return on common equity, as a component of the overall rate of return on rate base in a manner such that it can be used as an independent benchmark for other purposes in the same way as the overall determination of return on rate base can be. Alternatively, is the "determination" of the rate of return on common equity to be treated in the narrower sense of a mere calculation leading to the final determination of overall return?

[57] Subsection 80(1) makes no reference at all to determining, let alone setting and fixing, the rate of return on common equity. The calculation of an appropriate rate of return on common equity is truly a mere component in the overall process of determining a just and reasonable return on rate base. Furthermore, there is nothing in the purpose of the Act or the policies which the Board is to implement which would lead inexorably to the conclusion that the Board ought to have the power to prescribe a rate of return on common equity as a component of an overall return or rate base, any more than it ought to have a power to prescribe a return on any other component.

[58] The Consumer Advocate submitted that inasmuch as s-s. 80(1), by its express language, contemplates that the only measure of what NLP may earn annually is to be determined by a just and reasonable return on rate base, to allow the utility to measure what it may earn annually based upon a different factor, such as a rate of return on common equity which could very well be higher than the overall rate of return on rate base and might lead to a higher overall return that could be said to be justified, would be to allow the utility to earn more than that to which it is statutorily entitled.

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[51]Phillips, op.cit., fn. 9, p. 389

[59] It is to be noted, however, that in its previous orders[52] the Board has not sought to determine the level of return on the basis of anything other than a rate of return on rate base. For example, in the 1991 Order, the Board ordered:

> A just and reasonable return for [NLP] is determined to be between 10.96% and 11.19% on its average rate base for 1992, which will provide an opportunity to earn a rate of return on common equity between the range of 13.00% to 13.50%.
>
> [Emphasis added]

The reference to the range of rates of return on common equity appears to have been inserted more as information in support of a rationale for the determination of the overall return on rate base, since the Board states that the determination of the return on rate base "will provide" an "opportunity" to earn a rate of return on common equity. Similarly, the 1996-97 Order simply described the rate of return on rate base as being "derived from" a given range of return on common equity. This is the correct approach.

[60] As to whether the Board may make other decisions, for example relating to the manner in which an excess revenue fund should be maintained, by reference to the contemplated rate of return on common equity, is a separate matter which should be dealt with in that context.

[61] I therefore conclude that the power to "determine" a just and reasonable return on rate base, as contained in s-s. 80(1) does not include within it a power to "set and fix a rate of return on common equity" but it obviously does contemplate that the analysis of appropriate rates of return on common equity will be undertaken and factored into the conclusion as to what is a just and reasonable return on rate base.

[62] Accordingly, giving the words "set and fix" in the question a meaning which implies the notion of prescribing, I would answer Question 1 as follows:

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[52]See, e.g. P.U. 6 (1991) and P.U. 7 (1996-97)

As to:

1. (i) - Yes

1. (ii) - No

Question No. 2

> **(2) Does the Board have jurisdiction to set the rates of return referred to in Question (1) as a range of permissible rates of return.**

[63] In light of my answer to the second part of Question 1, it is only necessary to address Question 2 in the context of whether the Board has jurisdiction to set the rate of return on rate base as a "range of permissible rates of return".

[64] It has already been stressed that the determination of a just and reasonable return on rate base involves a consideration of the differing costs of the components of the utility's capital structure and that in arriving at the overall rate of return, it is permissible for the Board to use a weighted average of the rates associated with each individual component. It has also been pointed out that the cost of common equity is often difficult to estimate with precision. The best that experts are often able to do is estimate rates within a reasonable range. Inasmuch as the cost of common equity is weighted into the overall rate of return on rate base, that range would also have to be reflected in the ultimate rate of return on rate base, as determined by the Board.

[65] In **Northwestern Utilities Ltd. v. City of Edmonton**[53] Smith, J. emphasized:

> The question of a fair rate of return on a risky investment is largely a matter of opinion, and is hardly capable of being reduced to certainty by evidence, and appears to be one of the things entrusted by the statute to the judgment of the Board.

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[53]Supra fn. 13 at p.199

[66] It is evident, as **Newfoundland Light & Power Co. v. P.U.C. (Bd.)**[54] demonstrates, that the determination of a just and reasonable return is an area in which the Board is accorded a broad discretion as to the methodology to be adopted. Obviously, the striking of a balance between the interests of the utility and the consumer, whilst at the same time attempting to comply with the Board's obligation to approve rates which will produce a fair return to the utility, cannot be done with the precision of a simple mathematical calculation. Realistically, the balance can only be struck within a reasonable range. It is for that reason that the courts have, on subsequent appeal or applications for judicial review, generally deferred to the determinations of boards in this regard provided the determination is not arbitrary or capricious and can be said to fall within a reasonable range.[55] As indicated in the earlier discussion[56], in the United States the notion of a "zone of reasonableness" as an "area rather than a pinpoint" has been recognized. Whilst this notion has been enunciated as a justification for deference to Board decisions in the context of challenges on appeal or judicial review, it nevertheless indicates a recognition of what is inherent in the rate setting process.

[67] I see no reason, therefore, why, instead of attempting to justify a particular decision ex post facto by an argument that a particular rate falls within a zone of reasonableness, the Board could not expressly indicate what it believes that area of reasonableness to be by expressing what it believes to be a just and reasonable return in terms of a range of rates of return. This indeed is a practice that has been adopted elsewhere[57]

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[54]supra fn. 23

[55]**Re Union Gas Ltd. and Ontario Energy Board et al**, supra fn. 12

[56]para.[30]

[57]See **Bell Canada v. Canada (CRTC)**, supra, fn. 11 at page 1733. Yvonne Penning, "The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled" (1989), 47 U of T Fac. L.R. 607 observes at p. 617: "The CRTC has developed the practice of setting the allowed ROE on the basis of a one percentile range. While only one actual ROE - usually the middle of the range - is used in the calculation of rates to be charged customers, all rates encompassed by the range, in theory, represent a reasonable return. One reason for setting such a range is that it explicitly provides some incentive for the company to be efficient; financial rewards due to efficiency or productivity gains would accrue to the company's shareholders, rather than being passed on to consumers through lower prices." Another rationale for a range

[68] It is to be noted that s-s. 80(1) does not speak in terms of a "rate" or "rates" of return; rather, it speaks of a just and reasonable "return". It is not limited by its language to the pinpointing of a particular rate of return. I conclude that a liberal construction of the word "return" in the context of s-s. 80(1) leads to the conclusion that it can include a range of rates of return.

[69] Of course, in applying the rate of return to the rate base, as ascertained by the Board, a single figure will have to be used since rates, tolls and charges are expressed as finite numbers. The Board in practice has chosen the mid-point of its stated range of rates of return as the figure to be used for this purpose. This is a perfectly acceptable practice for the purpose of setting the rates. By expressing a range, however, the Board leaves open to the utility the flexibility of earning more than the mid-point up to the maximum end of the range so as, in effect, to give the benefit of the doubt to the utility that the expert evidence favouring the upper end of the range turns out to be the more accurate and to provide an incentive to the utility towards managerial efficiency.

[70] The Consumer Advocate expressed concern in argument that the use of the word "permissible" in Question 2, as qualifying the phrase "rates of return", might be misleading. As I understand the argument, the concern is that the adoption of a range approach might lead to the conclusion that the "entitlement" of the utility to a just and reasonable return would be regarded as an entitlement, or guarantee, of earning up to the maximum end of the range. While the utility, if it earned as much as the maximum would be entitled to keep that amount of earnings, it is not, for reasons already given, guaranteed that level of return if it is not in fact successful in earning them. The Board is under no obligation to adjust future rates or to take other steps to make up any such shortfall. Any rate of return earned within the range would be regarded as permissible and it is only when a rate of return exceeds the upper limit of the range that it would be regarded by the Board as subject to any excess revenue regulation.

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approach is given by Penning later in her article at p. 621 where, after noting that the U.S. Federal Communications Commission also employs ranges, states: "... it also serves a very useful administrative function in that it limits the circumstances under which it would be necessary to alter rates on a prospective basis, within the time period for which the range of rates of return was deemed to be reasonable, in response to changing economic circumstances."

[71] Accordingly, recognizing that, on my analysis, Question 2 only relates to whether the Board has jurisdiction to set rates of return as a range in relation to its determination of a just and reasonable return on rate base, the answer I would give to Question No. 2 is: "Yes".

Question Nos. 3 and 4

(3) **Should a public utility earn annually a rate of return which is in excess of the rate of return determined by the Board to be just and reasonable, either on:**

(i) **the base rate as fixed and determined by the Board for each type of service applied by the public utility; or**

(ii) **the investment, which the Board has determined, has been made in the public utility by holders of common shares,**

does the Board have jurisdiction to:

(i) **require the public utility to use the excess earnings to reduce revenue requirements for the succeeding year; or**

(ii) **require the public utility to place the excess earnings in a reserve fund for the purpose of adjusting rates, tolls and charges of the public utility at a future date, or**

(iii) **require the public utility to rebate the excess earnings to customers of the public utility.**

(4) **Does the Board have jurisdiction to order that the rates, tolls and charges of a public utility shall be approved taking into account earnings in excess of a just and reasonable return upon,**

(i) **the rate base as fixed and determined by the Board for each type of service applied by the public utility, or**

(ii) the investment, which the Board has determined, has been made in the public utility by the holders of common shares,

in prior years.

[72] The analysis leading to the answers to Questions 3 and 4 can be considered together since they both address the same general theme: the scope of the Board's powers to deal with situations where a utility in fact earns a rate of return that is greater than that determined to be a just and reasonable return.

[73] It was suggested by counsel for NLP that the concept of "excess earnings" does not exist under the Act other than by reference to a definition of what is to be deposited into a reserve fund which the utility may be ordered to create and maintain pursuant to s-s. 69(3) of the Act. This submission follows from the position taken by NLP that the Board has no power under s-s. 80(1) to "set and fix", in the sense of prescribing, a maximum rate of return. NLP had submitted that the Board's power to deal with excess earnings comes solely from its statutory powers to prescribe the form of accounts to be maintained by the utility[58] and to create a reserve fund "for a purpose which the Board thinks appropriate"[59] which could include the purpose of dealing with excess returns. This argument has already been rejected in the analysis relating to Question 1. It follows, therefore, that the issue of excess earnings may present itself for consideration by the Board in circumstances even where a reserve account has not been ordered to be set up. For the purpose of regulation by the Board, the concept of excess earnings is derived from the process of prescribing a just and reasonable return on rate base and not by the decision to require the creation of a reserve account. The question to be considered is what enforcement mechanisms the Board may use to deal with excess earnings so identified.

[74] If, as determined in the answer to Question 1, the Board has jurisdiction flowing from s-s. 80(1) to prescribe the maximum rate of return which a utility may earn in a given year, it is a necessary consequence of such a determination that revenue earned in excess of the maximum of the prescribed range of return is

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[58] s. 58

[59] s. 69(3)

excess revenue to which, by definition, the utility will not be entitled. The Board accordingly must have jurisdiction to regulate how that excess revenue is to be dealt with.

[75] Question 3 requires the Court to consider the range of enforcement mechanisms which the Board may employ to ensure that the utility does not benefit from any windfall profits resulting from earnings in excess of the just and reasonable return to which it is entitled. Three scenarios are proposed:

(1) use excess earnings to reduce revenue requirements for the succeeding year ("Revenue Reduction Approach");

(2) place the excess earnings in a reserve fund to enable an adjustment of rates, tolls and charges at a future date ("Reserve Fund Approach");

(3) require a rebate of excess earnings to consumers ("Rebate Approach").

Question 4 is really a subset of the Revenue Reduction Approach. In one sense it really asks the same question as in Question 3(i) but does not limit the process to the application of excess earnings to only the year next succeeding the year in which the excess earnings have been achieved. It appears to ask the Court to address the question of whether, in the absence of the existence of a reserve account, the Board may, upon being made aware of excess earnings in prior years, reach back into those prior years and take account of those excess earnings by using them to reduce rates, tolls and charges in subsequent periods below what would otherwise be indicated.

[76] In approaching these questions, it is important to bear in mind the nature of the rate setting process and the general principles which are recognized as being applicable to govern the manner in which that process is carried out.

[77] The process of rate setting is generally prospective by nature. Although the Board must set rates for the future, it only has data from past experience, the evidence from utility officials as to planned changes in operations and the opinions of experts as to future economic trends as a guide to what the revenue requirements of the utility will likely be. It is, therefore, necessarily speculative. In developing the utility's requirements, the Board focuses on a "test year" as the

basis for its estimates and adjustments. Traditionally, in North America the test year was chosen as the latest 12 month period for which complete data were available.[60] More recently, due largely to inflation, boards adopted a forward-looking test year which in effect amounts to a forecast of what expenses and costs, and hence revenue requirements, will be. This has been the practice of the Board[61] and is supported by the Act[62] and the **EPC Act**[63]. Past experience of course remains relevant, however, insofar as it gives insight into the possibility of forecasting error.[64]

[78] Because the process is prospective, there is a good possibility that all of the assumptions will not be achieved in practice. The actual rate of return may therefore differ from the rate, or range of rates, prescribed at a previous hearing. On paper, this difference may appear to redound to the benefit or detriment of the utility depending upon whether the actual rate is greater or less than the rate or range prescribed.

[79] When, as a result of actual experience, it appears that the actual rate of return was greater than the rate prescribed for the same period, it becomes necessary to address what the Board can do, if anything, to ensure that the earnings in excess of the prescribed level, (which by definition will be regarded as greater than a just and reasonable return on the rate base), are not allowed to remain with the utility or its investors. In the **Bell Rebate** case[65], Gonthier, J. observed that differences between projected and actual rates "call for a high level of flexibility in the exercise of the [Board's] regulatory duties".

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[60]Phillips, op cit. fn. 9, page 196

[61]See, eg. Board Order P.U.6 (1991), page 81

[62]S. 80(4)

[63]S. 3(a)(ii)

[64]**Northwestern Utilities Ltd. v. City of Edmonton**, supra fn. 35, per Estey, J. at p. 170: "... the Act does not prevent the Board from taking into account past experiences in order to forecast more accurately future revenues and expenses of a utility".

[65]supra, fn. 11 at p. 1734.

[80] Those opposing a broad jurisdiction on the part of the Board to define and deal with excess revenue couch the objection, at least in part, in terms of a violation of the non-retroactivity principle.[66] In its narrow sense, it is a principle of benefit to consumers, that "today's rate payers should pay the cost of today's services and not the cost of past or future services"[67]. More broadly, it also yields a presumption (which is of benefit to the utility as well), flowing from the idea that the Board acts prospectively in setting rates, that the Board cannot or, even if it has jurisdiction, should not as a general rule, make orders that have the retroactive effect of disturbing existing rights already enjoyed by the utility. In practical terms, it leads to the argument that where rates, tolls and charges have been approved by the Board as being permissible for the utility to charge, the Board cannot or should not make a subsequent order that has the direct or indirect effect of reducing or otherwise changing those rates. In other words, changing past transactions or attaching new consequences to past transactions would be prohibited.

[81] As Penning points out[68] the retroactivity rule has its genesis in general rules of statutory interpretation that guard against interpreting a statutory provision as having a retrospective operation unless it is clear that such an effect was intended. It is not an immutable rule but can give way to contrary legislative intention.

[82] Doctrinally, in the context of utility rate regulation, the retroactivity principle is described by Penning in this way:

> ... the rule is concerned more with issues of fairness, both to customers and to utility shareholders. The customer-related fairness issue is often referred to as the "inter-generational equity" problem, which, broadly stated, means that today's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers. The fairness concern in terms of utility shareholders arises because to attract and maintain reasonably-priced equity

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[66]See supra, para. [33]

[67]**Wabush (Town) v. Power Distribution District of Newfoundland & Labrador** (1988), 71 Nfld. & P.E.I.R. 29 (N.F.C.A.), per Goodridge, C.J.N. at p. 33.

[68]op cit. fn. 57, pp. 608-610

> investment in a utility, shareholders require some certainty that matters already dealt with by the regulator have some degree of finality associated with them.[69]

[83] It was argued that one of the questions that is theoretically presented in this case is the degree to which the Board is authorized to trespass on the no-retroactivity principle in fulfilment of its legislative powers, specifically, to enforce a prescription that a utility may earn a just and reasonable return and no more.

[84] In reality, however, in light of the prospective nature of this Opinion, the non-retroactivity principle is not, in practical terms engaged by Question No. 3. The answers to previous questions have already established that the concept of excess revenue is to be determined by reference to the meaning of a "just and reasonable return" as that phrase is understood in ss. 80(1); and not by the definition used to operate an excess revenue account. All participants in the regulatory process must therefore take account of that concept and conduct their activities accordingly. The "rules of the game" are known.

[85] Section 59 of the Act requires the utility, unless otherwise ordered by the Board, to close its accounts at the end of each calendar year and to file with the Board its balance sheet, together with such other information as may be required by the Board, before April 2nd of the following year. Effectively, therefore, within 3 months after the utility's year end, both the utility and the Board will know the financial position of the company for the previous year and from that, as well as any other information which the Board may require, a determination of the actual level of return earned by the utility in the previous year can be made. Applying the known definition of excess revenue, by reference to the upper end of the range of return on rate base, as determined by the Board's prior orders under ss. 80(1), it can be determined whether there has been any excess revenue earned. There is no revisiting and revision of a prior order respecting the allowable return on rate base. The examination of actual results in the context of a comparison with the previously prescribed rate merely leads to enforcement of the original order. Any decision by the Board with respect to disposition of excess revenue will therefore not retroactively interfere with past revenues which the utility assumes belong to it and which may be disbursed to shareholders or otherwise

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[69] Ibid, p. 610

spent. Given the concept of excess revenue, as explained in this option, the utility knows in advance that it is not entitled to excess revenue so defined and may institute whatever accounting practices are necessary to segregate and deal with such revenues pending direction from the Board.

[86] The situation is conceptually no different from the concept behind an excess revenue account set up under ss. 69(3), which the utility accepts as a legitimate way of dealing with such revenue. Just as in the case of an excess revenue account, the definition of excess revenue is known in advance and the utility can account for such revenue accordingly.

[87] The scenario contemplated by Questions 3 & 4 is unlike the situation which arises where an interim order setting rates, tolls and charges is subsequently superseded by a final order, resulting in excess revenue being earned in the intervening period because the rates, tolls and charges charged in that period pursuant to the interim order were higher than those which were ultimately found to be justified in the final order. In that situation, if the final order is treated as being operative as and from the date of the interim order that was superceded, the final order will, indeed, have a retroactive effect. In the context of the Newfoundland legislation, that situation is specifically contemplated and authorized by ss. 75(3) of the Act.

[88] In the situation presently under consideration, however, there is no subsequent order of the Board which retroactively changes previously-approved rates, tolls or charges or revises the prescribed level of return to which the utility is entitled. All that occurs is the subsequent examination of actual results and a determination of whether excess revenue was in fact earned by applying a pre-existing standard derived from a previous Board order made under ss. 80(1).

[89] I recognize that, to the extent that the utility in the past may have been operating under the impression, perhaps engendered by positions taken by the Board, that excess revenue need only be calculated by reference to the excess over the rate of return on common equity as defined for the purpose of operating the existing excess revenue account, it may consider that if the concept of excess earnings as discussed in this Opinion is applied at this stage to those previous years, there may effectively be a change in the "rules of the game". In that practical sense, there would be a "retroactive" readjustment.

[90] The Court is not being asked, however, to determine the position of the utility specifically in relation to the years 1991 through 1996 and to determine the entitlement of the utility to excess revenues as calculated by reference to the current definition. The degree of NLP's misapprehension, if any, the actions of the Board in dealing with the excess revenue issue in the past, the degree to which NLP may have acted to its prejudice, and the degree to which the utility may nevertheless be required to disgorge excess revenues in previous years in accordance with presently understood concepts raise complex issues of mistake of law in the law of restitution and the defence of change of position which require for their resolution a detailed factual base. It would be inappropriate to attempt to answer such questions in this Opinion.

[91] The issue, therefore, is not whether the Board may revise the definition of excess revenue and then apply the revised definition to the results of previous years. That might well engage the principle of non-retroactivity. Here, assuming (without deciding) there was a misapprehension in the past as to how excess revenue should be calculated, the "change" in calculation method comes about, not because of a retroactive change in the rule by the Board but by a (perhaps) unanticipated declaration and clarification by the Court of what the law is and how it is or should be applied.

[92] I turn now to the determination of the powers of the Board to deal with excess revenue once it has been determined to exist.

[93] The only express provisions of the Act dealing with excess revenue are s-s. 69(4) which provides a power to require a utility to refrain from distributing extra revenue as dividends until further order, and s-s. 75(3) which enables the Board to order that excess revenue earned as a result of an "interim order" made under s-s. 75(1) and not confirmed by final order be either refunded to customers or placed in a reserve account for an approved purpose. Does the fact that similar powers are not expressed in respect of "final" orders mean that they were not intended to be available?

[94] I do not believe so. The power to deal with excess revenue is inherent in the nature of the regulatory scheme the Board is required to administer. The starting point is the power, found to exist in the answer to Question 1, that the Board may

prescribe a rate of return under s-s. 80(1) which carries with it the necessary corollary that the utility is only entitled to earn that level of return, as determined by the Board to be just and reasonable. It follows that unless the Board is to be a "toothless tiger" it must be accorded the means by which revenues earned in excess of the prescribed level of return are used in furtherance of the objectives and policies of the legislation and not simply for the benefit of the utility's investors. Such policies as the maintenance of a sound credit rating by the utility[70], the efficient production, transmission and distribution of power[71], the delivery of power at the lowest possible cost[72] and the provision of reliable service[73] are all candidates for the use of the excess. It does not follow, as the Consumer Advocate argued, that any dealing with the excess should involve only a return or rebate to consumers so as to ensure that the goal of delivery of low cost power is vindicated. While the maintenance of low rates is an important objective of the legislation, it is not the only one. As emphasized earlier,[74] the Board is always engaged in a balancing exercise between the interests of the consumer and the interests of the utility. It is not correct to say that any revenues earned in excess of a just and reasonable return belong to the consumer. Just as the utility is not "entitled" to earn and retain revenues in excess of such a level of return, so also the consumer is not absolutely "entitled" to the excess. The Board, having identified that an excess exists, must deal with it in furtherance of the objectives of the legislation.

[95] The means whereby the excess is dealt with should not be, unless expressly limited by the legislation, rigidly prescribed provided the means chosen comport with the objectives and policies of the legislation. It is worth repeating Gonthier, J.'s observation in the **Bell Rebate** case that the fact that the differences between

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[70]**E.P.C. Act**, s. 3(a)(iii)

[71]s. 3(b)(i)

[72]s. 3(b)(iii)

[73]s. 3(b)(iii)

[74]Paras. [21]-[23]

projected and actual rates of return are common calls for "a high level of flexibility in the exercise of the [Board's] regulatory duties".[75]

[96] Counsel for NLP argued that the only power of the Board to deal with excess revenue, aside from interim order situations, flows from its power in s. 58 to prescribe the form of books and accounts to be kept by the utility and that, if it ordered, pursuant to s-s. 69(3), the creation of a reserve fund "for a purpose which the Board thinks appropriate", it could stipulate that the accounts should be kept in such a way as to require excess revenues to be accounted for in such a reserve account. I do not find the jurisdiction to deal with excess revenue in the power to prescribe the utility's accounts. That is only a procedural means of exercising powers, the jurisdiction for which must be found elsewhere. Whilst the creation, pursuant to s-s. 69(3), of a reserve fund to deal with excess revenues could be said to be "a purpose which the Board thinks appropriate" (provided that purpose is consistent with the powers otherwise conferred on the Board), there is nothing in the language of s-s. 69(3) which expressly makes it applicable to an excess revenue situation and there is certainly nothing there which would purport to make the use of a reserve fund for the purpose of dealing with excess revenue as the only mechanism which would be at the Board's disposal to deal with this issue.

[97] I conclude that, bearing in mind the approach to interpretation mandated by s-s. 118(2) of the **Act**, the Board must of necessity have broad powers to deal with revenue earned by a utility in excess of the prescribed rate of return. Inasmuch as the ascertainment of the existence of excess revenue can only be made following a subsequent review, any order dealing with excess revenue will of necessity have certain retrospective elements about it. But that is not the same as saying that an order dealing with excess revenue ascertained by application of a pre-existing concept of what constitutes excess revenue is a retroactive order. It was argued by NLP that the setting up of a reserve account would be the only method that would not involve any trespass on the principle of non-retroactivity because the utility would know in advance that it had to set up its reserve account and could therefore provide for it without running the risk of spending or distributing excess revenues in ignorance of the fact that they would have to be held accountable for them.

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[75]Supra fn 11, at p. 1734

[98] For reasons already given, this argument is unconvincing. By virtue of the answers given to Question 1, the utility knows that it is only entitled to earn a just and reasonable rate of return pursuant to any order made by the Board to that effect under s-s. 80(1). It can monitor its financial progress and can organize its accounts in such a way as to account for excess revenue so as to prevent the possibility of it being disposed of before any subsequent order dealing with the excess may be made. The utility does not need an express order of the Board requiring it, as a general rule, to set up a reserve account for this purpose. Nevertheless, the use of a reserve account is a convenient way of doing this. It may well be, however, that the Board may, through other directions with respect to the manner of keeping accounts, develop other accounting procedures that will enable the utility to identify excess returns and to segregate them for other use.

[99] A reserve fund could be ordered by the Board to be used in the future to improve service, or to keep rates low or for some other purpose that is consistent with the objectives and policies of the legislation. Whether the advancement of these policies is done formally through the use of a reserve fund or through some other mechanism such as an order setting further rates, tolls and charges taking the prior excess revenue into account, the utility should not be prejudiced, in light of the fact that it knows that it is not entitled to earn a return in excess of a just and reasonable return.

[100] A rebate to consumers would also be permissible since it would have the indirect effect of ex post facto keeping the rates low. While it is true that any rebate would not, because of the fluid nature of the customer base, result in a return to exactly the same body of consumers who had paid the original rates, this is not an insuperable objection to using this type of mechanism. Penning[76] observes:

> As a practical matter, however, at least some of this concern appears misplaced. By far the majority of today's rate payers for the majority of regulated public service utilities were also yesterday's rate payers - especially since the time frames at issue are typically not more than a year or two. So the unfairness argument about cost allocation loses some of its force. Furthermore, to the extent it is still present, it can be dealt with through the choice of mechanism design - so

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[76]Op.cit. fn. 57 at page 619

> instead of adjusting all rates, through either surcharges or refunds, the individual customers who met the timing criteria would receive an adjustment to their bill.

[101] This recognition was echoed by Gonthier, J. in the **Bell Rebate** case[77] as follows:

> ... it is true that the one time credit ordered by the appellant will not necessarily benefit the customers who are actually billed excessive rates. However, once it is found that the appellant does have the power to make a remedial order, the nature and extent of this order remain within its jurisdiction in the absence of any specific statutory provision on this issue. The appellant admits that the use of a one time credit is not the perfect way of reimbursing excess revenues. However, in view of the cost and the complexity of finding who actually paid excessive rates, where these persons reside and of quantifying the amount of excessive payments made by each, and having regard to the appellant's broad jurisdiction in weighing the many factors involved in apportioning respondent's revenue requirement among its several classes of customers to determine just and reasonable rates, the appellant's decision was imminently reasonable ...

[102] Accordingly, I conclude that each of the Revenue Reduction, Reserve Fund and Rebate approaches to dealing with excess returns are within the jurisdiction of the Board and could, in particular circumstances, all constitute reasonable responses to a finding that the utility has earned in excess of a just and reasonable return.

[103] I would also add that the setting up of a reserve fund in a given case does not exhaust the ways in which the Board may deal with excess revenue. The methodologies proposed are not mutually exclusive. The Board has jurisdiction to deal with all revenue in excess of a just and reasonable return on rate base using one, or a judiciously blended combination, of the methodologies identified.

[104] Having said that, it must be emphasized that just because the Board has the jurisdiction to use these approaches, the particular circumstances may well dictate that one or more of them may be inappropriate in a given case. For example, the ordering of a rebate to consumers of the total amount of an excess return might not, in the light of the general financial condition of the utility, be appropriate

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[77] supra, fn. 11 at page 1762 - 3

when measured against such legislative objectives as the maintenance of the utility's sound credit rating. It might be appropriate, when all of the interests are properly balanced, for the Board, for example, to order that only the excess over a stipulated rate of return on equity, or some other measure, be refunded or otherwise dealt with. These are all matters to be considered by the Board in a given case.

[105] The answers to Questions 3 and 4 can be given as follows:

As to: 3(i) - Yes
3(ii) - Yes
3(iii) - Yes

[106] The answer to Question 4 is also "yes" on the assumption that what is being asked is not whether the Board may retroactively revise a previous order but merely whether, applying a defined and understood concept of excess revenue, (ie. an excess of a just and reasonable return on rate base) the excess so determined to have existed in prior years may then be taken account of and applied in setting future rates, tolls and charges.

Question 5

> **Does the fact that the Board has advised the public utility that it is permitted to retain earnings in excess of the rate of return determined by the Board to be a just and reasonable return, upon the rate base as fixed and determined by the Board for each type of service supplied by the public utility, but not in excess of the return determined by the Board to be a just and reasonable return upon the investment which the Board has determined has been made in the public utility by the holders of common shares, affect the jurisdiction of the Board to approve rates, tolls and charges on the basis queried in Question (4).**

[107] In order to understand the import of this question, it is necessary to review the approach taken by the Board to the definition of excess earnings in past years.

[108] In correspondence passing between NLP, Newfoundland Telephone Company Limited (which at that time was regulated by the Board) and the Board during the late 1980's, there was considerable discussion as to the manner of

defining "excess revenue" for the purpose of the operation of the reserve account which the Board had required the utilities to maintain for that purpose. As a result of these discussions, the Board approved a change in the utilities' systems of accounts to recognize a new definition of excess earnings. As indicated, this was accomplished by defining the excess revenue account in the utilities' system of accounts as follows:

> This account shall be credited with any revenue in excess of the maximum return on common equity determined by the Board at the previous rate hearing to be refunded to customers or used for such purposes as the Board may order.

[109] By the operation of this definition, the situation could occur whereby the utility might earn a rate of return on rate base in excess of the maximum range of returns determined by the Board pursuant to s-s. 80(1) but could nevertheless be within the range of return on common equity used by the Board for the purpose of determining a just and reasonable return on rate base under s-s. 80(1). If that eventuality occurred, there would be no requirement on the utility to pay anything into the excess revenue account; yet, the result would be that the utility would have earned more than a just and reasonable return on rate base. In light of the answer given to Question 1, the benchmark for determining excess revenue is the range of return on rate base determined by the Board to be just and reasonable. Does the Board have jurisdiction to deal with this money as excess earnings in light of the fact that it has defined excess earnings for the purposes of the utility's accounting by reference to the maximum return on common equity?

[110] Question 5, we were told, attempts to address this issue. As phrased, however, the question merely asks whether the fact that the Board has "advised" (presumably, in the form of its order changing the definition of excess revenue for the purposes of the establishment of the excess revenue account) the utility of this new definition of excess revenue "affect" the jurisdiction of the Board to approve rates, tolls and charges. The short answer to this question, strictly construed, is "no". The Board cannot limit its jurisdiction, in the sense of its legal power, by determinations made in exercise of its powers. It either has the jurisdiction or it does not. Whether it chooses to exercise the jurisdiction is another matter.

[111] As a result of the discussions at the hearing, however, it is apparent that there is a more fundamental issue at stake. The assumption appears to be that if

the Board chooses to define excess revenue for the purpose of establishment of the excess revenue account in terms of revenue earned in excess of the maximum return on common equity, it is in effect saying that revenue earned below that maximum but which happens to be in excess of the just and reasonable return on rate base as determined by the Board under s-s. 80(1) is necessarily money which the utility can keep. This position is obvious from the arguments made by counsel for NLP since his position has been throughout that excess revenue has no meaning other than by reference to the definition used for the purposes of the excess revenue account. As indicated previously,[78] this is not a correct interpretation of the situation. The same assumption is also apparent from the position taken by the Consumer Advocate who argues that the decision of the Board to define excess revenue for the purpose of the excess revenue account in terms of exceeding the return on common equity, as opposed to rate base is ultra vires the Board because the Board must determine excess revenue by reference to revenues which are earned in excess of a just and reasonable return on rate base.

[112] The assumption that the definition of excess revenue for the purpose of the operation of the reserve account is equivalent to the concept of excess revenue flowing from earnings in excess of a just and reasonable return on rate base as prescribed under s-s. 80(1), is false. I agree with the Consumer Advocate, for reasons already given[79], that any revenues earned in excess of the maximum range of a just and reasonable return on rate base are revenues to which the utility is not automatically entitled. It does not follow, however, that for the purposes of regulating the accounts of the utility, the Board is prevented from requiring payment into an excess revenue account on a different basis (provided it does not deprive the utility of the level of return on rate base to which it has been determined to be entitled). The Board can and should deal with all revenue earned in excess of a just and reasonable return on rate base; however, it does not have to require that all of it be paid into an excess revenue account.

[113] As indicated in the answers to Questions 3 and 4, the Board has a broad jurisdiction as to how to deal with the excess and it may well be that, in the circumstances obtaining, it will determine that only a portion (i.e. that portion

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[78]para.[73]

[79]paras.[31], [50]

above the maximum return on common equity) should be paid into a reserve account. It might determine that the rest should be rebated to consumers or used by the utility in furtherance of the objective of ensuring that it maintains a sound credit rating in the financial markets of the world. In short, there is nothing wrong in principle with the Board defining excess revenue for the purposes of a reserve account differently from the notion of excess revenue as determined by a comparison with a just and reasonable return on rate base as determined by s-s. 80(1). In so doing, however, the Board ought not to assume that any additional excess revenue ought necessarily to be returned to the utility to be used as it sees fit. The Board has jurisdiction, and in exercise of its legislative mandate it ought to exercise that jurisdiction, to make a determination as to how that remaining excess revenue, if any, should be dealt with consistent with the objectives and policies of the legislation.

[114] Accordingly, the technical answer to Question 5 is "no" but so as to limit any confusion over the implications of the wording of the question, I would add that the Board has jurisdiction to define excess revenue for the purposes of maintenance of a reserve account by reference to the maximum level of return on common equity (or any other appropriate measure for that matter) but that does not mean that the Board may for all purposes define the level of excess revenue to which the utility is not entitled by reference to that measure; rather, the Board must determine, on the specific circumstances of the case, what is to be done with respect to any excess revenue measured against a just and reasonable return on rate base. If all or a portion of the excess revenue, measured against the return on rate base, is not ordered to be paid into a reserve account, it must nevertheless be dealt with in some other manner consistent with the objects and policies of the legislation. It should not be simply assumed that such excess revenue if not required to be paid into a reserve account belongs to the utility to be dealt with as it sees fit.

Question 6

> **Does the Board have jurisdiction to order the rates, tolls and charges of the public utility shall be approved taking into account the amount of expenses previously incurred by the public utility which the Board may now consider inappropriate to be allowed as reasonable and prudent and properly chargeable to operating account notwithstanding that such classes of**

expenses were allowed as reasonable and prudent and properly chargeable to operating account.

[115] The just and reasonable return on rate base which the Board determines that the utility is entitled to earn annually is "in addition to those expenses which the Board may allow as reasonable and prudent and properly chargeable to the operating account ..."[80]. Thus, in the process leading up to the prospective setting of rates, the Board may look at the type and level of projected expenses of the utility in the test year and determine whether they are reasonable and, if not, only allow, for the purposes of calculation of a just and reasonable return on rate base, such types and levels of expenses as are, in the opinion of the Board, reasonable.

[116] In the 1991 rate hearing, certain types and levels of projected advertising expenses were approved by the Board. At the 1996 rate hearing, it was suggested that in the light of what actually happened in the years subsequent to 1991, the utility had in fact incurred advertising expenses well in excess of the amounts approved as reasonable and also of a type different from those which were approved, i.e. for corporate image building rather than related to the supply of service. The issue posed by Question No. 6 is whether expenses of a class which were previously approved as reasonable but which are in excess of the projected amounts can be disallowed by the Board for the purposes of rate regulation.

[117] The level of operating costs is obviously an important factor in fixing rates. It is generally accepted that Board supervision as to reasonableness of such costs is therefore essential to effective regulation.[81] Phillips describes the matter thus:

> Commissions seldom challenge expenditures controlled by competitive forces, such as those for plant maintenance, raw materials and labor. Conflicts do arise over whether certain expenditures should be charged to operating expenses or paid for by owners out of earnings.
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> Management might vote itself high salaries and pensions. Payments to affiliated companies for fuel and services might be excessive. Expenses for advertising, rate investigations, litigation and public relations should be closely

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[80] **Act**, s. 80(2)

[81] Phillips, op.cit. fn. 9, pages 256-257

> scrutinized by the commissions to determine if they are extravagant or if they represent an abuse of discretion. In all cases, moreover, the commissions should require proof as to the reasonableness of a utility's charges to operating expenses.[82]

Accordingly, the power to determine reasonable rates necessarily requires supervision of operating expenses.

[118] In defining the parameters of such supervisory power, however, the Board must account for a competing principle, namely, that the Board is not the manager of the utility and should not as a general rule substitute its judgment on managerial and business issues for that of the officers of the enterprise[83].

[119] Nevertheless, it is recognized that regulatory boards have a wide discretion to disallow or adjust the components of both rate base and expense[84]. In an American case[85] the matter was put as follows:

> The contention is that the amount to be expended for these purposes is purely a question of managerial judgment. But this overlooks the consideration that the charge is for a public service, and regulation cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these or any other purposes.

[120] Having said that, however, there will normally be a presumption of managerial good faith and a certain latitude given to management in their decisions with respect to expenditures. In the United States, the test for disallowance is usually "abuse of discretion" showing "inefficiency or improvidence" or "extravagant or unnecessary costs".[86]

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[82]Ibid. page 256

[83]supra, para. 32

[84]**Re Union Gas Ltd. and Ontario Energy Board et al** supra fn. 12 per Anderson, J. at page 712.

[85]**Acker v. United States**, 298 U.S. 426 (1936), per Roberts, J. at pages 430-431

[86]Phillips, op. cit. fn. 9, at page 258

[121] When the issue becomes a retrospective examination of actual expenses as compared with what was projected and determined to be reasonable and prudent, there ought, similarly, to be caution exercised before determining that an expense was improperly incurred. The circumstances facing a utility are not static and a considerable latitude has to be given to the decisions of management in making expenditures to respond to the new situations as they present themselves.

[122] Nevertheless, it is still within the jurisdiction of the Board to supervise and review both the type and level of expenses incurred by the utility in respect of its operations. If it did not have that jurisdiction, the actual rate of return earned on rate base in a given year would be subject to manipulation by the utility as, for example, in a year where near the close of the fiscal period it appears that the rate of return will be more than anticipated, the utility, if totally unsupervised, could make large expenditures, unrelated to the delivery of service, simply to bring the rate of return in line with what had been projected.

[123] The jurisdiction of the Board to take account of deviations from estimates of expenses when setting future rates does not differ from that pertaining to its jurisdiction with respect to taking account of excess revenue. The disallowance of an expense may lead, in effect, to a greater rate of return, and potentially to excess revenue if the resulting actual adjusted rate of return is in excess of the previously determined acceptable range of return. The excess revenue over a just and reasonable range of return on rate base can be dealt with by the Board as discussed in the answers to Questions 3 and 4. It does not remain the property of the company.

[124] Accordingly, the answer to Question 6 is "yes". In giving this answer, however, I would emphasize that the question that was asked is a jurisdictional one. It does not give, in the circumstances of a particular case, a wide unfettered power to "second guess" managerial decisions with respect to expenses. In this regard, I agree with the comments of Phillips:

> Public utilities ... cannot spend freely and expect all expenditures to be included as allowable operating expenses. In effect, this means the commissions are permitted to question both the judgment and integrity of management. And if rates must be high enough to yield sufficient revenue to cover all operating expenses, the consumer has the right to expect that such expenditures will be necessary and reasonable.

At the same time, managerial good faith is presumed. Public utilities must be given the opportunity to prove the necessity and reasonableness of any expenditure challenged by a commission (or intervenor). To justify an expenditure, a company must show that the expense was actually incurred (or will be incurred in the near future), that the expense was necessary in the proper conduct of its business or was of direct benefit to the utility's rate payers, and that the amount of the expenditure was reasonable. Moreover, it must be emphasized again that a public utility may still spend its money in any way it chooses. Management's function is to set the level of expenses; the commission's duty is to determine what expense burden the rate payer must bear.

Question Nos. 7 and 8

(7) **Does the Board have jurisdiction to require a public utility to maintain:**

(i) **a ratio; or**

(ii) **a ratio within a stated range of ratios**

of equity and debt, as the means of obtaining the capital requirements of the public utility.

(8) **Does the Board, upon an application pursuant to Section 91 or otherwise, have the jurisdiction to require a public utility to obtain its capital requirements by the issue of specific financial instruments, whether common shares, preferred shares, stocks, bonds, debentures or evidence of indebtedness payable in more than one year.**

[125] These two questions will be considered together because the issues they raise are interrelated.

[126] In theory, both the overall level of capitalization and the individual components of a utility's structure are of interest to regulatory boards. Clearly, if a utility is allowed to engage in financing practices which result in overcapitalization, the whole viability of the enterprise may be threatened with consequent impact on the delivery of service to the public.

[127] Furthermore, unlike in competitive conditions where the enterprise would not be able effectively to raise its prices over those of its competitors even if its costs of capital were excessive, overcapitalization of a regulated utility may well affect rates. That is because, in principle, rates must be set at such a level as to allow for recovery of the utility's costs, including its costs of capital, as well as a just and reasonable return. Overcapitalization, if uncontrolled, would increase the utility's costs and hence its rates. If the utility is not permitted to recover its costs in this regard it will, like any unregulated business, face bankruptcy with the consequence of disruption of service to customers. Overcapitalization may therefore indirectly put an upward pressure on rates to ensure the continued viability of the utility to enable service to be maintained. Alternatively, service may suffer.

[128] Arguably, the purpose of s. 91 of the **Act** is to enable the Board to control the risk of overcapitalization and its impact on the viability of the utility, or at least on its credit standing. By examining each proposed new security issue in advance, the Board has a chance of minimizing the adverse effects of overcapitalization before they occur.

[129] The composition of a utility's capital structure, that is, the mix of debt and equity, is also a matter that is necessarily of interest to regulatory boards.

[130] Because the costs of the individual components of a utility's capital structure, i.e. the embedded costs of debt and preference shares and the reasonable rate of return on common equity, are given a weighted cost, proportional to their share of the total capital structure, for the purpose of deriving a reasonable rate of return on rate base, the level of the actual proportional share of each component will necessarily have an effect on the result of the overall determination of a just and reasonable return on rate base. The makeup of the utility's capital structure can therefore influence that determination.[87]

[131] Phillips[88] expresses it this way:

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[87] deGrandpré op cit. fn. 9, page 26; Phillips op. cit. fn. 9, page 233

[88] Phillips, op. cit. fn. 9, pages 388-389

> ... the traditional theory of business finance holds that the average cost of capital to a firm varies with the capital structure upon which it is based. The interest rate on debt is normally lower than the cost of equity capital. Consequently, within limits determined by such factors as the risk of a business, the overall cost may be somewhat lower when the debt-equity ratio is high than when the debt-equity ratio is low.

It is too simplistic, however, to say that in all cases, the higher the debt equity ratio, the lower will be the overall costs of capital. As deGrandpré[89] points out:

> It is often argued that if utilities increased their debt ratio, their cost of capital would be reduced since the cost of debt is less than the cost of equity. This may be true, but then the rate of return would have to be increased under the risk factor since the interest has to be paid before dividends and the investor might find himself deprived of dividends because of insufficient earnings.

The debt equity ratio can, therefore, have a complicated effect. What is undeniable, however, is that the debt-equity mix does have an effect on the rate of return. Hence, it is something which, in principle, should come within the regulatory umbrella in fulfilment of the policies of keeping the costs to consumers low and of ensuring a sound credit rating for the utility. The higher the cost of capital, the higher will be the return necessary to be awarded to the utility to enable it to maintain a sound credit rating in world financial markets. This would inevitably lead to higher rates, tolls and charges which would work against the policy of providing power to consumers at the lowest possible cost consistent with reliable service.

[132] From this, the Consumer Advocate and the Board itself argued that it is a necessary and appropriate power on the part of the Board to regulate the ratio of debt to equity in a utility's capital structure. Without such a power, the Board is limited, it was suggested, in its ability to ensure that sources and facilities for the production, transfer and distribution of power are managed and operated in a manner that would result in power being delivered to consumers at the lowest possible cost consistent with reliable service.

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[89] op. cit. fn. 9, page 26. See also to the same effect Phillips, op. cit. fn. 9, page 233

[133] In like manner, it was argued that the Board has the power, as a necessary incident of the legislative scheme, to stipulate, from time to time, that a public utility must obtain its capital requirements by the issue of financial instruments of a specified nature.

[134] Granting that the level of overall capitalization and the composition of the capital structure of a utility are both matters of regulatory concern, at least insofar as they affect the utility's rate of return on rate base and hence the cost to consumers of the delivery of reliable service, the question to be determined is the degree of intrusion which the Board may undertake into the financial affairs of the utility. Can it be proactive and, as Question 7 suggests, "require" the utility to maintain a particular debt-equity ratio or, as Question 8 implies, "require" the utility to finance its activities in a particular way, or is it limited to passive disallowance of particular financing proposals either in the process of setting rates or in the course of other applications?

[135] In approaching these questions, it has to be remembered that there is no such thing as one ideal capital structure. It is a function of economic conditions, business risks and "largely a matter of business judgment".[90] Furthermore, a given capital structure cannot be changed easily or quickly. As well, the long-term effects of changes on capital structure on the enterprise and on the future cost of capital may not be easily predictable. Capitalization decisions also have other business dimensions that transcend the considerations relevant to the issues directly presented in the regulatory process.

[136] All of these considerations favour an approach that, in principle, should limit the degree of intrusion by the Board into the managerial control by the utility over financial decision-making. As emphasized earlier[91] the powers of the Board should be generally regulatory and corrective, not managerial. A debate has nevertheless occurred over whether regulatory agencies can and should "fix" debt-

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[90]Phillips, op. cit. fn. 9, p. 234

[91]paragraphs [31] - [32]

equity ratios and restrict new financing techniques to specified types of instruments.[92] Phillips notes that:

> These methods, however, have limitations. For example, since the financial conditions of individual utilities vary, no one ratio of debt to equity is correct. The refusal to approve a bond issue may lead to no issue at all, since, if a utility's earnings are insufficient to maintain its stock at par, it is in no position to issue more stock; bonds are the only way new capital can be raised. As a result of these problems, few commissions are willing to substitute their judgments for those of management...[93]

[137] An alternative to actual intrusion into the utility's financial affairs in the form of a direction as to how the enterprise should be structured is for the regulator, for the purpose of setting rates, to base its estimates of the cost of capital on a hypothetical appropriate capital structure, thereby disregarding the utility's actual capitalization[94]. The justification for this approach is given by Phillips who, citing other authors, states:

> Locklin has argued that most commissions 'disregard actual capital structures and set up an ideal or normal structure for the purpose. To do otherwise would burden the public with the higher costs of obtaining capital that result from a capital structure that is something less than ideal, and may, in fact, be quite unsound'. And Rose argues: 'When a commission in determining cost of capital disregards the actual capital structure or a capital structure proposed by management it is no more invading the domain of management than when it disregards unreasonable expenses for labor, fuel, or other productive factors in prescribing rates'.[95]

It appears, however, that actual capitalization has also been used as a basis[96]. Nevertheless, the arguments in favour of the ability of the Board to disregard the actual capital structure in an appropriate case and base its determinations upon a

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[92]Phillips, op. cit. fn. 9, p. 236

[93]Ibid.

[94]Phillips, op. cit. fn. 9, pages 388-392

[95]Ibid., page 389

[96]Ibid., page 391

hypothetical structure are convincing. Indeed, this has occurred in Canada.[97] Without such a power, the Board would not be able effectively to fulfil its mandate of promoting the delivery of reliable service to consumers at the lowest possible cost and at the same time maintaining a sound credit rating for the utility in the financial markets of the world. Having said that, in exercising that power, it goes without saying that the Board ought to have a healthy respect for managerial judgment[98] in such matters since if a hypothetical capital structure is used that is too far off the mark of the actual structure, it may in practical terms make the utility unable to meet its actual commitments, thereby threatening its credit standing and possibly affecting service to customers.

[138] It is not necessary to go further, for the purpose of promotion of the objectives and policies of the legislation, and accord to the Board a power of actual intrusion into the capital structure of the utility. The distinction between actual intrusion and disallowance for rate making purposes is justified in the context of the existing legislation and enables the Board to respect the principle of general deference to managerial decisions.

[139] The question that remains is whether s. 91 of the Act, which is the only provision expressly dealing with the powers of the Board respecting capital structure, can be said, either expressly, or by necessary implication, to accord greater powers to the Board.

[140] On its face, s. 91 appears to be limited to a situation where the Board may approve or disapprove of a particular proposal from the utility for the issuance of a proposed form of securities. It is expressed in terms of a power of negative disallowance rather than positive direction.

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[97]Re **The Bell Telephone Company of Canada**, supra. fn. 33 at page 723: "... the Board has, when the circumstances so warrant it, seen fit to adjust the company's debt-ratio *for rate making purposes*."

[98]No doubt as a practical matter, the Board would also be hesitant to make assumptions respecting a utility's capital structure for rate-making purposes, that are different from the actual structure which will have been created as a result of previous approvals given by the Board (though perhaps in not as focused a context as a rate hearing and without the benefit of argument from rate hearing participants, such as the Consumer Advocate) to the issuing of individual share or other financial instruments in the past pursuant to s. 91.

[141] As noted previously[99], s. 91 enables the Board to control the level of overall capitalization. Is that the only purpose for which a disallowance under s. 91 can be made? Obviously, an indirect effect of an approval or refusal of a particular security issue could be to affect the utility's future proposed debt-equity ratio and hence the composition of its capital structure. In practical terms, the power to disallow a specific proposal will enable the Board to exercise at the very least, by means of moral suasion in discussion, a degree of positive influence over total capitalization as well as capital structure. The power of disallowance under s. 91 may, in my view, be used, in appropriate cases, to further such objectives. Subsection 91(3) requires the Board, before approving a security issue, to be satisfied that it is in accordance with law and "for a purpose approved by the Board". Accordingly, so long as the power of approval or disallowance under s. 91 is exercised in a manner that is consistent with and in furtherance of any of the policies which the legislation was designed to serve, it will be within the jurisdiction of the Board to so act. In that way, the Board may influence the total level of capitalization as well as the particular debt-equity ratio. It does not, however, permit the Board to direct the utility to raise money in a particular way or to maintain a particular debt-equity ratio. In other words, it cannot be used as a springboard for an aggressive intrusion into the day to day financial and managerial decision making of the utility with respect to the capital structure of the enterprise. Nor can the general policies underlying the legislation justify such a power. As indicated, financing is undertaken for considerations that are not necessarily directly related to utility regulation. Furthermore, it has also been noted that, within the regulatory context, the utility is still subject to business risks and the effects of management decisions and the utility, other things being equal, ought to have the power to respond to that zone of risk. To that extent, the utility must be able to make financial decisions related to the overall health of the enterprise for reasons other than strictly regulatory ones, provided that in so doing it does not trespass on the objectives and policies of the legislation.

[142] Accordingly, while recognizing that a degree of influence over the utility's capital structure and over the choice of financial instruments to be used in financing the enterprise can be exercised by means of the powers conferred by s.

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[99]paragraph [128]

91 and the powers inherent in the regulatory scheme itself, the answers to Questions 7 and 8, insofar as the questions imply an ability to directly stipulate particular financing results, is, in each case, "no".

General Observations

[143] In answering the foregoing questions, it is worth emphasizing that the answers are given in terms of the jurisdiction of the Board. The fact that the Board may have jurisdiction, in the sense of legal power, to do something does not mean that, in a particular case, the power ought to be exercised. In the arguments which were presented on the hearing of the stated case, it was apparent that some of the positions taken by a party were being advanced out of a concern that if the jurisdiction was conceded, it would necessarily follow that the Board would exercise its power in a manner adverse to that party.

[144] The question of whether the Board should in fact exercise powers within its sphere of jurisdiction and the question of the manner in which those powers should be exercised raise very different considerations. It must always be remembered that, as has been emphasized throughout this opinion, the Board is charged with balancing the competing interests of the utility and the consumers of the service it provides. Neither set of interests can be emphasized in complete disregard of the interests of the other. Thus, in choosing to exercise a particular power within the Board's jurisdiction, the Board must always be mindful of whether, in so acting, it will be furthering the objectives and policies of the legislation and doing so in a manner that amounts to a reasonable balance between the competing interests involved.

Opinion

[145] Pursuant to s. 101 of the **Act**, I would summarize my opinion on the questions posed as follows:

Question 1(i)	Yes
Question 1(ii)	No
Question 2	Yes

Question 3(i)	Yes
Question 3(ii)	Yes
Question 3(iii)	Yes
Question 4	Yes
Question 5	No
Question 6	Yes
Question 7	No
Question 8	No

I emphasize that inasmuch as the import of the answers given depends on my interpretation of the questions posed, it is necessary to read the answers in the context of the rest of this Opinion.

[146] Pursuant to s. 102, the Deputy Registrar of the Court is directed to remit this Opinion to the Board.

J. Derek Green, J.A.

I concur: Margaret Cameron, J.A.
M. A. Cameron, J.A.

Opinion of O'Neill, J.A.:

[147] The Board of Commissioners of Public Utilities (the Board) is a statutory body existing under the provision of the Public Utilities Act, R.S.N. 1990, c. P-47, as amended (the Act).

[148] The general powers of the Board are set out in s. 16 of the Act:

> The board shall have the general supervision of all public utilities, and may make all necessary examinations and inquiries and keep itself informed as to the compliance by public utilities with the law and shall have the right to obtain from a public utility all information necessary to enable the board to fulfil its duties.

[149] In addition to the powers and obligations given to and imposed on the Board by the Act, the Board has certain duties and powers under the Electrical Power Control Act, 1994, Chapter E-5.1, as amended and, by s. 4 of that Act, is specifically directed to "implement the power policy" of the Province, as set out in s. 3 of that Act, and in doing so to apply tests "which are consistent with generally accepted sound public utility practice".

[150] By s. 101 of the Act, the Board may, of its own motion, state a case in writing for the opinion of the Court upon a question which in the opinion of the Board is a question of law.

[151] On August 14, 1996, the Board stated a case requesting the opinion of the Court with respect to certain specific questions as set out therein. Following an application for directions, the court ordered that, inter alia, certain parties be notified of the proposed hearing. Subsequently Newfoundland Light & Power Co. Ltd., a utility, and "the Consumer Advocate" were granted status to appear and be heard at the hearing before the court.

[152] In its application to the Court, the Board stated that in the course of a hearing before it, the submissions of various parties raised questions as to the jurisdiction of the Board under the Act and the Board thereupon stated a case for the Court upon the following questions:

> (1) Does the Board have jurisdiction pursuant to the Act to set and fix the return which a public utility may earn annually upon:

(i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility; and/or

(ii) the investment which the Board has determined has been made in the public utility by the holders of common shares.

(2) Does the Board have jurisdiction to set the rates of return referred to in Question (1) as a range of permissable rates of return.

(3) Should a public utility earn annually a rate of return which is in excess of the rate of return determined by the Board to be just and reasonable, either on:

(i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility; or

(ii) the investment, which the Board has determined, has been made in the public utility by holders of common shares,

does the Board have jurisdiction to:

(i) require the public utility to use the excess earnings to reduce revenue requirements for the succeeding year; or

(ii) require the public utility to place the excess earnings in a reserve fund for the purpose of adjusting rates, tolls and charges of the public utility at a future date; or

(iii) require the public utility to rebate the excess earnings to customers of the public utility?

(4) Does the Board have jurisdiction to order that the rates, tolls and charges of a public utility shall be approved taking into account earnings in excess of a just and reasonable return upon:

(i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility, or

(ii) the investment, which the Board has determined, has been made in the public utility by the holders of common shares,

in prior years.

(5) Does the fact that the Board has advised the public utility that it is permitted to retain earnings in excess of the rate of return determined by the Board to be a just and reasonable return, upon the rate base as fixed and determined by the Board for each type of service supplied by the public utility, but not in excess of the return determined by the Board to be a just and reasonable return upon the investment which the Board has determined has been made in the public utility by the holders of common shares, affect the jurisdiction of the Board to approve rates, tolls and charges on the basis queried in Question (4).

(6) Does the Board have jurisdiction to order the rates, tolls and charges of the public utility shall be approved taking into account the amount of expenses previously incurred by the public utility which the Board may now consider inappropriate to be allowed as reasonable and prudent and properly chargeable to operating account notwithstanding that such classes of expenses were allowed as reasonable and prudent and properly chargeable to operating account.

(7) Does the Board have jurisdiction to require a public utility to maintain:

(i) A ratio; or

(ii) A ratio within a stated range of ratios

of equity and debt, as the means of obtaining the capital requirements of the public utility.

(8) Does the Board, upon an application pursuant to Section 91 of the Act or otherwise, have the jurisdiction to require a public utility to obtain its capital requirements by the issue of specific financial instruments, whether common shares, preferred shares, stocks, bonds, debentures or evidence of indebtedness payable in more than one year.

Question #1

(1) Does the Board have jurisdiction pursuant to the Act to set and fix the return which a public utility may earn annually upon:

(i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility; and/or

(ii) the investment which the Board has determined has been made in the public utility by the holders of common shares.

[153] It may be useful to set out here the relevant parts of ss. 37, 70 and 80 of the Act:

> 37.(1) A public utility shall provide service and facilities which are reasonably safe and adequate and just and reasonable.
>
> 70.(1) A public utility shall not charge, demand, collect or receive compensation for a service performed by it whether for the public or under contract until the public utility has first submitted for the approval of the board a schedule of rates, tolls and charges and has obtained the approval of the board and the schedule of rates, tolls and charges so approved shall be filed with the board and shall be the only lawful rates, tolls and charges of the public utility, until altered, reduced or modified as provided in this Act.
>
> 80.(1) A public utility is entitled to earn annually a just and reasonable return as determined by the board on the rate base as fixed and determined by the board for each type or kind of service supplied by the public utility but where the board by order requires a public utility to set aside annually a sum for or towards an amortization fund or other special reserve in respect of a service supplied, and does not in the order or in a subsequent order authorize the sum or a part of it to be charged as an operating expense in connection with the service, the sum or part of it shall be deducted from the amount which otherwise under this section the public utility would be entitled to earn in respect of the service, and the net earnings from the service shall be reduced accordingly.
>
> (2) The return shall be in addition to those expenses that the board may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the board according to this Act and the rules and regulations of the board.
>
> (4) The board may use estimates of the rate base and the revenues and expenses of a public utility.

[154] In the past, the Board has ordered that a just and reasonable return for a utility is "determined" to be between two stated percentages of its annual rate base

for a test year, and ordered the utility to file, for examination by the Board, a schedule of rates, tolls and charges which will comply with the Board's determination, and, if so found to comply, approval is granted for those rates, tolls and charges.

[155] The rate base is arrived at by calculating the utility's net investment in plant and equipment required for the rendering of the regulated service.

[156] While not having fixed the return which the utility may earn, the Board has, in its orders, directed that a utility establish an "excess revenue reserve" into which revenue exceeding a certain rate of return on equity is to be deposited.

[157] The Board, in its order dated December 4, 1991, having fixed the average rate base for Newfoundland Power for the year 1992, and having determined a just and reasonable return for Newfoundland Power on its average rate base for that year, noted that that return would provide an opportunity for it to earn a somewhat higher rate of return on common equity:

> A just and reasonable return for [Newfoundland Power] is determined to be between 10.96% and 11.19% on its average rate base for 1992, which will provide an opportunity to earn a rate of return on common equity between the range of 13.00% to 13.50%.

[158] The Board's position before the court was that since what is a just and reasonable return on rate base is influenced by the proportion of the various financing components, including long term and short term debt and preferred shares, it is imperative that the Board be able to set and fix the return which the holders of the common shares in the utility may earn since the market conditions for debt could alter the return to the holders of the common shares significantly.

[159] Although s. 80 does not specifically provide for a rate of return for common shares, the determination of a rate of return on the common shares of a utility is very much a part of the rate making process. Further, it must be noted that by s. 3 of the Electrical Power Control Act, the policy of the Province is declared to be that the rates to be charged, either generally or under specific contracts, for the supply of power within the Province "should provide sufficient revenue to the producer or retailer of the power to enable it to earn a just and reasonable return as

construed under the *Public Utilities Act* so that it is able to achieve and maintain a sound credit rating in the financial markets of the world...".

[160] For Newfoundland Power it was argued that the Board has the jurisdiction to determine the just and reasonable return on the rate base and, as part of that process, the jurisdiction to determine the return on common equity, it being one of its sources of funds. I see no distinction between "determine" and "set and fix" insofar as the jurisdiction of the Board here is concerned. The calculations and projections made by the Board in arriving at the rate of return, whether specifically on rate base or the return on common equity, involve by their very nature, looking into the future, estimating as best can be done the revenues and expenditures contemplated for the utility's operations, the costs of money which may vary substantially, up and down, and then to fix a rate base, and a just and reasonable return on that base upon which the rates, tolls and charges will be based and approved.

[161] Although the Board is supplied on a regular basis and has the authority to demand all the financial information it requires of a utility, the rates are, in effect, established for relatively long periods, (in excess of one year) and the likelihood of the accuracy of the forecasts which are necessarily made in setting the rate base and the rates of return is somewhat diminished.

[162] For the Consumer Advocate it was argued that s. 80(1) only gives the Board the jurisdiction to calculate the rate of return on rate base and does not allow a calculation of what return the common equity shares will have.

[163] As noted earlier, common shares constitute one of the components of the financial make-up of a utility and, as argued by counsel for the Board, while, theoretically, the Board only determines a just and reasonable return on the rate base as fixed and determined by it, in a practical sense, the return on common equity must be considered as part of the mix in setting the return on rate base, just as are the rates of interest paid on preferred shares, bonds and other financial obligations.

[164] In the result, in my opinion, questions 1(i) and 1(ii) should be answered in the affirmative.

Question #2

> Does the Board have jurisdiction to set the rates of return referred to in question (1) as a range of permissible rates of return?

[165] There is no question but that the rate setting process of the Public Utilities Board is prospective and is performed by the Board's making estimates of the myriad of factors which have to be considered. The problem is exacerbated by the fact that the process is not one which is contemplated to be reviewed regularly or on a short term basis. The meaningful interpretation of the word "return" as it appears in s. 80(1) allows for and, in the circumstances, contemplates a range of rates of return. It follows then that a just and reasonable return, though it may be stated as a fixed percentage, may be a range of rates which is determined to be just and reasonable. In making such a determination, the Board is clearly acting within its jurisdiction. As noted earlier, a consideration of a just and reasonable return on common equity as one of the components of the financial investment in the company is a necessary part of the process of arriving at a just and reasonable return on rate base, and this return may also be stated as a range.

[166] I would answer question 2 in the affirmative.

Question #3

> Should a public utility earn annually a rate of return which is in excess of the rate of return determined by the Board to be just and reasonable, either on:
>
> (i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility; or
>
> (ii) the investment, which the Board has determined has been made in the public utility by holders of common shares,
>
> does the Board have jurisdiction to:
>
> (i) require the public utility to use the excess earnings to reduce revenue requirements for the succeeding year; or

(ii) require the public utility to place the excess earnings in a reserve fund for the purpose of adjusting rates, tolls and charges of the public utility at a future date, or

(iii) require the public utility to rebate the excess earnings to customers of the public utility?

[167] Under s. 69 of the Act, the Board has very broad powers including requiring a public utility to set aside from earnings monies in a depreciation account and creating and maintaining a reserve fund. Section 69 of the Act is as follows:

> 69.(1) A public utility, if so ordered by the board, shall, out of earnings, set aside all money required and carry it in a depreciation account.
>
> (2) The depreciation account shall not, without the consent of the board, be spent otherwise than for replacements, new constructions, extensions or additions to the property of the company.
>
> (3) The board may by order require a public utility to create and maintain a reserve fund for a purpose which the board thinks appropriate, including the improvement of the public utility's status as a borrower or seeker of funds for necessary maintenance or expansion of its operations.
>
> (4) The board, in a case where it has made an order which has the effect of increasing a public utility's revenues, may require the public utility to refrain from distributing as dividends until further order the whole or a part of the extra revenue which is in the board's opinion attributable to the order.

[168] The answer to the question also requires a consideration of the powers of the Board as set out in ss. 58 and 59 of the Act.

[169] By ss. 58 and 59, the Board may prescribe the form of all books of account and records to be kept by the public utility and to make its returns to the Board on such forms as may be prescribed by it. By s. 59, unless otherwise ordered by the Board, the utility shall close its accounts at the end of each calendar year and shall file with the Board its balance sheet, together with such other information as may be required by the Board, before April 2nd of the year following. In effect, approximately three months after the close of the utility's financial year, the Board

is made aware of the exact financial position of the company at the end of the previous year and of any other information which it may require.

[170] It will be seen from s. 69(3) that the Board has the power to direct a utility to set up reserves out of revenue to be used for replacement of equipment, new construction, extensions or additions to the property of the company. As well, reserves may be ordered to be created which would have the effect of "improving the status of the utility as a borrower or seeker of funds for necessary maintenance or expansion". There is a further power which comes to the Board from s. 69(4) and that is to require the utility to set up a reserve of monies which may have been in excess of those anticipated by the Board at the time of setting the rate of return and to prevent the distribution of that money or any part of it as dividends until the further order of the Board.

[171] In the setting of rates, the Board is looking into the future and addressing the anticipated revenues and expenses of the utility with the many variables which may occur. It follows then that it must have the authority to anticipate that there will be variations from what was forecast. While the rates, tolls and charges are set following a hearing and only by an order following a hearing, the constant reporting which a utility must make to the Board allows the Board to be kept informed as to the financial operations of the utility and, in the result, to be aware of how these revenues and expenditures affect the rate of return anticipated by the Board and set out in its order. At the same time, as stated earlier, the rate of return on rate base and on common equity are set not as specific percentages but as a range.

[172] In order P.U. 6-1991, the following appears at p. 56:

> The applicant has applied for a rate of return on common equity in the range of 13.5% to 14.0%, with rates set at 13.75%. The midpoint of the range was chosen since it is consistent with past practice and gives the Company the motivation to strive for a higher range (up to 14.0%) while giving them an opportunity to remain within the range if they are unable to come in on forecast (i.e. earn 13.5%).

And later at p. 72:

> The Board orders a range of 13.00% to 13.50% be adopted as the Company's rate of return on common equity with rates being set at the mid-point of the range,

> 13.25%. In the opinion of the Board this will give [Newfoundland Power] the opportunity to earn a fair and reasonable return and will increase [Newfoundland Power's] interest coverage in 1992 to 2.87 times.
>
> The Board believes that [Newfoundland Power's] interest coverage in 1991 of 2.81 times at existing rates, which is an increase from 2.7 times in 1990, together with the increase to 2.87 in 1992 is satisfactory.

[173] In my view, when rates, tolls and charges are set, the revenues generated belong to the company. If the net revenues are less than forecast and result in a return on rate base or on common equity less than as set out in the Board's order, then that loss is the company's loss. Revenues which are greater than anticipated belong to the company and any revenues in excess of those forecast by the Board as reflected in its order belong to the company and cannot be used, except as discussed in the following paragraph, to reduce the revenues of the utility in the future.

[174] I see nothing to preclude the Board's directing that those revenues of a utility in excess of the top of the range allowed by the Board in its order as a return on common equity, be set aside and maintained in a reserve fund by an order of the Board, as contemplated by s. 69 "for a purpose which the [B]oard thinks appropriate, including the improvement of the public utility's status as a borrower or seeker of funds for necessary maintenance or expansion of its operations". I do not view any revenues of a utility in excess of those required to achieve the higher point of the range of return either on rate base or on common equity as becoming excess funds unless and until they are set aside by an order of the Board as authorized by s. 69. Until such order, these funds remain the property of the utility and may be treated as such. The creation of a reserve fund is a power given to the Board to be exercised as it sees fit. Indeed, s. 69(4) gives the Board the authority to "require the utility to refrain from distributing as dividends until further order the whole or a part of the extra revenue which is in the [B]oard's opinion, attributable to the order". Indeed, it may happen from time to time that circumstances may so change following the making of an order that a utility may need to and may actually earn revenues in excess of those contemplated by the Board when the last order was issued.

[175] It follows from what I have said that the Board does not have the power to order rebates to the customers of the utility other than out of such a reserve fund.

To order a rebate from revenues other than those which have been placed in a reserve fund and, in that sense, not available to the company directly, would be to make a retroactive order. A sufficiently good reason for this is that just as additional billings are not permitted to be made to customers because of revenues which have fallen below the range set when the order was made, so any additional revenues may not be paid out. The role of rate making is prospective and this in itself in my view would preclude any reaching back.

[176] Reference should also be made to s. 80(1) which in my view contemplates, by the use of the words "earn annually", that each year becomes a separate unit and the revenues from one year may not be applied to another year so as to effect any change in the financial makeup of the utility, except through the use of the reserve fund, which, on its creation by order of the Board, has the effect of removing funds from the particular financial year affected by the order of the Board creating or ordering the placing of funds in the reserve fund and, in effect, makes those monies unavailable for the general use of the utility, including the payment of dividends to the holders of common equity.

[177] I would answer question 3(i) in the negative, 3(ii) in the affirmative and 3(iii) in the negative.

Question #4

> Does the Board have jurisdiction to order that the rates, tolls and charges of a public utility shall be approved taking into account earnings in excess of a just and reasonable return upon,
>
> (i) the rate base as fixed and determined by the Board for each type of service supplied by the public utility; or
>
> (ii) the investment which the Board has determined has been made in the public utility by the holders of common shares,
>
> in prior years?

[178] Although the Board's jurisdiction is to fix and determine a rate base which will enable the utility to earn annually a just and reasonable return on that rate base, it follows that, depending on the range settled upon by the Board in its order

and considering that the rates, tolls and charges are set using the mid-point of that range as a basis, the utility may, from time to time, record net revenues which are less than or more than that contemplated by the range as set. Although the wording of s. 80 of the Act states that the utility is entitled to earn a just and reasonable return, it does not follow that it may not nor should not have revenues in excess of those contemplated. At the same time, for reasons which may be beyond the complete control of the utility, the revenues received might be substantially below those anticipated when the rates, tolls and charges were set and approved.

[179] In my view, the Board cannot set rates, as argued by counsel for the Board, in a manner that would compensate for prior "excess" earnings. At the same time, in setting rates, as it must do prospectively, the Board must be alive to the various factors which may have caused the utility in any previous year to earn more or less than that anticipated by the Board in its order, and it must factor those causes into the percentages and ranges for return on rate base and for return on common equity in future orders.

[180] I would answer question 4 in the negative.

Question #5

> Does the fact that the Board has advised the public utility that it is permitted to retain earnings in excess of the rate of return determined by the Board to be a just and reasonable return, upon the rate base as fixed and determined by the Board for each type of service supplied by the public utility, but not in excess of the return determined by the Board to be a just and reasonable return upon the investment which the Board has determined has been made in the public utility by the holders of common shares, affect the jurisdiction of the Board to approve rates, tolls and charges on the basis queried in Question 4.

[181] Counsel for the Board argued that the authority of the Board to amend, alter or rescind any order made by it is plenary and the Board has full power to reconsider any order made previously by it, notwithstanding that there is a right of appeal in respect of its decisions on questions of law. Further, he argued that the fact that the Board has previously ruled or ordered a particular basis for the calculation of excess revenue does not preclude the Board from considering the effect of such earlier decisions in determining what revenues will be required by

the utility in setting new rates based on a just and reasonable return in accordance with a new method of calculation.

[182] Counsel further argued that since there is no fixed term for the continuing application of any approved rates, tolls or charges, the Board is not precluded from altering its previous order and assessing what is a just and reasonable return based upon its current assessment of the utility. Counsel argued that s. 87(1) of the Act clearly sets out that power:

> 87.(1) Where upon an investigation the rates, tolls, charges or schedules are found to be unjust, unreasonable, insufficient or unjustly discriminatory, or to be preferential or in violation of this Act, the board has power to cancel those rates, tolls, charges or schedules and declare void all contracts or agreements, either oral or written, dealing with them upon and after a day named by the board, and to determine and by order substitute those rates, tolls or schedules that are reasonable.

[183] The investigation undertaken under s. 87(1) follows upon a complaint made to the Board as set out in s. 84(1) and following upon the procedures set out in ss. 85 and 86 of the Act.

[184] The legislation empowers and indeed directs the Board to conduct a constant monitoring of the financial position of the utility and gives the Board the authority to institute a correction process at any time. It does not, in my opinion follow, as argued by counsel for the Board, that the Board in setting new rates, tolls and charges may take into account earnings of the utility in previous years in excess of a just and reasonable return upon the rate base or upon the investment which the Board has determined has been made in the public utility by the holders of common shares. This is so notwithstanding that the Board has previously ordered or advised a utility that it is permitted to retain earnings in excess of the rate of return determined by the Board to be a just and reasonable return upon the rate base as fixed and determined by the Board where not in excess of the return determined by the Board to be a just and reasonable return upon the investment made by the holders of common shares.

[185] Counsel for the utility argued that the Board does not have jurisdiction to order that the rates, tolls and charges shall be approved taking into account earnings in excess of a just and reasonable return, either on rate base or on

common equity, in prior years. Counsel further argued that such a power would "constitute retroactive appropriation of past revenues for future purposes". He further argued that the only mechanism available to the Board, where a utility earns in excess of the rate of return on rate base or on common equity, is to require the utility to deposit excess revenue, as defined by the Board, into a reserve account in the year earned. It is then, he argued, that the Board may approve the application of these funds as revenue in determining the rates, tolls and charges for a future period but any funds not ordered to be deposited in the reserve account are funds of the utility, belong to the utility, and cannot be considered in setting future rates. To do so, he argued, would be to change the system of accounts so that funds which were not excess in a previous year will then become excess and be brought forward - a retroactive order which is beyond the jurisdiction of the Board.

[186] For the Consumer Advocate it was argued that although the Board had advised the utility that it was permitted to retain earnings in excess of the rate of return as determined by the Board, it is not precluded from later making an order under s. 80(1) and s. 76 of the Act rescinding, altering or amending any existing order and in declaring these earnings as excess revenue. The Consumer Advocate also argued that in light of its position taken in response to question 4, the Board does not have jurisdiction to order that the "excess revenue" earned in previous years by the utility should be taken into account in setting rates, tolls and charges in subsequent years but that the Board must order that it be rebated to customers of the utility.

[187] I agree with the position taken by the utility. I would answer question 5 in the negative.

Question #6

> Does the Board have jurisdiction to order the rates, tolls and charges of the public utility shall be approved taking into account the amount of expenses previously incurred by the public utility which the Board may now consider inappropriate to be allowed as reasonable and prudent and properly chargeable to operating account notwithstanding that such classes of expenses were allowed as reasonable and prudent and properly chargeable to operating account.

[188] The example given by the Board in its factum illustrative of the situation giving rise to question 6 is as follows:

> In determining in 1991 what was a just and reasonable return on the basis of projections for test year, 1992, the Board was presented with projections for the future cost of operating expenses including advertising. The actual cost of advertising for 1995 exceeded the projection for 1992 by some $314,000.00. As such, the amounts for advertising contemplated by the Board as being reasonable, prudent and properly chargeable to operating account vary significantly for the year 1995 from the estimate upon which the Board determined a just and reasonable rate of return.

[189] Counsel for the Board argued that "the circumstances of a significant increase in expenses over the estimates used for the test year is indistinguishable from the circumstances of an increase in net earnings. For the same reasons as advanced by it in question 5, it argued that the Board had jurisdiction to order that the rates, tolls and charges could be approved taking into account these expenses, previously incurred, but now considered inappropriate to be allowed as reasonable and prudent.

[190] For the utility, it was argued that once rates, tolls and charges are set, the resulting revenue belongs to the utility except for any amounts which the Board may order to be deposited into an excess revenue account. Further, although the Board has the authority to determine whether the expenses comply with s. 80(2), which jurisdiction is necessary to ensure the integrity of the excess revenue account, the Board does not have jurisdiction to disallow the amount of any operating expense which is reasonable or which had previously been allowed as a just allowance. Further, it argued that the Board may not disallow an expense because it is of the opinion that had it been the manager, it would not have made that expenditure. The question is whether the expenditure is one that could have been made by a reasonable and prudent manager.

[191] The utility further argued that there should be no "microscopic review" especially with the benefit of hindsight. Counsel argued that the Board makes its annual review of the returns made by the utility and, in the specific example here, the Board had obviously made the decision that that expense, although it exceeded predictions, was reasonable (or at least the fact that it didn't say anything about it would indicate that it was reasonable). That expense should not, except in very

rare circumstances, be later held to be unreasonable. The utility's position was stated in its factum as follows:

> The Board does not have jurisdiction to order that rates, tolls and charges shall be approved taking into account the amount of such "disallowed" expenses. The Board's jurisdiction is limited to disallowing expenses which it determines not to be "reasonable and prudent and properly chargeable to operating account" or otherwise not a "just allowance" under s. 80(2). The disallowance of an expense would lead to the company earning a somewhat greater return on common equity for the purpose of the excess revenue account for the year in which the expense was incurred. However, this revenue remains the property of the company and its shareholders unless the amount disallowed would mean that the company's return on common equity would exceed the maximum return on common equity previously allowed by the Board. If that were to occur, the amount which would be beyond the maximum return on common equity would be deposited into the "excess revenue account".

[192] For the Consumer Advocate, it was argued that the Board may take into account past expenses in order to forecast more accurately future revenues and expenditures. However, its counsel argued that the Board does not have jurisdiction to set future rates, tolls and charges designed to compensate for past expenses that the Board may now consider inappropriate to be allowed as reasonable and prudent and properly chargeable to operating account.

[193] I agree with the arguments proferred by the utility and the Consumer Advocate.

[194] I would answer question 6 in the negative.

Questions #7 & 8

Question #7

> Does the Board have jurisdiction to require a public utility to maintain:
>
> (i) A ratio; or
>
> (ii) A ratio within a stated range of ratios

of equity and debt, as the means of obtaining the capital requirements of the public utility.

Question #8

Does the Board, upon an application pursuant to Section 91 or otherwise, have the jurisdiction to require a public utility to obtain its capital requirements by the issue of specific financial instruments, whether common shares, preferred shares, stocks, bonds, debentures or evidence of indebtedness payable in more than one year.

[195] In his decision which I have read in draft, Green, J.A. considered questions 7 and 8 together because, as he stated, the issues they raise are interrelated. I agree with the reasoning of Green, J.A. in dealing with these questions and I would answer both questions, as he did, in the negative.

[196] I would also agree with the comments made by Green, J.A. in that part of his decision, entitled "General Observations".

Conclusion

[197] In the result then I would answer the questions posed as follows: 1(i) yes, 1(ii) yes, question 2 - yes, question 3(i) - no, question 3(ii) - yes, question 3(iii) - no, question 4 - no, question 5 - no, question 6 - no, question 7 - no, and question 8 - no.

J.A.

J.I. O'Neill, J.A.

78P

Date: 20120619
Docket: 10/113
Citation: *Newfoundland and Labrador Hydro v. Newfoundland and Labrador (Board of Commissioners of Public Utilities)*, 2012 NLCA 38

IN THE SUPREME COURT OF NEWFOUNDLAND AND LABRADOR
COURT OF APPEAL

BETWEEN:

NEWFOUNDLAND AND LABRADOR HYDRO — APPELLANT

AND:

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES — FIRST RESPONDENT

AND:

THE CONSUMER ADVOCATE as represented by THOMAS JOHNSON — SECOND RESPONDENT

AND:

CORNER BROOK PULP AND PAPER LIMITED — THIRD RESPONDENT

AND:

NORTH ATLANTIC REFINING LIMITED — FOURTH RESPONDENT

AND:

TECK RESOURCES LIMITED — FIFTH RESPONDENT

AND:

VALE NEWFOUNDLAND AND LABRADOR LIMITED — SIXTH RESPONDENT

AND:

ABITIBI CONSOLIDATED COMPANY OF CANADA — SEVENTH RESPONDENT

AND:

NEWFOUNDLAND POWER INC. — EIGHTH RESPONDENT

AND

Docket No. 10/114

BETWEEN:

THE CONSUMER ADVOCATE as represented by THOMAS JOHNSON — APPELLANT

AND:

THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES — FIRST RESPONDENT

AND:

NEWFOUNDLAND AND LABRADOR HYDRO — SECOND RESPONDENT

AND:

CORNER BROOK PULP AND PAPER LIMITED — THIRD RESPONDENT

AND:

NORTH ATLANTIC REFINING LIMITED — FOURTH RESPONDENT

AND:

TECK RESOURCES LIMITED — FIFTH RESPONDENT

AND:

VALE NEWFOUNDLAND AND LABRADOR LIMITED — SIXTH RESPONDENT

AND:

ABITIBI CONSOLIDATED COMPANY OF CANADA — SEVENTH RESPONDENT

AND:

NEWFOUNDLAND POWER INC. — EIGHTH RESPONDENT

Coram: Green C.J.N.L., Mercer and Harrington, JJ.A.
Appealed From: Newfoundland and Labrador Board of Commissioners of Public Utilities, (Order No. P. U. 25)

Appeal Heard: December 9, 10 and 13, 2010
Judgment Rendered: June 19, 2012

Reasons for Judgment by the Court.

Counsel for Newfoundland and Labrador Hydro: Geoffrey Young

Counsel for the Consumer Advocate: Thomas Johnson

Counsel for Newfoundland and Labrador Board of Commissioners of Public Utilities: Dan Simmons, Jackie Glynn

Counsel for Corner Brook Pulp and Paper Limited, North Atlantic Refining Limited, Teck Resources Limited and Vale Newfoundland and Labrador Limited:	Paul Coxworthy Dean Porter
Counsel for Abitibi Consolidated Company of Canada:	Greg Moores
Counsel for Newfoundland Power Inc.:	Ian Kelly, Q.C. Gerard Hayes

By the Court:

[1] Two appeals come before this Court arising from a preliminary decision of the Newfoundland and Labrador Board of Commissioners of Public Utilities ("Board") in Order No. P.U. 25 (2010) ("Decision") issued August 26, 2010. They come directly to this Court under s. 99 of the *Public Utilities Act*, RSNL 1990, c. P-47 as amended ("*PUB Act*").

[2] Fundamentally, what is at issue in this appeal is whether certain savings generated in a rate stabilization plan established by the Board can be shared among all residential and industrial power consumers on the island portion of the province or only among industrial customers. The appeal engages the interpretation of the Board's governing legislation, in particular, s. 75 of the *PUB Act*, and whether the Board erred in determining it did not have jurisdiction to allocate savings to customers other than certain industrial customers.

[3] The appellant, Newfoundland and Labrador Hydro ("Hydro"), is a Crown corporation and the appellant, the Consumer Advocate ("Advocate"), is a statutorily appointed representative of the interests of domestic and general service customers of both Hydro and Newfoundland Power Inc. ("Newfoundland Power") pursuant to s. 117 of the *PUB Act*. The Advocate does not represent Hydro's industrial customers or the utility, Newfoundland Power. A hearing was conducted following written submissions by interested parties regarding a series of preliminary questions posed by the Board. The questions were raised in the context of a pending general rate application by Hydro affecting its industrial customers to have interim rates for the years 2008, 2009 and 2010 made final ("2009 GRA").

[4] The appellants allege that the Decision unduly restricts the Board's authority to deal with the disposition of certain surplus revenue credits or system savings which have been accrued under a rate stabilization plan ("RSP") in accounts established for tracking cost of service to Hydro's industrial customers for the three year period under consideration. As noted, the characterization of these accounts and the determination of whether customers other than industrial customers can benefit from the disposition of these credits either prospectively or retrospectively is at the core of this appeal.

[5] The appellants allege that the Board erred by fettering its jurisdiction when it ruled in its preliminary determination of the scope of Hydro's 2009 GRA that it was prevented from conferring any benefit from the disposition of systems savings accruing within the RSP for industrial customers on any of its other customers. Specifically, the Board held that the fact that the rates for Hydro's non-industrial customers had been made final for the period 2008 to 2010 barred consideration of any claim of entitlement to the systems savings by non-industrial customers when settling the final rates for industrial customers for the three year period affected by the 2009 GRA.

BACKGROUND

[6] Hydro established the RSP effective January 1, 1986 under a directive from the Provincial Government. The Board modified and approved the RSP. The object of the RSP was to provide rate stability to Hydro's customers through a mechanism designed to eliminate volatility in Hydro's revenue requirements beyond its reasonable expectations.

[7] The RSP provided for adjustments to recover the differences between the forecasted test year costs used to set rates and the actual costs affected by: (i) differences in the price of bunker C fuel affecting the cost of oil-fired power generation at Holyrood, ii) variation in Hydro's hydraulic power generation; and iii) major variations in load consumed by its customers.

[8] These appeals directly affect customers who are on the Interconnected System on the island portion of the Province. These include Hydro's one utility customer, Newfoundland Power and in turn all of Newfoundland Power's customers. These appeals also directly affect Hydro's industrial customers and Hydro's own residential and general service customers on the Island Interconnected System.

[9] There are two major electrical systems operating within the Province. The Island Interconnected System functions as a stand-alone system comprised of various hydro-electric developments and thermal power generated at the Holyrood Thermal Generating Station ("Holyrood"). The Labrador Interconnected System is supplied by Churchill Falls and is connected to the North American power grid. The more remote and isolated areas of the Province, whether on the island or in Labrador, are serviced by individual diesel generating facilities owned and operated by Hydro.

[10] The primary source of electrical power and energy for the Island Interconnected System is hydro-electric with the other major source of power being the Holyrood generating plant which burns bunker C oil purchased by Hydro on the world oil markets. It is much less costly for Hydro to generate electricity on the Island Interconnected System by its hydro-electric sources than it is to generate electricity at Holyrood.

[11] Hydro is the primary generator of electricity in the province. Hydro sells its power to utilities, industrial and its own 35,000 residential and general service customers in over 200 communities across the Province. Newfoundland Power serves over 239,000 residential and commercial customers making up approximately 85% of all electricity customers in the province. Newfoundland Power purchases approximately 90% of its electricity from Hydro and generates the balance from its own smaller hydro electric stations.

[12] Hydro's overall fuel costs at Holyrood on an annual basis can vary significantly. These fuel costs are affected by:

a) the price of a barrel of oil as determined by the world market;

b) the amount of available hydro-electric energy - which essentially is a function of the amount of precipitation; and

c) the amount of energy consumed by the customers on the Island Interconnected System (referred to as "load").

[13] Given the variability that can occur in Hydro's annual fuel costs, a mechanism in the form of the RSP was developed to ensure that Hydro's rates are adequately collecting the cost of fuel that it is purchasing to service the needs of the Island Interconnected System customers. Absent such a mechanism, the rates that are set for Hydro to charge its customers for electricity which are based on forecast costs for the test year, could cause

Hydro to lose or gain considerable sums of money in a given year. At Hydro's last general rate application filed in 2006, a 2007 test year was used as the basis for establishing the electricity rates to be charged by Hydro. At that time, it was known that large increases in oil prices or lower than expected hydrology could create a significant revenue shortfall for Hydro. On the other hand, higher than expected hydrology at its hydro electric generating facilities and lower than expected load consumption by industrial consumers could result in large unexpected revenues.

[14] The RSP provides a mechanism to smooth the effects on rates of increases or decreases in commodity costs over time. The RSP has been modified a number of times since its introduction. However, the current RSP has been in place since Hydro's general rate application in 2003.

[15] Under the RSP, these variables are tracked for the purpose of calculating RSP adjustment rates for Hydro's utility and industrial customers. In the case of Newfoundland Power, Hydro makes an annual application to the Board for approval of the appropriate RSP adjustment to take effect on July 1st of each year. In the case of the industrial customers, the RSP adjustment takes effect on January 1st of each year. The amount of the rate adjustment and whether the adjustment will be a decrease or increase on January 1st or July 1st, as the case may be, depends upon the net activity in the RSP as calculated in accordance with its provisions.

[16] The load variation element of the RSP is of particular significance on these appeals. The load variation - the amount of energy consumed compared to the amount forecast for the test year - works generally in a similar manner to fuel price and hydrology - to the extent that if higher load occurs (i.e., more electrical energy must be generated to meet customers' electricity requirements than was forecast when rates were last set) it results in higher fuel costs at Holyrood and the corresponding amount is owed by customers to the RSP to be recovered in rates in a future period. However, if the load is lower than the test year forecast, it will result in an amount owing to customers from the RSP.

[17] In another way, the load variation provisions work differently from the fuel price and hydrology elements. Load variation can affect the amount of oil that is required to be burned at Holyrood, thereby affecting Hydro's costs. Load variation also has an impact upon the amount of revenue that Hydro receives from its rates. At Hydro's 2003 GRA the RSP was amended so as to place the financial consequences of the load variation on the

customer class whose actual load varied from the test year load forecast. Therefore, in a year in which the industrial customers' load was higher than forecast in the last test year, the effect of the variation would be to cause rate increases for the affected class.

[18] Increased industrial customers' load causes higher rates between GRAs because energy rates for this class are based upon Hydro's average costs of electricity production (e.g. reflecting a mix of cheaper hydro power and more expensive Holyrood power). However, the incremental energy production to actually service the increase in load comes from Holyrood where the cost of production is higher than the average energy cost which the energy rate reflects. Therefore, on each extra kilowatt hour that Hydro sells to fulfill an increased load, Hydro would, without an adjustment mechanism, be actually losing money. While it is collecting more revenue from the industrial customers because of the increased load, the increase in revenue is outstripped by the extra cost to which it is being put in order to supply the extra kilowatt hour. The load variation provisions in the RSP require that customer class which caused the load increase to bear the burden of those costs in a future period so that Hydro is made whole.

[19] On the other hand, if the industrial customers' load were to decrease relative to the test year forecast, the opposite would be the case. That is to say, a decrease in load would cause Hydro to burn less oil than anticipated thereby being able to supply more of the system's requirements with cheaper hydro energy instead of being required to burn the estimated number of barrels of oil that its rates were based upon in the last GRA. In this instance, while Hydro's revenues from the industrial customers would be decreased, so would Hydro's costs. In fact, the avoided costs vastly outstrip the loss in revenue occasioned by the decrease in load. The load variation provisions in the RSP assign to the customer class that caused the load decrease the benefit of these cost savings in a future period. It is this load feature of the RSP that is a key aspect in the factual matrix of these appeals.

[20] At Hydro's 2003 GRA, the participating parties agreed that both the revenue and the fuel amounts related to load variation should be assigned to the customer base within the RSP where the load variation occurred. Previously, revenues were assigned to the RSP based on which customer class caused the load variation but the related fuel costs were allocated between Newfoundland Power and the industrial customers based on the 12 months-to-date energy ratios for each customer class. The change in customer assignment was considered to improve fairness because costs

would now be assigned between Newfoundland Power and industrial customers based on causality.

[21] Hydro's 2006 GRA resulted in a Settlement Agreement which provided for a further review of the RSP (the "2007 RSP Review"). It was anticipated that any changes resulting from the 2007 RSP Review would be implemented by January 1, 2008. The allocation of load variation transfers was one of the items to be addressed in the review. Meanwhile, arising out of Hydro's 2006 GRA, final rates were approved for the industrial customers to be effective January 1, 2007 in Order No. P.U. 8 (2007).

[22] Starting in the fall of 2007, significant events were taking place in the province's pulp and paper sector adversely affecting the load variation of the normal operation of the RSP. In November of 2007, Corner Brook Pulp and Paper Limited shut down a paper machine which resulted in a 22% reduction in load from the industrial customers on the island. In 2008, Abitibi Bowater closed its paper mill at Grand Falls-Windsor. In anticipation of projected volatility in load during the 3 year rate period, Hydro sought and obtained an order from the Board for interim rates for 2008 and 2009 which were effectively sustaining those that were in place for 2007.

[23] A projected rate change that otherwise would have taken place for industrial customers on January 1, 2008 under the established rules, prompted Hydro to take another approach. On December 20, 2007 Hydro applied to the Board for an Order "that the Board approve and make an Interim Order that the rates currently in effect for industrial customers, which were approved in Order No. P.U. 8 (2007) and which are set out in Schedule "A" continue in effect on an interim basis until such time as the Board issues a final order with respect to industrial customers' rates for 2008".

[24] Hydro provided the Board with its rationale for the requested Order in the following terms:

> By Order No. P.U. 40 (2003) the Board approved the manner by which the Rate Stabilization Plan (RSP) is calculated and by which RSP adjustments are applied to the rates charged by Hydro to its Island Interconnected Industrial Customers. Under that Order, Hydro is required to provide an Industrial Customer fuel price projection to the Board and to certain of Hydro's customers by the tenth working day of October each year.

> Due initially to a projected increase in the RSP rate and subsequently to a significant load change of one of Hydro's Industrial Customers, Hydro determined that there was potential volatility in its Industrial Customers' rates both for 2008 and future years. The impact of these changes was deemed to be significant and it was judged to be prudent to further analyze and consider their impact, in conjunction with also determining the final level of year end hydraulic balances, prior to making application to the Board with respect to an appropriate treatment of this issue.
>
> Hydro wishes to have further opportunity to consider the appropriate means to address Industrial Customers' rates issues.

The Board approved the interim rates requested.

[25] On June 30, 2009, Hydro applied to the Board requesting the finalization of rates charged to industrial customers.

[26] In its cover letter accompanying the application, Hydro stated:

> Although the attached Application does not contain any proposed changes, the Board may wish to consider suspension of the existing load variation allocation rules and holding in abeyance current and future load variation amounts until such time as Hydro can develop a proposal to address the current anomalies in the RSP. Hydro anticipates that an application with regard to the RSP load variation can be made prior to the end of 2009.

[27] Since the industrial customers' rates were declared interim effective January 1, 2008 there had been large sums of money accruing in the RSP due to the fuel savings that Hydro was experiencing at Holyrood due to the steep decline in the load of the industrial customers since Hydro's last GRA. Evidence filed in the proceeding before the Board forecast that over the period 2007 to 2010 some $74 million in system savings tied to load would have accrued, with some $68 million accruing since the industrial customers' rates were declared interim.

[28] The load variation balances that have been assigned to the industrial customers under the interim RSP rules produced rate scenarios well beyond reasonable expectations. Using the refunding methods provided by the RSP rules, the forecast average rates for industrial customers for 2010 were projected to be *negative* figures reflecting a scenario where there would be more money to be refunded to customers than energy revenues received from them by Hydro.

[29] The industrial customers claimed entitlement to the entire load variation balance. Based on the available information prior to the preliminary hearing, the current industrial customers were paying approximately $20 million in annual electricity costs. However, $68 million of load variation transfers were accumulating as system savings on an interim basis since January 1, 2008 which represented approximately three and a half times the annual electricity costs of the current industrial customers.

[30] Hydro, Newfoundland Power and the Consumer Advocate in their evidence recommended that the Board allocate these system savings between the industrial customers and Newfoundland Power using a cost of service approach.

[31] The Board advised all parties that the public hearing respecting the 2009 GRA would not proceed and further advised that the Board wished to hold a preliminary hearing into its jurisdiction and authority. Counsel for each of the parties and the Board met and developed the preliminary issues that would be addressed by the Board. These issues were then formally posed to the Board by way of a letter from Hydro's counsel dated June 2, 2010.

[32] The questions posed were:

> Does the Board have the jurisdiction to issue an order which changes how the Rate Stabilization Plan (RSP) operated before the date of the order and, if so, does this jurisdiction extend to any aspect of the operation of the RSP, including the rate charged to customers, the determination of the balance(s) in the RSP, and how these balances are allocated to customers or customer classes? In particular:
>
> - Does legislation or common law give the Board any specific relevant authority or alternatively, restrict the Board's authority?
>
> - What would generally accepted sound public utility practice as set out in s. 4 of the EPCA require?
>
> - Are there any concerns in relation to vested rights, i.e. does the language of the RSP create a right/obligation in each of the customers or customer classes? If so, at what point does this right/obligation accrue? Does this mean that credits/debits allocated to each customer in accordance with the plan are the responsibility of or to the benefit of customers in the class at the time of the accumulation or does the Board have the jurisdiction to order alternative disbursements of the balances?

- Does the issuance of Order Nos. P.U. 34 (2007), P.U. 37 (2008), P.U. 6 (2009), the filing of Hydro's application on June 30, 2009, or any other order of the Board impact the jurisdiction of the Board?

THE BOARD DECISION

[33] The written decision of the Board issued August 26, 2010 was divided into a discussion of deferral accounts and interim orders. The deferral account section dealt primarily with the Board's general jurisdiction over the disposition of balances accumulated in deferral accounts, such as the RSPs. The interim order section dealt more specifically with the Board's jurisdiction under section 75 of the *PUB Act* to deal with balances accumulated due to a difference between interim and final rates.

[34] The Board considered the RSP to be an example of a deferral account. Such an account is used for various purposes in public utility rate regulation to, amongst other things, allow a public utility to maintain its approved rate of return when actual revenues or expenses vary from those that were forecast when rates were set. This would reduce fluctuations in rates charged to consumers of power if such variances were not spread over longer periods of time.

[35] With respect to its jurisdiction over deferral accounts generally the Board stated at p. 8:

> While the Board has jurisdiction in relation to deferral accounts the Board has stated that it views the use of these accounts to be an extraordinary measure ... The Board believes that its jurisdiction with respect to deferral accounts is limited by the principles of predictability and fairness, as discussed by the Alberta Court of Appeal in *ATCO [Calgary (City) v. Alberta (Energy and Utilities Board*, 2010 ABCA 132], and does not necessarily extend to changing how balances are calculated and allocated in the past.

[36] The Board continued at p. 9:

> In the Board's view changing how the RSP operated in prior years would be analogous to the situation that Mr. Justice Green suggested might constitute retroactive regulation in *Reference: re s. 101 of the Public Utilities Act (Nfld)* (1998), 164 Nfld & PEIR 60 (Nfld. C.A.) at paragraph 91:

> *The issue, therefore, is not whether the Board may revise the definition of excess revenue and then apply the revised definition to the results of previous years. That might well engage the principle of non-retroactivity.*
>
> (Emphasis in original.)

[37] The Board determined that the interim orders gave the Board the full jurisdiction to change all aspects of the industrial customers' rate, including the power to change the rules and regulations affecting the RSP.

[38] However, having noted that the Hydro applications for interim rates and its 2009 GRA seeking the approval of a final rate for industrial customers had not sought any changes to the RSP, the Board held at p. 9 that the RSP rules applying to allocation of load variations continued to apply:

> In the absence of an application, the Board did not take it upon itself to consider suspending the operation of the load variation allocation rules as suggested by Hydro in its correspondence [that accompanied the June 20, 2009 application for final rates].

[39] The Board then considered the effect on its jurisdiction of the interim rate orders and section 75 of the *PUB Act* which provides in pertinent part:

> **75.** (1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.
>
> ....
>
> (3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be
>
> (a) refunded to the customers of the public utility; or
>
> (b) placed in a reserve fund for the purpose that may be approved by the board.

[40] Addressing the position of Hydro, Newfoundland Power and the Consumer Advocate, the Board stated:

> Hydro, Newfoundland Power and the Consumer Advocate suggest that [s. 75] permits the Board to place any excess revenue paid by the Industrial Customer group as a result of the interim rates into an account for the possible benefit of [another] customer group. This interpretation would not appear to be consistent

> with the scheme of the legislation generally or with generally accepted sound public utility practice which requires that rates be just and reasonable and not unjustly discriminatory. The Board has reference to the comments of Mr. Justice Green in Reference Re: s. 101 of the Public Utilities Act (Nfld.) (1998), 164 Nfld. & P.E.I.R. 60 (Nfld. CA) ... at paragraph 18 ...

[41] The Board then concluded at pp. 11-12:

> Reading s. 75 in the overall context of the legislation and regulatory structure the Board believes that a purposeful interpretation would require that the refund or the reserve fund must, to the extent possible, be for the benefit of the customer group which was found to have paid the excess revenue. There may be times when it is not practical to refund to the customers that paid the excess, for example where the amount is nominal or the customers cannot be found. The Board believes that, in the absence of extraordinary circumstances, a finding that interim rates for a group of customers were in excess of reasonable rates would require that the same customer group be effectively charged the reasonable rates through a refund or the use of a reserve account.

[42] In response to the position of the industrial customers that the ability to set final rates under s. 75 of the *PUB Act* did not authorize the Board to revise the RSP rules that applied to the industrial customers, the Board concluded at p. 13:

> The interim orders clearly provide the Board with the full jurisdiction to, in the words of the Supreme Court of Canada, "*modify in its entirety the rate structure*" for the Industrial Customer group, which includes all aspects of the Industrial Customers' rate, including the RSP rate. The Board does not accept the position of the Industrial Customers that the Board has no power to change the rules and regulations affecting the RSP.

[43] However, the Board held at p. 14 that:

(i) it has jurisdiction to set "just and reasonable rates" for the Industrial Customers for 2008 and 2009, including the determination of the industrial customers' RSP rates and the manner of operation of the Industrial Customer RSP for those years,

(ii) "given the manner in which this matter was brought forward", it has no jurisdiction to change the manner in which the Newfoundland Power RSP operated in prior years, either in terms of the rates charged or the resulting balances, and

(iii) it has jurisdiction to determine whether overpayments by the Industrial Customers resulting from the interim rates should be refunded to the industrial customer group or placed in a reserve account to the benefit of that customer group.

[44] Although the Board ultimately determined that its jurisdiction to deal with the RSP balance was limited to determining "...whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group", the Board essentially determined that the accrued balance of system savings had to be used for the benefit of the Industrial Customer class only and could not be applied to the benefit of other customers on the Island Interconnected System or used for other purposes in connection with the operation of the Island Interconnected System.

LEAVE TO APPEAL

[45] Section 99 of the *PUB Act* provides that an appeal from an order of the Board can be taken directly to the Court of Appeal upon a question of the Board's jurisdiction or upon a question of law, but only with leave of a judge of the Court.

[46] Leave to appeal will only be granted: (i) where it is apparent that the question on appeal is one of jurisdiction or law; and (ii) where the appellant can show "a reasonably arguable case for success" on the appeal: *Consumer Advocate v. Newfoundland Power Inc.*, 2006 NLCA 20, 255 Nfld. & P.E.I.R. 234, per Cameron J.A. at para. 10; *Labrador City (Town) et al. v. Newfoundland and Labrador Hydro Inc.* (2004), 241 Nfld. & P.E.I.R. 81 (NLCA) at para. 5.

[47] It is manifest from the notices of appeal that have been filed that each of the stated issues involves a question as to whether the Board erred in determining its jurisdiction or erred in law in reaching the Decision it did. Given the position taken by the respondents and the Board in not opposing leave, it can be presumed that there is a reasonably arguable case to be made on appeal.

[48] In this case, on the application for leave, all parties, except the Board, who were provided with notice pursuant to s. 99 (2), consented to leave being granted and, in the case of the Board, it stated that it "does not object" to the granting of leave. Accordingly, on a preliminary application, both the Consumer Advocate and Hydro were granted leave to appeal.

[49] Newfoundland Power supports Hydro and the Consumer Advocate on these appeals. Various industrial customers support the decision of the Board. The Board itself was also represented by counsel in support of the Decision.

ISSUES

[50] The following issues arise on these appeals:

(a) What is the appropriate standard of review to be applied to the Board's decision?

(b) What is the extent of the Board's jurisdiction to change the operation of the RSP, particularly with respect to the operation of the load variation component, and to allocate load variation balances accrued to Industrial Customers before and after the interim order effective January 1, 2008 for the benefit of other customers on the Island Interconnected System?

(c) Is the Board's jurisdiction limited to determining whether any overpayment as a result of the interim rates is to be refunded to the industrial customer group or placed in a reserve account for the benefit of the industrial customer group?

[51] The main focus of this appeal is the Board's determination that it did not have the jurisdiction to allocate balances accrued under the RSP rules, while the industrial customer rates were interim, to other customer classes. The practical effect of this determination is that the system savings which accrued in what was characterized as a "deferral account" while rates were interim must flow to the exclusive benefit of the industrial customers.

ANALYSIS

(a) Statutory Framework and Basic Principles

[52] An outline of the Board's statutory framework and the nature of deferred accounts and interim rates will assist in the resolution of the issues before the Court.

[53] In *Reference Re Section 101 of the Public Utilities Act (Nfld.)* (1998), 164 Nfld. & P.E.I.R. 60 (Nfld.C.A.) ("*Stated Case*"), Green J.A. noted the Board's statutory basis as follows:

> [13] The answers to the questions which have been posed must, of course, be given taking account of the legislative framework within which the Board operates. The Board is a creature of statute and its jurisdiction and powers to deal with matters brought before it, and the manner of dealing with such matters, must be found, either expressly or impliedly, within the statutes conferring jurisdiction on and governing the operation of the Board.

[54] The Board's jurisdiction and powers are governed by the *PUB Act* and the *Electrical Power Control Act, 1994*, SNL 1994 c. E-5.1 (*"EPC Act"*). The *PUB Act* confers on the Board the power for "the general supervision of all public utilities". Specifically the Board has sole authority to approve the rates charged by public utilities – ss. 70(1) and 71 – and the power to approve interim rates unilaterally – s. 75. The breadth of the Board's authority over rates is illustrated by s. 76 which confers the right to rescind or alter rates, s. 82 which confers the right to investigate a rate, where the Board believes that it is unreasonable or unjustly discriminatory, and ss. 84-87 which authorize the Board, following a formal complaint, to investigate and to cancel rates and void contracts where rates are found to be unjust, unreasonable, insufficient or unjustly discriminatory.

[55] In considering the extent of the Board's powers under the *PUB Act* reference must be made to s. 118 which states:

> 118.(1) This Act shall be interpreted and construed liberally in order to accomplish its purposes, and where a specific power or authority is given the board by this Act, the enumeration of it shall not be held to exclude or impair a power or authority otherwise in this Act conferred on the board.
>
> (2)The board created has, in addition to the powers specified in this Act, all additional, implied and incidental powers which may be appropriate or necessary to carry out all the powers specified in this Act.
>
> .....

[56] The *EPC Act* states the electrical power policy of the province in s. 3. It obligates the Board to implement that policy as it carries out its duties and exercises its powers under the *PUB Act* and in so doing s. 4 requires the Board to apply tests which are consistent with "generally accepted sound public utility practice".

[57] In the *Stated Case* Green J.A. stated some of the general principles applicable to the interpretation of the *PUB Act* and *EPC Act* as follows:

[36] ...

1. The Act *(PUB Act)* should be given a broad and liberal interpretation to achieve its purposes as well as the implementation of the power policy of the province;

2. The Board has a broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the purposes of the legislation and to implement provincial power policy;

3. The failure to identify a specific statutory power in the Board to undertake a particular impugned action does not mean that the jurisdiction of the Board is thereby circumscribed; so long as the contemplated action can be said to be "appropriate or necessary" to carry out an identified statutory power and can be broadly said to advance the purposes and policies of the legislation, the Board will generally be regarded as having such an implied or incidental power;

4. In carrying out its functions under the Act, the Board is circumscribed by the requirement to balance the interests, as identified in the legislation, of the utility against those of the consuming public;

5. The setting of a "just and reasonable" rate of return is of fundamental importance to the utility and must always be an important focus of the Board's deliberations; however, the "entitlement" of the utility to a just and reasonable rate of return does not guarantee it that level of return. The "entitlement" is to have the Board address that issue and to make its best prospective estimate, based on its full consideration of all available evidence, for the purpose of setting rates, tolls and charges.

6. The Board has jurisdiction, which will not generally be interfered with on judicial review, to make a determination of what is a just and reasonable rate of return within a "zone of reasonableness" and in so doing is not constrained in its choice of applicable methodologies, so long as they can be rationally justified in accordance with sound utility practice and are not inconsistent with the achievement of the purposes and policies of the legislation.

[58] Though the *Stated Case* concerned a utility's rate of return, the principles stated above, including those in sub-paragraphs 5 and 6, apply in a similar manner to the determination of rates for a utility's customers.

[59] The *EPC Act* requires that, wherever practicable, rates are to be established based on forecast costs – s. 3(a)(ii) – and utilizing tests which are consistent with "generally accepted sound public utility practice" – s. 4. The

rates policy stipulated in s. 3 of the *EPC Act* is consistent with the widely accepted principle of ratemaking that rates should be set prospectively, i.e., retroactive ratemaking should generally not be permitted. That principle and the distinction between retroactive and retrospective ratemaking were summarized recently in *Calgary (City) v. Alberta (Energy and Utilities Board)*, 2010 ABCA 132 ("*Atco Gas*") in the following paragraphs of the majority decision:

> [46] A brief overview of some central principles of ratemaking, including the related concepts of retroactive and retrospective ratemaking, is necessary. Generally, ratemaking and rates must be prospective: *Coseka Resources Ltd. v. Saratoga Processing Co.* (1981), 31 A.R. 541 at para. 29, 16 Alta. L.R. (2d) 60 (C.A.). A utility's past financial results can be used to forecast future expenses, but a regulator cannot design future rates to recover past revenue deficiencies: *Northwestern Utilities Ltd. and al. v. Edmonton*, [1979] 1 S.C.R. 684 at 691 and 699 ("*Northwestern Utilities*").
>
> [47] Retroactive ratemaking "establish[es] rates to replace or be substituted to those which were charged during that period": *Bell Canada v. Canada (Canadian Radio-Television and Telecommunications Commission)*, [1989] 1 S.C.R. 1722 at 1749 ("*Bell Canada 1989*"). Utility regulators cannot retroactively change rates (*Stores Block* at para. 71) because it creates a lack of certainty for utility consumers. If a regulator could retroactively change rates, consumers would never be assured of the finality of rates they paid for utility services.
>
> [48] Retrospective ratemaking, in contrast, imposes on the utility's current consumers shortfalls (or surpluses) incurred by previous generations of consumers. It is generally prohibited because it creates inequities or improper subsidizations as between past and present consumers (who may not be the same). "[T]oday's customers ought not to be held responsible for expenses associated with services provided to yesterday's customers": Yvonne Penning, *"The 1986 Bell Rate Case: Can Economic Policy and Legal Formalism be Reconciled"* (1989), 47(2) U.T. Fac. L. Rev. 607 at 610. This is sometimes referred to as the problem of inter-generational equity (which the Board discusses at p. 12 of the Limitations Decision reproduced at para. 23).
>
> [49] Sometimes *retrospective* ratemaking is referred to as *retroactive* ratemaking. This is because rates imposed on a future generation of consumers, while prospective, create obligations in respect of past transactions, and in this sense they are retroactive: *City of Edmonton* at 402.

See also *Stated Case*, paragraphs 33 and 80.

[60] It is nevertheless clear from the authorities that the above noted principle of prospective ratemaking cannot bar the use of two widely used

regulatory tools authorized by applicable legislation though the same may be thought to have an element of retrospectivity. These two are interim rates and deferral accounts. See *Bell Canada v. Canada (Canadian Radio-television & Telecommunications Commission)*, [1989] 1 S.C.R. 1722 *(Bell Canada 1989); Bell Canada v. Bell Aliant Regional Communications*, 2009 SCC 40, [2009] 2 S.C.R. 764 *(Bell Canada 2009).*

[61] The power of the Board to authorize interim rates is granted in s. 75 of the *PUB Act.* That section allows the board to set rates expeditiously without full evidence and submissions, such rates being subject to review and possible modification in the final order of the Board, as is expressly provided for in subsections 75(2) and (3). Depending on the nature of the final order of the board it may have a retroactive or retrospective effect. In *Bell Canada 1989*, Gonthier J. stated:

> The statutory scheme established by the *Railway Act* and the *National Transportation Act* is such that one of the differences between interim and final orders must be that interim decisions may be reviewed and modified in a retrospective manner by a final decision. It is inherent in the nature of interim orders that their effect as well as any discrepancy between the interim order and the final order may be reviewed and remedied by the final order. I hasten to add that the words "further directions" do not have any magical, retrospective content. Under the *Railway Act* and the *National Transportation Act*, final orders are subject to "further [prospective] directions" as well. It is the interim nature of the order which makes it subject to further retrospective directions.
>
> (p. 1752)
>
> ...The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order. As a result, it cannot be said that the rate review process begins at the date of the final hearing; instead, the rate review begins when the appellant sets interim rates pending a final decision on the merits. As was stated in *obiter* in *Re Eurocan Pulp & Paper Co. and British Columbia Energy Commission* (1978), 87 D.L.R. (3d) 727 (B.C.C.A.), with respect to a similar though not identical legislative scheme, the power to make interim orders effectively implies the power to make orders effective from the date of the beginning of the proceedings. In turn, this power must comprise the power to make appropriate orders for the purpose of remedying any discrepancy between the rate of return yielded by the interim rates and the rate of return allowed in the final

> decision for the period during which they are in effect so as to achieve just and reasonable rates throughout that period.
>
> (p. 1761)

[62] The statutory scheme of the *PUB Act* is to the same effect, as noted in the *Stated Case* as follows:

> [87] The scenario contemplated by Questions 3 & 4 is unlike the situation which arises where an interim order setting rates, tolls and charges is subsequently superseded by a final order, resulting in excess revenue being earned in the intervening period because the rates, tolls and charges charged in that period pursuant to the interim order were higher than those which were ultimately found to be justified in the final order. In that situation, if the final order is treated as being operative as and from the date of the interim order that was superceded, the final order will, indeed, have a retroactive effect. In the context of the Newfoundland legislation, that situation is specifically contemplated and authorized by s. 75(3) of the **Act**.

[63] The operation of deferral accounts is permissible under the existing regulatory scheme in this province regardless of whether it might be argued they incidentally have retrospective or retroactive effect. Deferral accounts are utilized in public utility regulation to deal with the effects of uncertain or volatile costs in a manner that ensures that rates are reasonable, not unjustly discriminatory and that the utility earns a just and reasonable return. They permit the recovery or rebate in a subsequent period of any deficiency or excess between forecast and actual costs. Regulatory regimes generally permit the operation of deferral accounts. See *Bell Canada 2009* at paras. 54-55; *Atco Gas* at paras. 33-44; *City of Edmonton v. Northwestern Utilities Ltd.*, [1961] S.C.R. 392 at p. 406. It was properly acknowledged by all parties that the *PUB Act* authorizes the utilization of deferral accounts. See *Stated Case* at paras. 93-98.

[64] In *Bell Canada 2009* the use of deferral accounts to ensure that rates return to a utility the actual - not forecast - costs,was held to preclude a finding of retroactivity or retrospectivity:

> [63] In my view, the credits ordered out of the deferral accounts in the case before us are neither retroactive nor retrospective. <u>They do not vary the original rate as approved, which included the deferral accounts, nor do they seek to remedy a deficiency in the rate order through later measures, since these credits or reductions were contemplated as a possible disposition of the deferral account balances from the beginning.</u> These funds can properly be characterized as encumbered revenues, because the rates *always* remained subject to the deferral

> accounts mechanism established in the Price Caps Decision. The use of deferral accounts therefore precludes a finding of retroactivity or retrospectivity. Furthermore, using deferral accounts to account for the difference between forecast and actual costs and revenues has traditionally been held not to constitute retroactive rate-setting (*EPCOR Generation Inc. v. Energy and Utilities Board*, 2003 ABCA 374, 346 A.R. 281, at para. 12, and *Reference Re Section 101 of the Public Utilities Act* (1998), 164 Nfld. & P.E.I.R. 60 (Nfld. C.A.), at paras. 97-98 and 175).
>
> (Emphasis added.)

[65] As stated, funds in a deferral account can properly be characterized as encumbered revenues as the rates are subject to the deferral account mechanisms established by the regulatory authority.

(b) The Regulatory Context

[66] This appeal concerns the legal authority of the Board respecting the disposition of amounts accumulating in a deferral account, Hydro's RSP, while interim orders were in effect from January 1, 2008.

[67] Final rates for the Industrial Customers were last approved by the Board in Order No. P.U. 8 (2007) effective January 1, 2007. In the same year final rates for Newfoundland Power were established by Order No. P.U. 11 (2007) effective July 1, 2007. In the following years prior to the next GRA under the current RSP Hydro would have been expected to make annual applications to the Board to reflect the appropriate RSP adjustments to the rates. As noted previously, for the Industrial Customers the RSP adjustment would take effect as of January 1st each year and for Newfoundland Power the adjustments would take effect as of July 1st each year.

[68] Those adjustments have not been made for the Industrial Customers since July 1, 2007. For the stated reason of needing to assess the effect of significant changes in Industrial Customer load, Hydro applied on December 20, 2007 for the continuation on an interim basis of the Industrial Customer rates then in effect. By Order No. P.U. 34 (2007) the Board approved the required interim rates for 2008. In December 11, 2008 Hydro again applied to the Industrial Customer rates over an interim basis in view of inevitable changes to Industrial Customer load consequent upon closure of a paper mill. By Order P.U. 37 (2008) the Board approved the continuation of the rates until March 31, 2009, and subsequently under Order No. P.U. 6 (2009)

the duration of the interim order was extended to June 30, 2009. In the meantime, Newfoundland Power's rates for its customers had been made final.

[69] On June 30, 2009 Hydro applied to have the existing Industrial Customer rates made final. It was at that point that the issue of whether the Board had the legal authority to change the manner of operation of the RSP to benefit customers, other than industrial customers, in prior years when those other customers' rates had already been finalized, arose.

(c) Standard of Review

[70] As this tribunal appeal is taken from orders of the Board directly to this Court, it is necessary to apply a standard of review analysis in accordance with the principles in *Dunsmuir v. New Brunswick*, 2008 SCC 9, [2008] 1 S.C.R. 190 and subsequent cases, to determine the scope of review that this Court may undertake.

[71] As *Dunsmuir* pointed out, it is not necessary to undertake a full standard of review analysis if prior "jurisprudence has already determined in a satisfactory manner the degree of deference to be accorded with regard to a particular category of question" (paragraph 62). It is only when the inquiry into existing jurisprudence "proves unfruitful" that the court must proceed to a full analysis of the factors identified in *Dunsmuir* that make it possible to identify the proper standard of review.

[72] In the case of the Board, there is prior jurisprudence that has addressed the standard of review of Board decisions. In *Labrador City,* Cameron J.A. concluded on an application for leave to appeal, that the issues to be dealt with on the appeal, if leave were to be given (whether a common rate policy for electrical customers in Labrador was non-discriminatory; and whether the Board erred in failing to consider certain arguments submitted to it) should be reviewed on a standard of reasonableness. In like manner, in *Newfoundland Power*, Cameron J.A. held, on another application for leave, that an issue involving a contextual interpretation of a previous Board order, while involving a question of law, should nevertheless be reviewed on a standard of reasonableness. In both of these cases, the judge had to consider whether, as a condition of granting leave, the proposed appellant had a "reasonably arguable case" and in deciding that question, consideration should be given to the standard of review to be applied by the Court, if leave were granted, "in respect of the particular issues raised" (*Newfoundland Power*, paragraph 10; and *Labrador City*, paragraph 5).

[73] We do not consider the *Newfoundland Power* and *Labrador City* cases to be determinative of the issue of the standard of review in this case because: (i) they were decided before *Dunsmuir*; (ii) they are not decisions of a full panel; (iii) they were decided in the context of applications for leave to appeal, where the need for a definitive determination of the issue of standard of review was not directly engaged; and (iv) the issues being reviewed in those cases were dissimilar from the particular issues raised in the current case. They nevertheless remain of some assistance, insofar as they express views on the general structure of the legislation and the context in which the Board operates.

[74] Accordingly, it is necessary to engage in an analysis of the factors that have been identified in other cases to determine the proper standard of review (correctness or reasonableness) in this particular case.

[75] There are two statutory mechanisms whereby issues dealt with by the Board can be considered by this Court. They are contained in sections 99, 101 and 102 of the *PUB Act*:

> 99.(1) An appeal lies to the Court of Appeal from an order of the board upon a question as to its jurisdiction or upon a question of law ...
>
> 101. The board may of its own motion or upon the application of a party, ...state a case in writing for the opinion of the Court of Appeal upon a question which in the opinion of the board is a question of law and a similar reference may also be made at the request of the Lieutenant-Governor in Council.
>
> 102. The Court of Appeal shall hear and determine the question of law arising in a case stated under section 101 and remit the matter to the board with the opinion of the court attached.

[76] In matters brought before the Court under both s. 99 and s. 101, the focus is on considerations involving "a question of law". In s. 99, there is the additional focus on "a question as to [the board's] jurisdiction" but that is a specialized form of legal question as well. In references under s. 101, in which the Court's opinion is sought on questions of law, the Court is obligated, pursuant to s. 102, to provide its own view on what it considers to be the "correct" answer to the question posed, as was done in the *Stated Case*. By enacting ss. 101 and 102, the legislature has determined it appropriate for the Board to defer to the Court's opinion on questions of law, rather than the Court deferring to the expertise of the Board in determining those types of questions.

[77] On an appeal brought under s. 99 where the focus is also on "a question of law", the question arises as to whether the same standard for determining questions of law should be applied or whether something more restrictive – involving a degree of deference to the original decision-maker – should be employed. On one viewpoint, it could be said that if the legislature intended, in its similar characterization of the types of questions that could be raised under s. 99 and s. 101, that there should be more deference accorded under s. 99, it could have said so, but it did not. On the other side, it could be said that the process under s. 99 is different, involving as it does, a challenge to decisions of the Board that the Board believes are correct and does not involve the Board itself questioning its own view. In such situations, more deference might be justifiable.

[78] That said by way of preliminary observation, it is now necessary to turn to a consideration of the "contextual guideposts" (per Fish J. in *Nor-Man Regional Health Authority Inc. v. Manitoba Association of Health Care Professionals*, 2011 SCC 59, [2011] 3 S.C.R. 616 at paragraph 41) that are to be applied to assist in determining the scope of review. The basic factors to consider were re-iterated in *Dunsmuir* to include: (i) the presence or absence of a privative clause; (ii) the purpose of the tribunal as determined by interpretation of its enabling legislation; (iii) the nature of the question at issue; and (iv) the expertise of the tribunal (paragraph 64). These factors are non-exhaustive: *Nor-Man* at paragraph 40.

[79] It should be noted at the outset that the contextual factors are designed to assist in determining the intention of the legislature as to the intended scope of review. In the end, what is sought is to discern whether the legislature intended to limit the degree of scrutiny of the tribunal's decision by the court.

[80] Turning to the first guidepost – the presence or absence of a privative clause – the restriction placed by s. 99 on the Court by limiting appeals to questions of jurisdiction and law and effectively excluding appeals respecting factual matters and inextricably intertwined questions of mixed law and fact is effectively a privative clause regarding those factually-related matters. On the other hand, inasmuch as the legislation allows appeals on jurisdiction and law, it is not a privative clause in respect of those matters.

[81] In *Barrie Public Utilities v. Canadian Cable Television Association*, 2003 SCC 28, [2003] 1 S.C.R. 476 at paragraph 11, Gonthier J., for the majority , observed that: "While the presence of a statutory right of appeal is not decisive of a correctness standard ... it is a factor suggesting a more

searching standard of review". See also, Michel Bastarache, "Modernizing Judicial Review" (2009), 22 C.J.A.L.P. 227 at p. 234. It must also be recognized, however, that the absence of a privative clause does not necessarily lead to the conclusion that a high level of scrutiny is necessarily intended "where other factors bespeak a low standard" (*Pushpanathan v. Canada (Minister of Citizenship and Immigration)*, [1998]1 S.C.R. 982, per Bastarache J. at paragraphs 30, 37). That said, in the context of the legislative scheme involved in this case, this first factor, considered alone, points towards a correctness standard rather than a deferential one on issues of law and jurisdiction.

[82] As to the second guidepost – the purpose of the tribunal – Cameron J.A. observed in *Labrador City* that:

> [17] The Board is comprised of full and part-time members who have different backgrounds. This would include engineers and accountants, for example. It has a professional staff. Its role is a many-faceted one, including the supervision of all public utilities and the regulation of rates, tolls and charges. Policy, both that imposed by legislation and that developed by the Board, plays a major role in the Board's performance of its duties. Some of those policies are developed over time. There can be no doubt that the Board is a specialized tribunal with expertise in matters related to the regulation of electrical utilities. In questions related to the determination of rates, which involve the application of industry practice, the Board is clearly in a position superior to that of the Court. This would suggest a more deferential standard of review.
>
> ...
>
> [19] ... The *Public Utilities Act* and the *Electrical Power Control Act, 1994* provide a scheme for the regulation of electrical utilities which requires the Board to address policy issues and to balance interests. They operate in tandem. This factor suggest[s] a more deferential standard to the Board's decisions.

These observations are equally applicable today. I would add the caveat, however, that the deference to be shown is in relation to the area that is entrusted to the Board for regulation and where the Board's superior expertise in the understanding, development and application of policy and the application of regulatory legal standards and balancing of interests exists.

[83] In *Council for Licensed Practical Nurses v. Walsh*, 2010 NLCA 11 Welsh J.A. at paragraph 11 pointed out that the existence of a right of appeal does not automatically mean that a standard of correctness will apply where the nature of the question (in *Walsh*, one of mixed law and fact) engages the

expertise of the tribunal. That brings us to the two remaining factors to be considered: nature of the issue and tribunal expertise.

[84] With respect to the third factor – the nature of the issue – it is important to appreciate that "different standards of review will apply to different legal questions depending on the nature of the question to be determined and the relative expertise of the tribunal in those particular matters." (per Major J. in *Canada (Deputy Minister of National Revenue) v. Mattel Canada Inc.,* 2011 SCC 36, [2001] 2 S.C.R. 100 at paragraph 27.

[85] It is now recognized that deference should be shown to many types of tribunal decisions even though they involve a question of law. This is especially so where a specialized tribunal, in the course of carrying out its statutory duties, is interpreting its "home statute" within its area of expertise. See, *Smith v. Alliance Pipeline Ltd.*, 2011 SCC 7, [2011] 1 S.C.R. 160, per Fish J. at paragraph 37; *Celgene Corp v. Canada (Attorney General)*, 2011 SCC 1, [2011] 1 S.C.R. 3 per Abella J. at paragraph 34. In fact, in *Alberta (Information and Privacy Commissioner) v. Alberta Teachers' Association,* 2011 SCC 61, [2011] 3 S.C.R. 654, Rothstein J., writing for the majority, went so far as to say, at paragraph 39, that: "[w]hen considering a decision of an administrative tribunal interpreting or applying its home statute, it should be presumed that the appropriate standard of review is reasonableness."

[86] That said, there must remain, if the rule of law is to be given effect, an area where a statutory delegate must be required to make decisions that, on review by the superior courts, must be correct. In *Alliance Pipeline*, Fish J., writing for a majority of eight, identified the following areas where correctness still has application:

> [26] ... The standard of correctness governs: (1) a constitutional issue; (2) a question of "general law 'that is both of central importance to the legal system as a whole and outside the adjudicator's specialized area of expertise'" ...; (3) the drawing of jurisdictional lines between two or more competing specialized tribunals; and (4) a "true question of jurisdiction or *vires*" ...

[87] In the *Alberta Teachers' Association* case, the Supreme Court again recognized that the principle that deference will be shown to tribunal decisions interpreting their home statutes applies "unless the interpretation of the home statute falls into one of the categories of questions to which the correctness standard continues to apply" (paragraph 30), i.e. the four categories identified by Fish J. in *Alliance Pipeline*.

[88] *Alberta Teachers' Association* also stresses that the category of "true questions of jurisdiction or *vires*" is a very narrow one (paragraph 33) and that Courts should not be too quick to brand a legal question as jurisdictional and thereby revert to the interventionist attitudes towards judicial review that obtained prior to *Canadian Union of Public Employees, Local 963 v. New Brunswick Liquor Corp.*, [1979] 2 S.C.R. 227. Rothstein J. explained:

> [34] The direction that the category of true questions of jurisdiction should be interpreted narrowly takes on a particular importance when the tribunal is interpreting its home statute. In one sense, anything a tribunal does that involves the interpretation of its home statute involves the determination of whether it has the authority or jurisdiction to do what is being challenged on judicial review. However, since *Dunsmuir*, this Court has departed from that definition of jurisdiction... [I]t is sufficient in these reasons to say that, unless the situation is exceptional, and we have not seen such a situation since *Dunsmuir*, the interpretation by the tribunal of "its own statute or statutes closely connected to its function, with which it will have particular familiarity", should be presumed to be a question of statutory interpretation subject to deference on judicial review.

[89] Nothing written in *Alberta Teachers' Association* has eliminated true questions of jurisdiction or *vires* – narrow though that category may be – as attracting a correctness standard of review. The real question is what in essence constitutes a true question of jurisdiction or *vires*? Although Rothstein J. confessed in *Alberta Teachers' Association* that he was "unable to provide a definition of what might constitute a true question of jurisdiction" (paragraph 42), reference to *Dunsmuir* is nevertheless helpful. There, Bastarache and Lebel JJ. stated:

> [59] ... "Jurisdiction" is intended in the narrow sense of whether or not the tribunal had the authority to make the inquiry. In other words, true jurisdiction questions arise where the tribunal must explicitly determine whether its statutory grant of power gives it the authority to decide a particular matter. The tribunal must interpret the grant of authority correctly or its action will be found to be *ultra vires* or to constitute a wrongful decline of jurisdiction.

[90] In the instant case, it was the Board that determined that before it could hear Hydro's rate application (something that was clearly within its jurisdiction to hear) a "preliminary hearing" had to be held to determine the question set out previously in paragraph 32 of this decision. The formulation specifically raised the question:

> Does the Board have *jurisdiction* to issue an order which changes how the Rate Stabilization Plan (RSP) operated before the date of the order and, if so, does this

> *jurisdiction* extend to any aspect of the operation of the RSP, including the rate charged to customers, the determination of the balance(s) in the RSP, and how these balances are allocated to customers or customer classes?
>
> (Emphasis added.)

[91] In its Decision, the Board described the preliminary hearing as follows:

> The preliminary hearing was held to receive submissions from the parties on the question of whether the Board has the *jurisdiction* to change the manner in which the RSP operated, including the rates charged, the determination of the balance(s) in the RSP and how these balances are allocated to customer classes. This question of *jurisdiction* is raised in the context of the interim orders issued by the Board for Industrial Customer rates since December 2007.
>
> (Emphasis added.)

[92] The parties at the preliminary hearing divided as to whether the Board had legal authority to make an order dealing with the money in the RSP that would include residential customers, as well as industrial customers, as beneficiaries. The Board described the difference as follows:

> All parties agree that the Board has the *jurisdiction* to set final rates for the Industrial Customers as of January 1, 2008. Hydro, Newfoundland Power and the Consumer Advocate submit that, in establishing those rates, *the Board also has jurisdiction* to deal with the manner of how those rates, and in particular the RSP rates, are calculated as of the date of any interim order, including the disposition of any balances in the RSP arising. The Industrial Customers submit that *s. 75 of the Act only allows the Board to set interim rates* and that the rules and regulations affecting those rates cannot be made interim. The Industrial Customers argue that the Board's *jurisdiction* with respect to the disposition of any balances in the RSP is confined to the existing RSP rules and regulations.
>
> (Underlining added.)

Noting that the RSP was a type of "deferral account", the Board approached this issue by reference to, amongst other things, the scope of the authority granted by s. 75 of the *PUB Act*, as well as the underlying principles of utility regulation, derived in part from this Court's decision in the *Stated Case* as well as other jurisprudence.

[93] The Board's conclusions, reproduced in paragraph 43 of this decision, were also stated in jurisdictional terms. In particular, note is taken of the statement, "... *the Board does not have jurisdiction* to change how the

Newfoundland Power RSP operated in prior years, either in terms of the rates charged or the resulting balances" (Italics added.). While it is true that in the elaboration of its reasons leading to this conclusion the Board purported to rely on underlying principles and policies of utility regulation – matters with which it has great familiarity and some expertise – in the end the conclusion reached was that the Board had no jurisdiction, in the sense of legal authority, to distribute deferral account balances, and in particular the RSP in question, to customers other than industrial customers or to otherwise benefit them in the context or orders setting interim rates.

[94] We agree with counsel for Newfoundland Power, who submitted:

> The issue that the Board stated for itself was a true question of jurisdiction or *vires*. It engaged the question of what the Board had the legal power and authority to do, not what the Board should do as a matter of regulatory judgment and decision-making. The issue was engaged on a preliminary hearing before the Board proceeded to a hearing on the merits.
>
> (Paragraph 122, Newfoundland Power's Factum.)

[95] If the Board is incorrect on this issue, its decision in effect would amount to declining to exercise an authority it has by law (i.e. a "wrongful decline of jurisdiction", as referred to by Bastarache and Lebel JJ. in *Dunsmuir*, quoted above). The result, if incorrect, would be the shutting out of a large class of power consumers from the benefits of the legislative scheme being administered by the Board. The issue, therefore, of the authority of the Board to benefit customers other than industrial customers through regulating a deferral account like the RSP under s. 75 in the context of interim orders has all the hallmarks of a true question of jurisdiction.

[96] In *Milner Power Inc. v. Alberta (Energy and Utilities Board)*, 2010 ABCA 236, which dealt with a statutory appeal from a decision of the Alberta Energy and Utilities Board on questions of law and jurisdiction, the court confirmed that despite the general expertise of the Board and regulatory purpose of the legislation, the "key factor" was the nature of the questions raised on the appeal (whether the Board should have referred to investigate and hold a hearing into a complaint and, instead, summarily dismissed it). The court concluded that the question of law relating to the right of the Board to refuse to investigate or hold a hearing was an important question of law that did not engage the specialized expertise of the Board. The Court stated:

> [29] ... [T]he legislation provides for a right of appeal on questions of law and, in our view, because this is a question of the proper interpretation of the Board's right to refuse to act on a complaint, the Board must be correct.

[97] In similar manner in the instant case, because this is a question of the proper interpretation of the Board's right to decline, according to law, to deal with a deferral account, in the context of interim rates, for the benefit of certain classes of customers, the Board should also be correct because the matter involves the jurisdiction of the Board.

[98] Counsel for the Board submitted, however, that a key consideration differentiating the Board's decision in this case from a true question of jurisdiction is the statutory direction in the *Electrical Power Control Act, 1994*, s. 4 to apply "generally accepted sound public utility practice" to the implementation of the power policy of the province, something that falls within the expertise of the Board. That argument, however, has no application to the issue in this case. This is not a case where the Board purported to make a determination that, as a matter of sound public utility practice, it *should not* exercise its powers in a certain way; rather, it is a case where the Board purported to determine that it *could not* do so.

[99] To determine whether the Board *could* exercise its authority in the circumstances of this case, the Board had to interpret s. 75 in light of the underlying principles of utility regulation (such as the principle against retroactivity). There is nothing in s. 75 of a technical nature that requires the Board's expertise in its construction. Indeed, the underlying principles which the Board purported to apply are those which were pronounced upon by this Court in the *Stated Case*. As noted previously, the results of stated cases brought under s. 101 require the Board to defer to the view of the Court rather than the other way around. That would include the Court subsequently pronouncing on the meaning of what it said in earlier jurisprudence. The Court is therefore in as good a position as the Board to determine the scope of s. 75 insofar as it confers legal authority on the Board.

[100] In *Bell Canada 1989*, which involved a statutory appeal from the Canadian Radio-Television and Communications Commission to the Federal Court of Appeal on questions of law or jurisdiction, where the issues, as ultimately stated by the Supreme Court of Canada, were whether the Commission had the "legislative authority" to review revenues made by Bell Canada during a period when interim rates were in force and whether the Commission had "jurisdiction" to make an order compelling Bell to grant a one-time credit to its customers, the Court, recognizing that deference

should be given to the Commission's decisions on issues which fell within its area of expertise, nevertheless held that the issues at play were jurisdictional and were not within the Commission's area of expertise. Gonthier J. explained at p. 1747:

> In this case, the respondent is challenging the appellant's decision on a question of law and jurisdiction involving the nature of interim decisions and the extent of the powers conferred on the appellant when it makes interim decisions. ... It is ... a question of jurisdiction because it involves an inquiry into whether the appellant had the power to make a one-time credit order.
>
> Except as regards the choice, amongst remedies available to the appellant, of the most appropriate remedy to achieve the goal of just and reasonable rates throughout the interim period, the decision impugned by the respondent is not a decision which falls within the appellant's area of special expertise ...

[101] The decision in the foregoing case can usefully be contrasted with *Bell Canada 2009* where the issue was the appropriateness of the manner in which the Commission exercised its rate-setting jurisdiction in directing the allocation of certain funds to various purposes. In that, case, unlike the earlier *Bell Canada 1989*, the question was not whether the Commission had the legal authority to order certain dispositions but whether its choice of methodology was appropriate, something the Court held was at the "core" of the Commission's specialized expertise. As a result, a deferential standard of review was employed.

[102] The instant case is more akin to the 1989 decision. Here, the core of the dispute is the Board's decision that it did not have the jurisdiction, or legal authority, to allocate balances accrued under RSP rules to other classes in circumstances where industrial customers' rates were interim.

[103] We conclude, therefore, that the issue before the Board, as stated in its decision to hold a preliminary hearing, in the arguments made at the hearing, in the Board's formulation of the issues in its Decision and in the conclusions it reached, was a true question of jurisdiction and should be reviewed on a standard of correctness.

[104] There is, of course, a fourth factor to be considered – the expertise of the Board. However, in light of the conclusion reached above, little more need be said. As noted in *Barrie Public Utilities*, "The proper concern of the reviewing court is not the expertise of the decision-maker in general, but its expertise relative to that of the court itself *vis-à-vis* the particular issue" (per Gonthier J. at paragraph 12).

[105] There is certainly little doubt that the Board is regarded as a specialized tribunal with expertise in the area of regulation of electrical utilities and the establishment and approval of rates, tolls and charges. As noted in the *Labrador City* case, the legislative scheme requires the Board to develop and apply policy in the course of its work. Further, s. 6 of the *PUB Act* requires the Lieutenant-Governor in Council, when making appointments to the Board, to "take into consideration the need of the board to be composed of commissioners who have expertise in law, engineering, accountancy and finance." It is clear that the legislature intended the Board to be a tribunal with specialized expertise within the field of its legislative mandate.

[106] As pointed out in the *Bell Canada 1989* decision, however, the Board is not to be regarded as superior to the Court in respect of questions of a true jurisdictional nature. With respect to the issues engaged in this appeal, therefore, the fact that the Board is a specialized tribunal within the area of its mandate does not call for deference to its decisions relating to true jurisdictional matters.

[107] Taking all factors together, there should be appellate review of the Decision on a correctness standard.

(d) The Board's Approach

[108] In the context of an application by Hydro that previously-approved interim rates for certain industrial customers be made final, the Board determined that, by way of preliminary hearing, the parties should first address whether the Board had "jurisdiction to issue an order which changes how the ... RSP operated before the date of the order and, if so, does this jurisdiction extend to any aspect of the RSP, including ... how these balances are allocated to customers or customer classes."

[109] The Board appeared to be concerned, amongst other things, that a change to the RSP that could involve customers, other than industrial customers, potentially benefiting from any change in the RSP rules even though those other customers' rates were, for the relevant period, no longer interim, was not permissible. The Board was also concerned with whether exercising such a jurisdiction, if it existed, might offend the presumption against retroactivity.

[110] The Board described the position of Hydro, Newfoundland Power and the Consumer Advocate as follows:

> Hydro, Newfoundland Power and the Consumer Advocate submit that, in establishing these final rates, the Board also has the jurisdiction to deal with the manner of how those rates, and in particular the RSP rates, are calculated as of the date of any interim order, including the disposition of any balances in the RSP arising.
>
> (p.7)

[111] By contrast, the Industrial Customers took the position, in the view of the Board, that although the Board could set interim rates, "the rules and regulations affecting those rates cannot be made interim" and that "the Board's jurisdiction with respect to the disposition of any balances in the RSP is confined to the existing RSP rules and regulations". Put another way, it meant that the balances in the RSP could not be distributed to anyone other than the Industrial Customers under the guise of making interim rates for Industrial Customers final when other customers' rates had already been made final.

[112] The Board restated the "fundamental question" as follows: "how an established deferral account, such as the RSP, should be treated by the Board in the context of interim orders affecting the balances in the account" (p.7)

[113] The Board's approach to the questions it had posed for preliminary decision essentially involved a consideration of three matters:

1. The nature of deferral accounts generally and how they could be disposed of;

2. The impact of interim decision-making on the disposition of deferral accounts;

3. The impact of how, procedurally, the issue had been brought before the Board.

Although interrelated, it is necessary to consider each of these matters in turn. In fact, the procedural issues in item three cut across the Board's consideration of the other two items as well.

(i) Deferral Accounts

[114] A deferral account in utility regulatory practice is an accounting practice whereby a separate account is used to

> [54] ... "[e]nable a regulator to defer consideration of a particular item of expense or revenue that is incapable of being forecast with certainty for the test year". They have traditionally protected against future eventualities, particularly the difference between forecasted and actual costs and revenues, allowing a regulator to shift costs and expenses from one regulatory period to another.
>
> (Bell Canada 2009.)

[115] As discussed previously, use of such accounts helps to smooth out the occurrence of unexpected or currently unknown costs or revenues and to provide rate stability to customers. Deferral accounts are regarded as "accepted regulatory tools" to be operated as part of rate-setting powers: *Bell Canada 2009*, paragraph 54. As noted earlier, the proper use of deferral accounts does not involve violation of the principle against retroactivity or retrospectivity.

[116] Implicit in the creation of deferral accounts is the power of the regulator to order the disposition of the funds contained in them: *Bell Canada 2009*, paragraph 56. In *Bell Canada 2009,* for example, the Supreme Court held that deferral account balances representing the difference between certain telephone rates actually charged by local exchange carriers and those determined by a price-cap formula ordained by the regulator could be used to expand high-speed broadband internet services in remote and local communities, to improve accessibility for individuals with disabilities and to give a one-time credit to certain residential subscribers.

[117] The Board determined that the RSP was a form of deferral account because it "allows for the accumulation of balances which are subsequently collected from or refunded to customers". This determination was accepted by all parties.

[118] The RSP is arguably more complex than the normal type of deferral account such as the one which was the subject of discussion in *Bell Canada 2009*. In that case, the deferral account was used to record the difference between the revenues derived from certain residential telephone services that were actually charged, and the revenues that would otherwise have been derived from rates determined by a "price caps" formula designed to limit prices in accordance with inflation. In the instant case, however, the amount that accumulates in the RSP is determined by a number of factors, some of which may work against others in their ultimate effect. The amounts that accrue result not only from increases or decreases in cost – which could be said to relate to only the Industrial Customers operations – but also from

increases or decreases in load variation. In fact, this factor swamps the other factors in terms of magnitude.

[119] The Board, correctly, concluded that the use of deferral accounts is "consistent with prospective regulation" and does not violate the anti-retroactivity principle (p. 7). However, it went on to state that although it had "jurisdiction" in relation to deferral accounts, the use of such accounts is "an extraordinary measure" and that its jurisdiction was "limited by the principles of predictability and fairness ... and does not necessarily extend to changing how balances are calculated and allocated in the past" (p. 8; underlining added).

[120] It is apparent that in the foregoing passages, the Board is commingling two different concepts. The first reference to "jurisdiction" is to the existence of a legal authority for the establishment of deferral accounts. This is a correct use of the notion of jurisdiction. The second reference, on the other hand, is to the manner in which the jurisdiction, or authority, should be exercised – as an extraordinary measure, limited by certain rate-making principles, etc. This analysis does not go to the notion of jurisdiction, as legal authority, but to the manner in which the jurisdiction is to be exercised. This is evident from the observation of the Board that the use of deferral accounts does not "necessarily" extend to changing how balances were allocated in the past, thereby recognizing that these principles do not define the jurisdictional parameters of the operation of deferral accounts but would merely have an influence on the decision, in a given case, as to how a deferral account should be regulated.

[121] By intruding into the area of how the Board's jurisdiction with respect to the operation of a deferral account should be exercised, in the context of an examination of the true jurisdictional question it posed for itself, the Board committed legal error.

[122] In support of its analysis, the Board then referred to past practice of the Board. It stated at p. 8:

> While the Board acknowledges that the RSP has been used creatively over the years to address a variety of issues it is also clear that changes to the established RSP rules have always been made on a prospective basis.[1]

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[1] In support of this proposition, the Board cited a portion of Hydro's written submission to the Board, as follows:

> Barring an intervening order of the Board, which can be either a final order changing the way the collection or disbursement of amounts occur through rate setting of for future energy

While past Board practice may be relevant as to how the Board ought to exercise its jurisdiction in a given case, it cannot be used to determine the jurisdictional parameters of the legal authority which the Board has. In relying on past practice in this regard, the Board erred in its analysis.

[123] The Board then stated a conclusion which obviously drew upon its previous conclusions about exercising its jurisdiction only in "extraordinary" circumstances, not "necessarily" changing how balances were calculated or allocated in the past, and about the influence of past practice:

> In the Board's view changing how the RSP operated in prior years would be analogous to the situation that Mr. Justice Green suggested might constitute retroactive regulation in [the *Stated Case*]
>
> (p. 9)

Because the premises supporting this conclusion are, for the reasons given above, not valid when dealing with the jurisdiction of the Board to deal with deferral accounts, as opposed to the question of how that jurisdiction should be exercised in a given case, the conclusion that changing how the RSP operated in prior years might amount to retroactive regulation is severely weakened.

[124] Furthermore, it was of questionable utility for the Board to have stated this conclusion at this stage in its analysis, when it was only commenting on deferral accounts without reference to the effect of interim orders. The questions posed by the Board, set out in paragraph 32 above, were meant to address the Board's power of disposition over balances in the RSP which accumulated during the currency of interim orders. A conclusion that the RSP, as a deferral account, could not be changed relative to its operation in prior years, without considering the fact that what was being dealt with was in the context of interim orders, was therefore premature. We will come back to the issue of interim orders later in these reasons.

> consumption, or an interim order signaling a potential change in the rate for consumption that occurs after the interim order is issued, the customer can expect to rely upon the rate structure to provide an outcome which will be calculated in manner which has already been set.

This statement does not in fact support the Board's statement in the text. Hydro's submission contained the relevant qualification that the general proposition would not be applicable if there had been an interim order. It was therefore illogical for the Board to offer Hydro's statement as support when it was qualified by the reference to an interim order, clearly applicable to the matter under consideration.

[125] Finally, in the context of its discussion of deferral accounts, the Board made reference to a procedural consideration which appeared to affect its jurisdictional analysis.

[126] The Board noted that Hydro's applications for the interim rates for its Industrial Customers and its 2009 GRA had not sought any changes to the RSP rules, nor had Hydro filed any application for RSP reviews prior to the end of 2009 as had been indicated in the covering letter to its 2009 application. In the absence of an application, the Board declined "to consider suspending the operation of the load variation allocation rules as suggested by Hydro in its correspondence" (p. 9).

[127] The phraseology of that portion of the decision suggests that either the Board believed it could not act on that matter without an application or that the absence of an application was a sufficient reason for the Board not to exercise its jurisdiction. It is not clear which. With respect to the first possible interpretation, in our view the *PUB Act*, including s. 82, confers broad powers upon the Board to investigate rates and take remedial action if appropriate. Exercise of such powers is not dependent upon receipt of an application. Procedure cannot determine jurisdiction. It may affect its exercise but not its existence. With respect to the second interpretation of the Board's statement we consider the statement to be conclusory only, lacking an explanation of why the stated factor would be sufficient.

(ii) Interim Orders

[128] Section 75 of the *PUB Act* gives broad powers to the Board to make orders approving rates, tolls and charges on an interim basis until a final order of the Board is made. When made, the final order is treated as having been made as of the date of the interim order: *Stated Case*, paragraph 87. If therefore, the rates, tolls and charges collected pursuant to the interim order were higher than those finally approved, it is necessary to deal with the excess that, in accordance with the final order, should not have been collected.

[129] Subsection 75(3) provides, in broad terms, that the Board may order that excess revenue earned pursuant to an interim order be dealt with, not only by refunding it to the customers of the public utility concerned, but also by placing it in a reserve fund "for the purpose that may be approved by the board." This provides considerable flexibility to the Board to dispose of excess revenue earned as a result of an interim order, that is not confirmed in

the final order, in a variety of ways that may or may not involve the customers of the utility who contributed to the excess benefiting directly through a refund. As was noted in the *Stated Case*, "[t]he Board has a broad discretion, and hence a large jurisdiction, in its choice of the methodologies and approaches to be adopted to achieve the purposes of the legislation and to implement provincial power policy" (paragraph 36, item 2). In so doing, the Board must "balance the interests, as identified in the legislation, of the utility against those of the consuming public" (paragraph 36, item 4).

[130] Indeed, as noted in the *Stated Case*, paragraph 94, "[t]he power to deal with excess revenue is inherent in the nature of the regulatory scheme the Board is required to administer" even if there is no express statutory provision dealing with the type of excess revenue under consideration. The manner in which the Board can deal with excess revenue is limited only by the broad purposes of the legislative regime as it is perceived by the Board to apply in a given case.

[131] The Board rejected the submission of Hydro, with the support of Newfoundland Power and the Consumer Advocate, that, as the Industrial Customers had been subject to interim orders since January 1, 2008 under s. 75 of the *PUB Act*, the Board's power to determine the appropriateness of rates since January 1, 2008 included the power to determine the disposition of any accumulated balance in the RSP on a prospective basis to all customer groups, not just the Industrial Customers. Instead, the Board accepted the argument of the Industrial Customers that, although the rates applicable to the RSP could be changed back to the date of the last interim order, the balance in the RSP attributed to the Industrial Customer group had to be distributed only for the benefit of that group.

[132] In *Bell Canada 1989*, Gonthier J. stated at p. 1761:

> The underlying theory behind the rule that a positive approval scheme only gives jurisdiction to make prospective orders is that the rates are presumed to be just and reasonable until they are modified because they have been approved by the regulatory authority on the basis that they were indeed just and reasonable. However, the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order.
>
> (Emphasis added.)

[133] The Consumer Advocate relied on this passage to submit that if the Board is dealing with interim rates, the whole rate structure is "up for revision". The Board stated that it accepted the proposition in *Bell Canada*

1989 that "the power to make interim orders necessarily implies the power to modify in its entirety the rate structure previously established by final order" but interpreted that proposition restrictively:

> ... The Board does not believe that an interim rate order for one group of customers empowers the Board to change the utilities' entire rate structure. This interpretation would not be in keeping with the principles of predictability and fairness cited by the Alberta Court of Appeal in the 2010 ATCO decision or with the specific language of the Supreme Court of Canada in [Bell Canada 1989] where the Court states at para. 39:
>
> > "Thus, the question before this Court is whether the appellant has jurisdiction to make orders for the purpose of remedying the inappropriateness of rates which were approved by it in a previous interim decision."
>
> (p. 11; Emphasis added.)

[134] The above passage from *Bell Canada 1989* referenced by the Board was part of a paragraph in which Gonthier J. was describing the matter that was then before the Supreme Court of Canada and it should not be taken as a legal proposition that the powers of a regulatory authority in the context of interim orders are limited to that single defined situation. The propositions stated by Gonthier J. after a review of the applicable legislation and authorities are the legal principles established by *Bell Canada 1989* respecting the powers accruing to a regulatory authority which is authorized to make interim orders – see paragraph 61 above. In restrictively interpreting the general principles enunciated in *Bell Canada 1989* as it did, the Board erred.

[135] In like manner, the Board interpreted s. 75 restrictively to enable it to reject the proposition advanced by the Consumer Advocate that s. 75, by its language, allowed the Board, in its words, "to place any excess revenue paid by the Industrial Customer group as a result of the interim rates into an account for the possible benefit of [some] other customer group" (p. 11). The Board reasoned as follows:

> ... This interpretation would not appear to be consistent with the scheme of the legislation generally or with generally accepted sound public utility practice which requires that rates be just and reasonable and not unjustly discriminatory.
> ...

> Reading s. 75 in the overall context of the legislation and regulatory structure the Board believes that a purposeful interpretation would require that the refund or the reserve fund must, to the extent possible, be for the benefit of the customer group which was found to have paid the excess revenue. There may be times when it is not practical to refund to the customers that paid the excess, for example where the amount is nominal or the customers cannot be found. The Board believes that, in the absence of extraordinary circumstances, a finding that interim rates for a group of customers were in excess of reasonable rates would require that the same customer group be effectively charged the reasonable rates through a refund or the use of a reserve account.
>
> (pp. 11-12)

[136] In this passage the seeds of error are evident. Although commencing to interpret s.75 in accordance with the scheme of the *Act* and basic principles of utility regulation with a view to determining whether it had the legal authority to do what Hydro, Newfoundland Power and the Consumer Advocate submitted it *could* do, the Board's analysis morphed into determining what it *should* do in accordance with sound utility practice. This is evident from the conclusion that there "may be times when it is not practical to refund to the customers that paid the excess", thereby recognizing that other groups could in "exceptional circumstances" benefit. This analysis recognizes the Board was determining its jurisdiction according to what it considered, as a general rule, it *should* do, in a given case, not what it had, as a matter of law, authority to do.

[137] Noting that Newfoundland Power's rates had already been made final, the Board nevertheless concluded that s. 75 "does not ... contemplate a wholesale review of the rate structure of all the customers of the utility where only one group of customers has interim rates" and that "[t]his is the only reading ... which is consistent with fair and reasonable rates and the principles of predictability and fairness" (p. 12). While this might be an appropriate result in a given case, it does not follow that such an interpretation is the "only" appropriate reading. As the Board itself noted, there may well be circumstances where it would not be appropriate or possible to benefit only the group who paid the excess revenue. The Board has to have the authority to make other dispositions of that revenue. Its jurisdiction must therefore extend to such situations.

3. Procedural Considerations

[138] Reference has already been made to how the Board's perceptions of how the matter came before it procedurally appeared to affect the Board's jurisdictional analysis. See, paragraphs 125-127 above in relation to deferral

accounts. The Board also gave consideration to what it considered to be procedural problems when dealing with its analysis relating to interim orders.

[139] The Board placed great emphasis in its analysis on the fact that Hydro had not, in its applications for interim rates for the Industrial Customers, requested changes to the RSP rules or refunds of excess revenue to other customer groups:

> In its applications for interim rates for the Industrial Customers, Hydro did not request changes to the RSP rules and did not ask that any excess revenue be refunded to the benefit of other customer groups.
>
> (p. 12)

> The interim rate applications put the Industrial Customers on notice that the Board would be reviewing the Industrial Customers rates for reasonableness and that it may set different rates and a different method of calculating the Industrial Customers' RSP balances and rates. Hydro did not provide notice that anyone other than the Industrial Customers may be affected and did not put the Industrial Customers on notice that the accumulating balances in the RSP may be transferred to the benefit of other customer groups. The potential for a review of Hydro's rate structures or that any excess revenue as a result of the interim rates could be put to the benefit of other customer groups was not made clear. This result would not be consistent with the historical operation of the RSP and would be unprecedented in the context of an interim rate order in this province and therefore could not reasonably have been anticipated by the Industrial Customers.
>
> (p. 13)

[140] Accepting the foregoing paragraph as factually correct, its significance in our view was not properly explained. There was no finding that the Industrial Customers had to date suffered any actual detriment owing to the absence of prior notice of the possible disposition of the RSP balance other than for their exclusive benefit. The observation that Hydro's current proposal is unprecedented may be pertinent but of itself is of no significance on the jurisdictional issue. The jurisdictional issue cannot be resolved by reference to past practice or procedural issues of notice. References to sound utility practice may be relevant to making a decision within jurisdiction but not to whether jurisdiction exists in the first place.

[141] The Board did accept that it has the power to modify the entire rate structure for the Industrial Customer Group, including the RSP rules. It stated:

> The interim orders clearly provide the Board with the full jurisdiction to, in the words of the Supreme Court of Canada, "*modify in its entirety the rate structure*" for the Industrial Customer group, which includes all aspects of the Industrial Customers' rate, including the RSP rate. The Board does not accept the position of the Industrial Customers that the Board has no power to change the rules and regulations affecting the RSP. The Industrial Customers argue that because there is one set of RSP rules which apply to both the Industrial Customers and Newfoundland Power and because there was no interim order in relation to Newfoundland Power then the rules could not have been made interim. The Board notes, as referenced by the Consumer Advocate, that the Industrial Customers' rate sheet specifically states that the RSP adjustment reflects the operation of the RSP. The Board agrees with Hydro when it states "*The RSP rules are just a means of calculating a rate. That's their only role.*" (Transcript, June 12, 2010, pg.32 18/7-8) The Board finds no distinction between the rates and the RSP rules used to calculate the rates.
>
> The Board finds that it has the jurisdiction to set reasonable rates for the Industrial Customers for the period beginning on January 1, 2008 but it does not have the jurisdiction to make a comprehensive assessment of the reasonableness of Hydro's entire rate structure. Had there been an application for a change to the RSP along with an application for interim rates for Hydro's other customers or a request that any excess go to the benefit of other customer groups the Board may have taken a different view of the Application. ...
>
> (p. 13; Underlining added.)

[142] The Board was obviously concerned that the issue of the disposition of the RSP account should have been brought before it by Hydro in a different manner and at an earlier time. It stated:

> The Board is frankly disappointed with Hydro's handling of this matter, both substantively and procedurally. Hydro was in the best position to know the impacts of the anticipated significant load changes. Major changes in load will not only impact the operation of the RSP but may also potentially impact significantly the cost of service and base rates that were set in the last general rate application. The Board would expect that, in light of such major changes from test year forecasts and the resulting impact on Industrial Customer rates, Hydro would have filed a general rate application. Such major changes could only have been addressed through a general rate application or, alternatively, perhaps an application which sought a review of its rate structure, changes to the RSP and interim rates for all potentially affected customers. Such an application should have set out specific proposals in relation to the excess so that all affected customers understood what was at stake. In addition, the Board would have expected Hydro to address these load changes promptly to avoid the complications which have now arisen as a result of the passing of two years. Hydro failed to take timely appropriate steps in the circumstances so that the

> matter could be effectively addressed, ensuring that all stakeholders understood the issues.
>
> (p. 14)

[143] The significance of that concern was emphasized in the Board's "Conclusion" which stated:

> The Board finds that in the circumstances its jurisdiction to make orders in relation to how the RSP operated in prior years is limited. Given the manner in which this matter was brought forward the Board does not have the jurisdiction to change how Newfoundland Power's RSP operated in prior years, either in terms of the rates charged or the resulting balances. The Board does have the jurisdiction to issue an order which sets just and reasonable rates for the Industrial Customers for 2008 and 2009, including the Industrial Customers' RSP rates and how the Industrial Customers RSP operated for those years. The Board also finds that it has jurisdiction to determine whether any overpayment as a result of the interim rates is to be refunded to the Industrial Customer group or placed in a reserve account to the benefit of the Industrial Customer group. ...
>
> (Emphasis added.)

[144] For the reasons already expressed, procedural considerations cannot define the Board's jurisdiction. In allowing itself to be influenced by such matters, the Board erred.

(e) Conclusion

[145] The reasoning articulated by the Board does not justify the conclusions reached. The Board determined that as interim orders had been in effect it had the jurisdiction to modify, in its entirety, the rate structure for the Industrial Customers including the RSP rates and the RSP rules used to calculate that rate. That determination was not challenged on this appeal and we agree that it gave proper effect to the jurisprudence respecting interim orders. Our concerns are that the full implications of that determination were not recognized, that the Board failed to recognize the extent of the power conferred upon it by the *PUB Act*, and that it was unduly affected by procedural aspects whose effect upon jurisdiction was unexplained.

[146] It is apparent from the Board decision that it considered the load variation balances in the RSP to be "excess revenue" as contemplated by subsection 75(3) of the *PUB Act*. There was no explanation for that conclusion. We agree with the submission of Newfoundland Power that this was an error. "Excess revenue" in that subsection refers to the difference between the revenue received under the interim rates and the revenue

authorized to be received under the final rates. The subsection addresses revenue that was earned by a public utility. However, balances in the RSP are not revenue earned by the utility. They are encumbered revenues in a deferral account which are to be disposed of in accordance with an order of the Board pursuant to the RSP rules.

[147] The Board concluded that it had the power to modify the RSP rules and consequential rates for the Industrial Customers with effect from January 1, 2008. (We note that it was undisputed that there is one set of rules for the RSP which applies both to the Industrial Customers and Newfoundland Power.) It follows that it could modify the RSP rules pertaining to the method of allocating the cost effects of load variations if such modification were in accordance with generally accepted sound public utility practice. The Board did not appear to recognize the implications of its power to modify the RSP rules in that manner. The existing RSP rules apply a "class assignment approach" which means that the cost savings accruing to Hydro because of industrial shutdowns were allocated to the Industrial Customers' side of the RSP ledger. Clearly that is not the only possible approach to the allocation of such costs as witnessed by the operation of the RSP prior to the 2003 GRA. A modification of the RSP rules for the Industrial Customers, which the Board accepts is within its power, could therefore encompass a change from the class assignment approach with consequential effects upon the final rates for the Industrial Customers from January 1, 2008 and upon the appropriateness of contemplated prospective distributions of any balances in the RSP.

[148] The consequential effect of any modification of the RSP rules upon rates, upon the revenue authorized to be earned by Hydro and upon the accumulated balances in the RSP then fall to be addressed by the Board pursuant to the *PUB Act*, including but not limited to subsection 75(3).

[149] Subsection 75(3) authorizes an order that excess revenue be "refunded to the customers of the public utility" or "placed in a revenue fund for the purpose to be approved by the Board". The statutory language pertaining to the reserve fund confers a broad jurisdiction on the Board to deal with excess revenue which jurisdiction should be exercised "to achieve the purposes of the legislation and to implement provincial power policy". *Stated Case*, para. 36. The Board found that it was constrained to ensure that "excess revenue" be disposed of solely for the benefit of Industrial Customers. Clearly that constraint did not arise from the express statutory language of subsection 75(3). There was no analysis from the Board explaining how the scheme or purpose of the *PUB Act* required an

interpretation of that subsection that constrained the power of the Board to deal with reserve funds.

[150] The Board indicated that the constraint arose from "generally accepted sound public utility practice which requires that rates be just and reasonable and not unjustly discriminatory". While application of such practice considerations might (but not necessarily) justify a conclusion to limit disposition of reserve funds to industrial customers in a given case, it does not justify giving a restrictive interpretation to the broad language of subsection 75(3), thereby foreclosing its use and application for all such cases. As noted above, the Board approached this aspect on the basis that the RSP balances should be treated as excess revenue to Hydro. However, on that basis and given the magnitude of the anticipated RSP balances it is apparent that the constraint stated by the Board could adversely affect the ability to establish reasonable and non-discriminatory rates for the Industrial Customers from January 1, 2008. See paragraphs 29-30 above .

[151] Accordingly, the decision of the Board is not capable of being derived from its statement respecting the effect of public utility practice and its conclusion respecting subsection 75(3) is without support.

[152] Furthermore as stated earlier it follows from *Bell Canada 1989* and *Bell Canada 2009* that the balances in the RSP, which would be determined in the process of establishing final rates for the Industrial Customers, would be subject to disposition by the Board in accordance with the RSP rules which are subject to modification by the Board in the application before it.

[153] The Board made repeated reference to procedural considerations as affecting its decision. These procedural concerns do not logically justify the stated conclusion as to jurisdiction. We agree with the submission of the Consumer Advocate that:

> ... First, by virtue of the interim orders and as a matter of law, everything about the Industrial Customers' rates, including the rules pertaining to load variation and the normal load variation allocation rules were made interim and therefore are inherently subject to subsequent review and modification on a retrospective basis. To further insist that Hydro was required to state that which was already the case by operation of law in order for the Board to assume its jurisdiction, is not logical or sustainable.

[154] The Board was presented with an application for Hydro to set final rates for the Industrial Customers effective January 1, 2008. The accompanying letter stressed concern with "the appropriateness of the current mechanism for allocating the impact of the load variation in the

RSP". That was consistent with a concern raised by Hydro in its initial application for interim rates in December, 2007. We note that the record before this Court indicates that since Hydro's application for final rates for the Industrial Customers, all parties (excluding, of course, the Board) set forth their positions respecting the RSP in the course of an interrogatory process and the filing of expert evidence on that issue. The Board did not explain the necessity of a formal application for a change to the RSP in those circumstances, nor did it advert to subsection 3(4) of the *Board of Commissioners of Public Utilities Regulations, 1996*, which would permit the Board to direct Hydro to file a formal application if it considered it necessary for the proper consideration and disposition of an issue.

[155] As stated earlier, exercise of the Board's jurisdiction was not contingent upon the wording of Hydro's application. The Board had the jurisdiction to set final rates and consequently to address the appropriate disposition of balances in the RSP that accumulated during the currency of the interim orders.

[156] In summary, the Board erred in:

1. allowing its determination of its jurisdiction to be arbitrarily limited by the manner in which the issue was brought before it; procedure cannot trump jurisdictional substance;

2. not concluding, in accordance with *Bell Canada 1989*, that, in respect of interim orders, all aspects of rates, including RSP rules, were made interim and therefore inherently subject to subsequent review and possible modification, on an application to make interim rates final; and

3. concluding that the *PUB Act*, properly interpreted, restricted the manner in which deferral accounts could be dealt with and in particular, restricted the classes of beneficiaries of such accounts. See *Bell Canada 2009*.

[157] We conclude that the Board has jurisdiction to deal with and dispose of remaining amounts in the RSP in accordance with the broad powers contained in the legislation, which include, but are not limited to, refunding it to the Industrial Customers. But these powers are not necessarily confined to disposing of the RSP fund balances solely to the benefit of one class of customers, in this case the Industrial Customers. This is not to say, of course, that the Board should include customers other than the Industrial

Customers as beneficiaries, only that the Board has the jurisdiction and authority to, and should, consider the submissions of all interested parties on this issue, taking into account generally accepted sound public utility practice and the imperative of setting just and reasonable rates that are non-discriminatory.

SUMMARY AND DISPOSITION

[158] For the foregoing reasons the decision of the Board declining jurisdiction is incorrect. The appeals are allowed. Order No. P.U. 25 (2010) is set aside. The matter is remitted to the Board for hearing and determination on the merits in accordance with this decision.

[159] The matter of costs not having been fully addressed by all parties, leave is given to any party to apply within 15 days of the release of this judgment for a determination of costs on the appeal. In the absence of such an application, an order will go directing that each party shall bear its own costs.

J. D. Green C.J.N.L.

K. J. Mercer J.A.

M. F. Harrington J.A.

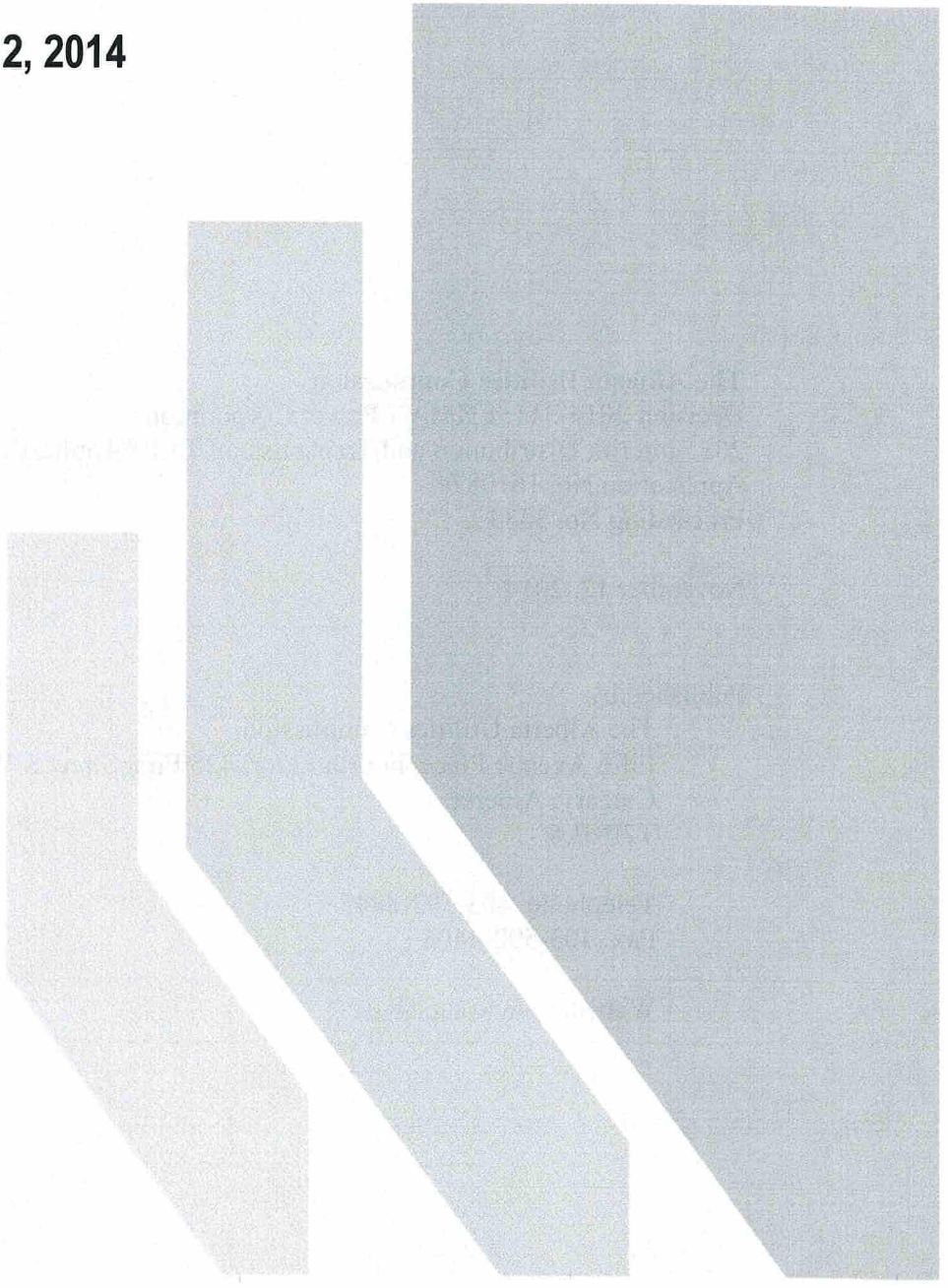
Decision **2014-311**

AUC
Alberta Utilities Commission

ENMAX Power Corporation

2015 Interim Distribution and Transmission Tariff Application

November 12, 2014



The Alberta Utilities Commission
Decision 2014-311: ENMAX Power Corporation
2015 Interim Distribution and Transmission Tariff Application
Application No. 1610874
Proceeding No. 3433

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The Alberta Utilities Commission
Calgary, Alberta

Decision 2014-311
ENMAX Power Corporation **Application No. 1610874**
2015 Interim Distribution and Transmission Tariff Application **Proceeding No. 3433**

1 Introduction

1. On September 25, 2014, ENMAX Power Corporation (EPC) submitted an application (application) to the Alberta Utilities Commission (AUC or Commission), pursuant to sections 37, 102, 119 and 124(2) of the *Electric Utilities Act*, SA 2003, c. E-5.1, applying for the following:

(i) Approval to implement 2015 distribution access service (distribution) rates on an interim basis, as described in Section 3 of the application,[1] calculated in Appendix 1[2] and set out in the rate schedules provided in Appendix 2,[3] effective January 1, 2015.

(ii) Approval to implement 2015 transmission rates on an interim basis, as described in Section 4 of the application, calculated in Appendix 3[4] and set out in the rate schedules provided in Appendix 4,[5] effective January 1, 2015.

2. On September 29, 2014, the Commission issued a notice of application advising interested parties to file a statement of intent to participate (SIP) to the Commission no later than October 9, 2014. In the SIPs, parties were asked to indicate whether they supported or objected to the application, provide reasons for their positions and comment on the need for further process and the supporting rationale.

3. The following parties registered in the proceeding by the specified deadline:

- FortisAlberta Inc.
- ATCO Electric Ltd.
- Alberta Electric System Operator (AESO)
- EPCOR Distribution & Transmission Inc.

4. None of the above-listed parties objected to the application or requested further process.

5. On October 21, 2014, the Commission issued a process letter classifying the proceeding as a *notice-only process* proceeding and advising that the Commission had two questions for EPC. On October 22, 2014, EPC filed its responses to the Commission's questions.[6]

---

1 Exhibit No. 3, application.
2 Exhibit No. 5, application, Appendix 1.
3 Exhibit No. 6, application, Appendix 2.
4 Exhibit No. 7, application, Appendix 3.
5 Exhibit No. 8, application, Appendix 4.
6 Exhibit No. 14.01, Commission process letter; Exhibit No. 15.01, Commission information request; Exhibit No. 16.01, EPC responses to information request.

6. The Commission considers that the record for this proceeding closed on October 22, 2014.

7. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to that matter.

2 Details of the application

8. On July 24, 2013, EPC filed an application with the AUC requesting approval of EPC's 2014 Phase I Distribution Tariff Application (DTA) and 2014-2015 Transmission General Tariff Application (GTA) (collectively Proceeding No. 2739).[7] According to EPC, even if a decision for Proceeding No. 2739 is issued in December 2014, given the likely timing of a compliance filing, it is unlikely that final 2014 rates will be approved before the end of 2014, and therefore final 2014 rates will not be available to be used as the basis of interim 2015 rates by January 1, 2015.[8]

9. EPC's current distribution and transmission tariffs were approved on an interim basis in Decision 2013-436[9] and have been in place on an interim basis since January 1, 2014. If existing 2014 interim rates continue for 2015, EPC forecasted a total revenue shortfall of $10.229 million for distribution and $14.260 million for transmission.[10]

10. EPC stated that the shortfall amount is significant. To reduce the impact of the rate increase that will be required when the final 2015 distribution and transmission rates are implemented, EPC requested approval of interim distribution and transmission rates to be effective January 1, 2015 and continuing until such time as the AUC approves revised interim or final 2015 distribution and transmission rates. EPC advised that, once matters in Proceeding No. 2739 have been decided by the Commission, EPC will make the required adjustments or applications to set final 2015 distribution and transmission rates.[11]

2.1 Distribution

11. EPC submitted that its forecast distribution revenue for 2015, included in Appendix 1 to the application, is $192.571 million based on current interim distribution rates. EPC's forecast distribution revenue requirement is $202.800 million, as determined by escalating the 2014 DTA revenue requirement by the placeholder performance-based regulation (PBR) formula described in Section 3 of the application. Consequently, if the 2014 DTA is approved as applied for, and no

[7] Application for Approval of 2014 Phase I Distribution Tariff Application and 2014-2015 Transmission General Tariff Application, Exhibit No. 3, Application 1609784, Proceeding No. 2739.
[8] Exhibit No. 3, application, paragraph 2.
[9] Decision 2013-436: ENMAX Power Corporation, 2014 Interim Distribution and Transmission Tariff Application, Application No. 1610012, Proceeding ID No. 2886, December 11, 2013.
[10] Exhibit No. 3, application, paragraph 4.
[11] Exhibit No. 3, application, paragraphs 3 and 20.

interim rate adjustment is made effective January 1, 2015, there will be a distribution revenue shortfall of $10.229 million from January 1, 2015 to December 31, 2015.[12]

12. In order to calculate its distribution revenue shortfall calculations, EPC adopted the PBR formula established in Decision 2012-237 (first generation PBR) for other utilities to adjust their distribution base rates on an annual basis:[13]

$$R_t = \underbrace{BR_{t-1} * (1+ (I-X))}_{\text{Base rates } (BR_t)}$$

Where:

R_t = Upcoming year's rates for each class

BR_{t-1} = Current year's base rates for each class

I = Inflation Factor ("I factor")

X = Productivity Factor ("X factor")

13. For its 2015 interim rate calculations, EPC adopted the first generation PBR formula using EPC's proposed 2014 DTA revenue requirement as BR_{t-1}.[14]

14. EPC requested the following first generation PBR placeholders for interim distribution rate setting purposes only:

(i) I factor placeholder of 2.93%, where the I factor placeholder is calculated the same as the first generation PBR I factor approved in Decision 2012-237, using the Alberta Average Weekly Earnings ("AWE") from July 2012 to June 2014 with a weighting of 55%, and the Alberta Consumer Price Index ("CPI") from July 2012 to June 2014 with a weighting of 45%. The Statistics Canada data for each index showing the placeholder I factor calculation is provided in Appendix 1, Schedule 1.2; and

(ii) X factor placeholder of 1.16%, where the X factor placeholder is the same as the first generation PBR X factor of 1.16% approved in Decision 2012-237.[15]

15. In response to a Commission information request, EPC revised the data used in calculating the I factor and calculated a new 2015 I factor of 2.65 per cent. EPC also provided revised 2015 interim distribution rate calculations and tariffs.[16]

---

12 Exhibit No. 3, application, paragraph 12; Appendix 1, schedules 1.1 and 1.5; 2014 Phase I DTA and 2014-2015 Transmission GTA; Exhibit No. 106.6, Schedule 12-1, Retail Sales of $310.888 (Line 21) less the cost of Sales of $111.615 million (Line 9), Application No. 1609784, Proceeding ID No. 2719.

13 Exhibit No. 3, application, paragraph 6; Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Application No. 1606029, Proceeding ID No. 566, September 12, 2012, at paragraph 963.

14 Exhibit No. 3, application, paragraph 7.

15 Exhibit No. 3, application, paragraph 8.

16. EPC noted that its proposal to use first generation PBR placeholders is for convenience, and does not necessarily mean that it will propose these factors in its forthcoming second generation PBR application, or that it accepts these factors would be reasonable for the same. EPC submitted that the use of first generation PBR placeholders is reasonable and conservative for the purposes of determining 2015 interim distribution rates.[17]

17. EPC's distribution rates would require an increase of 5.31 per cent to collect the forecast 2015 distribution revenue requirement of $202.800 million. However, EPC's proposed interim rate adjustment will result in an increase to distribution rates of 3.19 per cent, which will enable EPC to recover 60 per cent of its revenue shortfall and collect $198.710 million in 2015 distribution revenue. This will reduce the forecast 2015 distribution revenue shortfall from $10.229 million to $4.090 million.[18]

18. EPC also proposed that the requested interim distribution base rate increase of 3.19 per cent be applied to all rate classes on an across-the-board basis, therefore maintaining the currently approved rate structure based on EPC's last approved Phase II cost of service study.[19]

19. Subsequent to receiving a decision in Proceeding No. 2739, EPC plans to file for approval of a capital tracker, or K factor, in 2015 as part of the second generation PBR application or as a separate filing. While EPC did not propose a K factor placeholder in the application, EPC indicated that it will request approval to adjust the 2015 interim distribution base rates subsequent to the filing of its capital tracker application.[20]

20. In the application, EPC referred to its 2015 billing determinant forecast:

> EPC's forecast 2015 Distribution revenue is $192.571 million if the existing 2014 interim Distribution rates are continued in 2015 without an adjustment, based on the 2015 billing determinant forecast.[21]

21. In response to a Commission information request on the 2015 billing determinant forecast, EPC:

- confirmed that the forecast is a new forecast that has not been previously approved by the Commission
- explained that the forecast is based on the same methodology used in EPC's 2014 DTA but with updated historical data and key economic indicators
- submitted that it considers the forecast to be interim and will be including the forecast for full testing in its forthcoming PBR application[22]

---

16 Exhibit No. 16.01, AUC-EPC-1; Exhibit No. 16.02, Appendix 1, revised 2015 interim distribution rate calculations; Exhibit No. 16.03, Appendix 2, revised 2015 interim distribution tariffs.
17 Exhibit No. 3, application, paragraphs 9 and 10.
18 Exhibit No. 3, application, paragraphs 13 to 15.
19 Exhibit No. 3, application, paragraph 16.
20 Exhibit No. 3, application, paragraph 17.
21 Exhibit No. 3, application, paragraph 12.
22 Exhibit No. 16.01, AUC-EPC-2.

2.2 Transmission

22. EPC submitted that its forecast transmission revenue for 2015, included in Appendix 3 to the application, is $61.708 million based on current interim transmission rates. EPC's forecast transmission revenue requirement for 2015 is $75.968 million, as applied for in its 2014-2015 transmission GTA. Consequently, if the 2014-2015 GTA is approved as applied for and no interim rate adjustment is made effective January 1, 2015, there will be a transmission revenue shortfall for 2015 of $14.260 million from January 1, 2015 to December 31, 2015.[23]

23. EPC's transmission revenue requirement would require an increase of 23.11 per cent to collect the forecast 2015 transmission revenue requirement of $75.968 million, as applied for in its 2014-2015 GTA. However, EPC requested approval of an interim increase to its existing transmission revenue requirement of 13.87 per cent, which will allow EPC to recover 60 per cent of its revenue shortfall. The proposed adjustment would result in 2015 transmission revenue of $70.264 million, reducing the forecast 2015 transmission revenue shortfall from $14.260 million to $5.704 million.[24]

2.3 Test to support interim tariff applications

24. In the application, as justification for its interim rates, EPC relied on the two-part test that was originally used by the Commission's predecessor, the Alberta Energy and Utilities Board, in evaluating interim rate applications, and has since been used by the Commission. The two-part test is as follows:

> The first part of the test relates to quantum and need, and includes the following considerations:
>
> i. Is the identified revenue deficiency probable and material?
> ii. Can all or some portion of any contentious items be excluded from the amount collected?
> iii. Is the increase required to preserve the financial integrity of the applicant or to avoid financial hardship to the applicant?
> iv. Can the applicant continue safe utility operations without the interim adjustment?
>
> The second part of the test relates to the public interest and includes the following considerations:
>
> i. Will the interim rates promote rate stability and ease rate shock?
> ii. Will the interim adjustments help to maintain intergenerational equity?
> iii. Can the interim rate increases be avoided through the use of carrying costs?
> iv. Are the interim rate increases required to provide appropriate price signals to customers?
> v. Is it appropriate to apply the interim rider on an across-the-board basis?[25]

3 Issues and Commission findings

25. When evaluating the merits of an interim rate application, the Commission applies the above-stated test. It weighs the potential benefits of rate stability and minimization of rate shock and intergenerational inequity that might result on approval of final rates against the costs that

[23] Exhibit No. 3, application, paragraph 19; 2014 Phase I DTA and 2014-2015 Transmission GTA, Exhibit No. 124, Application No 1609784, Proceeding ID No. 2719; Appendix 3, Schedule 3.1.
[24] Exhibit No. 3, application, paragraphs 21 to 23.
[25] Exhibit No. 3, application, paragraphs 24-25.

underpin the interim rate increase, whether they be contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations.

26. The above-listed considerations in the two-part test may be given different weighting depending on the specific circumstances of each application. The Commission has evaluated the application with these considerations in mind.

27. The Commission has reviewed the transmission and distribution revenue shortfall calculations included in appendices 1 and 3 of the application, including the revised I factor calculations, and is satisfied that they are accurate.

28. In respect of the 2015 billing determinant forecast, the Commission accepts EPC's explanation and is satisfied that the forecast, using previously approved methodologies and updated historical data and key economic indicators, is sufficient for the purposes of 2015 interim distribution rates based on 60 per cent of EPC's applied-for 2014 DTA. The 2015 billing determinant forecast will be tested in EPC's upcoming PBR proceeding. The Commission will make a determination at that time on the reasonableness of the forecast.

29. The Commission considers that the forecast distribution revenue shortfall of $10.229 million and transmission revenue shortfall of $14.260 million, amounting to a total revenue deficiency of $24.289 million, is a material amount if the entire amount had to be collected from customers.

30. The Commission is also cognizant of the financial hardship that such a material deficiency could have on EPC, as it stated in its application, "[t]hese deficiencies will reduce cash flow, which will in turn require increased short-term borrowing. Long-term borrowing may also be impacted, if the existing rates will be in place for the majority of 2015."[26]

31. The Commission also notes EPC's arguments that it has experienced load growth and system infrastructure expansion over the formula-based ratemaking (FBR) term of 2007 to 2013, while revenues were decoupled from costs. Consequently, EPC submitted that its distribution rate base grew significantly, and the cost of providing service has increased beyond the difference between the approved FBR inflation and productivity factors.[27]

32. To understand the impact of EPC's proposed interim rate increases on typical customer bills, the Commission has reviewed the bill comparison submitted by EPC.[28] The Commission has used the bill comparison information to prepare Table 1 below which illustrates that the interim rate increase will promote rate stability for customers.

[26] Exhibit No. 3, application, paragraph 31.
[27] Exhibit No. 3, application, paragraph 27.
[28] Exhibit No. 5, application, Appendix 1, Schedule 1.8.

Table 1. Bill impacts

Rate Class	Total charges		
	Without interim rates	With interim rates	
	2015 PBR base rates January 1, 2015 (per cent)	2015 interim rates January 1, 2015 (per cent)	2015 PBR base rates January 1, 2015 (per cent)
Residential rate D100	4.0	0.6	1.6
Small commercial rate D200	2.9	0.4	1.2
Medium commercial rate D300	3.7	0.6	1.5
Large commercial - secondary rate D310	2.3	0.4	0.9
Large commercial - primary rate D410	1.0	0.2	0.4

33. Given the magnitude of the potential revenue shortfall and resultant financial impact to EPC and rate shock to customers' bills as demonstrated in Table 1 above, the Commission considers that some degree of interim rate adjustment should be made. The Commission is aware that the financial hardship to EPC could be mitigated by the award of carrying costs; however, it will not mitigate the risk of potential rate shock to customers. The Commission finds that approval of an interim increase to EPC's distribution rates will provide a gradual and stable transition to EPC's final 2015 distribution rates.

34. The Commission recognizes that while EPC's transmission tariff initially only applies to a single customer, the AESO, the increases to EPC's transmission tariff will flow-through to EPC's customers by way of EPC's system access service (SAS) rates and transmission access charge (TAC) deferral account riders. Consequently, the Commission accepts EPC's submission that "the proposed interim Transmission rates will help levelize the transmission Tariff throughout 2015, reducing the magnitude of the increase once final 2015 Transmission rates are approved"[29] and finds that, given the magnitude of the potential shortfall, an interim increase to its transmission rates will enable a more gradual transition to final 2015 transmission rates.

35. To better provide for both a gradual increase and a transitional rate level, the Commission considers that it is preferable to have an interim increase that reflects an intermediate position between the current rates and the proposed final rates. The Commission notes that for the period from January 1, 2014 to August 1, 2014, EPC estimated a distribution revenue shortfall of $20.175 million and a transmission revenue shortfall of $11.748 million.[30] The Commission approved EPC's request to collect 60 per cent of EPC's shortfall, reducing the forecasted shortfall to $8.069 million of revenue for distribution and $4.699 million of revenue for transmission.

36. In determining the reasonableness of the requested amount, the Commission notes that it received no objection from interveners on this application and accepts EPC's submission that a collection of 60 per cent of both its forecast distribution and transmission revenue deficiencies is

[29] Exhibit No. 3, application, paragraph 40.
[30] Decision 2013-436, paragraphs 7 and 11.

sufficient to account for any potentially contentious elements of EPC's 2014 DTA and 2014-2015 GTA. The Commission recognizes that the combined shortfall of $24.489 million is approximately $7.5 million lower than the combined shortfall than requested in EPC's 2014 Interim Distribution and Transmission Tariff Application. The Commission finds that as the proposed rate increases are requested on an interim basis, rates will be trued up once the final 2015 rates for distribution and transmission are approved.

37. The Commission also considers that applying the interim distribution rate increase to all rate classes on an across-the-board basis continues to be a reasonable method that is simple and cost effective to apply, and preserves the currently approved rate structure based on EPC's last approved Phase II cost of service study.

38. Accordingly, the Commission finds that the collection of 60 per cent achieves a reasonable balance in recognition of rate stability and minimization of rate shock that might result on approval of final rates against the costs that underpin the interim rate increase, contentious or non-contentious items, the impact the revenue deficiency has on the financial welfare of the utility, and the potential impact on safe utility operations. Consequently, the Commission approves the interim distribution and transmission rates as filed in this application effective January 1, 2015. The Commission approves:

- A 3.19 per cent interim increase to the distribution revenue requirement which represents 60 per cent of the 5.31 per cent applied for shortfall in the interim distribution revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $10.229 million to $4.090 million; and

- An interim increase to the interim transmission revenue requirement of 13.87 per cent which represents 60 per cent of the 23.11 per cent applied for shortfall in the interim transmission revenue requirement. This interim increase is designed to decrease the forecast 2015 revenue shortfall from $14.260 million to $5.704 million.

39. In determining the level of interim rates for EPC, the Commission is not making any finding or determination with respect to any of the matters in EPC's 2014 DTA and 2014-2015 GTA, which is currently pending before the Commission.

40. The Commission has attached appendices 2 and 3 to this decision showing the interim distribution and transmission rates to be applicable on and after January 1, 2015, until replaced by subsequent decisions or orders of the Commission.

4 Order

41. It is hereby ordered that:

(1) The interim distribution tariff rates schedules attached as Appendix 2 to this decision are approved on an interim basis effective January 1, 2015.

(2) The interim transmission tariff attached as Appendix 3 to this decision is approved on an interim basis effective January 1, 2015.

Dated on November 12, 2014.

The Alberta Utilities Commission

(original signed by)

Bill Lyttle
Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) counsel or representative
ENMAX Power Corporation (EPC) T. Carle R. Lottermoser
ATCO Electric Ltd. (AE) B. Yee L. Kerckhof
Alberta Electric System Operator (AESO) J. Martin R. Sharma
EPCOR Distribution & Transmission Inc. (EPCOR) J. Baraniecki G. Zurek N. Lamers
FortisAlberta Inc. (Fortis) T. Dalgleish J. Croteau M. Stroh J. Walsh

The Alberta Utilities Commission Commission Panel B. Lyttle, Commission Member Commission Staff G. Bentivegna (Commission counsel) P. Howard C. Runge J. Graham

Appendix 2 – Interim distribution tariff

(return to text)



Appendix 2 - Interim distribution tariff

(consists of 18 pages)

Appendix 3 – Interim transmission tariff

(return to text)



Appendix 3 - Interim transmission tariff

(consists of 1 page)



ENMAX POWER CORPORATION ("EPC")

DISTRIBUTION TARIFF

RATE SCHEDULE

RATES IN EFFECT AS OF JANUARY 1, 2015

EPC DISTRIBUTION TARIFF RATE SCHEDULE

Rate Code	Rate Description	Page
D100	Distribution Tariff Residential	4
D200	Distribution Tariff Small Commercial	6
D300	Distribution Tariff Medium Commercial	8
D310	Distribution Tariff Large Commercial – Secondary	11
D410	Distribution Tariff Large Commercial – Primary	13
D500	Distribution Tariff Streetlights	16
D600	Distribution Tariff Distributed Generation	17
D700	Distribution Tariff Transmission Connected	20

DISTRIBUTION TARIFF

RESIDENTIAL

RATE CODE D100

Rate Schedule for the provision of Electricity Services to residential Customers of a Retailer.

ELIGIBILITY

1. Sites which use Electricity Services for domestic purposes in separate and permanently metered single family dwelling units with each unit either metered separately or incorporated into a common building with other units.
2. As a single phase or three phase wire service supplied at a standard voltage normally available.
3. Sites eligible under 1 and 2 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.427587
System Usage Charge	per kWh	$0.008896
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.019463

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. No more than one additional unit of living quarters within a single family dwelling, such as a basement suite equipped with cooking facilities, may be provided Electricity Services through one Meter under Rate Code D100. If the dwelling contains more than one additional self-contained unit of living quarters, a Commercial Rate will apply unless a separate Meter is installed for each unit.

   All new construction in R2 or higher density areas shall have a separate Meter for each suite, or alternatively the Electricity Services may be invoiced at the appropriate commercial rate.

2. If a Residential Site has a garage with a separate meter, the garage will be assigned a commercial rate.

3. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

SMALL COMMERCIAL

RATE CODE D200

Rate Schedule for the provision of Electricity Services to small commercial Customers of a Retailer.

ELIGIBILITY

1. Commercial Sites where the Energy consumption is less than 5,000 kWh per month (includes all unmetered services that are not Rate Code D500).

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.979551
System Usage Charge	per kWh	$0.007632
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.015905

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Temporary Construction/Service

   Construction and rental costs for necessary transformers and equipment required for any temporary Electricity Services (whether single or three phase, or

whether served from an overhead or underground source), shall be payable by the Customer to EPC in advance and based on an EPC estimate. Construction costs include costs associated with:

(a) up and down labour;

(b) unsalvageable material;

(c) vehicles; and

(d) equipment.

2. Temporary Connection Service

   Where applied-for Connection Services are to be used for temporary purposes only, the Customer will pay EPC, in advance of the installation:

   (a) EPC's total cost of installation and removal of the Facilities required for the temporary service; and

   (b) the cost of unsalvageable material.

3. Unmetered Services

   For unmetered services where individual energy consumption is small and easily predicted, estimated consumption will be based on equipment nameplate rating and operational patterns.

4. If a Site that qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

MEDIUM COMMERCIAL

RATE CODE D300

Rate Schedule for the provision of Electricity Services to medium commercial Customers of a Retailer.

ELIGIBILITY

1. For Sites whose Energy consumption is equal to or greater than 5,000 kWh per month for at least six of the last 12 invoice periods, provided a peak demand greater than 150 kVA was not registered twice in the previous 365 days.

2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$5.539776
Facilities Charge	per day per kVA of Billing Demand	$0.037608
System Usage Charge	per kWh	$0.004081
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.118081
Variable Charge	per kWh	$0.004047

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period;

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period; and

(c) "Contract Demand" is the kVA contracted for by the Customer.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Non-Standard Residential "Bulk-Metering".

2. Bulk Metering is the metering of multiple-unit residential occupancies under one corporate identity, (e.g., town housing, apartments, mobile home parks). Where bulk-metering exists, the Customer shall not re-sell electricity, but may include electricity as part of the rental charge and not separate therefrom.

3. Includes Medium Commercial Sites served at primary voltage that existed prior to November 2004 rate class changes.

4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

5. D300 Primary Voltage Service Customers

    a. For locations or buildings that receive primary voltage service, there will be a transformation credit of $1.335496 per day applied to the Service Charge, and a transformation credit of $0.009234 per day per kVA of Billing Demand applied to the Facilities Charge.

    b. The transformation credit is applicable only to D300 sites receiving primary voltage service prior to January 1, 2009.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - SECONDARY

RATE CODE D310

Rate Schedule for the provision of Electricity Services to large commercial (secondary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that registered a monthly peak demand greater than 150 kVA twice in the previous 365 days and served at secondary voltage.
2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$16.089680
Facilities Charge	per day per kVA of Billing Demand	$0.098202
System Usage Charge On Peak	per kWh	$0.006604
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138805
Variable Charge On Peak	per kWh	$0.004574
Variable Charge Off Peak	per kWh	$0.003573

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer.

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all service supplied under this Tariff.

OTHER

If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE COMMERCIAL - PRIMARY

RATE CODE D410

Rate Schedule for the provision of Electricity Services to large commercial (primary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that are served at primary voltage.
2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Facilities Charge	per day per kVA of Billing Demand	$0.013834
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.138700
Variable Charge On Peak	per kWh	$0.004512
Variable Charge Off Peak	per kWh	$0.003525

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) "Contract Demand" is the kVA contracted for by the Customer,

"On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

"Off Peak" is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. The Customer is responsible for supplying all transformers whether owned by Customer or rented.
2. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.
3. Multi-Sites
   a) For Customers that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged based on Rate Code D410.
   b) For Customers that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged based on Rate Code D410 provided the service connections are:
      i) positioned on adjacent and contiguous locations;
      ii) not separated by private or public property or right-of-way; and
      iii) operated as one single unit.
4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

STREETLIGHTS

RATE CODE D500

Rate Schedule for the provision of Electricity Services to Customers of a Retailer.

ELIGIBILITY

For all photo cell controlled lighting services including all streetlights, traffic sign lighting, roadway lighting and lane rental lighting. Services with photo cell controlled lighting will not be eligible for a Meter.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
System Usage Charge	per kWh	$0.017490
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.016804

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

LARGE DISTRIBUTED GENERATION

RATE CODE D600

Rate Schedule for the provision of Electricity Services to Sites with on-site generation with a minimum export capacity of 1,000 kVA.

ELIGIBILITY

1. For services with on-site generation connected in parallel with the EPC Electric Distribution System with a minimum export capacity of 1,000 kVA.
2. For Electricity Services that are served at primary voltage.
3. For sites equipped with bi-directional interval recording metering.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
Dedicated Facilities Charge	per day	customer specific
System Usage Charge On Peak	per kWh	$0.008095
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs/Credits	$	Flow through

1. The customer specific Dedicated Facilities Charge daily amount will be determined as follows:

   Dedicated Facilities Charge = ((DFA + GA) x (CRF + OMA))/365 days.

Where:

a) DFA = current cost of dedicated feeder assets

b) GA = general assets associated with DFA and equal to 10.8% of DFA

c) CRF = Capital Recovery Percentage Factor based on EPC's weighted cost of capital and approved depreciation rate.

d) OMA = Operation, maintenance and administration factor equal to 3.1% of DFA.

The customer specific Dedicated Facilities Charge daily amount will be outlined in the Interconnection Agreement which will also include the term of the Agreement and an annual inflation adjustment.

2. The System Usage Charge will be determined using the net of the energy inflow and energy outflow at the Meter(s). System Usage Charge will be waived for sites that only have dedicated facilities and do not use the EPC primary feeder system.

3. "On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition), "Off Peak" is all Energy consumption not consumed in On Peak hours.

4. Flow-Through of ISO Costs/Credits will be determined by applying the ISO DTS rate (and any applicable riders) to the difference between the POD billing determinants with and without the site(s) billing determinants.

5. An initial fee will be charged for the incremental cost of bi-directional meter(s).

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of EPC form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

5. The Customer is responsible for supplying all transformers whether owned by customer or rented.

6. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.

7. Multi-Site Locations

   c) For locations or buildings that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged on Rate Code D600.

   d) For locations that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged on Rate Code D600.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF

TRANSMISSION CONNECTED

RATE CODE D700

Rate Schedule for the provision of Distribution Access Service to Customers of a Retailer that are connected directly to EPC Facilities at a transmission voltage.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$19.830314
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs	$	Flow through

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

TRANSMISSION RATE SCHEDULE

EFFECTIVE JANUARY 1, 2015

ENMAX POWER CORPORATION
RATE SCHEDULE
INTERIM 2015 TRANSMISSION TARIFF

ELIGIBILITY

To the Alberta Electric System Operator for use of ENMAX Power Corporation's Transmission facilities for the period

RATE

The Transmission tariff charged to the Alberta Electric System Operator is:

Monthly Charge: $5,855,318.18

TERMS AND CONDITIONS

The terms and conditions of ENMAX Power Corporation form part of this rate schedule and apply to service supplied under this tariff.

M A N I T O B A

THE PUBLIC UTILITIES BOARD ACT

Order No. 49/14

May 6, 2014

Before: Régis Gosselin, B és Arts, M.B.A., C.G.A., Chair
Marilyn Kapitany, B.Sc. (Hons), M.Sc., Member,
Larry Soldier, Member

INTERIM ORDER IN RESPECT OF MANITOBA HYDRO'S APPLICATION FOR INTERIM ELECTRICITY RATES EFFECTIVE MAY 1, 2014

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5.0 IT IS THEREFORE ORDERED THAT: 20

1.0 Executive Summary

By this Order, the Public Utilities Board (Board) denies Manitoba Hydro's Application for an interim electricity rate increase of 3.95% to all customer classes to be effective April 1, 2014. However, the Board approves an interim rate increase for all customer classes, effective May 1, 2014 of 2.00%, to approximate the annual rate of inflation, plus a further 0.75% interim rate increase, with the revenues from the 0.75% rate increase to flow into the existing Deferral Account established in Board Order 43/13 to assist with the payment of in-service costs of the Bipole III transmission project.

According to Manitoba Hydro, the energy future for the Province of Manitoba will require significant annual rate increases to support new electricity generation, regardless of the generation option selected. Manitoba Hydro's 3.95% interim rate request is consistent with the Preferred Development Plan that the Utility is advancing in the 'Needs For and Alternatives To' (NFAT) Review Hearing that is currently before the Board in a separate regulatory proceeding. Stakeholders and the Board are currently considering the many issues and decisions that will result from that NFAT Review. The issues and decisions that result from the NFAT Review will have impacts on the rate levels that are set in future General Rate Applications for Manitoba Hydro. It would be premature to reach any conclusions as to outcome and rate impacts flowing from the NFAT Review as those matters will be the subject of future General Rate Applications that Manitoba Hydro must bring before the Board.

However, on a *prima facie* basis, (and subject to the interim rate increase being varied or finalized in the next General Rate Application to be filed in the fall of 2014) the Board is satisfied that an interim rate increase is required by Manitoba Hydro for the costs of maintaining and replacing aging infrastructure such that it continues to provide safe and reliable service. The Board also notes that Manitoba Hydro's prices for electricity exports have continued to decline, resulting in less revenue to offset the requirement for domestic rate increases.

By this Order, the Board further disagrees with Manitoba Hydro's proposal to file a three-year General Rate Application in the fall of 2014, and instead directs Manitoba Hydro to file a fully comprehensive two-year General Rate Application for electric operations, to cover the 2014/15 and 2015/16 fiscal years. Manitoba Hydro's fiscal years run from April 1 to March 31.

2.0 Manitoba Hydro's Application for Interim Rates

Overview

On March 7, 2014, the Manitoba Hydro-Electric Board (Manitoba Hydro or the Corporation) applied to The Public Utilities Board (Board), for an interim electricity rate increase to all customer classes of 3.95% effective April 1, 2014, sufficient to generate additional revenue of approximately $56 million in 2014/15.

The Board established a written hearing process, with one round of written Information Requests posed to, and answered by Manitoba Hydro, followed by written submissions of all Parties. Four interveners, namely the Consumers' Association of Canada (CAC), the Green Action Centre (GAC), the Manitoba Industrial Power Users Group (MIPUG) and the Manitoba Keewatinowi Okimakanak (MKO) issued Information Requests and made written submissions.

Manitoba Hydro's Application for interim rates parallels the Corporation's Integrated Financial Forecast IFF-13, which projected annual rate increases of 3.95% over the next 20-year time period. Manitoba Hydro based its 3.95% Interim Rate Application on five principal reasons:

1. To avoid the potential for incurring financial losses on its electric operations;

2. To limit the extent to which financial ratios are projected to deteriorate;

3. To compensate for the fact that export prices continue to be significantly less than those experienced prior to the 2009/10 fiscal year;

4. To recognize that Manitoba Hydro's infrastructure is aging and that increased costs are necessary to maintain infrastructure in a safe and reliable manner; and

5. To provide customers with rate stability and predictability and to avoid the need for higher rates in the future.

Projected Income With and Without a Rate Increase

For the fiscal year 2014/15, Manitoba Hydro is forecasting, in IFF13, a net income of $55 million from electric operations after an assumed 3.95% rate increase, effective April 1, 2014. Manitoba Hydro indicates that if the rate increase is not granted, the Corporation could lose $1 million in 2014/15.

Overall net income, accumulated to the year 2032, is forecast to be $2.6 billion lower than the net income forecast in IFF-12, for the following reasons:

- The updated IFF-13 shows a deterioration in the financial figures presented in IFF-12, partially resulting from domestic revenues decreasing by $1.2 billion by 2031. Manitoba Hydro has primarily attributed this change to a reduced domestic (Manitoba) load forecast that projects load growth at 1.5% rather than 1.6%.

- Operating expenses are forecast to be $50 million lower in 2014/15 than forecast in in IFF-12 and $611 million lower through 2032. This reduction appears based on Manitoba Hydro limiting the growth in OM&A expenditures to 1% commencing in 2015/16 and continuing at that level through 2020/21.

- Finance expense is projected to increase by $1.4 billion to 2032 due to higher projected interest rates and an increase of $2.7 billion in debt financing between IFF-12 and IFF-13.

- Depreciation and amortization expenses are forecast to increase by $514 million by 2032 due to increased capital spending and Manitoba Hydro's proposed adoption of the Equal Life Group method of depreciation.

However, due in large part to a colder than normal winter and current favourable water levels, Manitoba Hydro's most recent projected revenues from electric operations for the 2013/14 year are significantly higher than those projected in IFF-12.

Specifically, IFF-12 projected net income of $60 million for the 2013/14 fiscal year, while IFF-13 has increased this projection to $116 million, an increase of $55 million over the course of a single year. This amount approximates the projected $56 million revenue increase for the 2014/15 year, sought in Manitoba Hydro's Interim Rate Application that is the subject of this Order. Actual financial statements for the 2013/14 fiscal year, which ended March 31, 2014, have not yet been filed with the Board as they are being finalized by Manitoba Hydro.

Manitoba Hydro projects Operation, Maintenance & Administration (OM&A) costs of $485 million in 2013/14 and $494 million in 2014/15. In the first nine months of 2013/14, OM&A expenses appear to have increased by 4.9%. The largest increases are attributed to Building & Property Services, Employee Benefits (due to an actuarial re-evaluation of pension and employee benefit obligations) and Consulting and Professional Fees. Growth in these areas was partially offset by reductions in the category of Customer & Public Relations, Sponsored Memberships, and Research & Development. The single largest expenditure category in Manitoba Hydro's OM&A is Wages & Benefits, representing approximately 79% of OM&A.

For the period of 2015/16 to 2020/21, Manitoba Hydro expects to limit OM&A costs to one percent per year, targeting approximately $600 million in total savings over that time span.

In the short term, Manitoba Hydro is forecasting finance expense to reduce slightly, from $452 million in 2012/13, to $437 million in 2013/14. However, in the long term, Manitoba Hydro is projecting cumulative finance expense to be $1.4 billion higher by 2032 due to increased forecast debt levels. Specifically, between IFF-12 and IFF-13, Manitoba Hydro has revised its assumed level of long-term debt upwards by $2.7 billion.

Financial Ratios

Manitoba Hydro monitors three self-imposed financial targets, namely:

- A debt-to-equity ratio of 75:25;
- An interest cost coverage ratio of greater than 1:20; and
- A capital cost coverage ratio of greater than 1.20.

In IFF-13, Manitoba Hydro predicts a debt-to-equity ratio of 76:24 for 2013/14. With the planned spending on its Preferred Development Plan (which includes the Keeyask and Conawapa Generating Stations), Manitoba Hydro expects the ratio to deteriorate to 90:10 by 2022/23, and not recover to the 75:25 target level until 2033/34.

The 'interest cost coverage' ratio indicates Manitoba Hydro's ability to meet interest payment obligations with the net income generated by the Corporation. IFF-13 projects an interest cost coverage ratio of 1.22 for 2013/14. At this time, Manitoba Hydro expects the level to deteriorate to less than 1.0 by 2019, remain at 1.0 for two years, and then gradually return to the target level by 2028.

The capital cost coverage ratio indicates the ability to use internally generated cash flows to finance base capital expenditures. A level of 1.0 means that all base capital expenditures can be met without incurring new debt. IFF-13 predicts a capital cost coverage ratio of 1.06 in 2013/14. Manitoba Hydro predicts that the level will be less than 1.0 by 2014/15, and return to the target level by 2016/17.

Changes in Export Revenue Projections

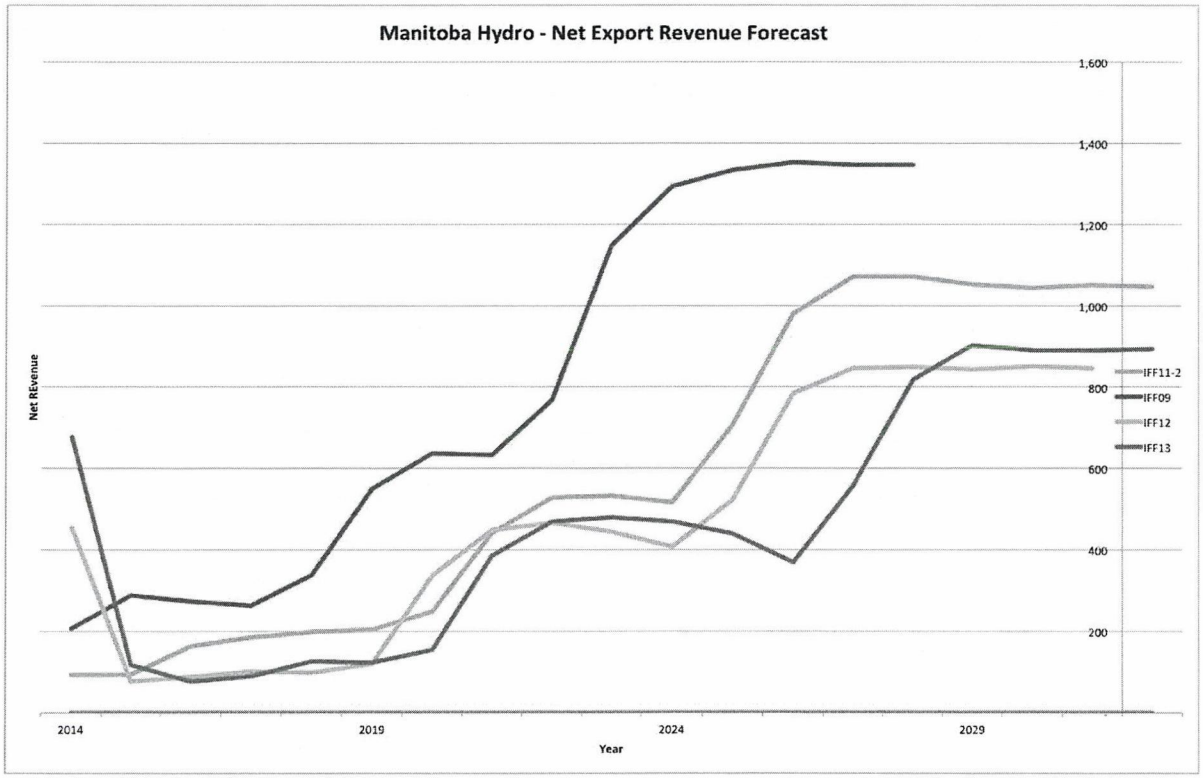
Since IFF-09 in 2009, Manitoba Hydro has repeatedly revised its export revenue projections downward. Specifically:

- For the short-term, in IFF-09, Manitoba Hydro projected gross export revenues of $615 million in 2013/14 and $590 million in 2014/15. Gross export revenue is now forecast in IFF13 to be only $408 million in 2013/14 and $383 million in 2014/15.

- For the long-term, IFF-09 projected annual export revenues to exceed $1 billion by 2020. This has now been revised downwards to $848 million.

Figure 1 illustrates the downward projections in Manitoba Hydro's export revenue forecast.

Figure 1 - Manitoba Hydro Export $ Revenue Forecast



Planned Capital Expenditures

Manitoba Hydro forecasts expenses for annual "base capital" expenditures to maintain and repair existing infrastructure, and for "major new generation and transmission" projects. Manitoba Hydro filed an updated 2013 Capital Expenditure Forecast(CEF-13) setting out Manitoba Hydro's planned 20-year capital spending. Compared to the prior forecast in CEF-12, Manitoba Hydro revised its planned expenditures on major generation and transmission projects over a 19-year timeframe upwards by $1.1 billion, and its base capital expenditures downwards by $122 million. However, from 2015 until 2018, Manitoba Hydro is now expecting a significant increase in base capital expenditure compared to the prior forecast.

The increased budget for major new generation and transmission is due to the one year deferral of the Conawapa Generating Station (now in 2026/27), the re-instatement of Electric and Gas demand side management costs in the capital forecast and the update of a number of project cost estimates. The revised in-service costs for Keeyask General Station have increased from $6.2 billion to $6.5 billion and the in-service costs for Conawapa Generating Station have increased from $10.4 billion to $10.7 billion.

The Board and Manitoba Hydro are currently engaged in a Needs For and Alternatives To (NFAT) Review into Manitoba Hydro's Preferred Development Plan, which, among other things, involves the planned construction of two new generating stations and a 750 MW U.S. transmission line. Manitoba Hydro's Preferred Development Plan, as filed August 2013, assumed annual rate increases of 3.95% over a 20-year period. However, even other alternative plans assume significant rate increases over the same timeframe.

Manitoba Hydro notes that all Canadian electric utilities are facing significant cost pressures. MH's current IFF13-1 reflects Manitoba Hydro incurring material operating losses in 2017/18 through 2021/22 which total over $245 million. The losses are attributable, in part, to the in-service revenue requirements related to Bipole III (in 2018/19) and Keeyask G.S. Rate increases to avoid these forecast financial losses

would appear to require rate increases in excess of 4% per year over the next several years. These and other forecasts, and the assumptions on which they are based, will be the subject of further review and testing at the next General Rate Application.

Next General Rate Application

Manitoba Hydro indicates that it is planning to file a three-year General Rate Application in the fall of 2014.

3.0 Intervener Submissions

Consumers' Association of Canada (Manitoba) Inc. (CAC)

The Consumers' Association of Canada (Manitoba) Inc. (CAC) opposes Manitoba Hydro's requested rate increase and considers it to be materially inflated in light of evidence that Manitoba Hydro could meet its 2014/15 financial targets without any rate increase. CAC submits that an interim rate increase should be limited to the rate of inflation. It states that Integrated Financial Forecast IFF-13 shows a forecast net income for electric operations of $116 million, which compares to only $78 million the previous year. CAC further cites several factors to suggest that actual net income for the 2013/14 fiscal year will likely be higher than projected in IFF-13.

CAC submits that Manitoba Hydro has not implemented cost control measures that would limit Operation, Maintenance & Administration (OM&A) expenditure growth to 1% per year, and only plans to do so starting in 2015/16. In CAC's view, implementing such cost constraint measures now would decrease projected OM&A costs in 2014/15 by $5 million.

CAC further states that there are several outstanding directives from Board Order 43/13 relating to the transition to International Financial Reporting Standards (IFRS), and that Manitoba Hydro has not yet performed an Asset Condition Assessment for its Generation and Transmission units.

In CAC's view, Manitoba Hydro is basing its request for a 3.95% rate increase on its planned implementation of the Preferred Development Plan, which has been challenged in the current NFAT review and may no longer be the best option.

Lastly, CAC expresses concern about Manitoba Hydro's stated intention to file a three-year General Rate Application in the fall, and suggests that any application should be limited to two years at most.

Green Action Centre (GAC)

The Green Action Centre (GAC) supports Manitoba Hydro's application, noting that capital costs for Manitoba Hydro's Preferred Development Plan have increased significantly over earlier projections. GAC further states that the costs of ongoing maintenance and the renovation of aging assets will be a reality for Manitoba Hydro in the current period as well as the future, and that an interim rate increase is required to ensure adequate resources for the safety and reliability of Manitoba Hydro's infrastructure. In GAC's view, rate increases above the rate of inflation will be required to keep Manitoba Hydro's financial status healthy or, at minimum, prevent a deterioration of the Corporation's debt-to-equity ratio over the next 15 years.

GAC further recommends that the Board should consider setting rates based on longer-term trends rather than short-term conditions, due to the inherent variability in such short-term conditions.

Manitoba Industrial Power Users Group (MIPUG)

The Manitoba Industrial Power Users Group (MIPUG) opposes Manitoba Hydro's request, and instead suggests two alternate approaches: (1) an inflationary rate increase of 2.0%, or (2) an interim increase based on the lowest-cost development plan reviewed in the NFAT. Specifically, MIPUG suggests that any interim rate increase be capped at 75% of the 3.32% even annual rate increases projected for Manitoba Hydro's All-Gas Plan, leading to an increase of 2.45%.

According to MIPUG, the proposed 3.95% rate increase is based on IFF-13, which not only includes projects that have yet to be approved, but also assumes that if the projects do not proceed, the costs incurred must be fully amortized immediately, which is inconsistent with regulatory practice.

MIPUG further states that changes to accounting procedures to comply with Integrated Financial Reporting Standards (IFRS) have not yet been fully vetted, and that if

Manitoba Hydro adopts the IFRS interim standard, rate-regulated assets will continue to be recognized. MIPUG further states that retaining the Average Service Life methodology of depreciation while eliminating the annual provision for Net Salvage would result in a $62 million benefit for the 2014/15 fiscal year, while benefiting future years by $37 million.

MIPUG further states that Manitoba Hydro has not provided cost containment details of Operating and Maintenance expenses, and that Manitoba Hydro should consider whether capital taxes relating to spending on new major projects should be capitalized, meaning they would not need to be included in rates until the respective new projects come into service.

MIPUG submits that there is a lack of urgency, as Manitoba Hydro's debt-to-equity level is close to the Corporation's 75:25 target, its capital coverage ratio remains at or above 1.0, and absent the rate increase, Manitoba Hydro is projecting only a very slight loss and does not forecast a cash shortage.

Manitoba Keewatinowi Okimakanak Inc. (MKO)

Manitoba Keewatinowi Okimakanak Inc. (MKO) submits that ideally, there should be no rate increase for Hydro-affected customers in the MKO First Nations, including customers in the four Diesel communities. Although MKO does not specifically object to the proposed rate increase, it recommends that the Board condition the current and any future rate increases on Demand-Side Management programs being made universally available and being provided to First Nations customers on a turnkey basis. MKO further seeks a direction from the Board to Manitoba Hydro requiring Manitoba Hydro to regularly report on the availability and penetration of low-income Demand-Side Management programs in the MKO communities.

MKO further submits that the Board should require Manitoba Hydro to provide rate mitigation measures, specifically the following:

1. The creation of a new class of Hydro-affected customers residing on the waterways utilized by Manitoba Hydro;

2. Specific sharing of net export revenues and a removal of mitigation costs for Hydro-affected customers;

3. An "equivalent to gas" rate for electric heat, as no MKO First Nation is connected to a natural gas distribution system, making it impossible for them to save money by switching to natural gas; and

4. An allocation of net export revenue to the Diesel communities, to be applied to the revenue requirement in the Diesel communities.

Lastly, MKO submits that any interim rate awarded in this proceeding should be subject to a rollback or refund to one or more customer classes based on sharing of net export revenues proposed by MKO.

With respect to Manitoba Hydro's proposal to submit a three-year general rate application in the fall of 2014, MKO recommends that such application do not apply to rates beyond March 31, 2016.

4.0 Board Findings

Test for Granting Interim Rates

The Board notes that Manitoba Hydro plans to file a General Rate Application in the fall of 2014, which Application would likely be heard in a public hearing in the spring of 2015. Accordingly, a General Rate Application would likely only be decided towards the end of the Corporation's 2014/15 fiscal year. Interim rate orders are intended to relieve Manitoba Hydro from the deleterious effects caused by the length of a regular regulatory proceeding. The questions to be determined by this Board are whether it would be just and reasonable to grant interim rates, and whether Manitoba Hydro would suffer a deleterious effect in the absence of an interim rate increase. For the reasons set out below, the Board considers it to be in the public interest to approve an interim rate increase, albeit at a level lower than requested by Manitoba Hydro.

Manitoba Hydro's Financial Position

According to Manitoba Hydro, the energy future in Manitoba will require significant annual rate increases regardless of which source of additional new generation is pursued, and regardless of which decision will be reached in the NFAT Review currently underway. All possible development plans presented in the NFAT Review require rate increases. As such, the Board and Manitoba Hydro customers cannot assume that in the absence of the Preferred Development Plan being approved, rate increases can be avoided. This requires the Board to take into account the need for rate stability and the avoidance of rate shock.

The Board notes that Manitoba Hydro's Interim Application for a 3.95% rate increase is consistent with the Preferred Development Plan that involves the construction of both Keeyask and Conawapa Generating Stations. The outcome of the NFAT Review will be known prior to the filing of Manitoba Hydro's next General Rate Application, and a full

General Rate Application is needed to examine the magnitude of additional rate increases.

Nonetheless, the Board is satisfied on a *prima facie* basis, that an interim rate increase is required. Reliability of Manitoba Hydro's infrastructure is paramount, and the Board accepts that investments in the maintenance and replacement of existing infrastructure is required.

Electricity export price forecasts have decreased over successive forecasts, resulting in less projected export revenue to help offset the requirement for domestic rate increases.

The Wuskwatim Generating Station is now 'in service' and has resulted in an additional domestic revenue requirement to be carried by domestic customers as those additional costs are not paid from export revenues.

Lastly, and despite the Board's comments in Order 43/13 with respect to the need for Manitoba Hydro to contain OM&A costs, those OM&A expenses are projected to increase above the rate of inflation in 2014/15.

The Board agrees with Manitoba Hydro's rebuttal submission that urgency is not a necessary precondition for an interim rate increase. However, it is appropriate to consider Manitoba Hydro's current financial condition in light of favourable recent financial results and the fact that a General Rate Application will be filed this Fall. The Board has determined that an interim rate increase of 2.00%, approximating the annual rate of inflation, is sufficient at this time to meet the needs of Manitoba Hydro. Whether or not an additional rate increase is required is an issue to be left to the General Rate Application, by which time actual financial results for the 2013/14 fiscal year will also be available.

Bipole III Deferral Account

The Board notes that Manitoba Hydro is continuing to spend money for the construction of the Bipole III transmission project which is estimated to cost approximately $3.2

billon. Once Bipole III will come into service (in 2018) it will affect Manitoba Hydro's Operating Statement. In Board Order 43/13, the Board determined that Bipole III will require additional annual revenue requirements of approximately $300 million when put into service, and which yearly amounts will have to be recovered in domestic customers' rates. As part of the last General Rate Application, the Board in Order 43/13, required Manitoba Hydro to establish a deferral account into which the proceeds of a 1.5% rate increase were to be deposited to defray a portion of the rate impacts of Bipole III. This deferral account continues to be active, and the Board remains concerned with the revenue requirement impact that Bipole III will have. Accordingly, in addition to the 2.00% interim rate increase approved above, the Board will approve an additional 0.75% interim rate increase to existing rates, the proceeds of which are to be collected in the Bipole III deferral account established in Order 43/13.

Depreciation & Amortization

As noted by CAC, Manitoba Hydro has not yet filed an Asset Condition Assessment that would provide additional clarity regarding expected depreciation and amortization expenses in the future. Directive 7 of Order 43/13 required Manitoba Hydro to file an Asset Condition Assessment no later than the filing of the Corporation's next depreciation study.

OM&A Increases

The Board has expressed concern with the growth of OM&A expense in prior Orders and remains concerned with Manitoba Hydro's increases in OM&A spending to date, as stated in Order 43/13. Manitoba Hydro's most recently filed financial information shows that since Order 43/13 was issued, OM&A costs have continued to escalate. While Manitoba Hydro has stated that it targets below-inflation growth in OM&A expenses of 1.0%/yr in 2015/16 and expects OM&A expense to grow by only 1.3% in 2014/15, the Board notes that to date, Manitoba Hydro has not been able to achieve below-inflation

growth in the past several years. The Board will review Manitoba Hydro's plans for OM&A cost containment at the next General Rate Application.

The Next General Rate Application

The Board shares the concerns of CAC and MIPUG with respect to Manitoba Hydro's plan to file a three-year General Rate Application in the fall of 2014. Manitoba Hydro is undergoing a period of significant and fairly rapid change, especially in light of its plan for substantial ongoing capital investments. The Board notes that it would be extremely reluctant to approve rates for a three-year timeframe in such a period of volatility and will direct that Manitoba Hydro file its next General Rate Application, for electric operations, for the 2014/15 and 2015/16 fiscal years.

Manitoba Hydro's request to implement new LED rates for the Area and Roadway Lighting class, will await further information and review at the General Rate Application.

5.0 IT IS THEREFORE ORDERED THAT:

1. Manitoba Hydro's Application for a 3.95% interim rate increase to all rate classes effective April 1, 2014 **BE AND HEREBY IS DENIED**.

2. The following interim rate increases to all Manitoba Hydro customer classes **BE AND HEREBY ARE APPROVED** effective May 1, 2014:

   (a) A 2.00% rate increase to existing rates to flow to Manitoba Hydro's general revenues; plus

   (b) A 0.75% rate increase to existing rates for all customer classes, with the revenues generated being placed into the Bipole III Deferral Account established in Order 43/13, to be dealt with at the next General Rate Application.

   (c) Manitoba Hydro file revised Rate Schedules, Proofs of Revenue and Customer Bill Impact Schedules;

   (d) The above rate increases will remain interim and are subject to being varied by the Board at the next General Rate Application;

3. Manitoba Hydro file a fully comprehensive two-year General Rate Application for electric operations, for the 2014/15 and 2015/16 fiscal years.

Board decisions may be appealed in accordance with the provisions of Section 58 of *The Public Utilities Board Act*, or reviewed in accordance with Section 36 of the Board's Rules of Practice and Procedure.

THE PUBLIC UTILITIES BOARD

"Régis Gosselin, B ès Arts, MBA, CGA"
Chair

"Kurt Simonsen, P. Eng."
Associate Secretary

Certified a true copy of Order No. 49/14
issued by The Public Utilities Board

C.C.S.M. c. P280

The Public Utilities Board Act

-Excerpt-

ORDERS OF THE BOARD

Power to order partial or other relief

44(1) Upon any application to it, the board may make an order granting the whole or part only of the application or may grant such further or other relief in addition to or in substitution for that applied for, as fully and in all respects as if the application had been for such partial, further or other relief.

Review of orders

44(2) The board may require a re-hearing of an application before making any decision thereon.

Varying order

44(3) The board may review, rescind, change, alter, or vary any decision or order made by it.

Interim orders ex parte

45 The board may, if the special circumstances of any case so require, make an interim ex parte order authorizing, requiring, or forbidding, anything to be done that the board would be empowered on application, petition, notice, and hearing to authorize, require, or forbid; but no such order shall be made for any longer time than the board deems necessary to enable the matter to be heard and determined, on such application, petition, notice or hearing.

Extension of time for compliance with order

46 Where any work, act, matter, or thing, by any order, regulation, or decision of the board is required to be done, performed, or completed within a specified time, the board may, if the circumstances appear so to require, upon such notice as it deems reasonable, or, in its discretion, without notice, extend the time so specified.

Orders subject to conditions

47(1) The board may direct, in any order, that the order or any portion or provision thereof shall come into force

(a) at a future fixed time; or

(b) upon the happening of any contingency, event, or condition specified in the order; or

(c) upon the performance to the satisfaction of the board, or a person named in the order for the purpose, of any terms that the board may impose upon any party interested;

and the board may direct that the whole or any portion of the order shall have force for a limited time, or until the happening of a specified event.

Interim order

47(2) The board may, instead of making an order final in the first instance, make an interim order and reserve further directions, either for an adjourned hearing of the matter, or for further application.

SIXTH FLOOR, 900 HOWE STREET, BOX 250
VANCOUVER, BC V6Z 2N3 CANADA
web site: http://www.bcuc.com

BRITISH COLUMBIA UTILITIES COMMISSION

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-182-14

TELEPHONE: (604) 660-4700
BC TOLL FREE: 1-800-663-1385
FACSIMILE: (604) 660-1102

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
Multi-Year Performance Based Ratemaking Plan
for the years 2014 through 2019
Order G-139-14 Amended Financial Schedules Compliance Filing and
Request for Approval of 2014 Permanent Rates and 2015 Interim Rates

BEFORE: D. A. Cote, Panel Chair / Commissioner
D. M. Morton, Commissioner
N. E. MacMurchy, Commissioner

November 24, 2014

O R D E R

WHEREAS:

A. On June 10, 2013 and July 5, 2013, FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC), respectively, applied to the British Columbia Utilities Commission (Commission) for approval of a multi-year performance based ratemaking (PBR) plan for the years 2014 through 2018;

B. On September 15, 2014, the Commission issued Order G-138-14 for FEI and Order G-139-14 for FBC, with accompanying decisions, setting out the approved PBR plans for FEI and FBC (collectively FortisBC) for the period from 2014 through 2019 (the PBR Decisions);

C. The PBR Decisions directed, among other items, that FortisBC submit compliance filings to the Commission within 60 days containing amended financial schedules and incorporating all the adjustments and directives as outlined in the PBR Decisions;

D. FEI filed its required compliance filing on October 14, 2014. On October 24, 2014, the Commission issued Order G-164-14 approving for FEI, among other things:

- The use of inflation data from the most recent 12 month period (July through June) for the 2014 rate change calculations and for future annual reviews.

- The use of Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.

.../2

- An adjustment to 2014 inflation for the transition from harmonized sales tax to provincial sales tax as of April 1, 2013 for an increase of 0.1750 percent.

E. On November 14, 2014, FBC filed its Amended Financial Schedules Compliance Filing (the Compliance Filing) and Application for Approval of 2014 Permanent Rates and 2015 Interim Rates (Application) with the following requested approvals:

- To use inflation data from July through June for the 2014 rate change calculations and the future Annual Reviews;
- To use Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC;
- To adjust 2014 inflation for the transition from harmonized sales tax to provincial sales tax as of April 1, 2013 for an increase of 0.1750 percent;
- That the current interim rates for 2014 be made permanent, effective January 1, 2014;
- Establishment of a non-rate base Interim Rate Variance deferral account, financed at the company's short-term interest rate, to record the difference between the 2014 permanent rates and the 2014 rates calculated in compliance with Order G-13-14, with a credit balance of $29.682 million (pre-tax), which is to be amortized in future rates over a period to be determined in the annual review of 2015 rates; and
- A 3.5 percent increase, effective January 1, 2015, on an interim and refundable basis, pending the outcome of the annual review of 2015 rates.

F. The Commission has reviewed the Compliance Filing and Application and considers that approval is warranted.

NOW THEREFORE pursuant to sections 59 to 61 of the *Utilities Commission Act* the Commission orders as follows:

1. FortisBC Inc. is approved to use inflation data from the most recent 12-month period (July through June) for the 2014 rate change calculations and future annual reviews.
2. FortisBC Inc. is approved to use Statistics Canada CANSIM Table 326-0020 to determine the CPI-BC and CANSIM Table 281-0063 to determine AWE-BC.
3. FortisBC Inc. is approved to adjust 2014 inflation for the transition from harmonized sales tax to provincial sales tax as of April 1, 2013 for an increase of 0.1750 percent.

4. FortisBC Inc.'s current 2014 interim rates are approved, on a permanent basis, effective January 1, 2014.

5. FortisBC Inc. is approved to establish a non-rate base 2014 Interim Rate Variance deferral account, financed at the company's short-term interest rate.

6. FortisBC Inc.'s request for a 3.5 percent increase over 2014 rates, effective January 1, 2015, is approved on an interim and refundable basis pending the outcome of the annual review of 2015 rates.

DATED at the City of Vancouver, In the Province of British Columbia, this day of November 2014.

BY ORDER

Original signed by:

D. M. Morton
Commissioner

IC Submission re : NLH - 2015 Interim Rates Application

Geoff Young to: Jill Chisamore 03/19/2015 10:27 AM
Sent by: Jill Chisamore

History: This message has been forwarded.

----- Forwarded by Jill Chisamore/NLHydro on 03/19/2015 10:27 AM -----

RE: NLH - 2015 Interim Rates Application

Paul L. Coxworthy to: Bobbi Sheppard, Cheryl Blundon 03/19/2015 10:17 AM

Cc: "Fred Cass (fcass@airdberlis.com)", "Gerard Hayes (ghayes@newfoundlandpower.com)", "Liam O'Brien (lobrien@curtisdawe.nf.ca)", "Thomas Johnson (tjohnson@odeaearle.ca)", "Colleen Lacey (clacey@odeaearle.ca)", "Doug Bowman (cdbowman@netzero.net)", "Dean Porter (dporter@pa-law.ca)", "Tom O'Reilly (toreilly@coxandpalmer.com)", "Denis Fleming (dfleming@coxandpalmer.com)", Genevieve Dawson , "tom_sheldon@nunatsiavut.com" , "christina_goldhar@nunatsiavut.com" , "chenderson@lumosenergy.com" , "Nancy Kleer (nkleer@oktlaw.com)" , "sluk@oktlaw.com", "Yvonne Jones 1 (Yvonne.Jones.A1@parl.gc.ca)", "Geoffrey Young (gyoung@nlh.nl.ca)", Yvonne Jones , "Edward Hearn (miller&hearn@crrstv.net)" , Cheryl Blundon, Jacqui Glynn , NL Public Utilities Board

Dear Ms. Blundon,

We advise that the Island Industrial Customers Group, other than affirming their February 23, 2015 submissions and subject to the comment below, do not intend to make any further submissions on the Interim Rates Application.

We have noted that the Board has granted Hydro's request to make a Reply Submission by March 23, 2015. The Island Industrial Customers Group respectfully reserve their right to seek the leave of the Board to comment on the Reply Submission, should it depart in a material way from Hydro's previous submissions on the proposed interim rates.

Regards,

Paul L. Coxworthy
Partner
D: 709.570.8830
pcoxworthy@stewartmckelvey.com

-----Original Message-----
From: Bobbi Sheppard [mailto:bsheppard@pub.nl.ca]
Sent: Wednesday, March 18, 2015 1:50 PM
To: Geoffrey Young (gyoung@nlh.nl.ca)
Cc: Fred Cass (fcass@airdberlis.com); Gerard Hayes

(ghayes@newfoundlandpower.com); Liam O'Brien (lobrien@curtisdawe.nf.ca); Thomas Johnson (tjohnson@odeaearle.ca); Colleen Lacey (clacey@odeaearle.ca); Doug Bowman (cdbowman@netzero.net); Paul L. Coxworthy; Dean Porter (dporter@pa-law.ca); Tom O'Reilly (toreilly@coxandpalmer.com); Denis Fleming (dfleming@coxandpalmer.com); Genevieve Dawson; tom_sheldon@nunatsiavut.com; christina_goldhar@nunatsiavut.com; chenderson@lumosenergy.com; Nancy Kleer (nkleer@oktlaw.com); sluk@oktlaw.com; Yvonne Jones 1 (Yvonne.Jones.A1@parl.gc.ca); Yvonne Jones; Edward Hearn (miller&hearn@crrstv.net); Cheryl Blundon; Jacqui Glynn; NL Public Utilities Board
Subject: NLH - 2015 Interim Rates Application - Reply Submission

Mr. Young:

Please see the attached in relation to the above-noted matter.

If you have any questions, please do not hesitate to contact the Board.

Bobbi Sheppard
Regulatory/Administrative Assistant
Board of Commissioners of Public Utilities P. O. Box 21040 (120 Torbay Road)
St. John's, NL A1A 5B2
Tel: (709) 726-0473
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****
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de vos dossiers.

Browne Fitzgerald
Morgan & Avis
LAWYERS

Dennis Browne, Q.C.
Tel: 709 724-3801
dbrowne@bfma-law.com

March 26, 2015

Via Courier / Email

Board of Commissioners of Public Utilities
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's 2013 Amended General Rate Application / 2015 Interim Rates Application

Further to the above-captioned, enclosed please find the original and twelve (12) copies of the Intervenor's Submission to the Public Utilities Board.

Yours truly,

Dennis Browne, Q.C.
Agent for Edward Hearn, Q.C.
Solicitor for the Intervenor
(Towns of Labrador City, Wabush,
Happy Valley-Goose Bay and
North West River)

Encl.
/bb

cc Newfoundland and Labrador Hydro
Mr. Geoffrey Young

cc Consumer Advocate
Mr. Thomas Johnson

.../2

cc Island Industrial Customers Group
Mr. Paul Coxworthy

cc Towns of Labrador City,Wabash, Happy Valley-Goose Bay and North West River

cc Nunatsiavut Government
Ms. Genevieve Dawson

cc Newfoundland Power Inc.
Mr. Gerard Hayes

cc Innu Nation
Ms, Nancy Kleer

cc Vale Newfoundland and Labrador Limited
Mr. Thomas O'Reilly, QC

cc Yvonne Jones MP, Labrador

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

AND IN THE MATTER OF an application by Newfoundland and Labrador Hydro, pursuant to Sections 70 and 75 of the Act, for the approval of customer electricity rates, rules and regulations on an interim basis to become effective March 1, 2015 (the "2015 Interim Rates Application").

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

RE: Newfoundland and Labrador Hydro's 2015 Interim Rates Applications and the Intervention of the Towns of Labrador City, Wabush, Happy Valley-Goose Bay and North West River (the "Intervenor").

SUBMISSION OF THE INTERVENOR

1. The Application by Newfoundland and Labrador Hydro ("Hydro") for interim rates is made pursuant to Section 75 of the Act which states:

> **75. (1) The board may make an interim order unilaterally and without public hearing or notice, approving with or without modification, a schedule of rates, tolls and charges submitted by a public utility, upon the terms and conditions that it may decide.**
>
> **(2) The schedule of rates, tolls and charges approved under subsection (1) are the only lawful rates, tolls and charges of the public utility until a final order is made by the board under section 70.**
>
> **(3) The board may order that the excess revenue that was earned as a result of an interim order made under subsection (1) and not confirmed by the board be**
>
> **(a) refunded to the customers of the public utility; or**
>
> **(b) placed in a reserve fund for the purpose that may be approved by the board.**

2. This submission applies to the intervention of the Towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River and is focused upon paragraph 12 of the January 28, 2015 interim rates application which states:

> **Labrador Interconnected Rates**
>
> **12. The cost of serving customers on the Labrador Interconnected System is not materially impacted by the revised fuel cost estimate for 2015. Therefore, Hydro is proposing that the rates for customers on the Labrador Interconnected System that accompanied the Amended Application, an average increase of 2.1%, be approved on an interim basis March 1, 2015.**

3. The Application by Newfoundland and Labrador Hydro ("Hydro") for interim rates (2015) should be dismissed by the Public Utilities Board. Hydro has failed to demonstrate any basis for applying for interim rate relief at this time. There is no evidence provided of exigent circumstances to ground an application for interim relief. Indeed, there is no evidence provided for any rate increase whatsoever. Therefore, the Public Utilities Board has no basis to grant any interim rate increase.

4. In 2009 Hydro commenced a project designed to upgrade its distribution system in western Labrador (the "Project"). The Project began in 2010 and was scheduled for completion in 2013. This date was not realized. The date keeps changing and has now been moved to 2015.

5. The Project and related work has jeopardized the emergency back-up power line to Labrador West made available by an agreement with Hydro Quebec through Fermont Quebec (the "Back-Up System"). This Back-Up System has been in place for decades and is an important emergency supply on which Labrador West relies, particularly in the winter months during which the temperature can drop to below 50℃.

6. The Back-Up System makes an emergency supply of 3-4 megawatts of power available for transmission to Labrador West. Hydro failed to inform their customers in Labrador West that the Project work would prevent access to the Back-Up System.

7. In August 2013 there was a major power failure, interrupting service throughout Labrador. Service was down for some 12 hours. Labrador City requested that Hydro access emergency power through the Back-Up System. Only then was Labrador West made aware that Hydro's

Project prevented Western Labrador from accessing the Back-Up System. Hydro failed to inform their Labrador West customers that the Back-Up System was no longer available. There were no consultations, no public hearings and no notice.

8. The Back-Up System is still not available. In the absence of the Back-Up System, Labrador City has in partnership with the Iron Ore Company of Canada made temporary accommodation to access a mobile (7200V/4160V) generator the event of an emergency. However, upon completion of Hydro's 2015 upgrade (4160V to 25KV) this temporary provision will no longer be an option, necessitating the Town secure an a 900kW generator and carry-out modification to the distribution system of the schools designated as emergency evacuation centres at a cost in excess of $700,000. However, the Town of Labrador City has been advised by Provincial Government officials the provision of redundancy power is the responsibility of Hydro.

9. After Hydro's Project is complete, it remains uncertain how long it will take to deploy the Back-Up System, thus necessitating acquisition of emergency generation capacity as described in paragraph 8 above.

10. In the result, for these and the other reasons previously stated, it is inappropriate to grant Hydro's 2015 Interim Application to increase rates to its customers in the interconnected Labrador system. These issues are best dealt with in Hydro's General Rate Application.

11. Based on the foregoing, no interim order pursuant to Section 75 of the Act is appropriate and there should be no increase to the rates charged to customers within the Labrador Interconnected System without a hearing into these matters.

DATED AT St. John's, in the Province of Newfoundland and Labrador, this 26th day of March, 2015.

Dennis Browne

Dennis Browne, Q.C. - Agent for Edward Hearn, Q.C.
Solicitors for the Intervenor,
The Towns of Labrador City, Wabush,
HappyValley-Goose Bay, and North West River
Whose address for service is:
Terrace on the Square, Level 2, P.O. Box 23135
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March 30, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro (Hydro) - 2015 Interim Rates Application

Hydro's submissions at this time are limited to issues arising from the Board's Requests For Information (RFIs) as of March 5, 2015 and from the submission made on March 26, 2015 on behalf of the Towns of Labrador City, Wabush, Happy Valley-Goose Bay and North West River (the Towns).

The Towns written submissions arise from allegations of reliability concerns in Labrador West. Aside from the contents of the Towns' submission of March 26, 2015, there is no evidence or information before the Board on those reliability issues - this is the first time these issues have been raised in these or other proceedings. Hydro submits that it would be improper for these issues to be considered further at this instance, in particular, in this specific proceeding, and that it would be more efficient and appropriate to respond to these allegations at another stage of Hydro's General Rate Application (GRA) or in another matter or proceeding that is focused on this issue.

The issues raised by the Towns in its written submission of March 26, 2015, should have been restricted to issues arising from the Board's last RFIs as an opportunity to provide submissions on this application generally was already provided. In this regard, Hydro notes that the Towns did not previously object to Hydro's 2015 Interim Rates Application. Hydro also observes that the rate of increase for the Towns' service area inherent in Hydro's 2015 Interim Rates Application was not large: Hydro's response to TIR-PUB-NLH-019 shows that the increase proposed by Hydro for the Towns' service area is 2.1% but that the increase with a scenario suggested by the question TIR-PUB-NLH-019 is 14.5%.

With respect to the paragraph 3 of the Towns' submission, Hydro wishes to reiterate the arguments and regulatory precedents cited in its February 25, 2015 written submission on its 2015 Interim Rates Application. Hydro submits that its application and subsequent written submission provides ample argument and authorities which establish that the presence of exigent circumstances is not a

prerequisite for the issuance of an interim rates order. The Board's discretion to order interim rates is properly triggered where doing so provides a utility with sufficient and reasonable revenues in circumstances where denying them would not accord with generally accepted sound utility practice. This requirement can arise from delays occasioned in regulatory proceedings. Moreover, Hydro submits that where, as in the present case, the interim relief is effectively not the full amount requested under its GRA (due to the timing of the rate implementation necessarily occurring long after January 1 of 2015) and given that the Board is always entitled on a final order to order a refund to customers of any amount of revenue that is determined to have been too large, the application of a test requiring that a utility show exigent circumstances before interim rates are awarded is unduly onerous.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Tracey L. Pennell
Legal Counsel

TLP/jc

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. 14(2015)

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

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

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

IN THE MATTER OF an application by Newfoundland and Labrador Hydro for the approval of, among other things, customer electricity rates for 2015 on an interim basis.

The Application

On January 28, 2015 Newfoundland and Labrador Hydro ("Hydro") filed an application with the Board seeking, among other things, approval of increases in base rates on an interim basis (the "Interim Rate Application") in advance of the conclusion of its general rate application. The Application requests:

> *An interim Order pursuant to Section 75 of the Act, approving*
>
> *(i) the schedule of rates, tolls and charges set out in Schedule 1 to this 2015 Interim Rates Application to be effective on and after March 1, 2015, until superseded by a final order of the Board;*
>
> *(ii) changes to the RSP rules to implement the phase-in of changes to the IIC rates and to remove the requirement for the RSP rate adjustment to NP scheduled for July 1, 2015, as set out in Schedule 1 of this 2015 Interim Rates Application, as follows:*

(a) *to provide for the allocation and disposition of the RSP load variation balance effective December 31, 2014;*

(b) *to provide for a one-time transfer from the IIC Surplus balance effective December 31, 2014 to provide recovery of the IIC current plan balance;*

(c) *to approve the proposed RSP Surplus Credit Adjustments to mitigate the rate impacts of implementing 2015 test year IIC base rates; and*

(d) *to suspend for 2015 the requirement for the July 1, RSP adjustment for Utility rates.*

A copy of the Interim Rate Application was provided to the parties in the general rate application proceeding: Newfoundland Power Inc. ("Newfoundland Power"); the Consumer Advocate, Mr. Thomas Johnson; Corner Brook Pulp and Paper Limited, NARL Refining Limited Partnership (formerly North Atlantic Refining Limited) and Teck Resources Limited (the "Industrial Customer Group"); Vale Newfoundland and Labrador Limited ("Vale"); the Innu Nation; the Towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River (the "Towns"); Yvonne Jones, MP and the Nunatsiavut Government.

Beginning February 5, 2015 requests for information were filed in relation to the Interim Rate Application.

On February 18, 2015 Newfoundland Power, the Consumer Advocate, and Vale filed submissions. On February 23, 2015 the Industrial Customer Group filed a submission. On February 25, 2015 Hydro filed a submission. Neither the Innu Nation, Yvonne Jones, MP nor the Nunatsiavut Government filed requests for information or submissions.

Further requests for information were issued by the Board on March 5, 2015 and answered on March 17, 2015. The parties were provided an opportunity to file further submissions and on March 26, 2015 the Towns filed a submission. Hydro filed a reply submission on March 30, 2015. No other submissions were filed.

Background

On July 30, 2013 Hydro filed a general rate application proposing, among other things, revised rates for its customers. This application was filed in accordance with Government direction issued on April 4, 2013 pursuant to section 5.1 of the *EPCA*.[1]

Hydro filed a second application on July 30, 2013, also in accordance with the direction of Government, for approval of changes to Island Industrial customer rates and Hydro's Rate Stabilization Plan ("RSP"). On August 30, 2013 the Board issued Order No. P.U. 26(2013) approving, on an interim basis, existing Island Industrial customer base rates with no RSP rate and ordering that the Industrial Customer RSP (the "IC RSP") be credited with $49 million from the accumulated load variation component of the RSP, with the remaining balance transferred to the credit of the Newfoundland Power RSP (the "NP RSP"). On September 30, 2013 the Board

[1] OC2013-089, OC2013-090, OC2013-091, OC2013-207 and OC2013-208

issued Order No. P.U. 29(2013) which, among other things, continued the existing rates on an interim basis for Island Industrial customers, except that a new RSP rate was established for Teck Resources Limited.

On November 18, 2013 Hydro filed an application seeking interim rate relief in advance of the conclusion of the general rate application. Hydro requested implementation of interim rate changes effective January 1, 2014 for most of its customers or, in the alternative, a deferral and recovery mechanism for the revenue shortfall. On December 13, 2013 the Board issued Order No. P.U. 40(2013) deferring consideration of Hydro's proposals for interim rate changes pending resolution of the issues and concerns raised in the Interim Rate Application and approving an amendment to the RSP rules to suspend the January 1, 2014 RSP adjustment for Island Industrial customers.

On January 17, 2014 Hydro filed another application for interim relief, which it stated was supplemental to its November 18, 2013 application, changing its proposals in relation to several matters, including rates for Newfoundland Power and certain Rural customers. On February 11, 2014 Hydro withdrew this application and filed an amended application, requesting new rates for Island Industrial customers and a deferral mechanism for any revenue shortfall between interim and final rates for other customers. On April 25, 2014 the Board issued Order No. P.U. 13(2014) denying Hydro's amended interim application, finding that Hydro had not filed an Application with supporting evidence setting out a comprehensive, unambiguous set of proposals.

On May 12, 2014 Hydro filed a further application for interim relief requesting approval, on an interim basis, to transfer $29.4 million from the credit balance in Hydraulic Production Variation component of the RSP to be recognized as revenue by Hydro in 2014 and to change Island Industrial customer rates for 2014. On June 6, 2014 Hydro provided notice by letter that in the fall of 2014 it would be amending its general rate application to provide forecast information for 2014 and a 2015 test year. Hydro explained that revisions to the general rate application were necessary to update financial information to provide a more current and relevant basis for rate setting purposes. The other parties did not object to Hydro's proposal to amend the general rate application or the resulting postponement of the hearing which was scheduled to begin on July 9, 2014. Hydro advised that it expected that the hearing would proceed in early 2015. Hydro did not amend the May 12, 2014 application for interim relief and on September 17, 2014 the Board issued Order No. P.U. 39(2014) denying the application.

On November 10, 2014 Hydro filed an amended general rate application (the "Amended General Rate Application"). In the Amended General Rate Application Hydro requests, among other things, an order of the Board approving interim rates for Island Industrial customers, effective January 1, 2015, and for Newfoundland Power and Hydro Rural customers, effective February 1, 2015.

On November 28, 2014 Hydro filed an application for approval of the deferral and recovery of $45.9 million associated with a forecast revenue deficiency in 2014. In Order No. P.U. 58(2014) the Board approved the creation of a deferral account and the segregation in the account of $45.9 million as of December 31, 2014, but did not approve Hydro's proposals for recovery.

On December 4, 2014 the Board established a process for the consideration of the request in the Amended General Rate Application for approval of interim rates. Submissions were filed by Newfoundland Power, the Consumer Advocate, the Industrial Customer Group, Vale and Hydro.

On December 24, 2014, following the filing of submissions, the Board directed Hydro to file an application setting out proposals for interim rates for Newfoundland Power and the Island Industrial customers to be effective March 1, 2015.

Interim Rate Application Proposals

The Interim Rate Application was filed on January 28, 2015 seeking interim approval of customer electricity rates effective on March 1, 2015 for Newfoundland Power, Island Industrial customers, Labrador Interconnected customers, and Government Diesel customers. The rates for Hydro's other customers will also be affected by this application as they are based on Newfoundland Power customer rates. Hydro states that approval of the proposed rates on an interim basis in advance of conclusion of the general rate application would reduce the amount of 2015 costs deferred for future recovery.

The rates proposed in the Interim Rate Application are based on the forecast 2015 revenue requirement and cost of service methodology set out in the Amended General Rate Application. However the Interim Rate Application states that the rate increases proposed in the Amended General Rate Application are no longer supported by the 2015 fuel forecast and therefore a fuel cost reduction has been reflected in the rates proposed in the Interim Rate Application. Since the filing of the Amended General Rate Application, the forecast cost of No. 6 fuel decreased materially from $93.32 per barrel to $65.63 per barrel which is estimated to reduce the 2015 Test Year cost of service by approximately $73 million. [2] The Interim Rate Application also proposes changes to the RSP rules, relating to:

i) the allocation and disposition of the load variation balance at December 31, 2014 using the energy ratio allocation approach proposed in the Amended General Rate Application;
ii) the transfer of an amount from the IC RSP Surplus balance at December 31, 2014 to provide recovery of the IC RSP current plan year-end balance and to approve the proposed RSP Surplus credit adjustment to mitigate the impact of the proposed 2015 base rates; and
iii) the suspension of the July 1, 2015 NP RSP adjustment.

The Interim Rate Application states that, based on existing rates, Hydro would achieve a forecast return on rate base of 3.33% in 2015, which is below the bottom of the approved range of return on rate base of 7.29% established in the 2007 general rate application.[3] Hydro states that the forecast income statement filed in the Amended General Rate Application shows that under existing rates Hydro would have a net loss of $34.6 million for 2015.[4] Hydro explains that, with approval of the proposed interim rates effective March 1, 2015, the net income shortfall resulting

[2] Interim Rate Application, Evidence, page 6-7
[3] Interim Rate Application, page 2
[4] Interim Rate Application, Evidence, page 1

from the delayed implementation is approximately $20 million.[5] The Amended General Rate Application proposes that the revenue shortfall be recovered through a rate rider with the implementation of final customer rates.

Hydro proposes to offset the 11.2% base rate increase to Newfoundland Power by resetting the NP RSP fuel rider from 1.526¢ per kWh to zero.[6] The net result is a 9.3% decrease to Newfoundland Power and an approximate overall average 6.3% reduction for Newfoundland Power customers. Given that Hydro Rural and Non-Government Diesel customer rates are based on Newfoundland Power's rates Hydro's proposals will also reduce rates for these customers on average by 6.3%. Hydro explains that Government Diesel customer rates are based on 100% recovery of the allocated test year costs and, because the cost of fuel has decreased materially, Hydro is proposing lower rate increases for these customers in the Interim Rate Application than proposed in the Amended General Rate Application. The Interim Rate Application requests approval of a 2.1% rate increase for the Labrador Interconnected system, which is the same increase proposed in the Amended General Rate Application, on the basis that the cost of serving these customers is not materially affected by the decrease in the cost of fuel.

The rate changes for Newfoundland Power are proposed to be implemented using the rate design approach set out in the Amended General Rate Application, except that the tail block rate for Newfoundland Power is reduced to reflect the reduced 2015 fuel forecast.[7] Hydro also proposes the suspension of the July 1, 2015 NP RSP adjustment and the continuation of the RSP current plan adjustment of (0.551)¢ per kWh. Hydro states that approval of the proposed disposition of the balance in the RSP segregated load variation balance December 31, 2014 would result in a credit of approximately $33 million to the NP RSP current balance, permitting the existing RSP current plan adjustment to continue until the end of June 2016 without resulting in a large RSP balance owing from customers.

The Interim Rate Application proposes a different phase-in of rate increases for Island Industrial customers than proposed in the Amended General Rate Application. Hydro states that reflecting the updated Holyrood fuel cost forecast in the revenue requirement reduces the base rate increase for Island Industrial customers from 39.2% to 18.1%.[8] Hydro explains that the material reduction in the proposed 2015 base rate increase for Island Industrial customers requires a modified phase-in approach. In particular the September 1, 2015 rate increase proposed in the Amended General Rate application for Island Industrial customers is eliminated and a rate increase is proposed for January 1, 2016. Hydro also offers an alternative approach with only two rate adjustments. The two alternatives are set out below with the rate phase-in proposed in the Amended General Rate Application:

[5] Interim Rate Application, Evidence, page 17
[6] Interim Rate Application, page 3
[7] Interim Rate Application, Evidence page 12
[8] Interim Rate Application, Evidence, page 7

IC Rate Proposals[9]				
	March 1, 2015	**September 1, 2015**	**January 1, 2016**	**September 1, 2016**
Alternative 1	2.7%	-	4.4%	10.2%
Alternative 2	4.9%	-	-	12.7%
Amended General Rate Application	17.9%	16.7%	-	10.0%

In its evidence, Hydro explains that the Island Industrial customer rates do not currently include a fuel rider to recover the increased cost of fuel since 2007. Hydro proposes to use the existing balance of $10.9 million in the IC RSP Surplus at December 31, 2014 to recover the 2014 year-end IC RSP current plan balance net of the credit associated with the disposition of the RSP segregated load variation.[10] Hydro explains that allocating the segregated net load variation based on energy ratios would result in a credit of $2.1 million to the IC RSP. The remaining balance of the IC RSP Surplus is to be used to phase-in the Island Industrial customer base rate increase over the period March 1, 2015 to August 31, 2016. Hydro notes that with either of the two phase-in alternatives the forecast IC RSP Surplus balance is virtually depleted by September 1, 2016. Hydro argues in respect of the disposition of the load variation component of the RSP that:

> *The proposed disposition reduces customer rate impacts and partially addresses fairness concerns related to the recovery of historic fuel costs through a future IC RSP recovery factor which would apply to all customers including new customers that were not operating at the time these costs were incurred.*[11]

Hydro notes that, as Vale and Praxair enter into full operations, the portion of the IC RSP current year-end balance recovered from them will increase. Hydro argues that it is reasonable to recover the 2014 year-end IC RSP balance remaining, after the credit of $2.1 million, from the IC RSP Surplus which also accumulated prior to these customers becoming fully operational.

Hydro also proposes new specifically assigned charges for each of the Island Industrial customers, as well as an RSP rate for Teck of (1.113)¢ per kWh to provide for the same rate increase to Teck as proposed for the other Island Industrial customers.

[9] Interim Rate Application, Evidence Table 1 and 2, pages 4 and 9; The proposed RSP adjustment for Teck is modified to provide the same 2015 rate increase for Teck as proposed for the other Island Industrial customers, Interim Rate Application, page 6.

[10] Interim Rate Application, Evidence, page 9, Footnote 27; The 2014 year-end IC RSP current plan balance of $6.8 million less the load variation credit of $2.1 million results in a net amount to be recovered from the IC RSP Surplus of $4.7 million.

[11] Interim Rate Application, Evidence, page 6

Submissions

Newfoundland Power submits that the Board should not approve the interim rates proposed in the Interim Rate Application because the rates have not been shown to be reasonable. Newfoundland Power suggests that the Board direct Hydro to create interim rates which exclude recovery of specified untested 2015 costs which the Board determines should not be included in interim rates. Newfoundland Power states that section 3 of the *EPCA* requires that rates should be reasonable and that in setting rates the Board should apply tests that are consistent with generally accepted sound public utility practice. Newfoundland Power argues that the recovery of some of the proposed costs would be contentious or premature. Newfoundland Power notes that there is an outstanding prudency review in relation to over $200 million in Hydro expenditures, that Hydro proposes a fuel conversion factor which is inconsistent with longstanding practice, and that there is an issue with respect to the timing of the implementation of the Government direction with respect to Hydro's return. Newfoundland Power references recent decisions of the Alberta Utilities Commission and argues that Canadian regulatory practice indicates consideration of excluding contentious costs and further that partial recovery of a forecast utility revenue deficiency in interim rates may be appropriate in certain circumstances. Newfoundland Power submits that reasonable interim rates for Hydro would not be based upon full recovery of these costs. Newfoundland Power states that, in principle, it does not oppose interim rates for Hydro but the interim rates set out in the Interim Rate Application are not, in Newfoundland Power's view, consistent with the reasonableness requirement of the legislation.

The Consumer Advocate submits that it is clear that Hydro requires an interim rate increase and recommends that the Board approve the Interim Rate Application as proposed although he suggests changes in relation to the proposals for the Island Industrial customer rates. The Consumer Advocate proposes that the Board apply the interim rate test used by the Alberta Utilities Commission and states:

> *It is clear that given these circumstances, Hydro requires an interim rate increase and its application passes Part 1 of the interim rates test. Hydro also shows that with respect to Part 2 of the interim rates test, its proposed interim rates will promote rate stability, ease rate shock, help to maintain inter-generational equity, and improve price signals to consumers. The Consumer Advocate submits that Hydro's 2015 Interim Rates Application meets the requirements set out in the two-part interim rates test. The key consideration in the assessment of this Application is the impact on the electricity consumers in the Province. The Consumer Advocate does not see how electricity consumers can possibly benefit from Hydro's continuing financial deterioration.*[12]

In relation to the amount of revenue requested the Consumer Advocate notes that the Interim Rate Application effectively requests 78.5% of the forecast revenue deficiency for 2015 as a result of the March 1, 2015 effective date. The Consumer Advocate states that there are ample opportunities to claw back any excess revenues. In relation to rate shock the Consumer Advocate argues that in most cases customer classes will see a rate decrease and, where there are increases,

[12] Consumer Advocate Submission, page 5

they are manageable. In addition, the Consumer Advocate supports Hydro's proposal that there be no July 1, 2015 RSP rate adjustment for Newfoundland Power customers.

The Consumer Advocate argues that, to be consistent with Government direction, the rate phase-in for Island Industrial customer rates must be implemented retroactively to September 1, 2014 with annual increases on September 1, 2015 and September 1, 2016 and the operation of the IC RSP in accordance with approved methodology effective January 1, 2014. The Consumer Advocate argues that it is inappropriate to transfer $2.1 million from the balance of the load variation component of the RSP to offset the 2014 IC RSP year-end 2014 balance before the Board rules that these funds are owed to the Island Industrial customers and further that the use of these funds is not consistent with Government direction. The Consumer Advocate references the evidence set out in TIR-IC-NLH-4 showing the impact on the phase-in without the $2.1 million transfer and argues that the rate shock argument is not valid in the circumstances.

The Industrial Customer Group states that it does not object to Hydro's proposals for interim rate increases effective March 1, 2015, except the rate increase to Corner Brook Pulp and Paper Limited associated with the proposed specifically assigned charge. The Industrial Customer Group notes that the proposed specifically assigned charge will result in an effective rate increase for Corner Brook Pulp and Paper Limited of 5.1%, and that the Corner Brook Pulp and Paper Limited specifically assigned charge was 0.4% of its power bill in 2001 but would be 25% of its bill if Hydro's proposals are approved. The Industrial Customer Group also argues that the specifically assigned charge sends no important price signal, that the monthly amount is not material to Hydro's application for revenue requirement relief but is very material as an interim rate impact on a contested rate issue, and further that if the general rate application had proceeded as originally filed this issue would in all likelihood have been addressed at this point.

The Industrial Customer Group states that it does not object to the interim allocation of the 2014 year-end segregated RSP load variation balance but that it is premature and unnecessary to make a final determination. The Industrial Customer Group submits that the $2.1 million allocation of the RSP load variation balance is the minimum which the Island Industrial customers can expect will be allocated to their benefit from the 2014 segregated RSP load variation balance. The Industrial Customer Group states:

> *It is neither reasonable nor necessary, in the context of an application for interim rates, that the island industrial customers be faced with the invidious choice of either acquiescing to a de facto final allocation of the current segregated load variation balance, in accordance with Hydro's proposed energy ratio approach, prior to a GRA where they reasonably expected a full and fair opportunity to make submissions on this issue, on the one hand, or should they not so acquiesce, be subjected to higher-than-warranted interim rates effective March 1, 2015.*[13]

The Industrial Customer Group expresses significant concerns in relation to a rate increase of more than 2.7% on March 1, 2015 and argues that, given the substantial RSP surplus balances available, the rate impact should be limited to no more than 2.7%. Further the Industrial

[13] Industrial Customer Group Submission, February 23, 2015, page 2

Customer Group reserves the right to make submissions in the general rate application regarding the proposed January 1, 2016 and September 1, 2016 rate increases.

In reference to the Consumer Advocate's submission that the proposed phase-in is not in accordance with Government direction, the Industrial Customer Group argues that it is not a reasonable interpretation of the Government direction that the rate phase-in must occur on September 1 each year. Further the Industrial Customer Group notes that some of the issues raised by the Consumer Advocate are addressed or determined by the Government directions.

Vale accepts that Hydro requires interim rate relief subject to Hydro demonstrating that the interim rates reasonably reflect the cost of service. Vale submits that Hydro should be granted interim rates to reduce the potential for intergenerational inequity. Vale argues that, because the makeup of the Island Industrial customers is changing radically over time, future recovery of current deficiencies will result in intergenerational inequity. Vale argues that fairness dictates that an order for interim rates should become effective at the earliest possible date. Vale supports Hydro's proposed method of calculating interim rates by adjusting the forecast cost of No. 6 fuel to $65.63 per barrel which, according to Vale, has the benefit of reducing the potential for rate shock and ensures that interim rates are based on the most up-to-date information in relation to fuel costs. Vale supports Hydro's proposed method for recovery of the IC RSP current plan year-end balance of $6.8 million because it reduces or eliminates the potential for intergenerational inequity created by the use of future rate riders to recover past balances. In relation to the rate phase-in proposal set out by Hydro, Vale prefers the alternate proposal as it reduces the number of rate changes. Vale argues that the difference between 10.2% and 12.7% is marginal and is offset by the increased rate stability, which is preferable for budgeting purpose.

The Towns submit that the application for interim relief should be dismissed. The Towns argue that Hydro has failed to demonstrate any basis for applying for interim rate relief at this time. The Towns further argue that the Board has no basis to grant any interim rate increase because there is no evidence provided of exigent circumstances to ground an application for interim relief or for any rate increase. The Towns explain that in 2009 Hydro commenced a project to upgrade its distribution system in western Labrador. This project was originally scheduled for completion in 2013 but is now not scheduled for completion until 2015. In addition the Towns explain that this upgrade has jeopardized the emergency back-up power line to Labrador West and that Hydro failed to inform Labrador West customers that the back-up system was no longer available. The Towns argue that it is inappropriate to grant Hydro's interim application to increase rates to its customers on the Labrador Interconnected system. The Towns argue that these matters should be addressed in Hydro's general rate application and that there should be no increase in rates charged to customers on the Labrador Interconnected system without a hearing.

In reply Hydro submits that the Interim Rate Application provides a reasonable balance of the interests of both the utility and customers and that the two-part test established by the Alberta Utilities Commission for consideration of interim rate adjustments is met in the circumstances. Hydro submits that it has shown that its 2015 net income deficiency is probable and material. Hydro argues that approval of the Interim Rate Application effective March 1, 2015 will provide recovery of approximately 70% of the forecast net income deficiency and further that if it is determined upon final testing in the general rate application that Hydro has received excess

revenue the Board has considerable flexibility to dispose of it in a variety of ways. Hydro further argues that approval of the Interim Rate Application will add rate stability for 2015, enable the phase-in of Island Industrial customer rates with materially lower customer impacts, and help to mitigate intergenerational equity concerns.

Hydro disagrees with Newfoundland Power that the proposed interim rates are not consistent with the reasonableness requirement of the *EPCA*. Hydro states that when final costs are approved the Board can remedy any discrepancy between the rate of return allowed in the interim rate and the final decision so as to achieve just and reasonable rates throughout the period. Hydro submits that the evidence shows that: i) Hydro has not had a base rate increase since 2007; ii) Hydro's net income in 2013 was $209,000; iii) Hydro, at the end of the third quarter 2014, forecast a net loss of approximately $27 million for 2014; iv) Hydro is forecasting a net loss of $68 million for 2015; and v) if the Interim Rate Application is approved effective April 1, 2015 Hydro forecasts a net income of $5.2 million for 2015. Hydro states that it has provided a complete filing of evidence and has responded to in excess of 1,400 requests for information and this constitutes strong prima facie evidence of a revenue shortfall.

Hydro submits that approval of interim rates based on untested costs and a forecast loss is consistent with regulatory practice. Hydro states:

> *As is discussed at greater length below, there is nothing in the Public Utilities Act or in the decision of other Canadian utility regulators that suggests that an application for an interim order ought to be denied on the basis that the evidence upon which it is grounded has not been tested. Moreover, there is nothing in section 75 of the Public Utilities Act to support the Board's characterization of interim rates as being an extraordinary measure and the regulatory and judicial jurisprudence make it clear that interim orders are part of the normal and common remedial measures to address circumstances such as those which Hydro finds itself in at present.*[14]

Hydro submits that the existing rates are based on 2007 tested forecast costs and are demonstrably not reasonable at this time. In relation to the inclusion of contentious costs Hydro notes that the Board has the authority to grant interim rates and to later provide a refund to customers. Hydro states:

> *Hydro submits that, as stated above in section 3.2 of this submission, if upon final testing of Hydro's costs in the GRA the Board determines that Hydro has received more revenues than it requires, subsection 75(3) of the Public Utilities Act provides considerable flexibility to the Board to dispose of any excess revenue earned by Hydro as a result of an interim order, that is not confirmed in the final order, in a variety of ways.*[15]

In relation to the RSP load variation proposals Hydro submits that the disposition of the 2014 year-end load variation balance using the energy ratio allocation approach set out in the Amended General Rate Application reduces customer rate impacts and supports the principle of intergenerational equity in the phase-in of Island Industrial customer rates.

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[14] Hydro Submission, page 12

[15] Hydro Submission, page 29

In relation to the suspension of the July 1, 2015 NP RSP adjustment Hydro states that the implementation of revised retail rates on March 1, 2015 which reflect both the disposition of the balance in the RSP segregated load variation component and the updated fuel forecast avoids the necessity for a July 1, 2015 rate change. Hydro states that it sees no additional benefit in providing a further fuel cost update effective July 1, 2015. Hydro further states in its submission that it is proposing that there be no NP RSP rate adjustment for 2015 to avoid any implications on Newfoundland Power's customers of the interim changes to the RSP rules.

Hydro submits that intergenerational equity is material to Newfoundland Power customers and explains that, if interim rates are not implemented and final rates take effect December 1, 2015, Hydro's net income deficiency would be approximately $61.0 million which, combined with the 2014 deferrals, represents a potential of $116.5 million to be recovered from future customers. Hydro states:

> *The magnitude of these deferred costs is the main driver for Hydro's intergenerational equity concerns for all customers, particularly those of NP. Keeping 2007 base rates in effect for the majority of 2015 will effectively require 2016 customers (and beyond) to subsidize the service provided to 2015 customers, as the rates charge in 2015 will not reflect the costs associated (sic) the service provided in that period.*[16]

With respect to Island Industrial customer interim rates Hydro states that it considers either of the two Island Industrial customer rate phase-in alternatives acceptable. Hydro disagrees with the submission of the Consumer Advocate that Hydro's alternatives are not in compliance with Government direction, arguing that the proposed approach starts and concludes within the three-year period specified by Government direction. In relation to the proposed increase in the specifically assigned charge for Corner Brook Pulp and Paper, Hydro states that it has invested significant funds in the plant dedicated to serve this customer since 2001. Hydro argues that the level of increase arising from this component of this customer's rate should not be singled out for differential treatment for purposes of the proposed interim order. Hydro disagrees with the Consumer Advocate in relation to the disposition of $2.1 million of the RSP segregated load variation balance to the Island Industrial customers on the basis that it reduces customer rate impacts and supports the principle of intergenerational equity. Hydro agrees with Vale's views on intergenerational equity and states that the composition of the Island Industrial customer class is changing radically with Vale ramping up production, which will make it Hydro's largest Island Industrial customer, and Teck Resources anticipating closing operations in 2015.

With respect to the submission of the Towns, Hydro notes that the Towns did not previously object to the Interim Rate Application. Hydro suggests that it would be more efficient and appropriate to respond to the reliability concerns raised by the Towns at another stage of the Amended General Rate Application or another proceeding. Hydro submits that the Interim Rate Application and its submission provide ample support which establish that the presence of exigent circumstances is not a prerequisite for the issuance of an interim rates order. Hydro states:

[16] Hydro Submission, page 34

> *The Board's discretion to order interim rates is properly triggered where doing so provides a utility with sufficient and reasonable revenues in circumstances where denying them would not accord with generally accepted sound utility practice.*[17]

Hydro suggests that the requirement for interim rates may arise from delays in regulatory proceedings and that requiring that a utility demonstrate exigent circumstances before interim rates are awarded is unduly onerous.

Board Findings

Pursuant to section 75 of the *Act* the Board may make an interim order unilaterally and without public hearing or notice approving with or without modification a schedule of rates, tolls and charges submitted by a utility. In exercising its discretion in relation to an interim rate application the Board balances the interests of the utility and consumers, considering the provisions of the *EPCA* which set out that rates should be reasonable and not unjustly discriminatory and should enable a utility to earn a just and reasonable return so that it is able to achieve and maintain a sound credit rating. The Board is directed to apply tests which are consistent with generally accepted sound public utility practice, which would include consideration of principles such as fair return, rate stability, rate shock, predictability, certainty, fair cost apportionment, appropriate price signals and intergenerational equity. It is notable that rate making is generally prospective and a utility has no guarantee that it will earn the approved rate of return but must manage its business effectively to do so.

There is no issue in this proceeding as to whether the Board has the jurisdiction to order interim rates. The issue for the Board is whether it should exercise its discretion to do so in the circumstances. The Alberta Utilities Commission has recently issued several decisions setting out some of the factors which it considers in assessing an interim rate application. The Board believes that, fundamentally, the assessment of an application for an interim rate increase requires that the interests of the utility in relation to its opportunity to earn a fair return must be balanced with the interests of consumers. The Board can consider alternatives to the proposed rate increase which may, in the circumstances better balance the competing interests. In the Board's view, where there has not been an opportunity for a full review of proposed rate increases, only those proposals which are demonstrated to be necessary and appropriate to provide interim relief should be approved.

Interim Rate Application Proposals

The Interim Rate Application requests interim implementation of most of the Amended General Rate Application proposals.[18] Approval of the Interim Rate Application would result in significant base rate increases for most consumers as well as significant changes to Hydro's cost of service methodology and the operation of the RSP. In many cases the proposed changes are complex and may have unique impacts on particular customer groups which may be difficult to appreciate fully at this stage of the proceeding. For example, the Interim Rate Application proposes changes to the allocation of the Rural Deficit which would tend to decrease the rates for Labrador Interconnected customers and increase the rates for Newfoundland Power customers.

[17] Hydro's Second Submission, page 2

[18] TIR-PUB-NLH-001

In addition, the Interim Rate Application proposes the disposition of the segregated RSP load variation balance based on the proposed energy ratio allocation. Further there are other cost of service issues which have not been fully assessed at this stage such as the Holyrood capacity factor, treatment of wind capacity and the capacity assistance agreements. The implications of the extensive changes proposed in the Interim Rate Application, especially the cost of service and RSP changes, are not clear at this stage of the general rate application proceeding.

In addition the Board notes that the forecast fuel price reflected in the proposed rates in the Interim Rate Application is substantially lower than the price reflected in the Amended General Rate Application, the price reflected in answers to requests for information, and the price in the NP RSP Fuel Price Projection filed on April 21, 2015.[19] The Board does not believe that Hydro has demonstrated that it is appropriate in the circumstances to suspend the July 1, 2015 NP RSP adjustment and continue the existing RSP recovery adjustment, given the volatility in the forecast price of fuel and the balance in the current plan.[20] Further, the Board notes that the forecast fuel cost reflects a revised Holyrood fuel conversion factor which is contentious.[21]

The Board has significant concerns in relation to the interim implementation of the extensive changes proposed in the Interim Rate Application. Hydro has not demonstrated that it is necessary or appropriate to reflect these proposals in interim rates established in advance of the conclusion of the general rate application. The Board will not approve the Interim Rate Application as proposed but instead will consider whether Hydro has demonstrated that base rates should be increased to provide interim revenue relief in advance of the conclusion of the general rate application.

Interim Revenue Relief

The Interim Rate Application states that under existing rates Hydro's forecast income statement shows a net loss of $34.6 million for 2015 with a forecast return on rate base of 3.33%, which is below the bottom of the approved range of rate of return on rate base of 7.29% established in the 2007 general rate application.[22] Hydro explains that it has not had a base rate increase since 2007, that its net income in 2013 was $209,000, and that there was a forecast revenue shortfall in 2014. Further Hydro states that, if only 50% of the proposed base rate increases are approved effective July 1, 2015, it forecasts a loss in 2015.[23] The Board is satisfied based on the evidence that Hydro has demonstrated a probable and material revenue shortfall for 2015 based on existing rates. In relation to whether this revenue shortfall will impact Hydro's financial integrity Hydro explains:

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[19] The fuel price in TIR-PUB-NLH-012 is $76.05/bbl, in TIR-PUB-NLH-016 it is $71.05/bbl, and in the April 21, 2015 letter from Hydro to the Board it is $73.35/bbl.

[20] TIR-PUB-NLH-018, Attachment 1 shows that the forecast recovery adjustment on July 1, 2015 is (0.749)¢ per kWh and the April 21, 2015 RSP adjustment report to the Board shows the recovery adjustment on July 1, 2015 would be (0.715)¢ per kWh.

[21] Newfoundland Power Submission, page 3 challenged the proposed fuel conversion factor of 607 kWh/bbl which is significantly reduced from the current factor of 630 kWh/bbl.

[22] Interim Rate Application, Evidence, page 1. It is noted that this is based on evidence filed in the Amended General Rate Application.

[23] TIR-PUB-NLH-019

> *The impact of a continued denial of the Board to permit cost recovery on Hydro's creditworthiness needs to be considered over the longer-term. Because the Province has unconditionally guaranteed Hydro's existing long-term debt, there is a direct linkage between Hydro's creditworthiness, which is influenced by Hydro's ability to achieve financial targets consistent with an investment-grade utility, and the credit rating of the Province. To the extent that credit rating agencies continue to view Hydro to be self-supporting, then the Province's credit rating is not likely to be affected. A poor financial position for Hydro over the long-term could adversely impact the Province's credit rating and thereby, increase the borrowing costs of the Province, and hence Hydro's own borrowing costs.*[24]

The Board notes that this explanation does not speak directly to Hydro's financial integrity and further that it relates to long-term considerations rather than the issues associated with the Interim Rate Application. In addition the Board notes that Hydro has stated that interim relief is not necessary for the continued safe operations of the utility.[25]

The Board finds that the evidence demonstrates deterioration of Hydro's financial position since the 2007 Test Year, and particularly since the filing of the latest general rate application in 2013. In addition the Board notes that Hydro has filed three applications for interim relief in the general rate application proceeding, the first of which was filed in November of 2013 for 2014. The Board accepts Hydro's submission that that there has been significant exchange of information in relation to Hydro's general rate application, with over 1400 requests for information filed and answered. While concerns were raised with respect to various discreet aspects of the Interim Rate Application, the parties, with the exception of the Towns, do not oppose reasonable interim rates. Vale states that it accepts that Hydro requires interim relief. Newfoundland Power states that it does not oppose interim rates for Hydro in principle. The Consumer Advocate goes so far as to say that he does not see how consumers can benefit from Hydro's continuing financial deterioration. The Board finds that based on existing rates Hydro will suffer a material loss in 2015 and given that the general rate application hearing is now scheduled for the fall of 2015 it is likely that an order will not be issued before very late in the year. In the circumstances the Board accepts that Hydro requires interim revenue relief in advance of the conclusion of the general rate application proceeding.

Quantum of Rate Increase

The Board agrees with the Consumer Advocate that a key consideration in an interim rates application is the impact of the proposed rate increase on electricity consumers. The Board also agrees with Hydro that the reasonableness of the end result should be considered in the evaluation of the Interim Rate Application.[26] The Board notes that approval of the Interim Rate Application would result in significant base rate increases for most consumers. The Board also notes that the implementation of the interim rates after January 1, 2015 results in partial recovery of Hydro's forecast 2015 net income deficiency. Hydro explains that there is a revenue requirement shortfall of approximately $20 million associated with the Interim Rate Application proposals.[27] Further, Hydro explains that if an increase in base rates of 50% of the proposed

[24] TIR-CA-NLH-001, page 6
[25] TIR-CA-NLH-001, page 7
[26] TIR-IC-NLH-006
[27] Interim Rate Application, Evidence, page 17

increase is approved, effective July 1, 2015, assuming the existing cost of service methodology, it forecasts a 2015 loss of $18.8 million with a rate of return of 3.93%.[28] The Board will consider the rate proposals for each customer class balancing the interests of the utility and consumers so that the rates, to the extent practical in the circumstances, allow the utility the opportunity to earn a fair return and ease rate shock and contribute to rate stability and intergenerational equity.

The Interim Rate Application proposes a base rate increase to Newfoundland Power of 11.2% as well as changes to the NP RSP which would result in an approximate average decrease of 6.3% to Newfoundland Power customers, Hydro Rural customers and Non-Government Diesel customers.[29] The Board notes Newfoundland Power's position that the proposed rates are not reasonable and that certain expenses included in the proposed revenue requirement are contentious. In particular Newfoundland Power takes issue with costs associated with the Board's Investigation and Hearing into Supply Issues and Power Outages on the Island Interconnected System, the proposed reduced Holyrood fuel conversion factor, and the proposed increase in Hydro's rate of return. In total, Newfoundland Power raises concerns in relation to $43.4 million of expenses included in the 2015 Revenue Requirement.[30] The Board notes that approximately 3.3% of the proposed 11.2% increase in Newfoundland Power's base rates flows from the updated forecast fuel cost.[31] Hydro estimates that, if the Board does not approve the Interim Rate Application and instead approves a base rate increase to Newfoundland Power of 8%, with no other changes so that the July 1, 2015 NP RSP adjustment operates normally, rates for Newfoundland Power customers would decrease on average by 5.9% on July 1, 2015.[32] The Board acknowledges that Hydro estimates a forecast 2015 net loss if only half of the proposed base rate increases are approved effective July 1, 2015 but notes that the Interim Rate Application proposals also resulted in a forecast revenue deficiency.[33] The Interim Rate Application notes that Hydro proposes in the Amended General Rate Application that the 2015 loss would be recovered through a rate rider when final rates are implemented. The Board will address this proposal in the general rate application proceeding. The Board is satisfied that approval on an interim basis of an 8.0% base rate increase for Newfoundland Power is a reasonable balance of the interests of the utility and customers in the circumstances.

The Interim Rate Application proposes that the rate increase for customers on the Labrador Interconnected system set out in the Amended General Rate Application of 2.1% be approved on an interim basis. The proposed increase does not reflect the revised forecast fuel cost set out in the Interim Rate Application, which would result in an increase to customers on the Labrador Interconnected system of 3.4%.[34] Hydro submits that, upon the Board's final determination of revenue requirement, any net income deficiency from customers on the Labrador Interconnected system may be recovered through future rates. The Board notes that some of the costs reflected

[28] TIR-PUB-NLH-019

[29] Interim Rate Application, page 3

[30] TIR-NP-NLH-003, TIR-NP-NLH-007 and PUB-NLH-056, Revision 1, from the general rate application

[31] TIR-PUB-NLH-007

[32] TIR-PUB-NLH-018. It is noted that the updated RSP Fuel Price Projection filed with the Board on April 21, 2015 suggests a somewhat lower decrease in the overall average rates for Newfoundland Power customers

[33] TIR-PUB-NLH-019

[34] TIR-PUB-NLH-010

in the proposed rate increase are contentious. Further the Board notes that the increased revenue associated with the proposed rate increase is not material in relation to Hydro's forecast revenue shortfall.[35] The Board accepts the position of the Towns that there should be no increase to the rates charged to customers on the Labrador Interconnected system without a hearing into the matters raised in the submission. The Board finds that it is not necessary or appropriate to approve the Interim Rate Application proposals in relation to the Labrador Interconnected system.

The Interim Rate Application also proposes significant rate increases for Government Diesel customers ranging from 14% to 27.5%. These rate increases are based on 100% recovery of the allocated 2015 Test Year costs. No party commented on these increases. The Board has concerns in relation to approving such large rate increases in advance of the conclusion of the general rate application proceeding. At the same time the Board is concerned about the impact of potentially larger increases for these customers at the end of the general rate application proceeding. The Board also acknowledges the impact on Hydro of delayed approval of rates which reflect cost recovery for these customers. Therefore Board will approve 50% of the proposed interim rate increases for these customers on the basis of rate stability and to reduce the potential for rate shock following the general rate application.

The Interim Rate Application proposes a base rate increase of 18.1% for Island Industrial customers with a phase-in of this increase in three stages: 2.7% on March 1, 2015, 4.4% on January 1, 2016 and 10.2% on September, 2016. The Board notes that the affected customers do not oppose an interim base rate increase but the Industrial Customer Group expresses significant concerns in relation to an effective rate increase of more than 2.7% and Vale supports a larger initial increase. The Board also notes the Consumer Advocate's position that the Island Industrial customer rate proposals are not consistent with the direction of Government. The Board believes that it is not necessary or appropriate to address how the phase-in of the Island Industrial customer rates is to be completed in advance of the general rate application, especially given the differing views expressed by the parties. The Board will therefore only address the increases proposed for 2015. Further, the Board agrees with the Industrial Customer Group that changes to the specifically assigned charges for the Island Industrial customers should not be addressed in advance of the general rate application. The Board notes that, based on the evidence, if there is a 10% increase in the base rate to Island Industrial customers, the amount in the IC RSP Surplus is adequate to fund an effective 2.7% rate increase as well as the 2014 year-end IC RSP current balance. The Board will approve an interim base rate increase for Island Industrial customers, effective July 1, 2015 of 10% and the necessary drawdown from the IC RSP Surplus to fund an effective interim rate increase of 2.7% for all Island Industrial customers, including Teck. The Board will also approve the necessary drawdown from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

Conclusions

The Board will not approve the Interim Rate Application as the Board is not satisfied that it is necessary or appropriate to approve the extensive proposals on an interim basis in advance of the conclusion of the general rate application. Specifically, the Board will not approve the proposals to reflect an updated forecast cost of fuel in base rates and to suspend the July 1, 2015 NP RSP

[35] Amended General Rate Application, Volume 1, Section 4, page 4.50

adjustment. In relation to the Island Industrial customers the proposed specifically assigned charges and the 2016 phase-in of base rate increases will not be approved and the provision relating to the January 1 IC RSP adjustment will not be removed. Further the Board will not approve the proposed changes to the cost of service including the proposed allocation of the RSP segregated load variation and the disposition of $2.1 million to the IC RSP and $33 million to the NP RSP. In addition the changes to the Rural Deficit allocation and the proposed increases for Labrador Interconnected system customers will not be approved at this time.

The Board does accept that Hydro requires interim revenue relief and considering Hydro's financial need and the impact on customers the Board will approve, effective July 1, 2015:

i) An interim increase of 8.0% in the base rate for Newfoundland Power;
ii) An interim increase of 50% of the proposed increase in the rates for Government Diesel customers;
iii) An interim increase of 10.0% in the base rate for Island Industrial customers;
iv) Changes to the RSP rules to allow a transfer from the IC RSP Surplus and to implement an IC RSP rate so that there is an effective interim increase of 2.7% in Island Industrial customer rates, including Teck; and
v) Changes to the RSP rules to allow a transfer from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

Hydro will be required to re-file a proposed Schedule of Rates, Tolls and Charges and RSP rules reflecting the findings of the Board in this decision and Order. The re-filing should include updated evidence detailing the impact on customer rates, Hydro's forecast 2015 revenue requirement, revenue, and rate of return, including an updated Table 5 from the evidence with additional columns showing the overall rate impacts for all customers effective July 1, 2015 and the impacts on rates including the effect of the Northern Strategic Plan.

Costs

Both the Industrial Customer Group and Vale requested an Order for costs. The Board finds that both of these intervenors have a genuine interest in the outcome of the Interim Rate Application and further that both participated in an efficient and meaningful manner and contributed to the Board's understanding of the issues. Therefore the Board will make an award of costs to the Industrial Customer Group and Vale. These Intervenors should file a detailed claim for the consideration of the Board within 30 days.

No other intervenors made a claim for costs. The Board will grant leave to any other intervenor to this Application to apply for an award of costs setting out a detailed claim for costs within 30 days of the Order.

IT IS THEREFORE ORDERED THAT:

1. The Interim Rate Application is denied.

2. Newfoundland and Labrador Hydro shall file a revised Schedule of Rates, Tolls and Charges and RSP Rules, effective July 1, 2015, with evidence showing the impacts on consumers and Hydro, incorporating the findings of the Board in this Order, including:

   i) an interim base rate increase of 8.0% for Newfoundland Power Inc.;

   ii) an interim base rate increase for Government Diesel customers of 50% of the proposed increases; and

   iii) in relation to Island Industrial customers:

      a) an interim base rate increase of 10.0%;
      b) an interim RSP rate adjustment which will result in an effective 2.7% rate increase for all Island Industrial customers;
      c) a transfer from the IC RSP Surplus to fund the difference between the approved 10.0% base rate increase and the effective 2.7% increase; and
      d) a transfer from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

3. The Industrial Customer Group and Vale Newfoundland and Labrador Limited are entitled to an award of costs in an amount to be fixed by the Board upon the filing of a detailed cost submission within 30 days of this Order.

4. Leave is granted to the other intervenors to apply for an award of costs setting out a detailed cost submission within 30 days of this Order.

5. Newfoundland and Labrador Hydro shall pay all the expenses of the Board arising from the Interim Rate Application.

DATED at St. John's, Newfoundland and Labrador, this 8th day of May 2015.

Andy Wells
Chair & Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

Cheryl Blundon
Board Secretary

Schedule 2

AMENDED 2015 COST DEFERRAL APPLICATION

NEWFOUNDLAND AND LABRADOR HYDRO

November 12, 2015

Schedule 2 – A – Revised 2015 Interim Rates Compliance Application

Schedule 2 – B – Evidence to the Revised 2015 Interim Rates Compliance Application

Schedule 2 – C – Written Submissions of the Parties

Schedule 2 – D – Order No. P.U. 17(2015)

newfoundland labrador hydro
a nalcor energy company

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June 5, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – 2015 Interim Rates Application (Revised)

Further to the Board's letter of June 3, 2015, enclosed please find the original plus 12 copies of Hydro's revised compliance application for interim rates complete with supporting evidence, a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015.

The primary differences between the earlier application and the revised application are as follows:

1) The evidence to support the fuel price projection filed with the Board April 21, 2015 has been included as a schedule to the revised application;
2) There is no change proposed for the specifically assigned charges to Island Industrial Customers (IIC) and the firm demand and energy base rates for the IIC are proposed to increase by 10% effective July 1, 2015;
3) The revised application includes a proposal to modify the RSP rules to discontinue the RSP adjustment that applies solely to Teck Resources given the conclusion of the operations of Teck Resources effective June 30, 2015; and
4) The revised application does not include a proposal for a 2015 revenue deficiency deferral account. Hydro will file a separate application to deal with this matter.

As this filing will totally replace the application filed on May 27, 2015, we ask that the Board and the parties disregard the earlier filing.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/cp

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Senwung Luk – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn
Genevieve M. Dawson – Benson Buffett

IN THE MATTER OF the *Public Utilities Act*, R.S.N. 1990, Chapter P-47 (the "Act"); and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2015; and

IN THE MATTER OF a revised application (the "Revised Compliance Application") by Newfoundland and Labrador Hydro for approval of: (i) customer rates, tolls and charges reflecting the determinations set out in Order No. P.U. 14(2015) and (ii) a revised Rate Stabilization Plan adjustment to apply to the Utility Rate for the period July 1st, 2015 to June 30th, 2016.

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

The REVISED COMPLIANCE APPLICATION of Newfoundland and Labrador Hydro (the "Applicant") states that:

1. Newfoundland and Labrador Hydro (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. On January 28, 2015 Hydro filed an application with the Board (the 2015 Interim Rates Application) seeking approval of adjustments to its customer rates to

provide interim rate relief effective March 1, 2015, in advance of conclusion of its General Rate Application (GRA).

3. The 2015 Interim Rates Application also requested approval for rates to be paid by Hydro's Island Industrial Customers (IIC) in compliance with Orders in Council OC2013-089 and OC2013-090, as amended, which provided direction to the Board and to Hydro, respectively, with regard to the phasing-in of rate changes to Hydro's IIC.

4. Order No. P.U. 40(2003) sets out the manner by which the Rate Stabilization Plan (RSP) is to be calculated and applied to the rates charged by Hydro to Newfoundland Power (NP) and to its IIC. Under that Order, Hydro is required to provide a NP fuel price projection to the Board, to NP and to Hydro's IICs by the tenth working day of April of each year.

5. In accordance with Order No. P.U. 40(2003), the RSP is calculated using the assumptions as to fuel consumption that were approved by the Board for Hydro's 2007 Test Year and that were amended in Order No. P.U. 11(2008) and Order No. P.U. 22(2009) to adjust the 2007 Test Year barrels of No. 6 fuel forecast to be consumed at the Holyrood Thermal Generating Station to reflect the substantial reduction in load applicable to the shutdown of one of the paper

machines at Corner Brook Pulp and Paper and the shutdown of Abitibi Consolidated (Grand Falls).

6. The RSP Adjustment factors reflecting the adjusted 2007 Test Year barrels of No. 6 fuel were provided to the Board accompanying the fuel price projection on April 21, 2015.

7. The current Section E of the RSP rules titled "Historical Plan Balances" is no longer necessary for the purpose of calculating RSP adjustments.

8. Order No. 29 (2013) approved the implementation of an RSP rate of (1.111) cents per kWh for Teck Resources Limited to comply with the direction of the Government.

9. Order No. P.U. 14(2015) (the 2015 Interim Rates Order) directed Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on consumers and Hydro incorporating the findings in the 2015 Interim Rates Order.

10. The 2015 Interim Rates Order requires the same interim rate increase apply to Teck Resources as approved for the other IIC. This would require maintaining a separate RSP rate for Teck Resources.

11. The application by Teck Resources filed with the Board on May 27, 2015 states Teck will be discontinuing its mining and milling operations effective June 30, 2015. There is no longer a requirement to maintain a separate RSP adjustment for Teck Resources effective July 1, 2015.

12. On May 27, 2015, Hydro filed an application in response to the Board's findings in the 2015 Interim Rates Order.

13. The Board provided correspondence by letter on June 3, 2015 stating that the 2015 Interim Rate Compliance Application does not comply with the 2015 Interim Rates Order and directed Hydro to amend and re-file the application.

14. Schedule 1 to this Revised Compliance Application provides the proposed (i) Utility Rate, (ii) IIC rates, (iii) Government Diesel rates, (iv) Hydro Rural Labrador Interconnected rates, and (v) revised RSP rules, to become effective July 1, 2015. Schedule 1 is in compliance with the directions of the Board provided in the 2015 Interim Rates Order and the correspondence to Hydro from the Board on June 3, 2015.

15. The rates for customers on the Labrador Interconnected System provided in Schedule 1 reflect no change from those currently approved by the Board.

16. Schedule 2 to this Revised Compliance Application provides the RSP Adjustment factors reflecting the adjusted 2007 Test Year barrels of No. 6 fuel that were provided to the Board accompanying the fuel price projection on April 21, 2015.

17. The revised RSP Rules in Schedule 1 provide for: (i) a transfer from the IIC RSP Surplus to fund the full amount of the 2014 year-end RSP current balance; (ii) the implementation of an IC RSP Surplus Adjustment rate so there is an effective interim increase of 2.7% to IIC on July 1, 2015; (iii) the elimination of the RSP adjustment in effect solely for Teck Resources; and (iv) the removal of the current Section E related to Historical Plan Balances.

18. Schedule 3 to this Revised Compliance Application provides the evidence showing the impacts on customers and Hydro by incorporating the findings of the Board in Order No. P.U. 14(2015).

19. Section 3 to this Revised Compliance Application also provides the evidence to support the calculation of an IIC RSP Surplus Adjustment of (0.349)¢ per kWh to become effective July 1, 2015.

20. An application for revised rates to Hydro Rural Customers whose rates are determined based upon the rates to the customers of NP will be filed

subsequent to NP filing its application for customer rates to become effective July 1, 2015.

21. Hydro submits that this Revised Compliance Application is in accordance with the directives of the Board in Order No. P.U. 14(2015) and correspondence provided to Hydro on June 3, 2015 and proposes the Board approve on an interim basis effective July 1, 2015:

(a) the RSP rate to be charged by Hydro to Newfoundland Power, as calculated in Schedule 2 to this Revised Compliance Application;

(b) the revised base Utility Rate;

(c) the revised base rate and RSP adjustment for Island Industrial Customers;

(d) the revised rates for Government customers on Isolated Diesel Systems;

(e) the removal of the RSP adjustment specifically for Teck Resources; and

(f) the revised RSP rules and the new IIC RSP Surplus Adjustment to provide for the disposition of the IIC RSP Surplus and limit the effective customer rate impact to 2.7%.

DATED AT St. John's in the Province of Newfoundland and Labrador this 5th day of June 2015.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
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IN THE MATTER OF the *Public Utilities Act*, R.S.N. 1990, Chapter P-47 (the "Act"); and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2015; and

IN THE MATTER OF a revised application (the "Revised Compliance Application") by Newfoundland and Labrador Hydro for approval of: (i) customer rates, tolls and charges reflecting the determinations set out in Order No. P.U. 14(2015) and (ii) a revised Rate Stabilization Plan adjustment to apply to the Utility Rate for the period July 1st, 2015 to June 30th, 2016.

AFFIDAVIT

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

1. I am Manager, Rates and Regulation, of Newfoundland and Labrador Hydro, the Applicant named in the attached Revised Compliance Application.

2. I have read and understand the foregoing Revised Compliance 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 5th day of June 2015, before me:

Barrister – Newfoundland and Labrador

Kevin J. Fagan

Schedule 1

Proposed Rates and Rate Stabilization Plan Rules

NEWFOUNDLAND AND LABRADOR HYDRO

June 4, 2015

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM)

Availability:

This rate is applicable to service to Newfoundland Power (NP).

Definitions:

"Billing Demand"

In accordance with Order No. P.U. 47(2014), the Curtailable Credit shall apply to determine the billing demand as an adjustment to the highest Native Load established during the winter period beginning in December 1, 2014 and ending March 31, 2015. The computation of the adjustment to reflect the Curtailable Credit is provided in the definitions below. The use of the Curtailable Credit in determining billing demand for subsequent winter periods will be subject to a further Order of the Board.

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit and the Curtailable Credit, beginning in the previous December and ending in the current Month; and
(b) the Minimum Billing Demand .

In the Months of April through December, billing demand shall be the greater of:

(a) the Weather-Adjusted Native Load less the Generation Credit and the Curtailable Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.

If at the time of establishing its Maximum Native Load, NP has been requested by Hydro to reduce its Native Load by shedding curtailable load, the calculation of Billing Demand for each month shall not deduct the Curtailable Credit.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	80,104
Thermal Generation Credit	37,826
Total Generation Credit	117,930

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM)

a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, Newfoundland Power will be provided an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

"Curtailable Credit" is determined based upon NP's forecast curtailable load available for the period in accordance with the terms and conditions set forth in NP's Curtailable Service Option. NP will notify Hydro of its available curtailable load with its forecast of annual and monthly electricity requirements.

In order to receive the Curtailable Credit, NP must demonstrate the capability to curtail its customer load requirements to the level of the Curtailable Credit. This will be verified in a test by curtailing load at a minimum of this level for a period of one hour. The test will be carried out at a mutually agreed time in December. If the level is not sustained, the Curtailable Credit will be reduced to the level sustained. If Hydro requests NP to curtail load before a test is completed and NP demonstrates the capability to curtail to the level of the Curtailment Credit, no test will be required.

NP will be required to provide a report to Hydro not later than April 15 to demonstrate the amount of load curtailed for each request of Hydro during the previous winter season. If the load curtailed is less than forecast for either request during the winter season, the annual Curtailable Credit will be adjusted to reflect the average load curtailed for the winter season. If NP is not requested to curtail during the winter season, the Curtailment Credit will established based upon the lesser of the load reduction achieved in the test or the forecast curtailable load (as provided in the previous two paragraphs).

"Maximum Native Load" means the maximum Native Load of NP in the four-Month period beginning in December of the preceding year and ending in March of the current year.

"Minimum Billing Demand" means ninety-nine percent (99%) of:

NP's test year Native Load less the Generation Credit and the Curtailable Credit.

The Curtailable Credit reflected in the Minimum Billing Demand will be set to equal the curtailable load used to determine the Maximum Native Load for NP for the most recently approved Test Year.

"Month" means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

"Native Load" is the sum of:

(a) the amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter;
(b) the total generation by NP averaged over the same fifteen-minute periods.

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load
plus (Weather Adjustment, rounded to 3 decimal places, x 1000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

(a) the greater of:
- the Weather Adjusted Native Load less the Generation Credit and the Curtailable Credit (if applicable), times three; and
- the Minimum Billing Demand, times three; and

(b) the sum of the actual billed demands in the Months of January, February and March of the current year.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Monthly Rates:

Billing Demand Charge:
Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

$4.32 per kW of billing demand

Energy Charge:
First 250,000,000 kilowatt-hours* ..... @ 3.506 ¢ per kWh
All excess kilowatt-hours* ..... @ 9.509 ¢ per kWh

Firming-up Charge:
Secondary energy supplied by
Corner Brook Pulp and Paper Limited* ..... @ 0.908 ¢ per kWh

RSP Adjustment:
Current Plan ..... @ (0.715) ¢ per kWh
Fuel Rider ..... @ 0.532 ¢ per kWh

Total RSP Adjustment – All kilowatt-hours ..... @ (0.183) ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses:

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering, shall be applied to the metered demand.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Weather Adjustment: This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

(a) Weather adjustment shall be undertaken for use in determining NP's Billing Demand.

(b) Weather adjustment shall be derived from Hydro's NP native peak demand model.

(c) By September 30th of each year, Hydro shall provide NP with updated weather adjustment coefficient incorporating the latest year of actuals.

(d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to weather station data for the St. John's, Gander, and Stephenville airports reported by Environment Canada. NP's regional energy sales shall be used to weight regional weather data. Hydro shall consult with NP to resolve any circumstances arising from the availability of, or revisions to, weather data from Environment Canada and/or wind chill formulation.

(e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding seven hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition on underlying weather data.

(f) Subject to the availability of weather data from Environment Canada, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of Weather-Adjusted Native Load by April 5th of each year.

General:

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach mutual agreement, the billing will be based on Hydro's best estimate.

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (continued) - INTERIM

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Demand Charge:

The rate for Firm Power, as defined and set out in the Industrial Service Agreements, shall be $7.35 per month per kilowatt of billing demand.

Firm Energy Charge:

Base Rate* ..... @ 4.044 ¢ per kWh

RSP Adjustment:

Current Plan ..... @ 0.000 ¢ per kWh
Fuel Rider ..... @ 0.000 ¢ per kWh
RSP Surplus Adjustment..... @ (0.349) ¢ per kWh

Total RSP Adjustment – All kilowatt-hours .....@ (0.349) ¢ per kWh

Net Energy Rate ..... @ 3.695 ¢ per kWh

Specifically Assigned Charges:

The table below contains the additional annual specifically assigned charges for customer plant in service that is specifically assigned to the Customer.

	Annual Amount
Corner Brook Pulp and Paper Limited	$ 347,167
North Atlantic Refining Limited	$ 150,976
Teck Resources Limited	$ 186,169

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (continued) - INTERIM

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - FIRM (continued) - INTERIM

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy.

Rate:

Non-Firm Energy Charge (¢ per kWh):

Non-Firm Energy is deemed to be supplied from thermal sources. The following formula shall apply to calculate the Non-Firm Energy rate:

$$\{(A \div B) \times (1 + C) \times (1 \div (1 - D))\} \times 100$$

A = the monthly average cost of fuel per barrel for the energy source in the current month or, in the month the source was last used

B = the conversion factor for the source used (kWh/bbl)

C = the administrative and variable operating and maintenance charge (10%)

D = the average system losses on the Island Interconnected grid for the last five years ending in 2005 (2.68%).

The energy sources and associated conversion factors are:

1. Holyrood, using No. 6 fuel with a conversion factor of 630 kWh/bbl
2. Gas turbines using No. 2 fuel with a conversion factor of 475 kWh/bbl
3. Diesels using No. 2 fuel with a conversion factor of 556 kWh/bbl.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year shall be applied.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

INDUSTRIAL - WHEELING - INTERIM

Availability:

Any person purchasing power, other than a retailer, supplied from the Interconnected Island bulk transmission grid at voltages of 66 kV or greater on the primary side of any transformation equipment directly supplying the person and who has entered into a contract with Hydro for the purchase of firm power and energy and whose Industrial Service Agreement so provides.

Rate:

Energy Charge:

All kWh (Net of losses)* ..... @ 0.384 ¢ per kWh

* For the purpose of this Rate, losses shall be 2.68%, the average system losses on the Island Interconnected Grid for the last five years ending in 2005.

General:

Details regarding the conditions of Service are outlined in the Industrial Service Agreements. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM)

The Rate Stabilization Plan of Newfoundland and Labrador Hydro (Hydro) is established for Hydro's Utility customer, Newfoundland Power, and Island Industrial customers to smooth rate impacts for variations 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 formulae used to calculate the Plan's activity are outlined below. Positive values denote amounts owing from customers to Hydro whereas negative values denote amounts owing from Hydro to customers.

Section A: Hydraulic Production Variation

1. **Activity:**
   Actual monthly production is compared with the Test Year Cost of Service Study in accordance with the following formula:

   $$\{(A - B) \div C\} \times D$$

   Where:

   A = Test Year Cost of Service Net Hydraulic Production (kWh)
   B = Actual Net Hydraulic Production (kWh)
   C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
   D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)

2. **Financing:**
   Each month, financing charges, using Hydro's approved Test Year weighted average cost of capital, will be calculated on the balance.

3. **Hydraulic Variation Customer Assignment:**
   Customer assignment of hydraulic variations will be performed annually as follows:

   $$(E \times 25\%) + F$$

   Where:

   E = Hydraulic Variation Account Balance as of December 31, excluding financing charges
   F = Financing charges accumulated to December 31

   The total amount of the Hydraulic Customer Assignment shall be removed from the Hydraulic Variation Account.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

4. Customer Allocation:

The annual customer assignment will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The portion of the hydraulic customer assignment which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The Newfoundland Power and Island Industrial customer allocations shall be included with the Newfoundland Power and Island Industrial RSP balances respectively as of December 31 each year. The Labrador Interconnected Hydraulic customer allocation shall be written off to Hydro's net income (loss).

Section B: Fuel Cost Variation, Load Variation and Rural Rate Alteration

1. Activity

1.1 Fuel Cost Variations

This is based on the consumption of No. 6 Fuel at the Holyrood Generating Station:

$$(G - D) \times H$$

Where:

D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
G = Monthly Actual Average No. 6 Fuel Cost ($Can /bbl.)
H = Monthly Actual Quantity of No. 6 Fuel consumed less No. 6 fuel consumed for non-firm sales (bbl.)

1.2 Load Variations

Firm: Firm load variation is comprised of fuel and revenue components. The load variation is determined by calculating the difference between actual monthly sales and the Test Year Cost of service Study sales, and the resulting variance in No. 6 fuel costs and sales revenues. It is calculated separately for Newfoundland Power firm sales and Industrial firm sales, in accordance with the following formula:

$$(I - J) \times \{(D \div C) - K\}$$

Where:

C = Test Year Cost of Service Holyrood Net Conversion Factor (kWh /bbl.)
D = Monthly Test Year Cost of Service No. 6 Fuel Cost ($Can /bbl.)
I = Actual Sales, by customer class (kWh)
J = Test Year Cost of Service Sales, by customer class (kWh)
K = Firm energy rate, by customer class

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Secondary: Secondary load variation is based on the revenue variation for Utility Firmed-Up Secondary energy sales compared with the Test Year Cost of Service Study, in accordance with the following formula:

$$(J - I) \times L$$

Where:

I = Actual Sales (kWh)
J = Test Year Cost of Service Sales (kWh)
L = Secondary Energy Firming Up Charge

1.3 Rural Rate Alteration

(a) Newfoundland Power Rate Change Impacts:
This component is calculated for Hydro's rural customers whose rates are directly or indirectly impacted by Newfoundland Power's rate changes, with the following formula:

$$(M - N) \times O$$

Where:

M = Cost of Service rate [1]
N = Existing rate
O = Actual Units (kWh, bills, billing demand)

(b) Rural Labrador Interconnected Automatic Rate Adjustments:
This component reflects the impact of the automatic rate adjustments for Hydro's rural customers on the Labrador Interconnected system, which arise from the phase-in of the application of the credit from secondary energy sales to CFB Goose Bay to the rural deficit.

Monthly adjustments will be subject to revision when a new Test Year Cost of Service is approved by the Public Utilities Board for Hydro. The amount of the automatic rate adjustment is ($98,295.)

2. Monthly Customer Allocation: Load and Fuel Activity

Each month, the load variation will be held in a separate account in the Plan, until its disposition is ordered by the Board of Commissioners of Public Utilities.

1

- Hydro's schedule of rates for its rural customers not affected by the December 6th, 2006 Government directive.
- For customers affected by the December 6th, 2006 Government directive, the Cost of Service rate equals the phased-in 2007 Forecast Cost of Service Rates for diesel rate classes 1.2D, 2.1D and 2.2D.
- No Rural Rate Alternation will arise from the phase-in of 2007 Forecast Cost of Service rates for the customers affected by the December 6th, 2006 Government directive.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Each month, the year-to-date total for fuel price variation will be allocated among the Island Interconnected customer groups of (1) Newfoundland Power; (2) Island Industrial Firm; and (3) Rural Island Interconnected. The allocation will be based on percentages derived from 12 months-to-date kWh for: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The year-to-date portion of the fuel price variation which is initially allocated to Rural Island Interconnected will be re-allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study.

The current month's activity for Newfoundland Power, Island Industrials and regulated Labrador Interconnected customers will be calculated by subtracting year-to-date activity for the prior month from year-to-date activity for the current month. The current month's activity allocated to regulated Labrador Interconnected customers will be removed from the Plan and written off to Hydro's net income (loss).

3. Monthly Customer Allocation: Rural Rate Alteration Activity

Each month, the rural rate alteration will be allocated between Newfoundland Power and regulated Labrador Interconnected customers in the same proportion which the Rural Deficit was allocated in the approved Test Year Cost of Service Study. The portion allocated to regulated Labrador Interconnected will be removed from the Plan and written off to Hydro's net income (loss).

4. Plan Balances

Separate plan balances for Newfoundland Power, the Island Industrial customer class and the segregated load variation will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

Section C: Fuel Price Projection

A fuel price projection will be calculated to anticipate forecast fuel price changes and to determine fuel riders for the rate adjustments. For industrial customers, this will occur in October each year, for inclusion with the RSP adjustment effective January 1. For Newfoundland Power, this will occur in April each year, for inclusion with the RSP adjustment effective July 1.

1. Industrial Fuel Price Projection:

In October each year, a fuel price projection for the following January to December shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(S - T) \times U\} - V] \times W$$

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

Where:

S = the September month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for the following January to December
T = Hydro's average Test Year contract discount (US $/bbl)
U = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of September
V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)
W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year.

The industrial customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of September and is the ratio of Industrial Firm invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy.

The amount of the forecast fuel price change, in Canadian dollars, and the details of an estimate of the fuel rider based on 12 months-to-date kWh sales to the end of September will be reported to industrial customers, Newfoundland Power, and the Public Utilities Board, by the 10th working day of October.

2. Newfoundland Power Fuel Price Projection:

In April each year, a fuel price projection for the following July to June shall be made to estimate a change from Test Year No. 6 Fuel Cost. Hydro's projection shall be based on the change from the average Test Year No. 6 fuel purchase price, in Canadian dollars per barrel, determined from the forecast oil prices provided by the PIRA Energy Group, and the current US exchange rate. The calculation for the projection is:

$$[\{(X - T) \times Y\} - V] \times W$$

Where:

T = Hydro's average Test Year contract discount (US $/bbl)
V = average Test Year Cost of Service purchase price for No. 6 Fuel ($Can /bbl.)
W = the number of barrels of No. 6 fuel forecast to be consumed at the Holyrood Generating Station for the Test Year. For the 2007 Test Year, test year barrels are reduced by 589,208 based on the reduction in forecast Island Industrial customer load caused by the shutdown of one of the paper machines at Corner Brook Pulp and Paper and the shutdown of Abitibi Consolidated (Grand Falls).
X = the average of the March month-end PIRA Energy Group average monthly forecast for No. 6 fuel prices at New York Harbour for July to December of the current year and for the January to June period of the subsequent year.
Y = the monthly average of the $Cdn / $US Bank of Canada Noon Exchange Rate for the month of March.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

The Newfoundland Power customer allocation of the forecast fuel price change will be based on 12 months-to-date kWh as of the end of March and is the ratio of Newfoundland Power Firm and Firmed-Up Secondary invoiced energy to the total of: Utility Firm and Firmed-Up Secondary invoiced energy, Industrial Firm invoiced energy, and Rural Island Interconnected bulk transmission energy. For the 12 months-to-date (April 2008 - March 2009) Industrial Firm invoiced energy is reduced by 87,991,636 kWh to reflect the forecast reduction in Abitibi Consolidated (Grand Falls) load.

The amount of the forecast fuel price change, in Canadian dollars, and the details of the resulting fuel rider applied to the adjustment rate will be reported to Newfoundland Power, industrial customers, and the Public Utilities Board, by the 10th working day of April.

Section D: Adjustment

1. Newfoundland Power

As of March 31 each year, Newfoundland Power's adjustment rate for the 12-month period commencing the following July 1 is determined as the rate per kWh which is projected to collect:

Newfoundland Power March 31 Balance

less projected recovery / repayment of the balance for the following three months (if any), estimated using the energy sales (kWh) for April, May and June from the previous year

plus forecast financing charges to the end of the 12-month recovery period (i.e., June in the following calendar year),

divided by the 12-months-to-date firm plus firmed-up secondary kWh sales to the end of March.

A fuel rider shall be added to the above adjustment rate, based on the Newfoundland Power Fuel Price Projection amount (as per Section C.2 above) divided by 12-months-to-date kWh sales to the end of March.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values.

Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2. Island Industrial Customers

2.1 As of December 31 each year, the adjustment rate for industrial customers for the 12-month period commencing January 1 is determined as the rate per kWh which is projected to collect:

Industrial December 31 Balance

plus forecast financing charges to the end of the following calendar year,

divided by 12-months-to-date kWh sales to the end of December.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

A fuel rider shall be added to the above adjustment rate, based on the Industrial Fuel Price Projection (as per Section C.1 above) amount divided by 12-months-to-date kWh sales to the end of December.

When new Test Year base rates come into effect, if a fuel rider forecast (either March or September) is more current than the test year fuel forecast, a fuel rider will be implemented at the same time as the change in base rates reflecting the more current fuel forecast and the new test year values. Otherwise, the fuel rider portion of the RSP Adjustment will be set to zero upon implementation of the new Test Year Cost of Service rates, until the time for the next fuel price projection.

2.2 Notwithstanding paragraph 2.1, as of July 1, 2015 the adjustment rate that provides for disposition of the current RSP balance and the application of the fuel rider to industrial customers will be set to zero until a further Order of the Board. Commencing July 1, 2015, the RSP Surplus Adjustment rate of (0.349)¢ per kWh will apply to industrial customers in accordance with Section E and Order No. P.U. 14(2015). The RSP Surplus Adjustment rate will remain in effect until a further Order of the Board.

[]

Section E: RSP Surplus:

1. August 31, 2013 Balance:

The net load variation for Newfoundland Power and the Industrial Customers from January 1, 2007 to August 31, 2013, including financing (the RSP Surplus), will be removed from the respective customer class balance, and allocated based upon direction provided by Government in Orders in Council OC2013-089 and OC2013-207. The balances which remain after this amount is removed will form the adjusted August 31, 2013 current plan balances for each customer class.

The Industrial Customer class allocated amount will be used, firstly, to reduce the Industrial Customer class adjusted August 31, 2013 RSP balance to zero. OC2013-089 states that the remaining IC RSP Surplus is to be used to fund a three-year phase-in of rate increases for Island Industrial customers.

1.1 Industrial Customer RSP Surplus Disposition

Effective December 31, 2014, a one-time transfer from the Industrial Customer RSP Surplus will be applied to the Industrial Customer RSP current plan balance to reduce the December 31, 2014 current plan balance to zero. This transfer is in accordance with Order No. P.U. 14(2015).

An RSP Surplus Adjustment rate determined in accordance with Order No. P.U. 14(2015) will become effective July 1, 2015 to phase-in Industrial Customer rates using funds from the Industrial Customer RSP Surplus.

1.2 Newfoundland Power RSP Surplus Disposition

The Newfoundland Power allocated amount of the RSP Surplus will be segregated and held until

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

such time as its disposition occurs in accordance with an Order of the Board of Commissioners of Public Utilities through a refund in accordance with Order in Council OC2013-089.

2. Plan Balances

Separate plan balances for Newfoundland Power and the Island Industrial customer class will be maintained. Financing charges on the plan balances will be calculated monthly using Hydro's approved Test Year weighted average cost of capital.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.2G (INTERIM)

DOMESTIC DIESEL

GOVERNMENT DEPARTMENTS

Availability:

For Service to Government Departments throughout the Island and Labrador diesel service areas of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge ..... $43.90 per month

Energy Charge:
All kilowatt-hours ..... @ 83.567 ¢ per kWh

Minimum Monthly Charge..... $43.90

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1G (INTERIM)

GENERAL SERVICE DIESEL 0-10 kW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge ..... $48.54 per month

Energy Charge:
All kilowatt-hours ..... @ 75.486¢ per kWh

Minimum Monthly Charge..... $48.54

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 2.2G (INTERIM)

GENERAL SERVICE DIESEL OVER 10 KW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: ..... $71.98 per month

Demand Charge:
The maximum demand registered on the meter in the current month..... @ $58.22 per kW

Energy Charge:
All kilowatt-hours..... @ 53.741 ¢ per kWh

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 4.1G (INTERIM)

STREET AND AREA LIGHTING SERVICE DIESEL

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Street and Area Lighting Service to Government Departments throughout the Island and Labrador Diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$72.74
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	58.92
150W (14,400 lumens)	72.74

[1] Only High Pressure Sodium fixtures are available for all new installations and replacements.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.1L

DOMESTIC

Availability:

For Service throughout the Labrador Interconnected service area of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge: ..... $7.15 per month

Energy Charge:
All kilowatt-hours ..... @ 3.280 ¢ per kWh

Minimum Monthly Charge..... $7.15

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations**.**
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1L

GENERAL SERVICE 0 - 10 kW

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge: ..... $10.45 per month

Energy Charge:
All kilowatt-hours ..... @ 5.240 ¢ per kWh

Minimum Monthly Charge: Single Phase..... $10.45
Three Phase..... $20.00

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.2L

GENERAL SERVICE 10 - 100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month ..... @ $2.20 per kW

Energy Charge:
All kilowatt-hours ..... @ 2.433 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kW of maximum demand occurring in the 12 months ending with the current month, but not less than $20.00 for a three phase service**.**

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.3L

GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate:

Demand Charge:
The maximum demand registered on the meter in the current month .... @ $2.00 per kVA

Energy Charge:
All kilowatt-hours..... @ 2.103 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations**.** **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.4L

GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service (excluding Domestic Service) throughout the Labrador Interconnected service area of Hydro, where the maximum demand occurring in the 12 month period ending with the current month is 1000 kilovolt-amperes or greater.

Rate:

Billing Demand Charge:
The maximum demand registered on the meter in the current month ..... @ $1.75 per kVA

Energy Charge:
All kilowatt-hours ..... @ 1.733 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 6.8 cents per kWh, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

An amount equal to $1.05 per kVA of maximum demand occurring in the 12 months ending with the current month.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.1L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR[1]	
250W (9,400 lumens)	$ 13.50
HIGH PRESSURE SODIUM [2]	
100W (8,600 lumens)	10.00
150W (14,400 lumens)	13.50
250W (23,200 lumens)	17.80
400W (45,000 lumens)	23.00

[1] Fixtures previously owned by the Town of Wabush as of September 1, 1985, and transferred to Hydro in 1987.

[2] Only High Pressure Sodium fixtures are available for all new installations and replacements installed after September 1, 2002.

Special poles used exclusively for lighting service

Wood ..... $ 3.40

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.11L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro existing as of September 1, 2002.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM[1]	
100W (8,600 lumens)	$ 6.75

[1] Any new fixtures added will be at the rates set out in Rate 4.1W.

Special poles used exclusively for lighting service

Wood ..... $ 3.25

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

Closed

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 4.12L

STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service throughout the Labrador Interconnected service area of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by the customer.

Monthly Rate:

	SENTINEL / STANDARD
HIGH PRESSURE SODIUM	
100W (8,600 lumens)	$ 4.10

Special poles used exclusively for lighting service

Wood ..... $ 3.40

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 5.1L

SECONDARY ENERGY

Availability:

For Service to Customers on the Labrador Interconnected grid engaged in fuel switching who purchase a minimum of 1 MW load and a maximum of 24 MW, who provide their own transformer and, who are delivered power at primary voltages. Hydro shall supply Secondary Energy to the Customer at such times and to the extent that Hydro has Churchill Falls electricity available in excess of the amount it requires for its own use, and to meet its commitments and sales opportunities, present and future, for firm energy. Moreover, Hydro may interrupt or reduce the supply of Secondary Energy at its sole discretion for any cause whatsoever. The energy delivered shall be used solely for the operation of the equipment engaged in fuel switching.

Energy Charge:

The energy charge shall be calculated monthly based on:

EITHER:

A. The Customer's cost of fuel (cents per litre) most recently delivered to the Customer including fuel additives, if any, in accordance with the following formula:

Secondary Energy Rate = Constant Factor x Fuel Cost/Litre x 90%

$$\text{Constant Factor} = \frac{3413\ \text{BTU/kWh} \times A \times B}{C \times D}$$

Where:

A = Customer's Electric Boiler Efficiency

B = Transformer and Losses Adjustment Factor

C = BTU/Litre of the Customer's fuel

D = Customer's Oil-fired Boiler Efficiency

OR:

B. One (1) cent less than the New York Mercantile Exchange (NYMEX) settlement price for New York Independent System Operator (NYISO) Zone A Swap Peak electricity after the end of trading on the 19th day of the previous month, converted to Canadian dollars using the exchange rate at the closing of the same day.

WHICHEVER IS GREATER

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 5.1L

SECONDARY ENERGY

Prior to the commencement of service, the Customer will provide to Hydro the rate component values for insertion in the pricing formula for Secondary Energy. If subsequent changes to any of these rate components are required, the Customer will provide them to Hydro as soon as practicable. Hydro may require that these rate component values be verified.

Communications

The Customer and Hydro shall each designate a position within their respective staffs to be responsible for communications as to changes in the cost of the fuel delivered to the Customer. Hydro will contact the Customer's designate on or before the second working day of each month at which time the Customer's designate will inform Hydro of the fuel cost. If this information is unavailable to Hydro for any reason, Hydro will use the previous month's fuel cost and other inputs and make the adjustment to the correct values in the following month's billing.

Hydro will inform the Customer of the value of part B of the energy charge calculation on the first business day following the 21st day of the month preceding the month for which the rate is being set.

Power Factor

If the Customer's power factor is lower than 90%, the Customer shall upon written notice by Hydro provide, at the Customer's expense, power factor corrective equipment to ensure that a power factor of not less than 90% is maintained.

General:

Insofar as they are not inconsistent with the forgoing, the conditions of service provided in the Rules and Regulations shall apply to Customers in this rate class.

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

Schedule 2

Rate Stabilization Plan Adjustment Update

NEWFOUNDLAND AND LABRADOR HYDRO

June 4, 2015

newfoundland labrador hydro
a nalcor energy company

NEWFOUNDLAND AND LABRADOR HYDRO
RATE STABILIZATION PLAN FUEL PRICE PROJECTION RIDER
No. 6 0.7% Sulphur Fuel Price Projection
Utility Customer

Line No	Customer Allocation	Amount	Comments
1	March Fuel Price Projection	$ 73.35	From Page 2
2	2007 Test Year Fuel Forecast Price	$ 55.40	
3	Forecast Fuel Price Variance	$ 17.95	Line 1 - Line 2
4	2007 Test Year No. 6 Barrels Consumed	1,878,188	From Line 41
5	Forecast Fuel Variance	$ 33,713,475	Line 3 x Line 4
6	Utility Customer Allocation Ratio for March	93.15%	From Line 8
7	Utility Customer Allocation	$ 31,404,102	Line 5 x Line 6

	Calculation of Customer Allocation	kWh	Percent of Total	Allocation of Rural	Total
8	12 months to date (Apr 2014-Mar 2015) Utility Sales	5,898,943,058	87.05%	6.10%	93.15%
9	12 months to date (Apr 2014-Mar 2015) Industrial Customer Sales	413,600,005	6.10%	0.00%	6.10%
10	12 months to date (Apr 2014-Mar 2015) Bulk Rural Energy	464,255,442	6.85%	-6.85%	0.00%
11	Total	6,776,798,505			

	Calculation of Utility Customer RSP Rate	Amount	Comments
	Rate Rider		
12	Utility Allocation March	$ 31,404,102	From Line 7
13	12 months to date Utility Sales (kWh)	5,898,943,058	From Line 8
14	Fuel Projection Rider (mills per kWh)	5.32	Line 12/Line 13 x 1000
15	March Balance	$ (46,968,960)	March RSP
16	Forecast Financing Costs	$ (2,541,168)	From Line 38
17	Forecast Recovery to June 30	$ 7,326,763	Lines 23 to 25
18	Total to be recovered	$ (42,183,365)	Lines 15 to 17
19	12 months to date (Apr 2014-Mar 2015) Utility Sales	5,898,943,058	From Line 8
20	Balance Rate (mills per kWh)	(7.15)	Line 18/Line 19 x 1000
21	RSP Adjustment Rate (mills per kWh)	(1.83)	Line 14 + Line 20

Utility Forecast Recovery
2014 - 2015

2007 Test Year Weighted Average Cost of Capital per annum 7.529%
Nominal Financing Rate 7.281%

		Sales kWh	Financing Costs	Adjustment	Total To Date Balance
22	Balance Forward				$ (46,968,960)
23	April	543,018,070	$ (284,984)	$ 2,992,030	(44,261,914)
24	May	458,076,079	(268,559)	2,523,999	(42,006,474)
25	June	328,626,921	(254,874)	1,810,734	(40,450,614)
26	July	303,484,393	(245,434)	2,170,218	(38,525,830)
27	August	300,338,819	(233,755)	2,147,724	(36,611,862)
28	September	315,235,972	(222,142)	2,254,254	(34,579,751)
29	October	401,788,711	(209,813)	2,873,193	(31,916,371)
30	November	508,174,745	(193,653)	3,633,960	(28,476,064)
31	December	619,191,220	(172,779)	4,427,839	(24,221,003)
32	January	740,593,181	(146,961)	5,295,985	(19,071,980)
33	February	668,359,635	(115,719)	4,779,442	(14,408,256)
34	March	712,055,312	(87,422)	5,091,910	(9,403,768)
35	April	543,018,070	(57,057)	3,883,124	(5,577,701)
36	May	458,076,079	(33,843)	3,275,704	(2,335,840)
37	June	328,626,921	(14,173)	2,350,012	(0)
38	Total		$ (2,541,168)	$ 49,510,128	

2007 Test Year Barrels Adjusted for Reduction in Corner Brook Pulp and Paper Limited (CBPP) and Abitibi Consolidated (Grand Falls) Load

39	2007 Test Year Barrels of No. 6 Fuel forecast to be consumed at Holyrood	2,467,396
40	Less: Reduction in Test Year Barrels of No. 6 Fuel approved in Board Order No. P.U. 11 (2008) to reflect reduction in CBPP load and in compliance with Board Order No. P.U.22 (2009).	(589,208)
41	Adjusted 2007 Test Year Barrels of No. 6 Fuel forecast to be consumed at Holyrood	1,878,188

NEWFOUNDLAND AND LABRADOR HYDRO
Fuel Price Projection
As at March 31, 2015

	$/bbl
PIRA Forecast $ US/bbl [1]	
July	46.68
August	49.23
September	52.07
October	56.09
November	59.10
December	57.78
January	60.15
February	61.85
March	63.85
April	66.25
May	64.44
June	62.66
Average $US/bbl [2]	58.35
NLH Test Year Contract Discount ($US/bbl)	(0.218)
	$58.13
Can$/US$ Noon Exchange Rate [3]	1.2619
NLH Fuel Price Projection ($Can/bbl) [2]	$73.35

Notes:

(1) The forecast for July to June is based on the PIRA Energy Group, World Oil Market Forecast, dated March 27, 2015.

(2) Price per barrel is rounded to the nearest $0.05.

(3) Monthly average of the Bank of Canada Can$/US$ Noon Exchange Rate for the month of March 2015, rounded to 4 decimal places.

Schedule 3

Evidence to Revised Compliance Filing in Response to Order No. P.U. 14(2015)

NEWFOUNDLAND AND LABRADOR HYDRO

June 4, 2015

newfoundland labrador hydro
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1.0 BACKGROUND

In its 2015 Interim Rates Application, Hydro requested that the proposed customer rates be approved on an interim basis effective March 1, 2015, in advance of completing its General Rate Application (GRA). This approach would reduce the amount of 2015 costs deferred for future recovery from customers. Hydro also proposed revised Rate Stabilization Plan (RSP) Rules to become effective on an interim basis effective March 1, 2015, to permit the continued phase-in of the Island Industrial Customer (IIC) rates.

In Order No. P.U. 14(2015) (the 2015 Interim Rates Order), the Board directed Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on consumers and Hydro by incorporating the Board's decision. In compliance with the 2015 Interim Rates Order, this evidence provides (i) proposed customer rates and customer rate impacts; (ii) revised RSP Rules to permit the next stage of the phase-in of rates to IIC in accordance with Government directives; and (iii) the forecast 2015 financial impact on Hydro resulting from the Board's Order.

2.0 UTILITY RATE

In the 2015 Interim Rates Order, the Board approved an 8% increase in the base Utility Rate effective July 1, 2015. Hydro is proposing to apply the 8% increase equally to all rate components. An 8% increase to the Utility Rate which applies to Newfoundland Power (NP) would normally increase retail customer rates by approximately 5.4%.[1] However, the Board approved the base rate increase to become effective on July 1, 2015 at the same time as the annual NP RSP rate adjustment occurs. Hydro filed its updated RSP rate adjustments relative to the 2007 Test Year on April 21, 2015. The customer rate impact of the RSP rate adjustment more than offsets the approved base rate increase.

Table 1 provides a comparison of the existing and proposed Utility Rate including both the change in the base rates and the RSP adjustments.

Table 1
Utility Rate

Rate Component	Existing Rate	Proposed Rate	Change	Change (%)
Monthly Demand Charge ($/kW)	4.00	4.32	0.32	8.0
Monthly Energy Charges (¢/kWh)				
1st 250 GWh	3.246	3.506	0.260	8.0
Excess	8.805	9.509	0.704	8.0
Firming Up Charge	0.841	0.908	0.067	8.0
RSP Adjustments **(¢/kWh)**				
RSP – Current Plan	(0.551)	(0.715)	(0.164)	
RSP – Fuel Rider	1.526	0.532	(0.994)	
Total RSP Adjustment	0.975	(0.183)	(1.158)	

[1] Purchased power costs reflect approximately 67.5% of NP's cost of supply. 67.5% times 8.0% Utility Rate increase equals 5.4% retail customer increase.

Table 2 provides a summary of the combined customer impact of the 8% base rate increase and the RSP rate adjustment update.

Table 2
Utility and End Consumer Rate Change - July 1, 2015

	2015 Test Year Billing Units	Unit	Jan 1 2015 Existing Rates	$	July 1 2015 Proposed Rates	$	Utility	End Consumer
Demand (kWs)	15,122,049	$/kW/mo	4.00	60,488,196	4.32	65,327,252		
Energy (MWhs)	3,000,000	mills/kWh	32.46	97,380,000	35.06	105,180,000		
Energy (MWhs)	2,924,100	mills/kWh	88.05	257,467,005	95.09	278,052,669		
Total before RSP				415,335,201		448,559,921	8.0%	5.4%
RSP: Current Plar	5,924,100	mills/kWh	(5.51)	(32,641,791)	(7.15)	(42,357,315)		
RSP: Fuel Rider	5,924,100	mills/kWh	15.26	90,401,766	5.32	31,516,212		
Total RSP			9.75	57,759,975	(1.83)	(10,841,103)		
Total - Base Rate Change plus RSP				473,095,176		437,718,818	-7.5%	-5.0%

The combined effect of the approved base rate increase and the update to the RSP rate adjustment is a decrease of approximately 5.0% to NP customers. The 5.0% decrease would also apply to Hydro's Rural Customers with the exception of customers on the Labrador Interconnected System.[2] However, the bill impact differs for Hydro's Rural Domestic Customers in L'Anse au Loup and in Labrador Diesel Systems that are eligible for the Northern Strategic Plan (NSP) rebate provided by the Provincial Government, as those customers pay the Labrador Interconnected Domestic rate for a portion of their charges for which there is no rate change approved at this time.

Table 3 provides a comparison of the estimated rate change and the customer billing impacts for Hydro's Rural Domestic Customers on the L'Anse au Loup and Labrador Diesel Systems.

[2] In Order No. P.U. 14(2015), the Board approved no change in rates to the customers on the Labrador Interconnected System at this time.

Table 3 Customer Impacts for Domestic Customers Eligible for the NSP		
System	**Rate Impact (Excluding NSP)**	**Bill Impact (Including NSP)**
L'Anse au Loup	(5.0%)	(3.4%)
Labrador Isolated[3]	(5.0%)	(2.4%)

3.0 ISLAND INDUSTRIAL CUSTOMERS

3.1 Customer Rates

In the 2015 Interim Rates Order, the Board approved a 10% increase in the base rate for IIC effective July 1, 2015. Hydro is proposing to apply the 10% increase equally to the demand charge and the energy charge excluding RSP adjustments. The Board also approved the use of the IIC RSP Surplus: (i) to fund an RSP Surplus adjustment which will result in an effective 2.7% rate increase for IIC effective July 1, 2015; and (ii) to fund the full amount of the 2014 year-end IIC RSP current balance of $6.8 million.

Table 4 provides the derivation of the RSP adjustment to reduce the customer rate impact from the approved 10% base rate increase to an effective 2.7% increase.

[3] The lesser billing impact of the rate decrease for customers on Labrador Isolated Systems relative to the L'Anse au Loup System relates to the lower average usage of the customers on the Labrador Isolated Systems. The lower energy usage results in a higher percentage of the customer usage on the Labrador Isolated Systems being billed on the Labrador Interconnected Domestic rate for which no rate change is approved.

Table 4 **Calculation of IC RSP Surplus Adjustment**		
2015 Test Year IIC Revenue at Existing Rates[4]	A	$30,546,755
Less Specifically Assigned Charges at Existing Rates	B	$591,228
Subtotal (Base Rate Revenue= A-B)	C	$29,955,528
10% Increase in Base Rate Revenue (D=C x 10%)	D	$2,995,553
2.7% Increase in Existing Revenue (E=A x 2.7%)	E	$824,762
RSP Surplus Funding (F=E-D)[5]	F	($2,170,791)
2015 Test Year Sales Forecast (kWh)	G	621,400,000
RSP Surplus Adjustment (H=F/G)	H	(0.349)¢ per kWh

Table 5 provides a comparison of the existing and proposed IIC rates including both the change in the base rates and the RSP adjustments.

Table 5 **Island Industrial Customer Rate**				
Rate Component	**Existing**	**Proposed**	**Change**	**Change (%)**
Monthly Demand Charge ($/kW)	6.68	7.35	0.67	10.0
Monthly Energy Charge (¢/kWh)	3.676	4.044	0.368	10.0
RSP Adjustment (¢/kWh)[6]	0.00	(0.349)	(0.349)	
Net Energy Rate (¢/kWh)	3.676	3.695	0.019	
Specifically Assigned Charges – Annual ($)				
CBPP	347,167	347,167	0.00	0.0
NARL	150,976	150,976	0.00	0.0
Teck Resources[7]	186,169	186,169	0.00	0.0
Vale	-	-	-	-
Praxair	-	-	-	-
Wheeling	0.384	0.384	0.0	0.0

[4] Source: Table 4.15, page 4.50 of Evidence to Hydro's Amended Application.

[5] The amount of RSP Surplus funding provided in Table 4 assumes the RSP Surplus Adjustment is in effect for all of 2015. The actual amount of RSP Surplus funding is dependent upon the time period the RSP Surplus Adjustment is in effect.

[6] There is also an existing RSP Adjustment of (1.111)¢ that applies solely to Teck Resources that is proposed to be eliminated July 1 due to the conclusion of operations by the customer on June 30, 2015.

[7] Teck Resources is scheduled to close operations June 2015.

3.2 RSP Rules

The 2015 Interim Rates Order directed Hydro to file revised RSP Rules to become effective July 1, 2015 with evidence showing the impacts on consumers and Hydro incorporating the findings in the 2015 Interim Rates Order.

Order No. P.U. 29(2013) approved the implementation of an RSP rate of (1.111) cents per kWh for Teck Resources Limited to comply with the direction of the Government. The 2015 Interim Rates Order requires the same interim rate increase apply to Teck Resources as approved for the other IIC. This would require maintaining a separate RSP rate for Teck Resources. The application by Teck Resources filed with the Board on May 27, 2015 states that it will be discontinuing its mining and milling operations effective June 30, 2015. There is no longer a requirement to maintain a separate RSP adjustment for Teck Resources effective July 1, 2015 as Teck Resources will no longer be in operation as an IIC. Hydro is proposing the elimination of the RSP adjustment in effect solely for Teck Resources effective July 1, 2015.

The use of the IIC RSP Surplus to fund the full amount of the 2014 year-end IIC RSP current balance and to provide for the creation of the RSP Surplus Adjustment to limit the average customer rate increase to 2.7% requires revisions to the RSP rules. The proposed RSP Rules provide for: (i) a transfer from the IC RSP Surplus to fund the full amount of the actual 2014 year-end RSP current balance; and (ii) the implementation of an IC RSP Surplus Adjustment rate so there is an effective interim increase of 2.7% to IIC on July 1, 2015. Table 4 to this evidence provides the proposed RSP Surplus Adjustment rate to become effective July 1, 2015.

The current Section E of the RSP rules titled “Historical Plan Balances” is no longer necessary for the purpose of calculating RSP adjustments. Hydro is proposing elimination of the section related to “Historical Plan Balances”.

The proposed RSP rules to comply with the 2015 Interim Rates Order are provided in Schedule 1 to the Revised Compliance Application.

4.0 GOVERNMENT DIESEL CUSTOMERS

In the 2015 Interim Rates Order, the Board approved an interim base rate increase for Hydro Rural Government Diesel Customers of 50% of the proposed increases.

Table 6 provides a comparison of the proposed percentage increases included in the 2015 Interim Rates Application and the proposed increases reflected in the Revised Compliance Application.

Table 6
Government Diesel Rate Increases

Class	2015 Interim Rates Application[8]	Compliance Application[9]
Domestic Diesel (1.2G)	14.0%	7.0%
G.S. Diesel 0-10 kW (2.1G)	16.6%	8.3%
G.S. Diesel >10 kW (2.2G)	16.9%	8.45%
Street and Area Lighting (4.1G)	27.5%	13.75%

Table 7 provides a comparison of the proposed Hydro Rural Government Diesel Customer rates included in the 2015 Interim Rates Application and the proposed customer rates included in the Revised Compliance Application.

[8] Source: Table 5 on page 16 of Evidence to 2015 Interim Rates Application.
[9] The proposed percentage increases are 50% of the increases proposed in the 2015 Interim Rates Application.

Table 7				
Hydro Rural Government Diesel Rates				
Rate Component	**Existing**	**Proposed**	**Change**	**Change (%)**
Domestic Diesel (1.2G)				
Basic Customer Charge ($)	41.03	43.90	2.87	7.00
Monthly Energy Charge (¢/kWh)	78.100	83.567	5.467	7.00
Minimum Monthly Charge ($)	41.03	43.90	2.87	7.00
G.S. Diesel 0-10 kW (2.1G)				
Basic Customer Charge ($)	44.82	48.54	3.72	8.30
Monthly Energy Charge (¢/kWh)	69.701	75.486	5.785	8.30
Minimum Monthly Charge ($)	44.82	48.54	3.72	8.30
G.S. Diesel >10 kW (2.2G)				
Basic Customer Charge ($)	66.37	71.98	5.61	8.45
Monthly Demand Charge ($/kW)	53.68	58.22	4.54	8.45
Monthly Energy Charge (¢/kWh)	49.554	53.741	4.187	8.45
Street and Area Lighting (4.1G)				
250 W MV ($)	63.95	72.74	8.79	13.75
100 W HPS ($)	51.80	58.92	7.12	13.75
150 W HPS ($)	63.95	72.74	8.79	13.75

5.0 SUMMARY OF CUSTOMER IMPACTS

The 2015 Interim Rates Order directed Hydro to file an updated Table 5 from the Evidence to Hydro's 2015 Interim Rates Application providing customer impacts including the effect of the NSP. Table 8 provides an update to Table 5 in the Evidence to Hydro's 2015 Interim Rates Application. The effect of the NSP on customer billings is provided in Table 3 to this evidence.

Table 8 **2015 Proposed Customer Rate Impacts[10]**			
	Revised Application	**2015 Interim Application**	**Interim Rates Compliance Application**
Island Interconnected System			
Newfoundland Power – Wholesale rate	4.1%	(9.3%)	(7.5%)
Estimated end consumers rate impact	2.8%	(6.3%)	(5.0%)
Estimated rural consumers rate impact	2.8%	(6.3%)	(5.0%)
Industrial Customers – Base Rates	39.2%	18.1%	9.8%[11]
Island Isolated Systems			
Domestic	7.1%	(6.3%)	(5.0%)
General Service 0-10 kW	18.5%	(6.3%)	(5.0%)
General Service Over 10 kW	19.2%	(6.3%)	(5.0%)
Street and Area Lighting	2.8%	(6.3%)	(5.0%)
Island Isolated - Government Departments			
General Service 0-10 kW	24.7%	16.6%	8.3%
General Service Over 10 kW	25.4%	16.9%	8.45%
Street and Area Lighting	27.5	27.5%	13.75%
Labrador Interconnected System			
Domestic	1.9%	1.9%	0%
General Service 0 – 10 kW	1.9%	1.9%	0%
General Service 10 - 100 kW	1.9%	1.9%	0%
General Service 110 - 1000 kVA	1.9%	1.9%	0%
General Service 1000 kVA and Over	1.9%	1.9%	0%
Street and Area Lighting	17.5%	17.5%	0%
Labrador Isolated Systems			
Domestic	7.1%	(6.3%)	(5.0%)
General Service 0-10 kW	18.5%	(6.3%)	(5.0%)
General Service Over 10 kW	19.2%	(6.3%)	(5.0%)
Street and Area Lighting	2.8%	(6.3%)	(5.0%)
Labrador Isolated - Government Departments			
Domestic	21.5%	14.0%	7.0%
General Service 0-10 kW	24.7%	16.6%	8.3%
General Service Over 10 kW	25.4%	16.9%	8.45%
Street and Area Lighting	27.5%	27.5%	13.75%
L'Anse Au Loup System			
Domestic	2.8%	(6.3%)	(5.0%)
General Service 0-100 kW	2.8%	(6.3%)	(5.0%)
General Service 110 - 1000 kVA	2.8%	(6.3%)	(5.0%)
General Service 1000 kVA and Over	2.8%	(6.3%)	(5.0%)
Street and Area Lighting	2.8%	(6.3%)	(5.0%)

[10] Excludes the effects of the NSP which applies to customers on Isolated Systems in Labrador.

[11] The revenue increase is slightly less than 10% because no increase is proposed for specifically assigned charges. The final customer rate impact is 2.7%; see Section 3.1 to this evidence.

6.0 FINANCIAL IMPACTS

6.1 Delayed Rate Implementation

The Amended General Rate Application ("Amended GRA"), filed on November 10, 2014, is based on a 2015 Test Year for the purpose of setting new base rates for customers to become effective in 2015. Based on existing rates, Hydro would achieve a return on rate base of 3.33% in 2015. The Amended GRA proposed to implement interim IIC rates and start the next stage of the IIC rate phase-in beginning January 1, 2015. The Amended GRA also proposed to implement proposed rates for NP and retail customers on an interim basis effective February 1, 2015 with the financial impact of delayed implementation set aside in a deferral account for future recovery. Hydro's proposals for early implementation of interim rates in 2015 would have minimized the amount of 2015 costs deferred for future recovery from customers.

In a letter to Hydro, dated December 24, 2014, the Board advised that it was unable to make a determination with respect to the proposed revised interim IIC rates prior to January 1, 2015. The Board directed Hydro to file a comprehensive and complete application setting out proposals for interim rates for NP and IIC to be effective March 1, 2015, and setting out the implications of these proposals for Hydro Rural Customers. Hydro filed its 2015 Interim Rates Application on January 28, 2015.

Hydro's 2015 Interim Rates Application stated that delayed implementation to March 1, 2015 would provide a net income deficiency of approximately $20 million in 2015. The evidence also stated that a further delay to a July 1, 2015 implementation date may result in a forecast net loss for 2015. The 2015 Interim Rates Order approved rate increases to become effective July 1, 2015.

6.2 Updated 2015 Test Year Financial Forecast

Hydro's 2015 Test Year forecast income statement showed a net loss of $34.6 million for 2015 under existing rates[12] and net income of $33.2 million under proposed rates[13] (i.e., assuming the proposed rates had been approved effective January 1, 2015). Table 9 provides an updated 2015 Test Year Forecast net income and 2015 Test Year Net Income Deficiency to reflect the additional revenue resulting from interim rate approvals provided by the Board.

Table 9
2015 Test Year Net Income Update
($millions)

2015 Test Year Net Income (Loss) under existing rates	(34.6)
Additional Revenue:	
Lab IC Transmission - Interim Approval effective January 1, 2015	4.1
Additional 2015 Revenue - Interim Approval effective July 1, 2015	21.9
Subtotal	26.0
2015 Updated Forecast Net Income (Loss)	(8.6)
2015 Test Year Net Income (Loss) under Amended GRA proposed rates effective January 1, 2015	33.2
2015 Test Year Net Income Deficiency	41.8

Table 9 shows that the approval of an additional $26 million in revenue for 2015 still results in a forecast net income deficiency of $41.8 million based upon the updated 2015 Test Year and a forecast net loss of approximately $8.6 million. The forecast net income deficiency for 2015 of $41.8 million results from the delayed rate implementation in 2015.

Appendix 1 to this evidence provides an update to the 2015 Test Year income statement provided in the Amended GRA to reflect the Board's decisions in the 2015 Interim Rates Order. It includes updates to revenues, return on equity and return on rate base based

[12] See Schedule II, Finance evidence in Hydro's Amended GRA.
[13] See Schedule I, page 1 of 11, Finance evidence in Hydro's Amended GRA.

upon the 2015 Test Year costs and the base rate increases approved in the 2015 Interim Rates Order and the interim order on Labrador Industrial transmission rates.

Appendix 1

Appendix 1
Page 1 of 1

Newfoundland and Labrador Hydro
Updated 2015 Test Year Income Statement Reflecting Interim Rate Approvals
($000s)

		Existing Rates 2015	Proposed Interim Rates [1] 2015	Change
1	**Revenue**			
2	Energy sales	520,329	546,347	26,018
3	Revenue deficiency	-	-	-
4	Other revenue	2,508	2,508	-
5	**Total revenue**	522,837	548,855	26,018
6				
7	**Expenses**			
8	Operating expenses	135,325	135,325	-
9	Fuels			-
10	No. 6 fuel	244,914	244,914	-
11	Rate stabilization plan deferral	(73,978)	(73,978)	-
13	Diesel and other	22,940	22,940	-
14	Total fuels	193,876	193,876	-
15	Fuel supply deferral	1,991	1,991	-
16	Power purchases	63,254	63,254	-
17	Amortization	63,792	63,792	-
18	Accretion	878	878	-
19	Other Income and expenses	4,074	4,074	-
20	Interest	94,561	94,561	-
21	**Total expenses**	557,751	557,751	-
22				-
23	**Net income before cost of service exclusions**	(34,914)	(8,896)	26,018
24	less: Assets Not In Service Depreciation	331	331	-
25		(34,583)	(8,565)	26,018
26				-
27	Return on regulated equity	(34,583)	(8,565)	26,018
28	Net interest	94,561	94,561	-
29	**Return on rate base**	59,978	85,996	26,018
30				
31	**Average rate base**	1,803,149	1,803,149	-
32				
33	**Rate of return on rate base**	3.33%	4.77%	1.44%

[1] Revenue has been updated to reflect interim rate increases approved in Board Order P.U. 14(2015) and Order No. 57(2014).

Hydro's 2015 Interim Rates Application - Compliance Application
Sara Kean
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History: This message has been forwarded.

Dear Sirs/Madams:

As per Mr. Hayes e-mail below, Newfoundland Power does not have any comments on the above-noted application.

Regards,

Sara Kean
Assistant Board Secretary and Records Administrator
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From: Hayes, Gerard [mailto:ghayes@newfoundlandpower.com]
Sent: June 11, 2015 1:13 PM
To: Cheryl Blundon; Sara Kean
Cc: Jacqui Glynn
Subject: Newfoundland and Labrador Hydro 2015 Interim Rates Application - Compliance Application

Newfoundland Power has no comments on the above-noted application.

Regards,

Gerard Hayes

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O'DEA EARLE
INJURY LAWYERS

June 15, 2015

Ms. G. Cheryl Blundon
Board of Commissioners of Public Utilities
120 Torbay Road, P.O. Box 12040
St. John's, NL A1A 5B2

Ladies & Gentlemen:

Re: Newfoundland and Labrador Hydro ("Hydro") 2015 Interim Rates Application (Revised)

In Order No. P.U. 14(2015), the Board denied Hydro's 2015 Interim Rates Application and ordered Hydro to file a revised schedule of rates, tolls and charges and RSP rules effective July 1, 2015 with evidence showing the impacts on consumers and Hydro incorporating the findings of the Board in its Order (see Order No. P.U. 14(2015), page 18, point 2). On May 27, 2015 Hydro filed a 2015 Interim Rates Application including evidence in response to the Board's Order. On June 2, 2015 Hydro followed this up with supplemental information based upon its recent telephone conversations with Board staff relating to the interpretation of the Board's Order. However, in a June 3, 2015 letter entitled *Newfoundland and Labrador Hydro – 2015 Interim Rates Compliance Application – Process and Schedule*, the Board indicated that the Application was not in compliance with Order No. P.U. 14(2015), and required Hydro to amend the Application with a number of clarifications and re-file on June 5, 2015. Hydro complied by filing a revised 2015 Interim Rates Application on June 5, 2015 (see June 5, 2015 letter from Hydro to Board entitled *Newfoundland and Labrador Hydro — 2015 Interim Rates Application (Revised)*).

The Board in its June 3, 2015 letter referenced earlier provides a "*schedule for the hearing of the Application, with the required amendments*". Comments from the Parties were due on June 10, 2015 (since delayed until June 15, 2015). This letter conveys the Consumer Advocate's comments in this regard.

The Consumer Advocate believes that, like Grant Thornton,[1] Hydro's June 5, 2015 Interim Rates Application is consistent with the Board's Order No. P.U. 14(2015). We do not believe that the exceptions identified in the Grant Thornton report are material, but point out that only the Board can make this determination. Importantly, some key information relating to the 2015 Interim Rates

[1] See June 10, 2015 report by Grant Thornton entitled *Newfoundland and Labrador Hydro – 2015 Interim Rates Application (Compliance Application) for Interim Rates effective July 1, 2015.*

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Application that we believe should be filed to support the conduct of a proper review of the Amended 2013 General Rate Application follows:

a) Assuming interim rates in the June 5, 2015 Application are approved as proposed, what percentage rate increase will be necessary to bring each customer class rate from the 2015 interim rates proposed for implementation on July 1, 2015 up to the rates proposed in the Amended 2013 GRA?

b) Assuming interim rates in the June 5, 2015 Application are approved as proposed, what percentage rate increase will be necessary to bring each customer class rate from the 2015 interim rates proposed for implementation on July 1, 2015 up to the rates proposed in the Amended 2013 GRA including all of the proposed rate adders/riders; i.e., such as the 2014 revenue deficiency, the 2015 revenue deficiency, etc?

c) Assuming interim rates in the June 5, 2015 Application are approved as proposed, what does Hydro now propose as a transition plan for bringing Island Industrial Customer rates up to the full cost of supply determined by the 2015 test year cost of service study consistent with Government Directive OC2013-089, as amended?
The Consumer Advocate requests the Board direct Hydro to file this information as soon as possible.

Please feel free to contact the undersigned if you have any questions.

Yours very truly,

O'DEA, EARLE

THOMAS JOHNSON, Q.C.
TJ/cel

cc: Newfoundland & Labrador Hydro
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June 15, 2015

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Via Electronic Mail and Courier

Newfoundland and Labrador Board
of Commissioners of Public Utilities
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Attention: Ms. G. Cheryl Blundon, Director of Corporate Services and Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro - Amended Interim Rates Compliance Application filed June 5, 2015

These are the submissions of the Island Industrial Customers Group or IIC Group (Corner Brook Pulp and Paper Limited, North Atlantic Refining Limited and Teck Resources Limited) regarding the Hydro's Application for implementation of interim rates, pursuant to the direction provided by the Board's Order No. P.U. 14 (2015), for, *inter alia*, Hydro's island industrial customers.

The interim rates are intended to be effective July 1, 2015, pursuant to the direction provided by Order No. P.U. 14 (2015) issued by the Board on May 8, 2015.

Deficiencies in Hydro's original Interim Rates Compliance Application

Hydro's original Interim Rates Compliance Application was filed on May 27, 2015. The Compliance Application included three new elements that could not have been anticipated based on the direction provided by P.U. No. 14 (2015):

1. a proposed 10% increase to Specifically Assigned Charges (SAC), in addition to a 10% increase to the firm demand and energy base rate components;

2. the apparent proposal to terminate the Teck Rider (confirmed by Hydro's correspondence of June 2, 2015 but of which there had not been prior notice); and

3. the proposal for a 2015 Revenue Deficiency Deferral Account.

By correspondence dated June 3, 2015, the Board directed Hydro to fix the above identified "deficiencies" (in the Board's words) in its Interim Rates Compliance Application, to bring it into compliance with the direction of Order No. P.U. 14 (2015).

The Board stated the following with respect to the first above identified deficiency:

> "The Board states on page 16 of Order No. P.U. 14(2015) that "The *Board agrees with the Industrial Customer Group that changes to the specifically assigned charges for the Island Industrial Customers should not be addressed in advance of the general rate application.*" The Board did approve a 10% base rate increase for Island Industrial customers which should not be applied to any other rate components such as the specifically assigned charges or RSP adjustments. It is an approved base rate increase only and not a 10% increase in revenue from the Island Industrial customers."

The Board stated the following with respect to the second above identified deficiency:

> "The Board also states on page 17 of Order No. P.U. 14(2015) that "*The Board will approve, effective July 1, 2015, ... (iv) changes to the RSP rules to allow a transfer from the IC RSP Surplus and to implement an IC RSP rate so that there is an effective interim increase of 2.7% in Island Industrial customer rate, including Teck,*". The omission of a separate RSP adjustment for Teck Resources as contained in the Application has not been approved by the Board."

With respect to the third above identified deficiency, the Board also noted that a deferral account had not been approved by the Board, and directed that Hydro file a separate application on that issue.

Hydro's revised Interim Rates Compliance Application remains non-compliant

Hydro's revised Interim Rates Compliance Application, filed on June 5, 2015, continues to be in non-compliance with P.U. 14 (2015).

Hydro's revised proposal for interim rates, illustrated in Table 1 below, results in two of the industrial customers, Corner Brook Pulp and Paper Limited and Teck Resources Limited, both incurring effective rate increases that are greater than the 2.7% directed by the Board. This is essentially due to the following factors:

- In Hydro's proposal, despite the rate increase being to both the demand and energy components, the RSP Surplus Adjustment is only applied to the energy component. This would cause different percentage rate impacts to the industrial customers under the same rate class due to load characteristics of each industrial customer (some industrial customers have a higher or lower load factor, i.e. relatively more demand use compared to energy). The mismatch arises as the 10% demand rate increase is offset by a -7.3% RSP credit, but the RSP credit is being refunded on the energy component of the bill, so it is not always reaching the correct customers who faced the 10% increase on their demand charges.

- for Teck, the non-compliant effective rate increase impact is exacerbated by the new proposal to terminate the Teck Rider.

Table 1. Interim Rate Impact to Island Industrial Customers at 2015 Test Year Billing Determinants (excluding revenues from Specifically Assigned Charges) [1]

Customer	Revenues at Existing Rates (including Teck Rider) - excluding SAC revenues	Revenues at Hydro's June 5, 2015 Proposed Interim Rates Effective July 1, 2015 - excluding SAC revenues	Rate Impact
	($)	($)	%
	A	B	C=B/A-1
CBPP	2,368,288	2,449,160	3.4%
NARL	10,591,608	10,871,310	2.6%
Teck	803,820	1,062,480	32.2%
Vale	13,587,392	13,968,240	2.8%
Praxair	2,377,776	2,435,820	2.4%
	29,728,884	30,787,010	3.6%

It is submitted that the proposed rates by IIC Group as provided in Table 2 below comes as close as is possible, given the difference in the weighting of demand versus energy components in the effective rates paid by individual industrial customers, to compliance with the Board's direction in P.U. 14 (2015).

[1] The bill impacts are calculated based on 2015 Test Year billing determinants as provided in response to IC-NLH-028 Rev1. Column A is the total revenue estimate at the existing rates as of June 2015; column B is the total revenue estimate at Hydro's June 5, 2015 proposed interim rates which includes only kW.h RSP adjustment and no Teck Rider.

Table 2. Existing and Proposed Interim Rates for Island Industrial Customers

	Rates			
	Energy	**Teck Rider (applicable only to Teck)**	**Demand**	**Specifically Assigned Charges (SAC)**
	(cents/kW.h)	(cents/kW.h)	($/kW)	($/year)
Existing Rates	3.676	-1.111	6.68	684,312
CBPP				*347,167*
NARL				*150,976*
Teck				*186,169*
Vale				*0*
Praxair				*0*
Hydro's Proposed Interim Rates (June 5, 2015)				
Proposed Rates (10% increase, excluding SAC)	4.044		7.35	684,312
CBPP				*347,167*
NARL				*150,976*
Teck				*186,169*
Vale				*0*
Praxair				*0*
RSP Surplus Adjustment	-0.349			
IIC Group Proposed Interim Rates				
Proposed Rates (10% increase, excluding SAC)	4.044		7.35	684,312
CBPP				*347,167*
NARL				*150,976*
Teck				*186,169*
Vale				*0*
Praxair				*0*
RSP Surplus Adjustment	-0.269	-1.111	-0.49	

Table 3 below illustrates the rate impact of the interim rate structure proposed above by the IIC Group.

Table 3. Interim Rate Impact to Island Industrial Customers at 2015 Test Year Billing Determinants (excluding revenues from Specifically Assigned Charges) [2]

Customer	Revenues at Existing Rates (including Teck Rider) - excluding SAC revenues	Revenues at IIC Group Proposed Interim Rates Effective July 1, 2015 - excluding SAC revenues	Rate Impact
	($)	($)	%
	A	B	C=B/A-1
CBPP	2,368,288	2,432,080	2.7%
NARL	10,591,608	10,876,890	2.7%
Teck	803,820	831,576	3.5%
Vale	13,587,392	13,953,368	2.7%
Praxair	2,377,776	2,441,820	2.7%
	29,728,884	30,535,734	2.7%

Table 3 demonstrates that the IIC proposed rates would yield a precise 2.7% rate impact on industrial customers (on the portion of their bills excluding specifically assigned charges) with the exception of Teck. The only reason for the Teck difference is that Teck's impact in the above table is being measured as a percentage of the bill after the unique Teck RSP credits. The impact on Teck's base bill (not counting RSP credits) is precisely the same as the other industrial customers, at 2.7%.

Comment on Grant Thornton report dated June 10, 2015

We have had the opportunity to review and consider the June 10, 2015 report of Grant Thornton to the Board, on Hydro's Compliance Application. In particular, we have reviewed and considered, with the input of the IIC Group consultant InterGroup, the following comments of Grant Thornton:

"...we can confirm that the interim rates included on Schedule 1 of the June 27 5, 2015 Compliance Filing are in accordance with P.U. 14(2015) with the exception of the following observations:

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[2] The bill impacts are calculated based on 2015 Test Year billing determinants as provided in response to IC-NLH-028 Rev1. Column A is the total revenue estimate at the existing rates as of June 2015; column B is the total revenue estimate at IIC Group proposed interim rates which includes both kW.h and kW RSP Surplus adjustment and Teck Rider at current rate of -1.111 cents/kW.h.

- *Depending on the interpretation of the specifically assigned charges in the calculation of the RSP Surplus Funding that would result in an effective 2.7% rate increase, the RSP Surplus Adjustment could be either (0.349) cents/ kWh or (0.352) cents/kWh. Currently, the RSP Surplus Adjustment rate included in the RSP Rules on Schedule 1 is (0.349) cents/kWh."*

With respect, and with reference to the submissions above, the IIC Group submit that the Grant Thornton interpretation of the options for the RSP Surplus Adjustment to IC Interim rates does not take into account the following statement of the Board, in its June 3, 2015 correspondence, regarding the interpretation of P.U. 14 (2015):

"The Board did approve a 10% base rate increase for Island Industrial customers which should not be applied to any other rate components such as the specifically assigned charges or RSP adjustments. It is an approved base rate increase only and not a 10% increase in revenue from the Island Industrial customers."

Grant Thornton's analysis is based on Table 4 of Hydro's Evidence to Revised Compliance Application filed with the Board on June 5, 2015, as reproduced on page 2 of its June 10, 2015 report, and on Grant Thornton's adaptation of that Table, on page 3 of its June 10, 2015 report. The calculations in Hydro's Table 4, and in Grant Thornton's adaptation of it, both derive from a 10% increase in "Base Rate Revenue" (per line D in each Table). This approach is inconsistent with the Board's June 3, 2015 direction reproduced above. The IIC Group respectfully submit that the rate-based approach developed by InterGroup to arriving at "*an effective 2.7% rate increase"* is the correct approach.

Table 4 below provides a reconciliation of the revenues at existing and proposed rates included in IIC Group submission Tables 1 and 3 to the Hydro's calculations in Table 4 of June 5, 2015 submission, as relied upon by Grant Thornton in its submission.

Table 4. Reconciliation of Industrial Customer Revenues at Existing and Proposed Rates [3]

Line No	Table Reference	Revenues at Existing Rates - excluding SAC revenues	Revenues at Hydro's June 5, 2015 Proposed Interim Rates Effective July 1, 2015 - excluding SAC revenues	Revenues at IIC Group Proposed Interim Rates Effective July 1, 2015 - excluding SAC revenues
		A	B	C
1	Table 1 of IIC Group submission	29,728,884	30,787,010	
	Table 3 of IIC Group submission	29,728,884		30,535,734
2	Grant Thornton Report, page 2	29,955,527	30,780,289	
	Grant Thornton Report, page 3	29,955,527		30,764,326
3=1-2	Difference	(226,643)	6,721	(228,592)
	Due to Teck Rider	(226,643)		(226,643)
	Due to rounding of rates (IIC Group calculations are based on rates, not revenues)	-	6,721	(1,949)

Note that Table 4 illustrates that the final effect on Hydro and the industrial class is not materially different between the IIC approach and the Grant Thornton approach shown on page 3 of Grant Thornton's Report. The differences are the effects on individual customers, which are not shown in the Grant Thornton analysis. The Grant Thornton revenue approach yields impacts that differ by customer from the intended 2.7% increase (even though the class overall achieves a 2.7% revenue increase). The IIC Group rates approach achieves the precise 2.7% impact on each customer[4], as well as the class overall.

Hydro's proposed termination of the Teck Rider

As noted above, there was no indication before Hydro's May 27, 2015 filing that the Teck Rider might be being put in issue by Hydro, and no explanation until Hydro's June 2, 2015 correspondence for this proposal. It is apparent that the proposed termination of the Teck Rider cannot be considered or deemed to have been approved by P.U. 14 (2015).

Moreover, Hydro's rationale for the proposed termination of the Teck Rider does not arise from any new developments since P.U. 14 (2015) was issued or indeed since Hydro filed its Interim Rates Application in January 2015. Hydro was aware, when Teck Resources filed, in the Fall of 2014, its Power on Order for 2015 that the Duck Pond operation would have reduced power

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[3] The total revenue of $30,780,289 shown in line No 2, column B is sum of $29,955,527 and $824,762 provided in table on page 2 of Grant Thornton's Report. The total revenue of $30,764,326 shown in line No 2, column C is sum of $29,955,527 and $808,799 provided in table on page 3 of Grant Thornton's Report.

[4] Teck will have slightly higher rate impact due to Teck Rider impact.

requirements effective July 1, 2015. Indeed, Hydro has been aware since at least the Spring of 2013 that there was a planned 2015 phase down of Duck Pond power requirements.

Hydro's proposal to now terminate the Teck Rider, in Interim Rates being sought in the context of Hydro's Amended General Rate Application (filed November 14, 2014), is in direct contradiction to that Application. At page 11 of the Amended General Rate Application (GRA), Hydro is seeking an order for a distinct Teck Resources RSP Rate, as further indicated at page 6 of 46 of the Rates Schedule filed with the Amended GRA, intended to be effective February 1, 2015.

Moreover, Hydro's proposal in the Amended GRA for a continuing distinct Teck Resources RSP Rate was contemplated to continue through the whole IC rate phase-in period, into 2016, as indicated by the following provision at page 17 of 47 of the Rate Stabilization Plan (Interim) Schedule to the Amended GRA:

The Teck Resources RSP Adjustment rate will be (1.119) ¢ per kWh for January 1, 2015 to August 31, 2015 and (1.131) ¢ per kWh for September 1, 2015 to August 31, 2016.

All of the foregoing was being sought by the Amended GRA in the context of Hydro's knowledge that Teck Resources' power requirements would reduce dramatically in mid 2015, as indicated by the following statement in the Amended GRA, Section 2: Regulated Activities, page 2.61, lines 16-17 that

Beginning in June 2015 it is expected that Teck Resources will no longer require power and energy from Hydro.

It is to be noted that the above Amended GRA statement overstates the change in Teck Resources' power requirements. As indicated by Teck Resources' Power on Order filed in the Fall of 2014 (and as confirmed by Teck Resources' own Application in respect of same filed on May 27, 2015), Teck Resources will continue to be an industrial customer of Hydro, albeit with reduced requirements, for the entirety of the IC rate phase-in period directed by the Provincial Government by OC2013-089.

Hydro's present Application has been explicitly brought to comply with P.U. 14 (2015). The proposed elimination of the Teck Rider is neither an expressly or implicitly necessary to achieve that compliance; indeed, it results in non-compliance with P.U. 14 (2015) by imposing on Teck Resources, per Table 1 above, an effective rate increase of 32.2%, clearly in contradiction with the Board's direction that interim rates be implemented *"so that there is an effective interim increase of 2.7% in Island Industrial customer rate, including Teck"*.

It is submitted that, as the Board has directed in relation to the proposed 2015 Revenue Deficiency Deferral Account, the issue of the proposed termination of Teck Rider, if Hydro intends to pursue it, can only be appropriately addressed by a separate Hydro application, explaining why Hydro is departing from its Amended GRA filings in respect of the Teck Rider, and explaining how such a change could be considered to be consistent with the direction of the Provincial Government in OC2013-089 with respect to how the IC rate phase is to be applied to Teck Resources.

Moreover, a separate application in relation to the Teck Rider (should Hydro decide it has grounds to proceed with it) would serve to better assure that there is not an inconsistency and unfairness in result between Hydro's proposal to terminate the Teck Rider (which apparently, but erroneously, is predicated on Teck Resources no longer being a "true" industrial customer) and the result that will be arrived at in the ongoing Application filed by Teck Resources on May 27, 2015 seeking from the Board an order for relief in respect of its 2015 Power on Order (the "Teck Application"). If the relief sought by the Teck Application is not granted, this will in effect mean that Teck Resources will continue to be billed as if its power requirements have not been reduced in the last half of 2015; paradoxically, it is this very reduction in power requirements that Hydro is apparently advancing as the basis for proposing the elimination of the Teck Rider. Eliminating the Teck Rider, in the context of not granting the relief sought by the Teck Application, would be doubly unfair to Teck Resources.

Interim rates effective July 1, 2015

The IIC Group respectfully submit that Hydro should be ordered to implement interim rates as provided in Table 2 of this submission, as the result that comes closest to compliance with the Board's direction in P.U. 14 (2015) that interim rates be implemented *"so that there is an effective interim increase of 2.7% in Island Industrial customer rate, including Teck"*.

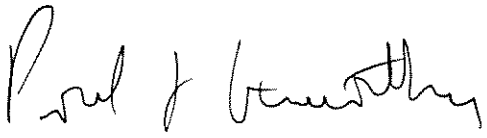
Costs

The IIC Group submit that their participation in these proceedings, with the assistance of legal counsel and of their consultants InterGroup, has been necessary. Moreover, the necessity and scope of the IIC Group's participation in this Application should be considered in the context of deficiencies and unexpected elements in Hydro's Interim Rates Compliance Application; this context has only added to the complexity of the information to be reviewed and the issues to be considered. The IIC Group respectfully submit that these considerations merit an order for costs in favour of the IIC Group, in the present Interim Rate Compliance Application, regardless of how the Application may ultimately be disposed of by the Board.

All of which is respectfully submitted.

Yours truly,

Stewart McKelvey



Paul L. Coxworthy

PLC/kmcd

c. Geoffrey P. Young, Senior Legal Counsel, Newfoundland and Labrador Hydro
Thomas J. Johnson, Consumer Advocate
Gerard Hayes, Newfoundland Power
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New Brunswick | Newfoundland and Labrador | Nova Scotia | Prince Edward Island

June 15, 2015

VIA COURIER and ELECTRONIC MAIL

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

Attention: Ms. G. Cheryl Blundon
Board Secretary

Dear Ms. Blundon:

RE: Newfoundland and Labrador Hydro – 2015 Interim Rates Compliance Application

Following a review of the Newfoundland and Labrador Hydro's ("NLH") 2015 Interim Rates Application (revised), dated June 5, 2015 and the Grant Thornton report dated June 10, 2015, Vale Newfoundland and Labrador ("Vale") submits that Hydro's Application is not in compliance with P.U. 14(2015).

Specifically, Hydro's proposal for Industrial Customer ("IC") rates calculates the effective rates based on the 2.7% revenue increase for demand, energy **and specific allocated** (Evidence, page 5, Table 4, calculation E). In the Board's letter to NLH dated June 3, 2015, the Board was clear in pointing out in deficiency (2) that the 10% increase in IC base rates was to be for **demand and energy only**. The Board further emphasized that the Order was for a 10% **rate** increase and not a 10% **revenue** increase for NLH. In deficiency (3), the Board noted "*..... that there is an effective interim increase of 2.7% in Island Industrial Customer rate (sic), including Teck*". Again, the Board ordered a 2.7% increase in rates; not in revenue. In its report, Grant Thornton prepared a chart that calculates the 2.7% increase based on demand and energy only (reference: report page 3, line 10).

Vale submits that the proper method of implementing the IC rate increase ordered in P.U. 14(2015) is to increase both the demand and energy rate components by 10% and then apply an adjustment from the IC RSP Surplus to reduce the increase to each of the demand and energy rates to 2.7%. This rate design will ensure that, as stated in section 2.iii.b of P.U. 14(2015), each member of the IC Group receives a 2.7% increase as opposed to the IC

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class of customers collectively receiving a combined 2.7% increase.[1] The rate design requested by Hydro in the current Application would not achieve this result as the rate increase will vary between members of the IC group based on their individual load factors. Creating a rate structure that results in an effective 2.7% increase to each of the demand and energy rates could be established by rewording the RSP using the same methodology that NLH proposed in its January 28, 2015 Application for interim rates.[2]

Yours faithfully,

Thomas J. O'Reilly, Q.C.

TJOR/js

c.c. Geoffrey P. Young, Senior Legal Counsel, Newfoundland & Labrador Hydro
Gerard Hayes, Senior Legal Counsel, Newfoundland Power
Thomas J. Johnson, O'Dea Earle
Paul Coxworthy, Stewart McKelvey
Dennis Browne, Q.C., Browne Fitzgerald Morgan & Avis
Nancy Kleer, Olthuis, Leer, Townshend LLP
Yvonne Jones, MP Labrador
Genevieve M. Dawson, Benson Buffett

[1] Reference: In the evidence, Hydro acknowledges a 2.7% increase to the IC class this when they refer to "..... the average customer rate increase ....." (evidence, page 6, lines 18-19).

[2] Reference: January 28, 2015 Interim Rate Application, Rate schedule RSP, page RSP-7, Section E.1.1, "Industrial Customer RSP Surplus Credit Adjustment". The same method was proposed by Hydro in the 2013 industrial RSP application (evidence page 9, section 4.3, lines 19-24, as well as appendix F and the response to IC-NLH-1 from the IC RSP application)

newfoundland labrador hydro
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June 17, 2015

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

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

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro – Interim Rates Revised Compliance Application - Revision

Enclosed please find an original plus 12 copies of Hydro's final submission and reply (Revision 1) regarding the Revised Compliance Application. The revisions are necessary to reflect word changes on pages 4 and 5.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Senior Legal Counsel

GPY/cp

cc: Gerard Hayes – Newfoundland Power
Paul Coxworthy – Stewart McKelvey Stirling Scales
Thomas J. O'Reilly, Q.C. – Cox & Palmer
Dennis Browne, Q.C. – Browne Fitzgerald Morgan & Avis
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Senwung Luk – Olthuis, Kleer, Townshend LLP
Genevieve M. Dawson – Benson Buffett

SUBMISSION AND REPLY OF

NEWFOUNDLAND AND LABRADOR HYDRO

Revised Compliance Application

June 17, 2015

newfoundland labrador hydro
a nalcor energy company

IN THE MATTER OF the *Public Utilities Act*, R.S.N. 1990, Chapter P-47 (the "Act"); and

IN THE MATTER OF a general rate application by Newfoundland and Labrador Hydro to establish customer electricity rates for 2015; and

IN THE MATTER OF a revised application (the "Revised Compliance Application") by Newfoundland and Labrador Hydro for approval of: (i) customer rates, tolls and charges reflecting the determinations set out in Order No. P.U. 14(2015) and (ii) a revised Rate Stabilization Plan adjustment to apply to the Utility Rate for the period July 1st, 2015 to June 30th, 2016.

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

SUBMISSION AND REPLY OF NEWFOUNDLAND AND LABRADOR HYDRO

The following is Newfoundland and Labrador Hydro's (Hydro) submission and its reply to the parties' submissions with regard to the above-noted application.

1.0 Application Background

On July 30, 2013, Hydro filed its General Rate Application (GRA) seeking approval of rates for January 1, 2014, based on a 2013 Test Year, in accordance with a government directive. Hydro subsequently filed two applications for interim relief recognizing that delayed rate implementation would deprive Hydro of the opportunity to earn a just and reasonable return on rate base for 2014. Both of these applications were denied. On June 6, 2014, Hydro notified the Board of Commissioners of Public Utilities (the Board) and the Parties that it would be filing an amended GRA in the fall of 2014 based on updated financial information. It became apparent to Hydro that because of changes in its forecast costs since

filing the 2013 GRA, the prudent course of action was to update the evidence in its 2013 GRA to derive rates based upon 2015 forecast costs. The stipulation in the Order in Council which required the use of a 2013 Test Year for the GRA was rescinded effective October 30, 2014.

On November 10, 2014, Hydro filed its Amended General Rate Application (the Amended Application) with the Board. In its Amended Application, Hydro requested that the proposed customer rates be approved on an interim basis in advance of completing the GRA. Hydro also proposed revised Rate Stabilization Plan (RSP) Rules to become effective on an interim basis on January 1, 2015 to permit the continued phase in of the Island Industrial Customer (IIC) rates.

On November 28, 2014, Hydro filed an application requesting approval of the deferral and recovery of $45.9 million in revenue deficiency for 2014. The creation of a deferral account to address Hydro's 2014 revenue deficiency of $45.9 million was approved by the Board. In addition, Hydro's application regarding deferral of increased capacity-related supply costs of $9.6 million, dated October 8, 2014, was approved for deferral by the Board.

On December 24, 2014, Hydro was directed by the Board to file a comprehensive and complete interim rates application for rates to be charged effective March 1, 2015. In accordance with this direction from the Board, Hydro filed its 2015 Interim Rates Application on January 28, 2015, for an interim order from the Board as to rates to be charged to Hydro's IIC, Newfoundland Power (NP) and Hydro's Rural Customers, as well as changes to the RSP Rules to implement the phase in of changes to the IIC rates.

Order No. P.U. 14(2015) (the 2015 Interim Rates Order) directed Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on consumers and Hydro incorporating the findings in the 2015 Interim Rates Order. On May 27, 2015, Hydro filed an application in response to the

Board's findings in the 2015 Interim Rates Order. The Board provided correspondence by letter on June 3, 2015 stating that the 2015 Interim Rate Compliance Application did not comply with the 2015 Interim Rates Order and directed Hydro to amend and re-file the application. On June 5, 2015, Hydro filed a Revised Compliance Application to comply with the Board's direction. This submission is filed in response to other parties comments on the Revised Compliance Application.

2.0 Interim Rates Order

The 2015 Interim Rates Order directed Hydro to file:

"a revised Schedule of Rates, Tolls and Charges and RSP Rules, effective July 1, 2015, with evidence showing the impacts on consumers and Hydro, incorporating the findings of the Board in this Order, including:

i) an interim base rate increase of 8.0% for Newfoundland Power Inc.;
ii) an interim base rate increase for Government Diesel customers of 50% of the proposed increases; and
iii) in relation to Island Industrial customers:
    a) an interim base rate increase of 10.0%;
    b) an interim RSP rate adjustment which will result in an effective 2.7% rate increase for all Island Industrial customers;
    c) a transfer from the IC RSP Surplus to fund the difference between the approved 10.0% base rate increase and the effective 2.7% increase; and
    d) a transfer from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

3.0 Hydro's Revised Compliance Application

3.1 Utility Rate

In the 2015 Interim Rates Order, the Board approved an 8% increase in the base Utility Rate effective July 1, 2015. Hydro proposed to apply the 8% increase equally to all rate components. The base rate increase is to become effective on July 1, 2015 at the same time as the annual update to the NP RSP rate adjustment. As a result, the Revised Compliance Application also provided the derivation of the RSP Adjustments to apply to NP relative to the 2007 Test Year, in accordance with the approved RSP rules.

Grant Thornton confirmed that the interim rates included on Schedule 1 of the Revised Compliance Application represents an 8% increase in the monthly demand and energy rates in comparison to the rates currently being charged to NP.[1]

Grant Thornton also confirmed that the proposed RSP Fuel Rider and the RSP Adjustment Rate based on the March 31, 2015 balance is in accordance with Board Orders.

Based on the Grant Thornton review, the proposed Utility Rate included in the Revised Compliance Application is in accordance with the Board's direction in the 2015 Interim Rates Order. NP provided no comments on the Revised Compliance Application. The Consumer Advocate submitted that the proposed Utility Rate is compliant with the 2015 Interim Rates Order.

3.2 Hydro Rural Government Diesel Rates

In the 2015 Interim Rates Order, the Board approved an interim base rate increase of 50% of the increase proposed in the 2015 Interim Rates Application in the rates for Government Diesel Customers effective July 1, 2015. Grant Thornton concluded that the proposed interim rates included in the Revised Compliance Application for this customer group are in accordance with the Board's direction in the 2015 Interim Rates Order.[2] The Consumer Advocate also submitted that the proposed Government Diesel rates are compliant with the 2015 Interim Rates Order.

3.3 IIC Rates

Base Rates

The Revised Compliance Application proposed a 10% base rate increase to base demand and energy charges with no proposed change in specifically assigned charges. No party disagreed with the proposed base rates.

[1] See page 4 of Grant Thornton Report filed June 10, 2015.
[2] See page 5 of Grant Thornton Report filed June 10, 2015.

Calculation of RSP Surplus Adjustment

The Board also approved an interim RSP rate adjustment which will result in an effective 2.7% rate increase for all IIC. In the Revised Compliance Application, Hydro computed a proposed RSP Surplus Adjustment based upon a (0.349)¢ per kWh rate that would result in an effective 2.7% increase in billings to IIC based upon the 2015 Test Year forecast.

Grant Thornton noted that depending on the interpretation of the 2015 Interim Rates Order in the calculation of the required RSP Surplus funding, the RSP Surplus Adjustment could be either (0.349) ¢/kWh or (0.352) ¢/kWh to provide an effective 2.7% rate increase. Hydro notes that page 17 of the 2015 Interim Rates Order stated the Board will approve "an effective interim increase of 2.7% in Island Industrial ***customer rates***"[3] (emphasis added). The Board did not stipulate an effective 2.7% increase in base rates. Customer rates include all charges to customers including specifically assigned charges and the RSP Adjustment.

Rate increases expressed as a percentage are generally calculated as the change in customer billings in dollars expressed as a percentage of total customer billings on existing rates.[4] Therefore, Hydro did not exclude the existing rate revenues from specifically assigned charges in computing the amount of funding required from RSP Surplus Adjustment.[5]

The IIC Group and Vale submitted the RSP Surplus Adjustment to be implemented as a result of the 2015 Interim Rates Order should include both a demand RSP Surplus credit and an energy RSP Surplus credit to ensure the base rate impacts of the rate change equalled 2.7% for each customer. As noted above, the Board did not stipulate a 2.7% increase in

[3] See lines 17-18 on page 17 of Order No. P.U. 14(2015).

[4] This approach is consistent with the calculation of rate increase percentages used by Newfoundland Power. For example, in the case of a Rate Stabilization Adjustment and Municipal Tax Adjustment rate change being implemented by Newfoundland Power, it is not uncommon that no change in the customer charge or demand charge is required. However, the rate increase is still calculated based upon the estimated change in total billings as a percentage of total existing billings (i.e., sum of demand charges, energy charges and customer charges).

[5] The only RSP Adjustment currently in effect applies to Teck Resources who has indicated to the Board that it will be discontinuing its mining and milling operations prior to the July 1, 2015 rate change implementation.

base rates but an effective 2.7% increase in customer rates. The approach proposed by the IIC will not result in a 2.7% increase in IIC rates but will result in a lower percentage increase as no increase is proposed in specifically assigned charges.

In the 2015 Interim Rates Order, the Board did not stipulate the method for calculating the RSP Surplus Adjustment. However, the current RSP rules provide for RSP adjustments to be calculated on a ¢ per kWh basis. The impacts of RSP rate changes typically impact customer bills differently on a percentage basis depending on their usage characteristics. The implementation of an RSP Adjustment reflects a fuel cost variance which would normally be recovered through energy charges. Given the RSP Surplus has accumulated based upon fuel savings, unless the Board provided direction to take an alternate approach, Hydro believes it was reasonable for Hydro to assume disposition of the RSP Surplus in a manner consistent with the disposition of fuel savings through the RSP (i.e., on a ¢ per kWh basis).

Teck RSP Adjustment

The 2015 Interim Rates Order requires the same interim rate increase apply to Teck Resources as approved for the other IIC. This would require maintaining a separate RSP rate for Teck Resources. The application by Teck Resources filed with the Board on May 27, 2015 states Teck will be discontinuing its mining and milling operations effective June 30, 2015. The Application also states that Teck will be operating an office type environment beyond June 30, 2015. As a result of Teck's closure of its mining and milling operations, Hydro's Revised Compliance Application proposed to discontinue the Teck Resources RSP adjustment of (1.111)¢ per kWh that has been in effect since September 1, 2013.

The information from Teck Resources indicates that beyond June 30, 2015, Teck will have materially reduced energy requirements from Hydro. As Teck Resources still requires electrical service, Teck will be required to pay specifically assigned charges; the current specifically assigned charge for Teck is $186,169 per year. The monthly specifically assigned charge will be a material portion of the Teck monthly bill for electrical service. For the

remainder of 2015, Teck is also required to pay demand charges in accordance with their Service Agreement.[6]

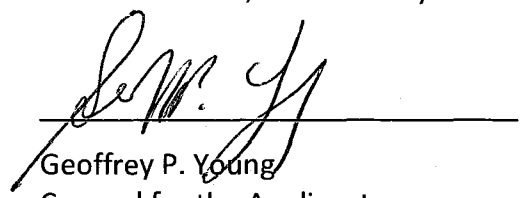
The IIC Group submission shows a 32.2% increase for Teck Resources based upon the calculation of revenues under existing and proposed rates excluding revenues from specifically assigned charges.[7] Hydro notes that the IIC Group calculation of the percentage increase was based upon energy usage of Teck for the 2015 Test Year. This includes the amount used prior to Teck closing the mining and milling operations. The 32.2% also does not include the specifically assigned charge for which no increase is proposed at this time. As a result, both the dollar impact and the percentage impact presented in the IIC Group submission do not accurately reflect the prospective customer rate impact of Board approval of the Revised Compliance Application.

To limit the percentage rate increase to Teck Resources to 2.7% would require a larger RSP credit adjustment than currently approved (i.e., (1.111)¢ per kWh). The larger credit is required to reduce the rate impact of the 10% increase in demand charges to become effective July 1, 2015. Increasing the RSP credit adjustment at this time for Teck Resources is not consistent with the phase-in of cost based rates. Hydro submits that given the material reduction in Teck Resources load requirements, it is reasonable at this time to phase-out the RSP credit adjustment of (1.111)¢ per kWh which only applies to Teck Resources. Approval of Hydro's proposal would result in all the IIC paying the same customer rates effective July 1, 2015.

All of which is respectfully submitted.

[6] There is currently an application before the Board on this matter.
[7] Source: page 3 of IIC Group submission on June 15, 2015.

DATED at St. John's, in the Province of Newfoundland and Labrador, this 17th day of June, 2015.



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NEWFOUNDLAND AND LABRADOR
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

AN ORDER OF THE BOARD

NO. P.U. 17(2015)

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

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

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

IN THE MATTER OF an application by Newfoundland and Labrador Hydro for approval of (i) customer rates, tolls and charges reflecting the determinations set out in Order No. P.U. 14(2015) and (ii) a revised Rate Stabilization Plan adjustment to apply to the Utility Rate for the period July 1, 2015 to June 30, 2016.

The Application

On January 28, 2015 Hydro filed an application seeking, among other things, approval of increases in customer rates on an interim basis (the "Interim Rate Application") in advance of the conclusion of its general rate application. In Order No. P.U. 14(2015) the Board approved, effective July 1, 2015:

i) an interim base rate increase of 8.0% for Newfoundland Power;

ii) an interim base rate increase for Government Diesel customers of 50% of the proposed increases; and

iii) in relation to Island Industrial customers:

   a) an interim base rate increase of 10.0%;

b) an interim RSP rate adjustment which will result in an effective 2.7% rate increase for all Island Industrial customers;
c) a transfer from the IC RSP Surplus to fund the difference between the approved 10.0% base rate increase and the effective 2.7% increase; and
d) a transfer from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

On May 27, 2015 Hydro filed a compliance application to give effect to the findings of the Board in Order No. P.U. 14(2015). The application also requests approval of the RSP rate to be charged to Newfoundland Power for the period July 1, 2015 to June 30, 2016. On June 2, 2015 Hydro provided supplemental information in relation to the application. On June 3, 2015 the Board wrote Hydro clarifying the requirements in relation to the compliance application. On June 5, 2015 Hydro filed a revised application (the "Application") requesting approval of:

i) the RSP rate to be charged by Hydro to Newfoundland Power;

ii) the revised base Utility Rate;

iii) the revised base rate and RSP adjustment for Island Industrial Customers;

iv) the revised rates for Government customers on Isolated Diesel Systems;

v) the removal of the RSP adjustment specifically for Teck Resources; and

vi) the revised RSP rules and the new IC RSP Surplus Adjustment to provide for the disposition of the IC RSP Surplus and limit the effective customer rate impact to 2.7%.

The revised RSP Rules also provide for the removal of Section E related to Historical Plan Balances.

A copy of the Application was provided to the parties in the general rate application proceeding: Newfoundland Power; the Consumer Advocate, Mr. Thomas Johnson; Corner Brook Pulp and Paper Limited, NARL Refining Limited Partnership (formerly North Atlantic Refining Limited) and Teck Resources Limited (the "Industrial Customer Group"); Vale Newfoundland and Labrador Limited ("Vale"); the Innu Nation; the Towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River (the "Towns"); Yvonne Jones, MP and the Nunatsiavut Government.

The Board's financial consultants, Grant Thornton LLP, reviewed the Application and filed a report on June 10, 2015 which was circulated to the parties.

On June 11, 2015 Newfoundland Power advised that it had no comments on the Application. The Industrial Customer Group, Vale, and the Consumer Advocate filed submissions on June 15, 2014. Hydro filed a reply submission on June 17, 2015.

Grant Thornton's report

Grant Thornton concludes in its report that the proposed interim rates for Newfoundland Power and Government Diesel customers are in accordance with Order No. P.U. 14(2015). Grant Thornton also confirmed that Hydro's calculation of the RSP adjustments for Newfoundland Power to be effective July 1, 2015 is in accordance with Board orders.

In relation to the Island Industrial customers, Grant Thornton concluded that the proposed base rate increase was in accordance with Order No. P.U. 14(2015) but noted that, depending on the interpretation of whether the 2.7% effective increase for industrial customer rates was to be applied to specifically assigned charges or not, the RSP adjustment could be either (0.349) cents per kWh or (0.352) cents per kWh.

Grant Thornton also noted that the Application included revisions to the RSP rules to eliminate the RSP adjustment for Teck Resources Limited and the section related to the Historical Plan Balances, neither of which had been included in Order No. P.U. 14(2015).

Submissions

The Industrial Customer Group submits that the Application is not in compliance with Order No. P.U. 14(2015) as it results in two industrial customers, Corner Brook Pulp and Paper Limited and Teck Resources Limited, incurring effective rate increases greater than the 2.7% directed by the Board. The Industrial Customer Group states that, despite the rate increase of 10% being applied to both the demand and energy components, the IC RSP Surplus adjustment is only applied to the energy component, which would cause different percentage rate impacts to industrial customers under the same rate class due to load characteristics of each industrial customer. The Industrial Customer Group also submits that Hydro's calculations in Table 4 of the evidence and Grant Thornton's adaption of the table both derive from a 10% increase in base rate revenue, which is inconsistent with the Board's direction of June 3, 2015, which stated that the Board approved a base rate increase, not an increase in revenue. In its submission the Industrial Customer Group proposes rates which, they submit, come as close as is possible to compliance with Order No. P.U. 14(2015).

With respect to Hydro's proposal to terminate the RSP adjustment for Teck Resources Limited the Industrial Customer Group submits that this issue can only be appropriately addressed in a separate application, with explanation as to why Hydro is departing from its amended general rate application filing and how such a change could be considered to be consistent with the direction of OC2013-089.

Vale submits that the proper method of implementing the industrial customer rate increase ordered in Order No. P.U. 14(2015) is to increase both the demand and energy rate components by 10% and then apply an adjustment from the IC RSP Surplus to reduce the increase to each of the demand and energy rates to 2.7%. Vale submits that this rate design will ensure that each member of the Industrial Customer class receives a 2.7% increase as opposed to the Industrial Customer class collectively receiving a combined 2.7% increase.

The Consumer Advocate believes that the Application is consistent with Order No. P.U. 14(2015) and does not believe that the exceptions identified in Grant Thornton's report are material but points out that only the Board can make that determination. The Consumer Advocate requests that the Board direct Hydro to file information he believes is necessary to support a proper review of the amended general rate application.

Hydro's Reply Submission

Hydro notes that Grant Thornton concluded that the rates for Newfoundland Power and for Government Diesel customers were in compliance with Order No. P.U. 14(2015) and that there was no disagreement with the 10% base rate increase to demand and energy charges for the Island Industrial customers. Hydro submits that the Board did not stipulate a 2.7% increase in base rates but an effective 2.7% increase in customer rates and that customer rates include all charges to customers including specifically assigned charges and the RSP adjustment. Hydro states that rate increases expressed as a percentage are generally calculated as the change in customer billings in dollars expressed as a percentage of total customer billings on existing rates and, therefore, Hydro did not exclude the existing rate revenues from specifically assigned charges in computing the amount of funding required from the IC RSP surplus.

With respect to the RSP Surplus adjustment Hydro states that the Board did not stipulate the method for calculating the RSP Surplus adjustment and that the current RSP rules provide for RSP adjustments to be calculated on a cent per kWh basis. Hydro submits that, because the RSP Surplus has accumulated based upon fuel savings, in the absence of direction from the Board to take an alternate approach it was reasonable for Hydro to assume disposition of the RSP Surplus in a manner consistent with the disposition of fuel savings through the RSP.

Hydro states that it proposed to discontinue the RSP adjustment for Teck Resources Limited as a result of Teck Resources Limited's closure of its mining and milling operations effective June 30, 2015. Hydro submits that to limit the percentage rate increase to Teck Resources Limited to 2.7% would require a larger RSP credit adjustment than currently approved and that increasing the RSP credit adjustment for Teck Resources Limited would not be consistent with the phase-in of cost based rates. Hydro also submits that, given the material reduction in Teck Resources Limited load requirements, it is reasonable at this time to phase-out the RSP credit adjustment which only applies to Teck Resources Limited. Hydro submits that approval of its proposal would result in all the Island Industrial customers paying the same customer rates effective July 1, 2015.

Board Findings

i) Rates for Newfoundland Power and Government Diesel Customers

The Board has reviewed the Application, the submissions of the parties and Grant Thornton's report and is satisfied that the proposed base rate to Newfoundland Power as well as the proposed rates to Government Diesel customers reflect the determinations of the Board in Order No. P.U. 14(2015) and should be approved.

ii) Newfoundland Power RSP adjustment for July 1, 2015

The Board has reviewed the Application, the submissions of the parties and Grant Thornton's report and is satisfied that the proposed Current Plan and the Fuel Rider rates and the RSP adjustment to be applied to the rates to be charged by Hydro to Newfoundland Power are in accordance with the methodology of the interim Rate Stabilization Plan approved by the Board and should be approved.

iii) Island Industrial Customer Rates

In Order No. P.U. 14(2015) the Board approved, in relation to Island Industrial customers, an interim base rate increase of 10%, and an interim RSP adjustment to result in a 2.7% rate increase for all Island Industrial customers. The Board also approved a transfer from the IC RSP Surplus to fund the difference between the approved base rate increase and the effective 2.7% increase, and the full amount of the 2014 year-end IC RSP current balance.

The Application proposes Island Industrial customer rates which will not result in an effective 2.7% rate increase for individual customers and which reflect amounts related to higher specifically assigned charges. In Order No. P.U. 14(2015) the Board approved an effective interim rate increase of 2.7% for all Island Industrial customers, including Teck Resources Limited, and found that there should be no changes to the specifically assigned charges in advance of the general rate application. The Board stated that the impact on electricity consumers and the reasonableness of the end result were key considerations in the interim rate application. The Board noted that the Island Industrial customers expressed significant concern about an effective rate increase of more than 2.7%.

The Board acknowledges Hydro's submission that disposition of the RSP Surplus in a manner consistent with the disposition of fuel savings through the RSP is not unreasonable but reiterates that the determinations of the Board in Order No. P.U. 14(2015) were based on the impact on customers, in the context of an interim application as a part of a general rate application. The Board finds that the proposed Island Industrial customer rates are not in compliance with Order No. P.U. 14(2015). The Board will require Hydro to develop rates which would result in an effective base rate increase of 2.7% for each individual Island Industrial customer, with no changes to the specifically assigned charges. This may result in unique interim RSP rates for each of the Island Industrial customers considering both the energy and demand rates. Final rates for 2015 for the Island Industrial customers will be established following the general rate application hearing.

In the Application Hydro also proposes that the Teck Resources Limited RSP adjustment be discontinued. Hydro notes that Teck Resources Limited will be discontinuing its mining and milling operations effective June 30, 2015 and states that there is no longer a requirement to maintain a separate RSP adjustment for Teck Resources Limited. The Board notes that this is a new proposal that was not before the Board in the interim rate application and which raises issues relating to the three-year phase-in of rates as directed by Government and addressed in Order No. P.U. 29(2013). In addition, the Board notes that there is another application before the Board in relation to Teck Resources Limited rates seeking relief from its 2015 Power on Order as

provided for in its Service Agreement. The Board specifically set out in Order No. P.U. 14(2015) that the rate changes were approved for all Island Industrial customers, including Teck Resources Limited. The Board will not discontinue the Teck Resources Limited RSP adjustment at this time. If Hydro wishes to request approval to discontinue the Teck Resources RSP adjustment it should file a separate application to allow a full review of the issues associated with its proposals.

iv) Conclusion

The Board will approve, on an interim basis, effective July 1, 2015, the proposed rates to be charged to Newfoundland Power, including the RSP adjustment, and the proposed rates to be charged to Government Diesel customers.

The Board will not approve the proposed Island Industrial customer rates and will require Hydro to re-file a proposed Schedule of Rates, Tolls and Charges and RSP rules reflecting an effective 2.7% base rate increase for each Island Industrial customer. For clarity, the calculation of the RSP Surplus adjustment for each Island Industrial customer should not reflect any changes to the revenue to be received for 2015 from specifically assigned charges or the proposed discontinuation of the Teck Resources Limited RSP adjustment.

The Board will not order Hydro to provide the information requested by the Consumer Advocate as this request would best be addressed as a part of the general rate application process.

The Board also notes that the proposed amendment to the RSP rules to remove Section E: Historical Plan Balances was not addressed in the Interim Rate Application or Order No. P.U. 14(2015) and the Board will not approve this amendment at this time.

IT IS THEREFORE ORDERED THAT:

1. The rates to be charged by Hydro to Newfoundland Power as set out in Schedule "A" to this Order, to be effective for electrical consumption on or after July 1, 2015, are approved on an interim basis.

2. The rates to be charged by Hydro to Government Diesel customers, as set out in Schedule "B" to this Order, to be effective for electrical consumption on or after July 1, 2015, are approved on an interim basis.

3. Hydro shall file a revised Schedule of Rates, Tolls and Charges and RSP Rules, effective July 1, 2015, to reflect for Island Industrial customers:

    i) an interim base rate increase of 10.0%;
    ii) interim RSP rate adjustments which will result in an effective 2.7% base rate increase for each Island Industrial customer, including Teck Resources Limited;
    iii) a transfer from the IC RSP Surplus to fund the difference between the approved 10.0% base rate increase and the effective 2.7% base rate increase; and
    iv) a transfer from the IC RSP Surplus to fund the full amount of the 2014 year-end IC RSP current balance.

4. The Industrial Customer Group is entitled to an award of costs in an amount to be fixed by the Board upon the filing of a detailed cost submission within 30 days of this Order.

5. Leave is granted to the other intervenors to apply within 30 days of this Order including a detailed cost submission for an award of costs.

6. Newfoundland and Labrador Hydro shall pay all the expenses of the Board arising from the Application.

DATED at St. John's, Newfoundland and Labrador, this 23rd day of June 2015.

Andy Wells
Chair & Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

Sara Kean
Assistant Board Secretary

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM)

Availability:

This rate is applicable to service to Newfoundland Power (NP).

Definitions:

"Billing Demand"

In accordance with Order No. P.U. 47(2014), the Curtailable Credit shall apply to determine the billing demand as an adjustment to the highest Native Load established during the winter period beginning in December 1, 2014 and ending March 31, 2015. The computation of the adjustment to reflect the Curtailable Credit is provided in the definitions below. The use of the Curtailable Credit in determining billing demand for subsequent winter periods will be subject to a further Order of the Board.

In the Months of January through March, billing demand shall be the greater of:

(a) the highest Native Load less the Generation Credit and the Curtailable Credit, beginning in the previous December and ending in the current Month; and
(b) the Minimum Billing Demand .

In the Months of April through December, billing demand shall be the greater of:

(a) the Weather-Adjusted Native Load less the Generation Credit and the Curtailable Credit, plus the Weather Adjustment True-up; and
(b) the Minimum Billing Demand.

If at the time of establishing its Maximum Native Load, NP has been requested by Hydro to reduce its Native Load by shedding curtailable load, the calculation of Billing Demand for each month shall not deduct the Curtailable Credit.

"Generation Credit" refers to NP's net generation capacity less allowance for system reserve, as follows:

	kW
Hydraulic Generation Credit	80,104
Thermal Generation Credit	37,826
Total Generation Credit	117,930

In order to continue to avail of the Generation Credit, NP must demonstrate the capability to operate its generation to the level of the Generation Credit. This will be verified in a test by operating the generation at a minimum of this level for a period of one hour as measured by the generation demand metering used to determine the Native Load. The test will be carried out at

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

a mutually agreed time between December 1 and March 31 each year. If the level is not sustained, Newfoundland Power will be provided an opportunity to repeat the test at another mutually agreed time during the same December 1 to March 31 period. If the level is not sustained in the second test, the Generation Credit will be reduced in calculating the associated billing demands for January to December to the highest level that could be sustained.

"Curtailable Credit" is determined based upon NP's forecast curtailable load available for the period in accordance with the terms and conditions set forth in NP's Curtailable Service Option. NP will notify Hydro of its available curtailable load with its forecast of annual and monthly electricity requirements.

In order to receive the Curtailable Credit, NP must demonstrate the capability to curtail its customer load requirements to the level of the Curtailable Credit. This will be verified in a test by curtailing load at a minimum of this level for a period of one hour. The test will be carried out at a mutually agreed time in December. If the level is not sustained, the Curtailable Credit will be reduced to the level sustained. If Hydro requests NP to curtail load before a test is completed and NP demonstrates the capability to curtail to the level of the Curtailment Credit, no test will be required.

NP will be required to provide a report to Hydro not later than April 15 to demonstrate the amount of load curtailed for each request of Hydro during the previous winter season. If the load curtailed is less than forecast for either request during the winter season, the annual Curtailable Credit will be adjusted to reflect the average load curtailed for the winter season. If NP is not requested to curtail during the winter season, the Curtailment Credit will established based upon the lesser of the load reduction achieved in the test or the forecast curtailable load (as provided in the previous two paragraphs).

"Maximum Native Load" means the maximum Native Load of NP in the four-Month period beginning in December of the preceding year and ending in March of the current year.

"Minimum Billing Demand" means ninety-nine percent (99%) of:

NP's test year Native Load less the Generation Credit and the Curtailable Credit.

The Curtailable Credit reflected in the Minimum Billing Demand will be set to equal the curtailable load used to determine the Maximum Native Load for NP for the most recently approved Test Year.

"Month" means for billing purposes, the period commencing at 12:01 hours on the last day of the previous month and ending at 12:00 hours on the last day of the month for which the bill applies.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

"Native Load" is the sum of:

(a) the amount of electrical power, delivered at any time and measured in kilowatts, supplied by Hydro to NP, averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter;
(b) the total generation by NP averaged over the same fifteen-minute periods.

"Weather-Adjusted Native Load" means the Maximum Native Load adjusted to normal weather conditions, calculated as:

Maximum Native Load
plus (Weather Adjustment, rounded to 3 decimal places, x 1000)

Weather Adjustment is further described and defined in the Weather Adjustment section.

"Weather Adjustment True-up" means one-ninth of the difference between:

(a) the greater of:
- the Weather Adjusted Native Load less the Generation Credit and the Curtailable Credit (if applicable), times three; and
- the Minimum Billing Demand, times three; and

(b) the sum of the actual billed demands in the Months of January, February and March of the current year.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Monthly Rates:

Billing Demand Charge:
Billing Demand, as set out in the Definitions section, shall be charged at the following rate:

$4.32 per kW of billing demand

Energy Charge:
First 250,000,000 kilowatt-hours* ..... @ 3.506 ¢ per kWh
All excess kilowatt-hours* ..... @ 9.509 ¢ per kWh

Firming-up Charge:
Secondary energy supplied by
Corner Brook Pulp and Paper Limited* ..... @ 0.908 ¢ per kWh

RSP Adjustment:
Current Plan ..... @ (0.715) ¢ per kWh
Fuel Rider ..... @ 0.532 ¢ per kWh

Total RSP Adjustment – All kilowatt-hours ..... @ (0.183) ¢ per kWh

***Subject to RSP Adjustment:**

RSP Adjustment refers to all applicable adjustments arising from the operation of Hydro's Rate Stabilization Plan, which levelizes variations in hydraulic production, fuel cost, load and rural rates.

Adjustment for Losses:

If the metering point is on the load side of the transformer, either owned by the customer or specifically assigned to the customer, an adjustment for losses as determined in consultation with the customer prior to January 31 of each year, shall be applied to metered demand and energy.

Adjustment for Station Services and Step-Up Transformer Losses:

If the metering point is not on the generator output terminals of NP's generators, an adjustment for Newfoundland Power's power consumption between the generator output terminals and the metering point as determined in consultation with the customer prior to the implementation of the metering, shall be applied to the metered demand.

NEWFOUNDLAND AND LABRADOR HYDRO

UTILITY (INTERIM) (continued)

Weather Adjustment: This section outlines procedures and calculations related to the weather adjustment applied to NP's Maximum Native Load.

(a) Weather adjustment shall be undertaken for use in determining NP's Billing Demand.

(b) Weather adjustment shall be derived from Hydro's NP native peak demand model.

(c) By September 30th of each year, Hydro shall provide NP with updated weather adjustment coefficient incorporating the latest year of actuals.

(d) The underlying temperature and wind speed data utilized to derive weather adjustment shall be sourced to weather station data for the St. John's, Gander, and Stephenville airports reported by Environment Canada. NP's regional energy sales shall be used to weight regional weather data. Hydro shall consult with NP to resolve any circumstances arising from the availability of, or revisions to, weather data from Environment Canada and/or wind chill formulation.

(e) The primary definition for the temperature weather variable is the average temperature for the peak demand hour and the preceding seven hours. The primary definition for the wind weather data is the average wind speed for the peak demand hour and the preceding seven hours. Hydro will consult with NP should data anomalies indicate a departure from the primary definition on underlying weather data.

(f) Subject to the availability of weather data from Environment Canada, Hydro shall prepare a preliminary estimate of the Weather-Adjusted Native Load by March 15th of each year, and a final calculation of Weather-Adjusted Native Load by April 5th of each year.

General:

This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

With respect to all matters where the customer and Hydro consult on resolution but are unable to reach mutual agreement, the billing will be based on Hydro's best estimate.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 1.2G (INTERIM)

DOMESTIC DIESEL

GOVERNMENT DEPARTMENTS

Availability:

For Service to Government Departments throughout the Island and Labrador diesel service areas of Hydro, to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate:

Basic Customer Charge.....$43.90 per month

Energy Charge:

All kilowatt-hours .....@ 83.567 ¢ per kWh

Minimum Monthly Charge $43.90

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST) which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE No. 2.1G (INTERIM)

GENERAL SERVICE DIESEL 0-10 kW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate:

Basic Customer Charge.....$48.54 per month

Energy Charge:
All kilowatt-hours .....@ 75.486¢ per kWh

Minimum Monthly Charge.....$48.54

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 2.2G (INTERIM)

GENERAL SERVICE DIESEL OVER 10 kW

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Service (excluding Domestic Service) to Government Departments throughout the Island and Labrador diesel service areas of Hydro where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater.

Rate:

Basic Customer Charge: .....$71.98 per month

Demand Charge:
The maximum demand registered on the meter in the current month.....@ $58.22 per kW

Energy Charge:
All kilowatt-hours.....@ 53.741 ¢ per kWh

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00 or more than $500.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales tax (HST) which applies to electricity bills.**

NEWFOUNDLAND AND LABRADOR HYDRO

RATE 4.1G (INTERIM)

STREET AND AREA LIGHTING SERVICE DIESEL

GOVERNMENT DEPARTMENTS (Continued)

Availability:

For Street and Area Lighting Service to Government Departments throughout the Island and Labrador Diesel service areas of Hydro, where the electricity is supplied by Hydro and all fixtures, wiring and controls are provided, owned and maintained by Hydro.

Monthly Rate:

	SENTINEL / STANDARD
MERCURY VAPOUR	
250W (9,400 lumens)	$72.74
HIGH PRESSURE SODIUM [1]	
100W (8,600 lumens)	58.92
150W (14,400 lumens)	72.74

[1] **Only High Pressure Sodium fixtures are available for all new installations and replacements.**

General:

Details regarding conditions of service are provided in the Rules and Regulations.
This rate schedule does not include the Harmonized Sales Tax (HST), which applies to electricity bills.

Schedule 3

2015 Net Income Deficiency Deferral Account

NEWFOUNDLAND AND LABRADOR HYDRO

July 10, 2015

newfoundland labrador hydro
a nalcor energy company

2015 Net Income Deficiency Deferral Account

This account shall provide for cost deferral of $20 million in 2015 to reduce Hydro's 2015 forecast net income deficiency which has resulted from delayed implementation of the rates proposed in its 2013 General Rate Application. Disposition of the balance in this account will be subject to an order of the Board.

Schedule 3

AMENDED 2015 COST DEFERRAL APPLICATION

NEWFOUNDLAND AND LABRADOR HYDRO

November 12, 2015

Evidence

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Evidence to the Amended 2015 Cost Deferral Application

NEWFOUNDLAND AND LABRADOR HYDRO

November 12, 2015

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Appendix F - 2015 Cost Deferral Account
Appendix G - Settlement Agreement – August 14, 2015
Appendix H – Hydro's 2015 Conservation Cost Deferral and Program Expansion Report

1.0 BACKGROUND

On January 28, 2015 Hydro filed an application with the Board (the 2015 Interim Rates Application) seeking approval of adjustments to its customer rates to provide interim rate relief effective March 1, 2015, in advance of conclusion of its General Rate Application (GRA). On May 8, 2015 the Board issued Order No. P.U. 14(2015) (the 2015 Interim Rates Order) directing Hydro to file a revised Schedule of Rates, Tolls and Charges and RSP Rules to become effective July 1, 2015 with evidence showing the impacts on customers and Hydro incorporating the findings in the 2015 Interim Rates Order. On June 5, 2015, Hydro filed a Revised Compliance Application reflecting the direction of the Board as provided in the 2015 Interim Rates Order. Approval of customer rates changes, reflecting the determinations set out in Order No. P.U. 14 (2015), was forecast to result in a net income deficiency based upon the 2015 Test Year of $41.8 million as a result of delayed rate implementation beyond January 1, 2015.

On July 23, 2015, Hydro filed a 2015 Cost Deferral Application requesting a cost deferral in amount of $20.0 million to reduce Hydro's forecast 2015 net income deficiency. Approval of the original 2015 Cost Deferral Application would have provided for a forecast net income of $11.4 million based upon the forecast 2015 Test Year. This amount was $21.8 million less than the proposed 2015 Test Year net income of $33.2 million. The original 2015 Cost Deferral Application did not anticipate the final GRA Board order being delayed beyond 2015.

The hearing portion of Hydro's GRA began on September 9, 2015. The hearing process is ongoing. Therefore, Hydro does not expect the Board will be in a position to make final determinations on the GRA before the conclusion of 2015. As such, Hydro is filing an Amended 2015 Cost Deferral Application to address the 2015 financial impacts of the delayed conclusion of Hydro's GRA beyond 2015. Approval of the Amended 2015 Cost Deferral Application is required to provide Hydro the opportunity to recover its costs, including a reasonable return on rate base for 2015, as required by Section 80 of the Public Utilities Act.

2.0 2015 NET INCOME DEFICIENCY

The updated forecast of the 2015 Net Income Deficiency is primarily related to three areas: (i) the 2015 net income deficiency resulting from billing customers for the first 6 months of 2015 based on 2007 Test Year base rates; (ii) the additional 2015 costs incurred by Hydro as a result of operating the Rate Stabilization Plan (RSP) relative to the 2007 Test Year; and (iii) the additional 2015 supply costs which Hydro proposed in the Amended GRA be recovered through new supply cost recovery mechanisms.

The updated forecast net income deficiency for 2015 is approximately $60.5 million based on a forecast net loss of $30.8 million. Hydro's Amended 2015 Cost Deferral Application provides proposals to the Board to address the forecast 2015 net income deficiency in a reasonable manner which does not disadvantage customers.

2.1 Delayed 2015 Rate Implementation

Due to the delayed implementation of 2015 Test Year rates, Hydro will not have the opportunity to recover its full test year revenue requirement in 2015. While the approval of interim rates effective July 1, 2015 has mitigated a portion of this impact, there still remains a material net income deficiency forecast for 2015.

Table 1 shows that the impact of delayed implementation of rates in 2015, adjusted for opening balance rate base reductions for 2015, is $36.8 million.

Table 1

Line No.	Particulars	$000's	
1	2015 Test Year Rates Net Income	33,232	[1]
2	2015 Existing Rates Net Income	(34,583)	[2]
3	Net Income Deficiency	67,815	[3]
4	Less Impact of Interim Rates	(26,000)	[4]
5	Gross Deficiency	41,815	[5]
6	Rate Base Adjustment	(5,000)	[6]
7	Net 2015 Deficiency	36,815	[7]

The $5.0 million revenue requirement reduction in line 6 of Table 1, relative to the $41.8 million deficiency based on the 2015 Test Year, reflects lower actual capital additions in 2014 when compared to the 2014 Test Year. The requirement for these rate base adjustments for 2015 were outlined in Grant Thornton's Financial Consultants Report.[8]

The adjustment to revenue requirement to reflect a lower opening balance in rate base for the 2015 Test Year is made because these assets were not in service at year-end 2014. However, this rate base adjustment is appropriate for the 2015 Cost Deferral only and not for the purpose of determining revenue requirement for 2016. These assets are forecast to be in service in 2015 and therefore, will be used and useful in the provision of service to customers for all of 2016. As such, it is appropriate that Hydro should be given the opportunity to earn a return on these assets in 2016.

[1] 2013 Amended General Rate Application, Finance Schedule I, Page 1 of 11, Line 17.
[2] 2013 Amended General Rate Application, Finance Schedule II, Page 1 of 1, Line 31.
[3] Line 1 minus Line 2.
[4] Evidence to Revised Compliance Filing dated June 4, 2015, Page 11, Table 9.
[5] Line 3 plus Line 4.
[6] Rate base adjustment per PUB-NLH-487.
[7] Line 5 plus Line 6.
[8] See page 115 of Grant Thornton's report to the Board dated June 12, 2015 and Hydro's response to PUB-NLH-487.

Hydro proposes the Board approve a cost deferral for 2015 which offsets the net income deficiency from delayed rate implementation in 2015. The recovery of the actual amount resulting from delayed implementation of final customer rates will be dealt with in a future order of the Board subsequent to conclusion of the GRA.

2.2 RSP Test Year

The RSP inputs (e.g., load forecast, fuel cost forecast, Holyrood fuel conversion rate, rates) that are currently in effect for use in the determination of Hydro's fuel costs and RSP interest are calculated, on an interim basis, in accordance with the 2007 Test Year Cost of Service (COS) estimates in relation to actual fuel costs. Hydro's Amended Application is based on a 2015 Test Year. Upon approval of the 2015 Test Year, the RSP balances for 2015 will be recalculated based on the Board approved RSP inputs from the 2015 Test Year COS. Given that the Board's final order will not be implemented in 2015, Hydro will incur an estimated increase in 2015 interest costs of $7.6 million as a result of the use of 2007 Test Year RSP inputs rather than the 2015 Test Year RSP inputs.[9]

Table 2 provides the 2015 forecast year-end RSP balances using the 2015 Test Year COS inputs and Table 3 provides the 2015 forecast year-end RSP balances under the 2007 Test Year COS inputs. Table 4 provides a comparison of the 2015 interest expense under both scenarios.

[9] For the purposes of the forecast interest expense, Hydro assumed the 2015 Test Year will be based on a No. 6 fuel cost of $64.41 per barrel ($CDN) consistent with the correspondence provided to the Board in the Island Industrial Customer (IIC) Interim Rates Application filed on October 28, 2015. The RSP energy rates for Newfoundland Power and IIC were also assumed to reflect the revised No. 6 fuel price. Hydro also assumed the 2014 Deficiency will be recovered through the Hydraulic Variation Account balance as of December 31, 2014.

Table 2

($000's)

Rate Stabilization Plan Overall Summary 2015 COS Estimates 31-Dec-15							
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total
Balance before interest	(19,760)	(14,025)	443	(41,085)	(124,014)	(4,118)	(202,558)
Interest	-	(2,635)	(65)	(2,664)	(8,454)	(281)	(14,099)
Balance	(19,760)	(16,660)	378	(43,749)	(132,468)	(4,399)	(216,657)

Table 3

($000's)

Rate Stabilization Plan Overall Summary 2007 COS Estimates 31-Dec-15							
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total
Balance before interest	(57,942)	(60,788)	1,082	(55,265)	(124,014)	(2,999)	(299,926)
Interest	-	(8,412)	(296)	(3,405)	(9,337)	(293)	(21,744)
Balance	(57,942)	(69,201)	787	(58,670)	(133,351)	(3,292)	(321,670)

Table 4

($000's)

Rate Stabilization Plan Interest Adjustment 2007 COS Base vs. 2015 COS Base 31-Dec-15							
	A	B	C	D	E	F	G
	Hydraulic Balance	Utility Balance	Industrial Balance	Segregated Load Balance	Utility RSP Surplus	Industrial RSP Surplus	Total
Interest expense - 2015 COS Base	-	(2,635)	(65)	(2,664)	(8,454)	(281)	(14,099)
Interest expense - 2007 COS Base	-	(8,412)	(296)	(3,405)	(9,337)	(293)	(21,744)
Interest adjustment	-	5,777	230	741	883	12	7,644

Table 4 demonstrates that as a result of the materially higher forecast 2015 year-end RSP balances based on the RSP inputs from the 2007 Test Year COS, Hydro will incur an additional $7.6 million in interest in 2015.

Board approval of the 2015 Test Year in 2016 and the subsequent updating of the RSP based on the 2015 Test Year will result in a reversal of the increased 2015 interest expense to provide an interest expense savings in 2016. The delay in implementation of the 2015 Test Year for purposes of determining the RSP balance results in a timing difference that spans Hydro's fiscal year-end. Due to the materiality of the impact on 2015 financial results and recognizing the cost will be reversed in 2016, Hydro proposes to record the additional interest expense in a deferral account for 2015.

2.3 Supply Cost Variances

Hydro is currently forecast to incur materially higher supply costs in 2015 compared to the 2015 Test Year forecast. In the Amended Application, Hydro proposed three new deferral accounts to deal with variances from the Test Year forecast of supply costs. These included the Isolated Systems Supply Cost Variance Deferral Account, the Energy Supply Cost Variance Deferral Account and the Holyrood Conversion Rate Deferral Account. The delay in implementation of the 2015 Test Year beyond year-end 2015 also results in Hydro's 2015 financial reporting reflecting the use of the 630 kWh per barrel Holyrood fuel conversion rate approved for the 2007 Test Year. The difference between the Holyrood fuel conversion rate proposed for the 2015 Test Year and the conversion rate approved for the 2007 Test Year results in a material increase in the Holyrood fuel costs that will be incurred in 2015.

Table 5 shows the forecast 2015 year-end balances if the proposed deferral accounts were approved for implementation effective January 1, 2015 plus the forecast fuel cost impact of

delayed implementation of the proposed test year change in the Holyrood fuel conversion rate.[10]

Table 5

Line No.	Particulars	$000's (Due To)/From Customers
1	Isolated Systems Supply Cost Variance Deferral Account	(955)
2	Energy Supply Cost Variance Deferral Account	7,064
3	Holyrood Conversion Rate Deferral Account	2,418
4	Change in Test Year Holyrood Fuel Conversion Rate	4,214
5	Proposed 2015 Supply Cost Deferral	12,741

The deferral account balances in Table 5 have been calculated in a manner consistent with the proposed deferral mechanisms in Hydro's Amended Application. Due to the materiality of the impact on 2015 financial results and recognizing that costs are not controllable by Hydro and were proposed for recovery in the Amended Application, Hydro proposes to record the additional supply costs in a deferral account for 2015. The following sections provide more detail on each of the supply cost deferral amounts provided in Table 5.

2.3.1 Isolated Systems Supply Cost Variance Deferral Account

The Isolated Systems Supply Cost Variance Deferral Account is forecast to provide savings of approximately $1.0 million to customers in 2015. These savings reflect a lower cost of No. 2 fuel used in serving Hydro's Isolated Systems than the forecast cost reflected in the 2015 Test Year. Appendix B to this evidence provides the calculation of the forecast 2015 year-end balance in the Isolated Systems Supply Cost Variance Deferral Account.

[10] Forecast amounts reflect actual results to August 31, 2015.

2.3.2 Energy Supply Cost Variance Deferral Account

The Energy Supply Cost Variance Deferral Account is forecast to have a balance of approximately $7.1 million at year-end of 2015. This balance is primarily due to variances in hydraulic and gas turbine production. Decreased hydraulic production, primarily on the Nalcor Exploits system, is being replaced by more expensive thermal generation. The replacement of low cost purchases with Holyrood generation has resulted in a significant increase in supply costs for 2015.

In addition, operational requirements have increased production at the Holyrood Combustion Turbine (Holyrood CT) in 2015. Production at the Holyrood CT is forecast to increase by approximately 20.5 GWh more than the 2015 Test Year forecast in order to increase system reliability on the Avalon Peninsula.[11] This increased production at the Holyrood CT, in combination with lower hydraulic production at Nalcor Exploits, is the other primary driver of the forecast balance for 2015. The forecast balance of $7.1 million in this account reflects the proposed cost variance threshold of $0.5 million which would accrue as a supply cost to Hydro.

Increased production at the Holyrood CT resulted in Hydro operating in a manner that enabled more reliable service to customers throughout 2015. In addition, consistent with the operation of the RSP, levels of hydraulic production are, to a great degree, beyond management's control. Hydro submits that both sources of variance result in a material increase in the cost of providing reliable service to customers and were prudently incurred. Appendix C to this evidence provides the calculation of the forecast 2015 year-end balance in the Energy Supply Cost Variance Deferral Account.

[11] See testimony from Hydro's 2013 GRA Amended Application, October 20, 2015, Pages 131 through 133.

2.3.3 The Holyrood Conversion Rate Deferral Account

The Holyrood Conversion Rate Deferral Account is forecast to have a balance of $2.4 million.[12] This balance is due to a forecast fuel efficiency factor of approximately 597 kWh/bbl versus 607 kWh/bbl proposed for the 2015 Test Year. The decline in fuel conversion performance is primarily due to changes external to the operation of the Holyrood Thermal Generating Station (Holyrood TGS). There have been lower production requirements at the Holyrood TGS as a result of reduced system loads, higher energy purchases, and higher levels of hydraulic generation.[13] Appendix D to this evidence provides the calculation for the forecast 2015 year-end balance in the Holyrood Conversion Rate Deferral Account.

2.3.4 Change in Test Year Holyrood Conversion Rate

Hydro is currently using a Holyrood fuel conversion rate of 630 as approved in the 2007 GRA. Fuel related expenses that are incurred as a result of achieving lower fuel conversion rate are not stabilized through the normal operation of the RSP and are priced at the 2007 Test Year fuel cost. The fuel cost variance between the forecast conversion rate of 597 kWh/bbl and the 2015 Test Year proposed conversion rate of 607 kWh/bbl are reflected in the Holyrood Conversion Rate Deferral Account noted above. However, the variance between the proposed conversion rate of 607 kWh/bbl in the 2015 Test Year and the conversion rate of 630 kWh/bbl in the 2007 Test Year is estimated to be $4.2 million in 2015. This material fuel cost difference arises due to the timing of the approval of the 2015 GRA.

As with the RSP interest expense, Board approval of the 2015 Test Year in 2016 and the subsequent updating of the RSP based on the 2015 Test Year will result in a reversal of the increased fuel cost in 2015 to provide a fuel cost savings in 2016. Due to the materiality of the impact on 2015 financial results and recognizing the cost will be reversed in 2016, Hydro

[12] The 2015 Test Year assumes a fuel efficiency factor of 607 kWh/bbl. Hydro's forecast estimates that for the 2015 Test Year the Board will approve a No. 6 fuel cost of $64.41 ($CDN) per barrel.
[13] See Hydro's Amended Application, Section 2: Regulated Activities, page 2.74.

proposes to record the additional $4.2 million in fuel cost expense in a deferral account for 2015. Appendix E to this evidence provides the calculation of the forecast 2015 fuel cost impact of using the 2007 Test Year conversion rate for 2015.

3.0 OTHER 2015 ADJUSTMENTS

A final order of the Board on Hydro's GRA is not expected before the conclusion of Hydro's 2015 financial year-end. As such, Hydro's is requesting interim approval of several items for financial reporting and planning purposes.

3.1 General Rate Application Costs

Hydro is forecast to incur $1.2 million in 2015 associated with external GRA hearing costs. In Hydro's Amended Application, these costs were proposed to be deferred and recovered over a period of three years.[14] Without an order to permit the deferral of these costs, Hydro will be required by International Financial Reporting Standards (IFRS) to expense these costs in 2015. Should the Board then approve any amount of these costs for deferral in the final GRA order, Hydro would be deferring costs already expensed in the previous fiscal year. Such a scenario would result in an overstatement of Hydro's 2015 expenses and a corresponding understatement in 2016. Hydro proposes that deferral of these costs for 2015, with recovery to be determined in a future order of the Board, would provide for more accurate annual financial reporting of Hydro's results.

[14] See Hydro's 2013 Amended Application, Section 3: Finance, Page 3.22, Lines 7-14.

3.2 Settlement Agreement

On August 14, 2014 Hydro entered into an all party settlement agreement (the Settlement Agreement). This agreement, among other items, provided for: specific deliverable dates for reports from Hydro and the filing of Hydro's next GRA; adjustments to Hydro Asset Retirement Obligation (ARO) costs in the 2015 Test Year; accounting treatment for Employee Future Benefits (EFBs); and deferral of Conservation Demand Management (CDM) costs. Hydro is requesting interim approval of this agreement to provide for greater certainty regarding Hydro's year-end financial reporting, and agreed upon deliverable dates.[15] Appendix H provides Hydro's 2015 CDM Report providing support for the proposed cost deferral.

In the Settlement Agreement, Hydro committed to providing a number of reports and applications by specific agreed upon dates. Specifically, Hydro committed to a marginal cost study, a cost of service methodology report, a report on the RSP, and a filing date for its next General Rate Application. Approval of the Settlement Agreement on an interim basis will provide Hydro a degree of certainty with respect to these deliverable dates.

The Settlement Agreement states that Hydro's 2015 Test Year ARO costs are to be reduced by $0.6 million.[16] The impact of this adjustment on Hydro's forecast 2015 results is shown in Appendix A to this Evidence. Interim approval of the ARO cost reduction will reduce Hydro's net income deficiency for 2015.

In accordance with Board Order P.U. 13 (2012), Hydro has effectively deferred all actuarial gains and losses associated with employee future benefits. In the Amended Application, Hydro has proposed to include a portion of these costs in revenue requirement.[17] Without an interim order of the Board in 2015, these costs will remain deferred thereby understating Hydro's 2015 expenses. A final GRA Order on this matter in 2016 without recognition of these costs in 2015

[15] See August 14, 2015 Settlement Agreement.
[16] See August 14, 2015 Settlement Agreement, Page 2, Item 9.
[17] 2013 Amended Application, Section 3: Finance, Page 3.51, Section 3.9.2 Employee Future Benefits.

will result in a corresponding overstatement of these expenses in 2016. Hydro submits that interim approval of this settled issue will provide for more accurate financial reporting of Hydro's results in both 2015 and 2016.

The Settlement Agreement states that the parties agree with Hydro's proposal to defer and amortize CDM costs.[18] Deferral of these costs would be consistent with the Settlement Agreement and past practice of the Board for the years 2009 through 2014. Without an interim order of the Board to defer these costs, Hydro will be required under IFRS to expense $1.2 million in CDM costs in 2015, thereby overstating Hydro's expenses in 2015. The proposed treatment of CDM costs in the Settlement Agreement is consistent with the methodology approved for Newfoundland Power in dealing in CDM costs.

4.0 SUMMARY

Table 6 provides a summary of the proposed 2015 cost deferral.

Table 6

Line No.	Particulars	$ Millions	
1	2015 Delayed Rate Implementation	36.8	
2	2015 Supply Costs	12.7	
3	2015 RSP Interest	7.6	
4	Other Items	3.4	[18]
5	Proposed 2015 Cost Deferral	60.5	

Approval of the proposed cost deferral of $60.5 million will provide Hydro the opportunity to earn a reasonable return in 2015 and maintain the Board's ability to test 2015 costs throughout the GRA. Of the proposed $60.5 million proposed deferral, $11.8 million will be disposed of through updating the RSP for the 2015 Test Year upon final approval of new customer rates.[20]

[18] August 14, 2014 Settlement Agreement, Page 4, Item 17.
[19] Other items include EFB of $1.6M, CDM Costs of $1.2M, GRA Costs of $1.2M, less ARO of $0.6M.
[20] RSP Interest Adjustment of $7.6 million plus Change in Test Year Holyrood Fuel Conversion Rate of $4.2 million.

The recovery approach to the remaining $48.7 million would subject to a future order of the Board upon finalization of the actual 2015 net income deficiency.

Hydro submits that such a deferral account would be consistent with past practice of the Board and does not disadvantage customers. The Board, in Order No. 58 (2014), approved the creation of a deferral account in relation to delayed recovery of Hydro's proposed 2014 revenue requirement.

Hydro's original 2015 Cost Deferral Application proposed a 70% recovery of the forecast 2015 Net Income Deficiency resulting from delayed rate implementation. The original 2015 Cost Deferral Application did not anticipate the final GRA Board Order being delayed beyond 2015.

Appendix A to this evidence includes Hydro's most recent 2015 forecast. This forecast demonstrates a material net income deficiency for 2015. If the Board does not approve any of the items in the 2015 Cost Deferral Application, Hydro is forecasting a net loss of $30.8 million in 2015 and a return on rate base of 3.56%.

Table 7 provides Hydro's forecast net income and return on rate base in 2015 under a range of recovery percentages applied to the total 2015 revenue deficiency relative to the Amended Application.[21]

Table 7

Line No.	Scenario	Deferred Recovery ($ Millions)	2015 Net Income ($ Millions)	2015 Return on Adjusted Rate Base (%)
1	70% Recovery	60.6	3.8	5.25%
2	80% Recovery	69.2	12.4	5.71%
3	90% Recovery	77.9	21.1	6.17%
4	100% Recovery	86.5	29.7	6.62%

[21] Table 7 includes the $26 million forecast additional revenue from rates in 2015 resulting from Order No. P.U. 14 (2015) and related orders. For example, 80% recovery equals 80% x ($60.5 million + $26.0 million) = $69.2 million.

Approval of all of Hydro's proposals in the 2015 Cost Deferral Application would result in a forecast net income of $29.7 million in 2015. This net income for 2015 would provide a forecast return on rate base of 6.62% which is at the bottom of the proposed range of return on rate base of 6.62% to 7.02% in the 2015 Test Year. As shown in Table 7, approval of a recovery percentage below 100% would not provide Hydro the opportunity to earn a reasonable return on rate base in 2015.

Hydro is also proposing an interim order of the Board to deal with several issues which would otherwise negatively impact the reporting of Hydro's, 2015 year-end financial results, as a result of the issuing of a final GRA Order beyond year-end 2015. Further, interim approval of settled issues will allow for more accurate financial reporting of Hydro's regulated financial results.

Board approval for the proposed cost deferral combined with the Interim approval of the Settlement Agreement will ensure that Hydro is provided the opportunity to recover costs incurred in the provision of reliable service to customers and the opportunity to achieve a reasonable return on rate base in 2015. Hydro will ultimately recover from customers the costs fully tested by the Board through final customer rates.

Appendix A
Newfoundland and Labrador Hydro
2015 Forecast vs. 2015 Test Year

Line No.		Actuals to August 2015 Forecast	2015 Test Year	Variance	Forecast Return on Rate Base [2]	Note
1	**REVENUE**					
2	ENERGY SALES	545.5	660.1	(114.6)		**1**
3	OTHER REVENUE	2.1	2.4	(0.3)		
		547.6	662.5	(114.9)		
4	**EXPENSES**					
5	OPERATING EXPENSES					
6	Salaries and benefits	91.2	88.9	2.3		**2**
7	System equipment maintenance	28.2	26.8	1.4		**3**
8	Office supplies and expenses	2.8	2.8	-		
9	Professional services	11.9	9.5	2.4		**4**
10	Insurance	2.6	2.6	-		
11	Equipment rentals	3.5	3.1	0.4		**5**
12	Travel	3.9	3.7	0.2		
13	Miscellaneous expenses	6.0	5.7	0.3		
14	Building rental and maintenance	1.3	1.2	0.1		
15	Transportation	1.7	2.3	(0.6)		**6**
16	Cost recoveries	(8.9)	(8.4)	(0.5)		**7**
17	NET OPERATING EXPENSES	144.2	138.2	6.0		
18	LOSS ON DISPOSAL OF PPE	6.0	4.1	1.9		**8**
19	OTHER EXPENSE	2.0	2.2	(0.1)		
20	FUELS	209.2	269.8	(60.6)		**9**
21	POWER PURCHASED	61.5	63.3	(1.8)		**10**
22	AMORTIZATION	63.2	64.7	(1.5)		**11**
23	INTEREST	92.3	87.1	5.2		**12**
		578.4	629.2	(50.8)		
24	**NET (LOSS)/INCOME WITHOUT REGULATORY ADJUSTMENTS**	**(30.8)**	**33.2**	**(64.1)**	**3.56%**	
25	2015 Delayed Rate Implementation Deferral	36.8	-	36.8		
26	**NET INCOME WITH PROPOSED 2015 TEST YEAR RATES**	**6.0**	**33.2**	**(27.3)**	**5.69%**	
27	Isolated Systems Supply Cost Deferral Account	(1.0)	-	(1.0)		
28	Energy Supply Cost Variance Deferral Account	7.1	-	7.1		
29	Holyrood Conversion Rate Deferral Account	2.4	-	2.4		
30	Change in Test Year Holyrood Fuel Conversion Rate	4.2	-	4.2		
31	**NET INCOME WITH TY RATES & SUPPLY COST RECOVERY**	**18.7**	**33.2**	**(14.6)**	**5.98%**	
32	RSP Interest Adjustment	7.6	-	7.6		
33	Employee Future Benefits Actuarial Loss [1]	1.6	-	1.6		
34	CDM Cost Deferral [1]	1.2	-	1.2		
35	GRA Cost Deferral	1.2	-	1.2		
36	ARO Adjustment per Settlement Agreement [1]	(0.6)	(0.6)	-		
37	**NET INCOME WITH PROPOSED 2015 COST DEFERRAL**	**29.7**	**32.6**	**(3.0)**	**6.62%**	

[1] August 14, 2015 Settlement Agreement.

[2] Hydro's 2015 Test Year Average Rate Base $1,802.0 million per Hydro's Amended Application, Finance Schedule I, Page 5 of 11, Line 21 less an opening Rate Base adjustment of $148.0 million (average of $74.0 million) per PUB-NLH-487.

[3] Totals may vary due to rounding differences.

Note	Description	Variance Explanation
1	Energy sales	Revenue from energy sales have decreased by $114.6 million from the 2015 Test Year primarily due to delayed implementation of 2015 Test Year rates.
2	Salaries and benefits	Salaries and benefits have increased by $2.3 million from the 2015 Test Year. The primary driver is an increase in employee future benefits expense of $1.1 million and an increase of $0.7 million associated with new union agreement and other benefit costs.
3	System equipment maintenance	System equipment maintenance has increased by $1.4 million from the 2015 Test Year to the 2015 Forecast due to increased maintenance on Holyrood units 1, 2 and 3.
4	Professional services	Professional services increased by $2.4 million from the 2015 Test Year to the 2015 Forecast primarily due to an increase in regulatory activity of $2.0 million and CDM program costs of $0.5 million.
5	Equipment rentals	Equipment rental costs have increased by $0.4 million from the 2015 Test Year to the 2015 Forecast primarily due to rental of backup diesel generation in TRO Central and Northern.
6	Transportation	Transportation costs have decreased by $0.6 million from the 2015 Test Year to the 2015 Forecast primarily due to fuel price savings of $0.2 million, an increase in charges to capital of $0.2 million and lower aircraft costs of $0.1 million due to new a contract in place.
7	Cost recoveries	Cost recoveries have increased by $0.5 million from the 2015 Test Year to the 2015 Forecast primarily due to additional administration fee recovery.
8	Loss on Disposal of PPE	Loss on disposal costs have increased by $1.9 million from 2015 Test Year to the 2015 Forecast primarily due to a $1.2 million increase in costs associated with asset disposals, as well as an increase in removal costs of $0.7 million. The disposals relate to a supplemental capital application for Hardwoods Engine Overhaul resulting in an unbudgeted $0.7 million asset disposal, combined with disposals related to capital work carried over from 2014.
9	Fuels	Fuel costs have decreased by $60.6 million from the 2015 Test Year primarily due to delay in implementation of customer rates to reflect the 2015 Test Year fuel price, partially offset by additional supply costs at the Holyrood Thermal Generating Station as well as the Holyrood Combustion Turbine.
10	Power Purchased	Power Purchased has decreased by $1.8 million from 2015 Test Year to the 2015 Forecast primarily due to $1.4 million in lower production at Exploits, Star Lake and Rattle Brook as well as $0.4 million in lower wind production from St. Lawrence.
11	Amortization	Amortization costs have decreased by $1.5 million from 2015 Test Year to the 2015 Forecast primarily due to delay in the Holyrood CT coming into service and capital work carried over from 2014.
12	Interest	Interest costs have increased by $5.2 million from 2015 Test Year to the 2015 Forecast primarily due to an increase in RSP interest of $7.6 million, a decrease of $7.3 million in capitalized interest primarily due to postponement of LabWest capital project, and higher short term interest costs of $1.7 million related to delay in long term borrowing. These amounts are partially offset by interest savings of $10.8 million due to a delay in debt issue from April 1, 2015 to December 1, 2015.

Appendix B
Isolated Systems Supply Cost Variance Account - 2015 Forecast

Particulars	Diesel	HQ Purchases	Other [1]	Total
A - 2015 Forecast Supply Produced and Purchased (kWh)	52,945,609	23,973,640	650,140	77,569,389
B - 2015 Forecast Cost / 2015 Actual Production ($/kWh) [B1 / B2]	0.3073	0.1243	0.2667	0.2504
C - 2015 Test Year Cost / 2015 Test Year Production ($/kWh) [C1 / C2]	0.3259	0.1303	0.2941	0.2691
Isolated Supply Costs [A x (B-C)]				(1,454,872)
Cost Variance Threshold				(500,000)
Isolated Systems Supply Cost Deferral Balance				**(954,872)**
B1 - 2015 Forecast Cost of No. 2 Fuel + Purchases ($)	16,270,399	2,978,831	173,366	19,422,596
B2 - 2015 Forecast Production + 2015 Actual Purchases (kWh)	52,945,609	23,973,640	650,140	77,569,389
C1 - 2015 Test Year Cost of No. 2 Fuel + Purchases ($)	18,592,400	3,054,696	173,500	21,820,596
C2 - 2015 Test Year Production + 2015 Test Year Purchases (kWh)	57,048,141	23,435,400	590,000	81,073,541

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

Appendix C
Energy Supply Cost Variance Deferral Account - 2015 Forecast

	Power Purchases					
Particulars ($)	**Wind**	**CBPP**	**Hydraulic [1]**	**Diesel**	**Gas Turbine**	**Total**
A - Forecast Energy Supply Costs	12,318,933	10,703,687	30,823,334	115,161	10,557,465	64,518,580
B - Test Year Energy Supply Costs	12,732,178	10,281,290	32,280,949	87,140	3,473,690	58,855,247
C - Energy Supply (Costs)/Savings [D/E x F]						(1,900,475)
Energy Supply Costs [(A-B)-C]						7,563,809
Cost Variance Threshold						500,000
Energy Supply Costs Deferral Balance						**7,063,809**

D - Holyrood 2015 Test Year Average Fuel Cost (bbl)	64.41
E - Test Year Fuel Conversion Factor (kWh/bbl)	607
F - Annual kWh variance - 2015 Forecast vs. 2015 Test Year (kWh) [F1-F2]	(17,910,079)
F1 - Forecast Consumption (kWh)	1,027,549,921
F2 - Test Year Consumption (kWh)	1,045,460,000

[1] Includes Nalcor Grand Falls, Bishop Falls and Buchans.

Appendix D
Holyrood Fuel Conversion Rate Deferral Account

Particulars	2015 Forecast	Effciency Factor (kWh/bbl)
A - Forecast quantity of No.6 fuel consumed (bbl)	2,284,246	597
B - Calculated quantity of No. 6 fuel consumed using the 2015 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,246,707	607
C - 2015 Test Year Cost of Service No. 6 fuel cost ($) per bbl	64.41	
Holyrood Fuel Conversion Rate Costs Deferral Balance ($) [(A - B) x C]	2,417,870	

[1]Calculation of B:

D - Forecast net Holyrood production (kWh)	1,363,751,309
E - 2015 Test Year Cost of Service fuel conversion rate (kWh/bbl)	607

Appendix E
Change in Test Year Holyrood Fuel Conversion Rate

Particulars	2015 Forecast	Effciency Factor (kWh/bbl)
A - Forecast quantity of No.6 fuel consumed (bbl)	2,284,246	597
B - Calculated quantity of No. 6 fuel consumed using the 2007 Test Year Cost of Service fuel conversion rate (bbl) [1]	2,164,685	630
C - 2007 Test Year Cost of Service No. 6 fuel cost ($) per bbl	55.47	
Holyrood Fuel Conversion Rate Costs ($) [(A - B) x C]	6,632,070	
Less 2015 Test Year Calculation from Appendix D (607 kWh/bbl @ $64.41)	(2,417,870)	
Holyrood Fuel Conversion Test Year Differential	4,214,200	

[1]Calculation of B:

D - Forecast net Holyrood production (kWh)	1,363,751,309
E - 2007 Test Year Cost of Service fuel conversion rate (kWh/bbl)	630

Appendix F

2015 Cost Deferral Account

This account shall be charged with the variance of $60.5 million between forecast operating costs, amortizations and cost of capital for 2015, and forecast revenue for 2015. Disposition of the balance in this account will be subject to a further order of the Board.

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

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

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

WHEREAS Newfoundland and Labrador Hydro ("Hydro" or the "Applicant") has applied to the Board of Commissioners of Public Utilities (the "Board") to establish customer electricity rates for 2015 and to recover a 2014 revenue deficiency (the "Application"); and

WHEREAS the Consumer Advocate; Newfoundland Power Inc. ("Newfoundland Power"); Corner Brook Pulp and Paper Limited, NARL Refining Limited Partnership and Teck Resources Limited (the "Industrial Customer Group"); Vale Newfoundland and Labrador Limited ("Vale"); the Innu Nation; the Towns of Labrador City, Wabush, Happy Valley-Goose Bay, and North West River; Yvonne Jones, MP and the Nunatsiavut Government have been granted Registered Intervenor status; and

WHEREAS the Applicant, the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale (the "Parties"), with participation by Board Hearing Counsel, have engaged in negotiations regarding Island Interconnected System and other issues.

Terms of Agreement

1. The Parties jointly advise the Board that certain issues arising from the Application have been settled by negotiations between them in accordance with this Settlement Agreement (the "Settled Issues").

2. The Parties recommend that the Board implement the agreement of the Parties regarding the Settled Issues in its Order.

3. The Parties consent to the admission in the record of this Application of all pre-filed testimony, exhibits and responses to requests for information pertaining to the Settled Issues. At the hearing of the Application, the Parties do not intend to present evidence, examine, cross-examine or present argument in relation to the Settled Issues beyond that which is reasonably necessary to assist the Board's understanding, and to explain or clarify the Parties' agreement concerning the Settled Issues, except insofar as may be necessary to

address issues that have not been settled by this Agreement and provided further that the Board includes the Settled Issues in its Order.

4. This Settlement Agreement represents a reasoned consensus on the Settled Issues and the agreements on individual issues are not intended to be severable.

5. This Settlement Agreement does not dispose of all issues arising from the Application. It does not limit the rights of the Parties to present evidence, examine, cross-examine and present argument at the hearing of the Application on issues that have not been settled by this Agreement.

6. This Settlement Agreement is without prejudice to the positions the Parties may take in proceedings other than the Application. Its sets no precedent for any issue addressed in this Settlement Agreement in any future proceeding or forum.

Matters Agreed Upon

Range of Return

7. The Parties agree that the allowable range of return on rate base for Hydro will be +/- 20 basis points.

Revenue Requirement

8. The Parties agree that Hydro's proposed accounting treatment to include actuarial gains and losses in Employee Future Benefits in the 2015 Test Year should be approved.

9. The Parties agree that Hydro's proposal to include depreciation and accretion expenses associated with Asset Retirement Obligations should be approved with the amounts reduced from $3.1 million and $3.2 million for the 2014 and 2015 Test Years, respectively, as proposed in the Application to $2.6 million and $2.6 million, respectively. The reduction from the amounts proposed in the Application reflects amounts excluded for construction and selective decommissioning costs at the Holyrood generating plant as these costs will be incurred to the benefit of customers subsequent to the Labrador-Island Interconnection and Hydro may apply for recovery of such costs in future applications.

10. The Parties agree that the methodology used by Hydro to estimate its average annual hydroelectric energy productions should be approved and the 2015 hydraulic production calculation forecast of 4,604 GWh should be approved for all purposes, including the calculation of No. 6 fuel expense for the 2015 Test Year and for the Rate Stabilization Plan.

11. The Parties agree that Hydro's proposed depreciation methodology used to determine depreciation expense in the 2015 Test Year is appropriate.

Cost of Service

12. The Parties agree that Hydro's cost of service study filed in this proceeding is in general compliance with Board Orders regarding the use of embedded cost of service studies as a guide in determining the revenue requirement to be applied to each customer class.

13. The Parties agree on the cost of service methodologies in Exhibit 13 (2015 Test Year Cost of Service) with respect to Functionalization, Classification and Allocation, with the exception of:
    (a) the treatment of the curtailable load of Newfoundland Power;
    (b) the classification of wind energy purchases as 100% energy related;
    (c) the calculation of the capacity factor for the Holyrood Generating Plant;
    (d) the classification of all Holyrood fuel costs to energy;
    (e) Newfoundland Power's load factor;
    (f) the use of the forecast 2015 load for rate-setting purposes;
    (g) the basis on which specifically assigned charges to customers is calculated;
    (h) the specific assignment of the frequency converter to Corner Brook Pulp and Paper Limited, the calculation of that charge and any credit in the cost of service study associated with the frequency converter; and
    (i) the allocation methodology for the Rural Deficit.

14. The Parties agree, notwithstanding the generality of the principle agreed to in paragraph 13 of this Settlement Agreement, on the following specific elements of Hydro's 2015 Cost of Service:
    (a) the Utility Rate shall include a generation credit for Newfoundland Power of 119,329 kW applied in the same manner as in the last approved 2007 cost of service study to reduce Newfoundland Power's peak demand for cost allocation purposes; and
    (b) the costs associated with Hydro's capacity assistance agreements with Vale and Corner Brook Pulp and Paper Limited shall be treated as demand related.

Rate Design

15. The Parties agree that the current rate design for industrial customers should continue to apply as Hydro proposed in the Application.

Rate Stabilization Plan

16. The Parties agree that, if load variation is maintained as an element of the Rate Stabilization Plan, year-to-date net load variations for Newfoundland Power and industrial customers shall be allocated among the customer groups based upon energy ratios, with effect from the date to be determined by the Board.

Regulatory Deferral and Recovery Mechanisms

17. The Parties agree that Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved.

18. The Parties agree that the Board should approve that costs related to the Application be recovered in customer rates evenly over a three year period, commencing with the date that new rates approved in this proceeding become effective with the amount of such costs to be determined by the Board.

Agreement with Corner Brook Pulp and Paper Limited

19. The Parties agree that the generation credit agreement between Hydro and Corner Brook Pulp and Paper Limited which was approved on a pilot basis by the Board in Order No. P.U. 4(2012) should be continued on a pilot basis at this time and that it will be reviewed in the cost of service generic hearing referred to in paragraph 23 of this Settlement Agreement.

Wheeling Rate

20. The Parties agree that upon finalization of the 2015 Test Year by the Board there shall be an industrial wheeling rate with the specific rate to be calculated in accordance with the methodology proposed by Hydro in its Application as may be modified by the Board in an Order arising from the Application.

Customer Service Strategy

21. The Parties agree that the Customer Service Strategic Roadmap 2015-2017 filed by Hydro in this proceeding reflects appropriate customer service improvement objectives, but this does not preclude additional customer service improvements being raised during the hearing of this Application or being considered by the Board .

Reporting on Key Performance Indicators

22. The Parties agree that Hydro should continue to report functionally oriented key performance indicators as required by the Board in Order No. P.U. 14(2014), however, such reporting will be based on the most recent Test Year Cost of Service Study that is approved by the Board and not on a forecast basis.

Future Reports and Applications

23. Hydro has stated in this proceeding that in preparation for the implementation of customer rates reflecting the costs of the Labrador-Island interconnection, it will file with the Board the following:

(a) a marginal cost study no later than December 31, 2015;
(b) a cost of service methodology report no later than March 31, 2016;
(c) a report on the Rate Stabilization Plan and supply cost recovery mechanisms no later than June 15, 2016; and
(d) a General Rate Application no later than March 31, 2017 for rate changes based on a 2018 test year.

The Parties agree that the Board should in its Order direct Hydro to file these reports, studies and applications by the relevant dates set out in this paragraph. The Parties further agree that a generic cost of service hearing should be held following the filing of the reports outlined in (a) to (c) above.

24. Notwithstanding the requirements of paragraph 23 of this Settlement Agreement, the Parties agree that the Board in its Order should direct Hydro to file a General Rate Application on or before March 30, 2017 proposing rates based on a 2018 test year.

Remaining Issues

25. The Parties agree that issues not included in this Settlement Agreement remain unresolved and will be the subject of viva voce evidence at the hearing of the Application.

Agreed to as of the 14th day of August, 2015.

For Newfoundland and Labrador Hydro:

For the Consumer Advocate:

For Newfoundland Power Inc.:

For the Industrial Customer Group:

For Vale:

For Board Hearing Counsel:

A REPORT TO
THE BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

2015 CONSERVATION COST DEFERRAL AND PROGRAM EXPANSION REPORT

Newfoundland and Labrador

November 12, 2015

newfoundland labrador hydro
a nalcor energy company

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1.0 Introduction

Newfoundland and Labrador Hydro (Hydro) has applied for approval from the Board of Commissioners of Public Utilities (the Board) for the deferral of the costs to be incurred by Hydro that are associated with the 2015 implementation of the Conservation and Demand Management (CDM) Programs and approach as outlined in the Five-Year Energy Conservation Plan: 2012-2016.[1] The purpose of this report is to provide the details of the 2015 CDM Program costs and an update of activities undertaken in 2015. The report also provides an overview of the conservation program planning activities completed during 2015 and included in a new Five-Year Conservation Plan: 2016-2020.[2]

The 2012-2016 Plan outlined the joint utility approach undertaken in partnership with Newfoundland Power. This report describes the provincial approach but focuses on the costs and reach of initiatives for Hydro's portion of program implementation that are addressed by the deferral request.

Hydro is requesting a deferral of an estimated $1,213,000 to be incurred in 2015, which was not included in Hydro's 2007 Test Year approved expenses for rates set by Board Order No. P.U. 8(2007).

2.0 Background

Energy Conservation initiatives was a topic of discussion during Hydro's 2006 General Rate Application (GRA). Since that time, Marbek Resource Consultants Limited (Marbek) was commissioned and completed a CDM Potential study in 2008 that provided information to assist in identifying cost-effective conservation programs and the potential contribution of specific technologies and measures in reducing forecast electricity consumption. From the potential study a five-year energy conservation plan was completed which outlined proposed energy conservation initiatives to be implemented jointly by Newfoundland Power

[1] The Five-Year Energy Conservation Plan: 2012-2016 was filed with the Board on September 14, 2012 as part of Newfoundland Power's General Rate Application.
[2] The Five-Year Conservation Plan: 2016-2020 was filed with the Board on October 16, 2015 as part of Newfoundland Power's 2016/2017 General Rate Application.

and Hydro (the Utilities), including technologies, programs, support elements and cost estimates that promote a long-term goal of an established conservation culture with sustained reductions in electricity consumption. The potential study was filed with the Board on March 20, 2008 and the 2008-2012 Plan was filed with the Board on June 27, 2008.

In September 2012, the Five-Year Energy Conservation Plan: 2012-2016 was filed with the Board. This updated Plan outlined additional programs to be launched to complement the existing portfolio of programs. The focus for joint utility conservation continues to be energy savings through the development of a culture of conservation. The activities in the 2012-2016 Plan include rebate programs for each sector (residential, commercial and industrial) and supporting activities for awareness, education and community engagement to stimulate attitude change.

An application to defer the recovery of 2009 costs to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on November 21, 2008. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2009. The Board approved the application in Order No. P.U. 14(2009).

An application to defer the recovery of 2010 costs estimated at $2.3 million to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on January 26, 2010. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2010. The Board approved the application in Order No. P.U. 13(2010).

An application to defer the recovery of 2011 costs estimated at $840,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on March 10, 2011. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2011. The Board approved the application in Order No. P.U. 4(2011).

An application to defer the recovery of 2012 costs estimated at $1,673,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed

on December 22, 2011. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2012. The Board approved the application in Order No. P.U. 3(2012).

An application to defer the recovery of 2013 costs estimated at $1,950,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on November 1, 2013. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2013. The Board approved the application in Order No. P.U. 35(2013).

An application to defer the recovery of 2014 costs estimated at $2,520,000 to be incurred by Hydro in association with the implementation of the Energy Conservation Program was filed on September 30, 2014. This filing addressed forecasted costs for delivering the programs to Hydro customers in 2014. The Board approved the application in Order No. P.U. 43(2014).

Hydro is forecasting $1,213,000 to be accumulated in the deferral account associated with its energy conservation program activities for the 12-month period of January 2015 to December 2015.

3.0 Five-Year Plan Update

2015 has been an active and successful year with respect to Hydro's conservation and planning efforts. Significant energy savings are expected to be achieved within the residential and commercial energy efficiency program activities, particularly in the business efficiency, isolated community, and small technology (instant rebate) programs. Hydro continues to engage with its industrial customers concerning energy conservation improvements but no energy savings projects are forecast for this year. The ENERGY STAR® Window Program concluded at the end of 2014 having achieved its objective of making more efficient windows the standard in the local market. All program profiles are included with Appendix A.

Beginning in January 2015 the Utilities contracted with ICF International to undertake a conservation and demand management potential study to identify the achievable, cost-

effective electric energy efficiency and demand management potential in the Province. The study was completed in 2015 and included consultation with customers, trade allies, retail partners, and other interested parties. A copy of the Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 for each of the Residential, Commercial, and Industrial Sectors was filed with the Board on September 15, 2015.

The Conservation and Demand Management Potential Study: 2015 was used by the Utilities to develop the Five-Year Conservation Plan: 2016-2020. A copy of the Five-Year Conservation Plan: 2016-2020 is included with Appendix B. This plan includes a new residential benchmarking program; expansion of existing commercial programs; and reshaping or discontinuation of elements of the residential program offerings. Hydro is also assessing implementation of a direct load control pilot for the community of Postville, Labrador with aim to reduce peak loading and defer system expansion. Hydro is presently managing a home energy monitoring project on behalf of the Provincial Office of Climate Change and Energy Efficiency, which will be completed in 2016. The results of this project will be used to assess whether real time monitoring of home energy may be considered for future conservation initiatives.

4.0 Program Portfolio

The existing Energy Savers Rebate programs offered through the takeCHARGE program launched in June 2009 continued to be offered in 2015. These programs have shown energy savings and continue to encourage consumers to consider energy efficiency in their purchasing decisions. The programs target the highest end uses for the residential and commercial markets of heating and lighting, respectively. These programs are:

- Residential Thermostats;
- Residential Insulation; and
- Commercial Lighting.

The custom Industrial Energy Efficiency Program (IEEP) was also available to transmission level Industrial Customers if they wished to participate, however 2015 mainly involves

engagement with industrial facility managers to promote and seek future energy efficiency projects. No energy savings were forecast for the industrial sector in 2015.

The Energy Savers Rebate Programs are offered provincially, however the costs associated with delivery in the Labrador Interconnected System are recorded separately than those for the Island Interconnected and the Isolated Diesel systems. Outside the Labrador Interconnected System, the dominant economic driver is the avoided fuel cost. In the Labrador Interconnected System the dominant economic driver is export market sales. To ensure the costs of conservation are associated with those who receive the primary benefits, the costs of conservation and efficiency on the Labrador Interconnected System are considered non-regulated.

In addition to the existing Energy Savers programs, there are two programs currently being delivered in Hydro's service area. The Isolated Systems Community Program and Isolated Systems Business Efficiency Program were launched in June 2012 and provide rebates, information and technical support to home and business owners in isolated communities.

The following tables show Hydro's total CDM expenses and energy savings from 2009 to 2015 across all of Hydro's systems, including the Labrador Interconnected System. This report will provide further detail and breakdown of the costs that will be recovered through the deferral account and the associated energy reductions. The energy conservation programs are assessed economically using current standard utility economic screening tests[3]. All program descriptions and profiles are provided in Appendix A.

[3] The primary test for economic viability is the Total Resource Cost (TRC) test which includes both the participants' and Utility's costs and benefits as factors in the net value of the program. As outlined in the Plan, each program has a positive TRC, which means the total program benefits exceed the total costs of the program.

Table 1: Hydro CDM Portfolio Spending ($000s)							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**
Windows	44	49	80	117	169	38	8
Insulation	40	61	140	126	157	92	98
Thermostats	13	19	31	47	51	35	37
Coupon Program	-	135	135	-	-	-	-
Commercial Lighting	12	12	59	20	29	15	65
Industrial	57	226	103	173	89	1,244	5
Block Heater Timer				31	8	8	-
Isolated Community				858	871	615	550
ISBEP				93	115	96	68
Heat Recovery Ventilator				-	11	7	57
Business Efficiency Program				-	45	101	90
Small Technologies				-	1	252	329
Total Portfolio	**166**	**502**	**548**	**1,465**	**1,546**	**2,503**	**1,307**

Table 2: Hydro's Annual CDM Portfolio Energy Savings (MWh)							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015 (F)**
Windows	13	37	61	136	99	85	0
Insulation	35	126	404	382	794	142	76
Thermostats	9	35	30	53	24	38	8
Coupon Program	-	64	256	-	-	-	
Commercial Lighting	3	10	227	95	99	79	52
Industrial	-	-	165	3,172	-	22,258	
Block Heater Timer				-	288	-	
Isolated Community				1,676	1,096	1,357	650
ISBEP				3	27	111	232
HE HRV					1	6	6
Business Efficiency Program					-	107	500
Small Technologies					-	148	81
Total	**60**	**272**	**1,143**	**5,517**	**2,428**	**24,331**	**1,605**

4.1 takeCHARGE Approach

The takeCHARGE approach was described in detail in Hydro's 2010 Conservation Cost deferral report submitted in January 2011. The joint utility effort allows for economies of scale to be achieved where possible in areas such as marketing and outreach efforts. The technologies selected for rebate programs address large energy use opportunities and have been verified as cost effective through standard utility economic screening. In addition, a range of education efforts around general energy efficiency messaging have also been implemented to develop a culture of conservation.

The utilities continue to receive positive response to the existing programs that address a wide provincial customer base. However, there have been opportunities identified that address different needs within each utilities' customer base. For example, Hydro's rural customers respond positively to community engagement efforts as demonstrated by the Isolated Systems Community Program, which includes hiring and training local community representatives to communicate directly with customers through home visits and direct installation of energy efficient measures. The Utilities continue to work together to create and improve provincial scope programs, but also seek projects and programs that can be of benefit if implemented in a system-targeted program.

Technology selection continues to follow the same process of focusing on the significant end uses and identifying niche opportunities where the market can be moved to a more efficient choice. For example, residential home heating is a large end use but the technology portfolio also includes a range of savings options for customers to reduce their electricity consumption across more end uses. This is reflected in the small technology (Instant Rebates) program that provides incentives to homeowners for smaller technologies such as lighting options, timers, and water conservation, as well as rebates for appliance and electronics, opening new ways to save energy.

The utilities will continue to use traditional methods of advertising and promotion, participate in community events, work with community leaders and utilize social media opportunities. This holistic approach to addressing technology, the end user and the community is an effective option for fostering sustainable behaviour and attitude change.

4.2 Program Highlights and Next Steps

Participation continues to increase through Hydro's service area. Retailers continue to be key partners in reaching customers, and a pilot project undertaken in 2011-2012 with retailers to promote ENERGY STAR Window purchases and rebate submission demonstrated this role. Hydro continued to partner and work with retailers in 2015 for the Small Technologies program that enables customers to receive point-of-sale rebates on a number of energy

efficient products. Building relationships with retailers will continue to be a focus as part of the energy efficiency promotion.

Outreach and non-traditional promotions and awareness building have also shown to have impact in reaching Hydro's diverse market. For example, the takeCHARGE program has been represented through community events, product exchanges and giveaways to reach customers in a variety of ways. The direct install approach involves training and using local representatives in isolated communities to provide technologies to homeowners and businesses as well as the free installation of the technologies. This program clearly shows the value of community engagement and creating an interest around the program at community launch events.

Much of Hydro's customer base for high performance commercial lighting consists of government facilities and we continue to work with government departments to identify lighting improvement opportunities when facility renovations and construction are planned. Hydro also continues to work with lighting distributors to promote sale and installation of high performance lighting products.

In the summer of 2011, the Isolated Systems Business Efficiency Program (ISBEP) was launched, providing rebates and technical assistance for commercial customers in isolated diesel communities. This custom approach is similar to the Business Efficiency (BEP) and Industrial Energy Efficiency (IEEP) programs where Hydro technical staff work with customers one-on-one to address their energy efficiency needs. The business efficiency programs have seen steady activity and commercial customers have been engaged in the Central, Northern, and Labrador Regions that identified several projects for 2015. Hydro continues to work with its commercial and Industrial Customers to identify opportunities that produce energy and operational savings.

The utilities initiated a new CDM Potential Study in late 2014 with a final report completed in 2015. Hydro continues to work with Newfoundland Power and other partners to determine

emerging opportunities for CDM programming and develop appropriate strategies for developing a conservation culture in the province.

5.0 Program and Support Costs

The energy savings from Hydro customers in relation to programming associated with the annual CDM deferral requests to date and forecast in 2015 are shown in Table 3. It should be noted that while there are costs associated with the Small Technologies program in 2013 there are no associated savings. This is because the program detailed design stage began in 2013, and the program was launched 2014.

Table 3: Annual Energy Savings from Deferral Account Activity (MWh)

	2009	2010	2011	2012	2013	2014	2015 (F)
Windows	8	14	38	50	43	40	0
Insulation	29	63	229	126	123	100	26
Thermostats	2	16	16	28	14	16	4
Coupon Program	-	47	166	-	-	-	
Commercial Lighting	3	-	92	25	19	22	16
Industrial	-	-	165	3,172	-	22,258	
Block Heater Timer				-	-	-	
Isolated Community				1,676	1,096	1,357	650
ISBEP				3	27	111	232
Heat Recovery Ventilator				-	-	1	2
Business Efficiency Program				-	-	73	500
Small Technologies				-	-	80	44
Total	**42**	**140**	**706**	**5,080**	**1,322**	**24,058**	**1,474**

In 2015 the Commercial Lighting program continued to be offered solely through the distributors and as such there is little to no direct customer contact for promotions and information, so this program remains somewhat unpredictable for savings estimates. The Block Heater Timer program was offered in the Labrador Interconnected area from 2012 to 2014, therefore no savings are associated with the deferral account.

Program costs associated with this deferral[4] request for 2015 are shown in Table 4.

[4] Proposed definition of the deferral account was submitted to the Board on April 22, 2009.

Table 4: Program Costs from Deferral Account Activity ($000s)							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**
Windows	44	41	69	102	150	31	8
Insulation	40	53	116	108	112	87	89
Thermostats	13	18	25	43	47	32	34
Coupon Program	-	113	123	-	-	-	
Commercial Lighting	13	-	43	10	17	10	59
Industrial	57	190	98	170	88	1,244	5
Block Heater Timer				-	-	-	
Isolated Community				858	871	615	550
ISBEP				93	115	96	68
Heat Recovery Ventilator				-	8	3	44
Business Efficiency Program				-	40	92	68
Small Technologies				-	1	219	289
Total Portfolio	**167**	**415**	**474**	**1,384**	**1,449**	**2,429**	**1,213**

The costs associated with the delivery of the CDM program portfolio include direct costs for advertising, salaries, rebates and other expenses directly associated with a specific rebate program. These costs vary depending on the uptake of the program and the number of programs offered.

There are two components of the costs associated with the conservation and efficiency function. In addition to direct program costs which are charged to the deferral account, there are costs associated with general energy efficiency awareness and education, strategic planning and program development. These costs remain relatively stable regardless of the number of rebate programs currently offered in the portfolio.

Hydro's support costs are outlined in Table 5 below. While these costs were in line with expectations for education and support, there was an increase in planning costs as a result of consultant support for the 2015 CDM Potential Study, and Hydro's contributions to the Potential Study, and development of the Five-Year Conservation Plan: 2016-2020.

Table 5: Hydro's Support Costs ($000s)							
	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015(F)**
Education	262	106	212	200	135	158	156
Support	53	48	43	53	27	52	65
Planning	176	180	304	127	152	224	434
Total	**491**	**334**	**559**	**380**	**314**	**434**	**655**

6.0 Justification

Hydro is seeking approval to defer the CDM program costs it will incur in 2015 and for the recovery of these amounts in a manner to be determined by the Board in Hydro's Amended General Rate Application (2013), filed November 10, 2014. Hydro's total annual program costs in 2015 to be deferred are forecast to be $1,213,000. These costs were not forecast in Hydro's 2007 Test Year to be recovered in rates as set by Board Order No. P.U. 8(2007). Hydro is not seeking approval to defer non-program costs for 2015, estimated to be $655,000.

If the 2015 CDM program costs are not deferred they must be recognized as expenses incurred in 2015. This will have significant impact on Hydro's income in that year. The CDM costs incurred provide ongoing system benefits through energy reductions and associated fuel savings. The appropriate regulatory treatment of these costs is included in Hydro's Amended General Rate Application (2013), filed November 10, 2014.

7.0 Conclusion

Hydro has estimated that it will incur $1,213,000 in CDM Program expenses in 2015 associated with the Deferral Account. These expenses are in excess of Hydro's forecast costs used to set rates by Board Order P.U. 8(2007). Therefore, Hydro is requesting approval from the Board for the deferral of the costs to be incurred by Hydro that are associated with the implementation of the joint utility CDM approach as outlined in the Plan and further described in this report.

Appendix A:

NLH Program Profiles

Insulation Program

Program Description

The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers. Changes to the National Building Code of Canada mandates that all new homes install basement insulation. As a result, this program was modified in 2013 to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be aligned with National Building Code of Canada.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the *ENERGY STAR* window, thermostat and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers and trade allies in the home building and renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through customer application.

Insulation Program

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, and the practical difficulties of renovating an existing living space. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities. With the implementation of the new building standards, market penetration of basement insulation in new homes is expected to increase.

Incentive Strategy

Incentives for this program include rebates. The rebate amount changed in 2014 to 75% of the cost for basement insulation and 50% of the cost for attic insulation up to $1,000.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:
Deferral Cost - $89,000
Associated Savings – 26 MWh/yr

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats (those which control within +/- 0.5^{o}C.)

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the insulation, windows and Heat Recovery Ventilation (HRV) programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable and high performance thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through customer-submitted coupons.

Thermostat Program

Market Considerations

Market penetration of programmable and high performance electronic thermostats has increased in the past two years, but continues to represent a small portion of the overall sales volume. Minimum quality thermostats continue to be widely used in new home construction. The St. John's Energy Reduction Strategy that was implemented in September 2011 requires all new homes in the city to have electronic thermostats installed. This is expected to create increased participation in the program for customers residing in the city and may have some spillover effects. Thermostat requirements are not expected to be affected by National Building Code changes.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit will be implemented for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:
Deferral Cost - $4,000
Associated Savings – 34 MWh/yr

ENERGY STAR Window Program

Program Description

The objective of this program was to increase the installation of *ENERGY STAR* windows instead of standard windows. *ENERGY STAR* windows improve the efficiency of the home's building envelope and provide savings in space heating energy. The program components consisted of rebates, financing options, and a variety of education and marketing tools. This program was offered through takeCHARGE from 2009 to 2014.

Target Market: Residential

Until December 31, 2014 this program targeted new and existing residential home owners to install more energy efficient windows. Eligibility was limited to electrically-heated homes. This program was closed at the end of 2014 as result of the market having transformed to ENERGY STAR windows as the standard.

Eligible Measures

Eligible measures in this program are *ENERGY STAR* qualified windows.

Delivery Strategy

The delivery strategy for this program remained unchanged to December 31, 2014 when it ended. Delivery of the program was bundled with the insulation, thermostat and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives included partnering with retailers and trade allies in the home building and renovation industry, and targeted both do-it-yourself and professional installers. Communications incorporated the *ENERGY STAR* brand and related marketing support. Tools and tactics included retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed primarily through customer application.

ENERGY STAR Window Program

Market Considerations

ENERGY STAR qualified windows currently comprise approximately 50% - 60% of window sales in the province, compared to 10% - 15% in 2008. With the implementation of National Building Code changes in 2013, market penetration is expected to increase in new homes. Understanding of the product is improving among customers and retailers. Eligible windows are widely available.

Incentive Strategy

Incentives for this program included rebates and financing. A rebate of $2 per square foot of window installed was offered.

Program Monitoring & Evaluation

The program was monitored for participation level, service quality, and cost effectiveness, market penetration and a representative sample of installations were inspected.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $8,000 – this was residual rebate applications from late 2014 processes early 2015.

Associated Savings – N/A

Isolated Systems Community Program

Program Description

The objective of this program is to provide a portfolio of technologies and opportunities to save energy that will move the residential and commercial isolated system customers along an energy efficiency continuum.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island and in Labrador and the L'Anse au Loup system. Eligibility for specific components of the program will be determined on a per customer basis and may be limited by primary heating source.

Eligible Measures

Measures will be wide ranging, from smaller items such as CFLs, showerheads and hot water pipe insulation, to high efficiency appliances, and cross promotions for the existing takeCHARGE Energy Savers Rebate programs.

Delivery Strategy

Hydro has engaged Summerhill Group to deliver this program, using a number of delivery strategies to engage residential and commercial customers. These include direct install efforts, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options. Mail-in rebates are provided for eligible purchases, such as appliances. Local retailers are engaged to provide additional coupons and price reductions on other products as well as exchange events for products such as LED holiday lighting. The existing takeCHARGE programs are being promoted to increase participation in those programs within the isolated systems.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability and as the avoided costs in isolated markets are higher than the Island Interconnected system, programming can be more aggressive. The customer base has been primarily non-electric heat, but electric heat load has been growing. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues and this program will provide the one on one interaction needed to assist these customers.

Incentive Strategy

The technologies used in the direct install component of the program will be installed at no cost to participating homes and businesses. Additional incentives will be dependent on the technology and the resulting savings.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and a representative sample of direct installs will be surveyed for confirmation of continued installation and use.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $550,000

Associated Savings -650 MWh/yr

Small Technologies Program

Program Description

The objective of this program is to increase the efficiency levels in homes and increase energy efficiency awareness by offering instant rebate coupons on a list of energy efficient technologies. There will also be promotional events to raise awareness of the technologies and to engage the public.

Target Market: Residential

The small technology program will be marketed toward residential customers province wide. All customers will be eligible to participate regardless of age of home or heat source.

Eligible Measures

Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions.

Delivery Strategy

Partnerships will be made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. The intent is to update the list each year, encouraging customers to purchase more products over time.

Coupon campaigns will be offered each year. These campaigns will include the delivery of public engagement events held at retailers. These events will consist of exchanges and giveaways that will promote the technologies offered through the coupons.

Small Technologies Program

Market Considerations
The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.
Incentive Strategy
Incentives for this program include instant rebates that will vary by year and campaign. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.
Program Monitoring & Evaluation
The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation.
Estimated Costs & Energy Savings
2015 Hydro Estimated: Deferral Cost - $289,000 Associated Savings -44 MWh/yr

HE HRV Program

Program Description

The objective of this program is to increase the installation of higher efficiency HRVs (those with a sensible heat recovery efficiency, or SRE, level of 70% or more). In 2013, the National Building Code is expected to require all new home HRV installations to have an SRE level of at least 60%. The program components include rebates and financing, and a variety of education and marketing tools.

Target Market: Residential

This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.

Eligible Measures

Eligible measures in this program include all HRV models that have an SRE of 70% or more.

Delivery Strategy

Delivery of this program will be bundled with the insulation, window and thermostat programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers and trade allies in the home building and renovation industry, particularly certified HRV installers. Tools and tactics will include retail and model home point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through customer application.

HE HRV Program

Market Considerations

The market includes new construction and existing HRV replacement. HRVs are widely used in new home construction in the province. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these will require replacement in the planning period. Initial cost is a barrier to increased market penetration, as is awareness of the benefits of selecting more efficient HRVs.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is estimated to be $175 for qualifying HRV units. This will reflect incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted after the first year of implementation, and every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:
Deferral Cost - $44,000
Associated Savings -2 MWh/yr

Block Heater Timers Program

Program Description

This program encourages the use of block heater timers by residential vehicle owners in the Labrador West and Central regions. Vehicle owners regularly plug in their block heaters overnight but three hours is enough for the safe operation of the vehicle to warm the coolant and the engine. The timers are available through giveaway and incented through at cash retail coupons.

Target Market: Residential

The program targets residential vehicle owners in the Labrador West and Central regions that do not currently use timers for their block heaters. It is estimated there is a potential market of nearly 10,000 residential vehicles in the region.

Eligible Measures

Eligible timers are 120 volt heavy duty outdoor timers with either manual or digital programming options. Timers provided through Hydro's giveaways are pre-programmed for a three hour operation whereas those available at retailers may be pre-programmed or require set up.

Delivery Strategy

The Block Heater Timer Program will run during the winter months with active promotions and giveaways to highlight the technology. The program will be launched with giveaway events happening at partner retailers in both Labrador West and Central and follow with the introduction of the $10 at cash rebate on pre-approved models of timers. Marketing and promotions include print and radio and efforts are made to engage local employers and find champions to be advocates of the product.

The launch event giveaway provides a limited number of pre-programmed timers to customers. These customers are required to participate in survey research to determine their attitudes towards and use of the timers for future verification of savings and to adjust marketing and promotional efforts.

Hydro will also explore partnerships with other groups and businesses in the region regarding further promotions and awareness of the product.

Block Heater Timers Program

Market Considerations

Initial research indicates that while block heaters are used extensively, timers are rarely used. It is common perception that a block heaters need to be plugged in overnight, rather than for limited time before start up. As well, due to lack of demand, retailers do not regularly carry the product and efforts need to be made with partner retailers to ensure on-going access to the timers. The average retail price for an eligible timer is approximately $23. Promotions and delivery strategies address both the customer perception and retail access components.

Incentive Strategy

The program provides giveaway of the technology initially to create awareness of the product and a $10 at cash rebate is provided through partner retailers, covering more than 40% of the cost of the product.

Program Monitoring & Evaluation

Contact information is collected for those redeeming at cash rebates and participating in the giveaways. Phone surveys will be conducted to validate usage and attitudes towards the product. The program will also be monitored for participation level and cost effectiveness.

Estimated Costs & Energy Savings

This program was closed in 2014 due to lack of participation.

2015 Hydro Estimated:
Deferral Cost - $0
Associated Savings -0

Lighting Program

Program Description

The objective of this program is to reduce energy use through more efficient lighting technologies in commercial buildings. The program components include rebates on a specific list of qualifying technologies, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Commercial

This program targets the owners of commercial buildings, encouraging these customers to install more efficient lighting equipment in new construction and retrofit of existing buildings.

Eligible Measures

The eligible measures for this program have included high performance T8 lamps and ballasts, and LED exit signs. Beginning in 2013, additional measures will be eligible, including T8 and T5 fluorescent fixtures used in areas with high ceilings, such as warehouses, gymnasiums, arenas and garages.

Delivery Strategy

Delivery will be integrated with other takeCHARGE commercial sector programming. Marketing for this program will include partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient lighting products.

The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association.

Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants. Rebates will be processed both through distributor point-of-sale and through customer application, depending on the lighting measure.

Lighting Program

Market Considerations

Use of high performance T8 fluorescent lighting has increased since the program was introduced. Approximately 60% of fluorescent ballasts sold annually are now high performance T8, rather than less efficient T12 or standard T8. However, less than 25% of fluorescent lamps are a high performance type. Some high efficiency technologies, such as T5 fluorescent high bay lighting, are now widely used in new commercial construction, but are used less frequently in existing buildings.

High performance fluorescent lighting systems use 25% to 40% less energy than standard fluorescent systems. LED technologies, such as LED exit signs, use 80-90% less energy than fixtures with incandescent lamps. The eligible technologies are widely available through existing channels. The primary market barriers include higher initial cost and lack of understanding of appropriate lighting technologies and savings potential.

Incentive Strategy

Program incentives reduce the cost differential for higher efficiency products and also provide a sales incentive to participating lighting distributors to sell high performance T8 lighting, ballasts and lamps to their customers. The incentives offered are $1.25 for lamps and $4.25 for ballasts. The incentive for exit signs is $21.00 per unit. The incentive for T8 and T5 fluorescent fixtures is estimated to be $60 per T5 fixture for replacement of 400 watt and 250 watt metal halide fixtures in high bay and $55 per T8 fixture for medium bay applications. Pricing of some eligible measures has increased materially in the past 12 to 18 months. This largely reflects international supply dynamics. As a result, incentive levels will be reviewed annually to ensure consistency with incremental costs.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $59,000

Associated Savings -16 MWh/yr

Isolated Systems Business Efficiency Program

Program Description

The objective of the program is to improve electrical energy efficiency across a variety of end uses. The program components include financial incentives based on energy savings, and other supports to assist in opportunity identification and evaluation. This program provides a custom approach that will allow larger commercial customers to explore a wide range of technologies suitable to their own operations, as well as an engineered track that allows for smaller customers to assess opportunities for common end uses.

Target Market

Non-residential customers in Hydro's isolated diesel and L'Anse au Loup systems are eligible.

Eligible Measures

Eligibility of the measure is based on engineering analysis of the savings. Technologies would include, but not be limited to, lighting, (heating ventilation air conditioning) HVAC, compressed air and others.

Delivery Strategy

For the engineered track, customers are able to utilize spreadsheets to assess their savings and potential rebates for common end uses, including:

- Commercial lighting – Interior, High bay or Directional
- Unitary A/C equipment (i.e. roof top units)
- Variable speed drives for fans or pumps
- Compressed air

The engineered track allows customers' progress to be incented based on their actual savings and baselines, unlike the traditional prescriptive incentive. Hydro staff will work with customers to determine baselines and estimates of savings based on the suggested retrofit. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

The program is managed internally with some external engineering verification of projects. The Utility facilitates customers through the appropriate processes to evaluate and implement approved projects. This model has been used successfully in other jurisdictions.

Isolated Systems Business Efficiency Program

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to product and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing those gaps.

Incentive Strategy

Incentives will include rebates based on energy savings, as well as funding assistance for feasibility and engineering analysis of opportunities. Rebate levels and available engineering assistance will vary based on forecasted savings and scale of the project.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, and include site visits, engineering reviews and other methods of verifying savings.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $68,000

Associated Savings -232 MWh/yr

Business Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency projects.

Target Market: Commercial

This program targets existing commercial facilities that can save energy by installing more efficient equipment and systems. The program will include a custom projects approach which will appeal primarily to large commercial customers with annual energy consumption of 1,000,000 kWhs or greater. The program will also include rebates for specific measures on a per unit basis, which will appeal to small to medium commercial customers as well.

Eligible Measures

Custom projects' eligibility will be based on engineering review and verification of estimated energy savings impacts. Specific measures eligible for per unit rebates will include HVAC equipment, refrigeration, motors and variable speed drives. It is expected that the initial list of eligible technologies will be expanded as the program matures based on program experience and market opportunities.

Delivery Strategy

For this program, the utility will manage the delivery and take the role of facilitator and consultant, supporting commercial customers to complete project proposals and implement approved projects. The program will utilize external engineering consultants for evaluation of larger project proposals and for monitoring and verification of energy savings.

The program will target equipment suppliers, service providers and consultants as key market influencers and allies in the promotion of energy efficient equipment. Rebates which reduce the cost of efficiency upgrade projects also provide a sales opportunity for these trade allies. Direct marketing to commercial facility owners and to industry associations will support the sales efforts of equipment and service providers.

Business Efficiency Program

Market Considerations

The custom project approach requires one-on-one support for project design and delivery at larger commercial facilities. The lifecycle for each custom project will be measured in months rather than weeks due to project planning and implementation timelines as well as post-installation verification and evaluation. This type of program requires that facilities have business and financial stability to continue operations for a time period appropriate to achieve cost effective savings.

Rebates for specific measures will appeal to a broad range of customers, providing a simpler approach for program participation.

Incentive Strategy

Incentives for this program include rebates based on $0.10 per kWh of energy savings in the first year of implementation. Financial support will also be available for facility energy audits and feasibility studies, if required, based on 50% cost sharing. Guidelines for maximum incentive per project and for scheduling incentive payments for custom projects will be determined in the program detailed design phase. A list of rebates will be developed to reflect incremental cost for specific measures on a per unit basis or based on energy use and hours of operation (for example, lighting controls or thermostats).

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality and cost effectiveness, including engineering review and inspection of all custom projects and assessment of long-term impact on customer processes. Formal program evaluations will be conducted within the first year of implementation and every two years during operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $68,000

Associated Savings -500 MWh/yr

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings, and other supports to enable industrial facilities to identify and implement efficiency and conservation opportunities. This program is a custom program to respond to the unique needs of the industrial market, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets new and existing industrial process equipment in the transmission level customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally with external engineering verification of projects and monitoring and evaluation of energy savings. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects. This program model has been used successfully in other jurisdictions.

This program was launched as a pilot program in 2009. With the first project applications being submitted in 2011, the pilot was closed to new projects at the end of 2013. A review of the pilot was conducted by CLEAResult to assess opportunities for moving forward. Findings indicate there continues to be a strong interest from Industrial Customers in participating. CLEAResult's recommendations will be used to develop a continued plan to ensure relevant programming is available to the industrial sector.

Industrial Energy Efficiency Program

Market Considerations

This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources.

The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, implementation timelines and post-installation monitoring and evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.

Incentive Strategy

Incentives for this program include rebates based on energy savings, as well as funding assistance for additional enabling mechanisms.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes. Formal program evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

2015 Hydro Estimated:

Deferral Cost - $5,000

Associated Savings –none for 2015

Appendix B:

Five-Year Conservation Plan: 2016 - 2020

FIVE-YEAR CONSERVATION PLAN: 2016 – 2020





October 2015

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1.0 EXECUTIVE SUMMARY

Newfoundland and Labrador Hydro ("Hydro") and Newfoundland Power have offered customer energy conservation programs on a joint and coordinated basis under the *takeCHARGE* brand since 2009. These programs provide a range of information and financial supports to help customers manage their energy usage.

The joint *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan") builds on this experience, and continues to reflect the principles underlying two previous joint, multi-year conservation plans developed by Hydro and Newfoundland Power (the "Utilities").[1] It reflects refinement of the opportunities identified in a recently updated conservation potential study (the "2015 CPS") through in-depth local market research and program cost benefit analysis.

The 2016 Plan represents both growth and evolution of the Utilities' joint customer energy conservation program portfolio. It includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. The approach outlined in this plan will remain flexible to address the changing provincial landscape, in terms of customer expectations, market conditions for energy efficient products, and electrical system costs. The 2016 Plan also addresses customer support and education, program planning and evaluation processes, as well as the Utilities' costs and cost recovery arrangements.

The total estimated energy savings for 2016 through 2020 are 883 GWh.[2] Total estimated costs through this period are $41.1 million.

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1 The *Five-Year Energy Conservation Plan: 2008-2013* was filed with the Board on June 27, 2008. The *Five-Year Energy Conservation Plan: 2012-2016* was filed on September 14, 2012.

2 The energy savings indicated throughout the *Five-Year Energy Conservation Plan: 2016-2020* represent *gross* energy savings achieved by customers. These savings reflect all technologies installed by participating customers since program implementation. *Net* energy savings would reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings; and (ii) program *free ridership* (an estimate of participants who would have chosen the more efficient product without the program).

2.0 BACKGROUND

2.1 Planning Context

Hydro and Newfoundland Power have collaborated on customer energy conservation program planning and delivery for the past 8 years. The programs offered jointly under the takeCHARGE brand have included a variety of information and financial supports which help customers manage their energy usage. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service. Initiatives address conservation opportunities for customers in each sector: residential, commercial and industrial.

The Utilities' practice has been to refresh their joint strategic plans for customer conservation programming every three to four years. This ensures programs achieve long term goals while being responsive to changes in customer expectations, market barriers, technology developments, and economics. Current program offerings are based on the Five Year Energy Conservation Plan: 2012-2016 ("the 2012 Plan").

One of the key inputs into the 2016 Plan was the outcome of the Conservation Potential Study ("CPS"), completed by the Utilities in 2015. The CPS identified cost-effective energy and demand reduction measures, outlined general parameters for program development, and quantified achievable energy savings potential by sector and end-use. The results of the CPS are considered with the Utilities' experience and other factors in the local market to determine potential programs and energy saving targets for the 2016 Plan.

The Utilities' conservation planning is coordinated with overall planning for the electrical system. Significant changes to the Island Interconnected System are anticipated to occur in this planning period. Interconnection of the Muskrat Falls hydroelectric development is forecast for 2018 and will include the Island's first connection to the

North American grid. As a result, there is uncertainty with respect to the marginal cost of energy and capacity on the Island Interconnected System beyond 2017.

Schedule A provides the current forecast marginal cost of energy and capacity for 2015-2035.[3] The forecast indicates a decrease in the marginal cost of energy beginning in 2018. This effectively reduces the value of energy savings arising from customer energy conservation programming, and limits the types of programs that can be cost effectively offered.

Costs of electricity supply additions are expected to be incorporated into customer rates starting in 2018, putting upward pressure on customers' rates. This is expected to increase customers' motivation to conserve energy to manage their electricity costs. Also, the recent economic slowdown is anticipated to continue into this planning period and will influence customer behaviour with regards to conservation.

The 2008 and 2012 Five Year Conservation and Demand Management Plans, delivered jointly by the Utilities, had focused primarily on energy conservation. This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Generating Station) which justified such a focus. The events of recent winters have since brought to light issues with peak load and generation capacity on the Island Interconnected System which are anticipated to continue into this planning period. The 2016 Plan therefore considers demand management opportunities as well as energy conservation.

The Utilities have been offering some form of customer energy conservation programming since 1991, and have achieved significant energy savings over this time. The current forecast, particularly for insulation, anticipates diminishing returns. For example, the remaining potential for energy savings through insulation upgrades has

[3] The marginal costs used to determine cost effectiveness of the customer energy conservation programs are based on the most recent marginal cost forecast as projected by Hydro in February 2015. These estimates are currently under review by Hydro to incorporate the forecast interconnection with the North American grid. Once more current estimates are available, they will be incorporated in the screening process.

been impacted by changes to the National Building Code requiring basement insulation in new homes, as well as barriers to retrofitting many of the eligible existing homes. This is consistent with experience in other North American jurisdictions where utility programming has harvested the “low hanging fruit” and subsequently has moved on to address more challenging and costly opportunities.

Energy conservation programming has also been affected by technology advancements and changes to standards. Lighting product standards changes have effectively eliminated availability of incandescent bulbs for consumers. At the same time, LED technology has advanced and become more affordable and available. The pace of this change has been even faster than anticipated in the 2012 Plan. This is demonstrated by higher than projected uptake in the Utilities’ Instant Rebate component of the Small Technologies program.

The Utilities continue to work with the Provincial Government, through the Office of Climate Change and Energy Efficiency, regarding policy development for energy conservation and efficiency, and particularly potential impacts and approaches to building codes, product standards and broader market transformation objectives.

Many of the influences on the provincial energy conservation market can be seen in other North American jurisdictions. In recent years, many jurisdictions have experienced decreasing marginal costs of energy and increasing program costs due to maturing conservation programs. As a result, utilities and program administrators have revised their approach to economic analysis of energy conservation. The Utilities have conducted research on current economic evaluation practices. A summary of this research is provided in Schedule B. It indicates that Canadian jurisdictions use the Total Resource Cost (“TRC”) test as their primary benefit cost test for program screening, with the Program Administrator Cost test as a secondary test. Only one of the seven Canadian utilities researched used Ratepayer Impact Measure as a primary benefit cost test for program screening. In the United States, most jurisdictions follow

similar practices with over 70% using TRC as the primary benefit cost test and 2% using Ratepayer Impact Measure for program screening.

2.2 Energy Conservation Programs

Based on the 2012 Plan, the Utilities have jointly offered customer energy conservation programs which provide both information and financial incentives to encourage customer installation of energy efficient technologies.[4] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table 1 shows, by sector, the portfolio of programs that have been offered under the 2012 Plan.[5]

Table 1
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation Thermostat ENERGY STAR Window[6] HRV Block Heater Timer Small Technologies Isolated Systems Community Program	Lighting Business Efficiency Program Isolated Business Efficiency Program	Industrial Energy Efficiency Program

[4] Once installed, these more energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, an HRV has an estimated life of 15 years and will result in energy savings benefits throughout that period.

[5] The Utilities also engage in demand management activities, including Newfoundland Power's Curtailable Service Rate Option and Hydro's interruptible load arrangements with its Industrial Customers.

[6] The ENERGY STAR Window Program concluded at the end of 2014.

Schedule D summarizes the energy savings and costs for the customer energy conservation programs offered by the Utilities from 2009 through 2015.

Residential Programs

Table 2 provides a summary of residential customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).[7]

Table 2
Residential Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	**2010**	**2011**	**2012**	**2013**	**2014**	**2015F**	**Total**
Energy Savings	2.5	7.1	18.6	28.5	38.4	51.5	65.7	**212.3**

The takeCHARGE residential programs are expected to result in aggregate energy savings of approximately 212.3 GWh by the end of 2015.[8]

Insulation Program

As a result of the updates to the National Building Code in 2012, several changes were made to the Insulation Program. New homes are no longer eligible and the minimum R-value requirements for existing homes have been increased. As well, the rebate structure was revised to provide a higher, easy-to-calculate rebate. Customers can receive an incentive of 75% of basement wall or ceiling insulation material costs up to $1,000, and 50% of attic insulation material costs up to $1,000.

[7] Energy savings include savings arising from all technologies installed by all participants since program implementation. This reflects the fact that these technologies provide energy savings benefits for the customer throughout the life of the product.

[8] Since implementation in 2009, there have been approximately 36,650 participants and over 638,000 at-the-cash rebates were provided on energy efficient products in the takeCHARGE residential customer programs.

Thermostat Program

High efficiency programmable and electronic thermostat replacements allow customers to conserve energy at relatively low cost and effort. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage.

ENERGY STAR Window Program

This program concluded at the end of 2014. After 5 years, and over 9,200 participating customers, the program had achieved its objective of making more efficient windows the standard in the local market.

Heat Recovery Ventilator Program

This program promotes the installation of high efficiency heat recovery ventilators ("HRVs"). HRVs have been widely used in new home construction in the province since the 1990s, to control humidity and air quality. The HRV program has experienced lower than projected participation since its launch in late 2013.[9] There has been improvement in 2015, and the Utilities will continue to monitor and evaluate this program in order to find opportunities to increase participation.

Block Heater Timer Program

Hydro provided giveaways and at-the-cash coupons for block heater timers to customers in Hydro's Labrador Interconnected System from 2012-2014. While vehicle engine block heaters are used extensively in this area, timers are rarely used. Instead of using electricity throughout the night, block heater timers allow vehicle owners to reduce the amount of time that electricity is used to warm the vehicle engine. Due to lack of participation this program was not continued past 2014 but commercial customers can take advantage of this technology through the Business Efficiency Program ("BEP") or the Isolated Systems Business Efficiency Program ("ISBEP").

[9] The Utilities have received feedback regarding low customer knowledge of home ventilation, with many customers being unaware of the purpose of a HRV in their home and how it can save energy. Also, there are complexities in the supply chain for acquiring a high efficiency HRV which can be problematic for potential participants.

Small Technologies

The small technologies program is supported by retail partners and appeals to a broad customer group as it does not involve a major home renovation. The program uses different marketing approaches for two different groups of energy efficient products.

The Instant Rebate component offers relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home.[10] Participation and energy savings results in the first two years of the program have exceeded the forecast in the 2012 plan. The Appliance and Electronics component offers incentives that are relatively higher value and available by mail-in and online application throughout the year.[11]

Isolated Systems Community Program

Following two pilot programs in 2010 and 2011, Hydro launched a full-scale, energy efficiency direct install program in 2012. The program includes direct installations of energy efficient products at no cost to homes and businesses.[12] The program also focuses on customer education and building capacity in the communities by hiring and training local representatives. These representatives work in their own communities to promote the program, provide information on energy use, and install the products.

[10] Products include LED lighting, motion sensors, timers, dimmer switches, smart power strips and more.

[11] Products include energy efficient clothes washers, full-size refrigerators, full-size freezers and TVs.

[12] Products include low-flow showerheads and aerators, CFLs, smart power strips, and hot water tank and pipe insulation.

Commercial Programs

Table 3 provides a summary of commercial customer energy savings achieved through the Utilities' conservation programs from 2009 through 2015(F).

Table 3
Commercial Portfolio Energy Savings
2009 through 2015F
(GWh)

	2009	2010	2011	2012	2013	2014	2015F	Total
Energy Savings	0.2	0.9	2.4	3.3	3.9	6.5	11.4	**28.6**

The takeCHARGE commercial programs will result in estimated aggregate energy savings of approximately 28.6 GWh by the end of 2015.[13]

Commercial Lighting Program

The Commercial Lighting Program targets reduced energy use through efficient lighting in commercial buildings, including high performance T8 and T5 fluorescent lighting and LED exit signs. This program has primarily been promoted through local lighting distributors by discounting lighting products at time of purchase.

The Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings from custom projects, and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency improvement projects. It also includes rebates for specific measures on a per unit basis.

[13] Since implementation in 2009, there have been over 1,050 participants in the takeCHARGE commercial customer programs.

Isolated Systems Business Efficiency Program

This program is targeted toward commercial customers located in Hydro's isolated system communities. This custom program provides incentives based on the energy savings from efficiency improvement projects. This allows customers to implement energy efficient technologies that are suitable for their specific buildings, equipment and operations.

Industrial Programs

Table 4 provides a summary of industrial customer energy savings achieved through Utility customer energy conservation programs from 2009 through 2015(F).

Table 4
Industrial Program Energy Savings
2009 through 2015(F)
(GWh)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Energy Savings	-	-	0.2	3.3	3.3	25.6	25.6	58.0

The takeCHARGE Industrial Energy Efficiency program will result in estimated aggregate energy savings of approximately 58.0 GWh by the end of 2015.[14]

The Industrial Energy Efficiency Program is a custom program that responds to the unique needs of Hydro's transmission level industrial customers. This program provides financial support for engineering feasibility studies of efficiency projects and for project implementation costs. The Industrial program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011 and the last being submitted in 2013. No projects were completed in 2013 as focus was put on feasibility studies for work to be completed in 2014. The program then underwent an assessment by an external third party in 2014 and was re-launched as a full program in 2015.

[14] Since implementation in 2009, there have been 5 projects completed under the takeCHARGE Industrial Energy Efficiency Program.

2.3 Education & Support

The Utilities continue to provide energy efficiency education and support to customers through a variety of channels, which include a joint website, outreach activities, school presentations and partnerships with other organizations.

Table 5 shows the number of customer-initiated contacts with the Utilities for energy conservation information from 2010 through 2015 YTD.

Table 5
Customer Contacts for
Energy Conservation Information

	2010	2011	2012	2013	2014	2015YTD
Contact Centre Inquiries	11,704	12,624	9,793	9,630	10,830	5,328
Website Visits	52,013	72,996	49,202	76,278	186,003	197,973

The majority of customers chose electronic means of communication with the Utilities to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information. Customer visits to the takeCHARGE website grew by 144% from 2013 to 2014. Activity in the first eight months of 2015 shows continued growth, with approximately 80% of website visits via a mobile device. This increase is related to increased promotion, changes to existing programs, and addition of new programs.

The Utilities have participated in an average of 214 community outreach events each year since 2012. This included presentations to retailers and suppliers, senior citizens, trade allies and other groups. takeCHARGE information booths were displayed at home shows, trade fairs, and retail stores across the province. The Utilities also offer a number of outreach events, such as the annual takeCHARGE of Your Town Challenge and Energy Efficiency Week. Through these outreach activities, members of the takeCHARGE team assisted customers with their energy efficiency questions, while raising awareness of energy conservation and the takeCHARGE rebate programs.

Over the last three years the takeCHARGE *Kids in Charge* K-I-C Start school program, has provided energy efficiency and conservation education support to students throughout Newfoundland and Labrador. This has included delivering in classroom presentations and an annual contest for primary and elementary students. In 2014, takeCHARGE partnered with the Provincial Office of Climate Change and Energy Efficiency to extend this program through the Hotshots pilot program.[15] As a result, in 2014-15 school year, over 11,000 students in 106 schools throughout the province participated in 448 presentations about energy conservation.

Trade allies play an integral role in helping customers make knowledgeable decisions regarding energy conservation and related home improvements. Retail partners display information about takeCHARGE programs and energy efficiency products in their stores and in flyers, as well as during special promotional events.[16] Similarly, the Utilities are continuing to grow a network of business to business service providers and suppliers that support the commercial and industrial sectors.[17]

The Utilities have also developed partnerships with a variety of other organizations that share common goals for the province's conservation market, including the Association of Newfoundland and Labrador Realtors, the Canadian Home Builders Association, Newfoundland and Labrador Housing Corporation, and the Canadian Mortgage and Housing Corporation.

[15] Through the HotShots pilot, the Province provided funding and support for additional in-class presentations, curriculum linked teacher materials, and a contest for high school students.

[16] The Utilities continue to work with over 160 retail store partners, 11 manufacturers/distributors, and approximately 50 HRV installers.

[17] These include lighting equipment manufacturers and distributors, electrical and HVAC contractors, and engineering firms.

Table 6 shows costs for education and support for the period 2009-2015(F).

Table 6
Conservation Education & Support
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Education	666	486	428	426	501	647	693	3,847
Support	236	206	219	222	186	174	158	1,401
Total	**902**	**692**	**647**	**648**	**687**	**821**	**851**	**5,248**

2.4 Planning & Evaluation

Planning

The focus of the Utilities' CDM planning process is to develop a 5-year plan for the implementation of comprehensive customer energy conservation and demand management programs around the technologies that were determined to have conservation potential in the provincial market. The completion of the CPS in 2015 effectively initiated the development of the 2016 Plan.

Programs are developed and revised through consultation with the various market stakeholders, such as government, trade allies and local interest groups, to gather feedback on program delivery strategy.

Table 7 shows costs for conservation planning for the period 2009-2015(F).[18]

Table 7
Conservation Planning
Costs 2009-2015(F)
($000s)

	2009	2010	2011	2012	2013	2014	2015(F)	Total
Planning	401	429	509	404	462	958	1,202	4,365

Variations in annual conservation planning costs primarily reflect the periodic nature of the Utilities' program planning and research activities.

Research

In 2013, the Utilities completed a joint Commercial Facility Equipment Inventory ("CFEI") on 54 commercial facilities.[19] This research provided information on how commercial customers use electricity, through an inventory and analysis of all mechanical and electrical equipment in each facility.[20] This data was used as a direct input into the CPS conducted in 2015.

In 2014, Newfoundland Power and Hydro jointly conducted a survey to gather information regarding electricity end uses in the residential sector. The information gathered was used to assess potential electricity savings opportunities, and was used as a direct input into the current planning cycle. These results are also being taken into account in making adjustments to the *takeCHARGE* programs. For example, because

[18] Conservation planning costs include costs related to surveys and research, development of the potential study and the five-year plan, and general administration.

[19] The CFEI was completed by CBCL Limited, a consultant that conducted on-site facility audits for participating commercial customers. CBCL Limited is a leading employee owned multidisciplinary engineering and environmental consulting firm in Atlantic Canada.

[20] The CFEI found, for example, that the food retail sector are the largest users of electricity on a square footage basis of the customers audited, followed by the manufacturing/fish processing sector.

of survey findings regarding the prevalence of CFLs, these have been removed from the Instant Rebates Program beginning in the fall of 2015.[21]

Newfoundland Power completed research on ductless mini-split heat pumps ("MSHP") from 2013 to 2015. The objectives of this research were to assess the current MSHP market in Newfoundland, the use of the MSHP as a supplementary heat source and the potential impact of MSHPs on the electricity system. The results indicate that MSHP are more efficient and do save energy compared to electric baseboard heat.[22] This analysis also shows that there is not likely to be peak demand reduction on the electricity system from installation of MSHPs.[23] Customer demand for MSHP products has grown significantly in recent years and continues to be strong. However, there are issues with availability of qualified installers and customer understanding of product quality requirements.

In the fall of 2014, Newfoundland Power launched a pilot program to assess the economic, market, and technical feasibility of direct load control to reduce overall peak demand. This pilot was initiated in response to the constraints on system capacity that became evident after the events in January of 2013 and 2014. The pilot involved controlling hot water tanks in approximately 500 customer homes in Paradise and Mount Pearl. Demand reduction achieved by the direct load control events on average was 0.6 kW per participant, and for events that included all participants, approximately

[21] Customers were asked what types of lighting they use in areas of their house where they spend the most time: 63% reported that they use incandescent bulbs, 53% CFLs, and 18% LEDs (multiple responses allowed). In another question, 31% of respondents claimed to have changed all their bulbs to more energy efficient types, and 45% indicated that they have begun to change to more energy efficient types.

[22] Approximately half of the homes in the study recorded energy savings after installation of the MSHP. In these homes, electricity usage declined by an average of 5,300 kWh or 19% per year, with savings ranging from 7% to 50%. The remaining homes recorded an increase or no change in energy usage. This appears to reflect factors such as heating of additional living space, fuel switching, or operational issues with the MSHP.

[23] Savings at time of system peak are dependent on a number of factors such as the efficiency and defrost cycle of the MSHP system, and temperature. A high efficiency MSHP may be capable of providing peak savings in warmer parts of the province but not in colder regions, while a less efficient MSHP may not be capable of providing peak savings in any region. On colder weekdays, the study observed little difference in the load profile of the MSHP homes vs. electric baseboard homes, and occasionally the MSHP homes' peak load was slightly higher.

298 kW of demand reduction was achieved. The Pilot results also indicate that a full scale provincial program does not meet the economic requirements.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project, which is supported by the Utilities and administered by Hydro, began in September 2014 and aims to assess whether real time display of energy use has a positive effect on electricity conservation behavior. The pilot involves approximately 750 customers: 250 with an in-home display device, 250 with an in-home display device as well as electricity conservation information in a monthly mail out, and 250 with only the electricity conservation information. Monitoring of participants will continue until January 2016 and the final report will be submitted to Government by end of March 2016.

Evaluation

The customer energy conservation programs are continuously evaluated by the Utilities on their energy savings, market impacts and delivery process effectiveness. Additional review by external third party evaluators has also been conducted. Program evaluation findings are used to refine program design and implementation details on an ongoing basis, as well as support further planning.

For example, the third party residential program evaluation in 2013 found that two-thirds of windows sold in the province were ENERGY STAR, which supported the Utilities' decision to conclude the ENERGY STAR Windows Program.[24]

Economic and energy savings evaluation of the customer energy conservation programs is performed annually. Program participants are required to provide certain information on program rebate applications. This information ranges from technical data, such as the R-value of installed insulation, or efficiency rating of a HRV to the type of heating in the home and its geographic location. Analysis of this data allows the

[24] The 2013 residential program evaluation was conducted DNV GL- Energy, headquartered in Burlington, Massachusetts, and specializing in evaluating programs that promote energy efficiency, demand response, and distributed generation.

Utilities to accurately estimate the energy savings for each program and perform industry standard economic cost-benefit tests.

2.5 CDM Costs & Cost Recovery

Table 8 provides a summary of the customer energy conservation program and general costs of the Utilities from 2009 through 2015(F).[25]

Table 8
Conservation Costs
2009 through 2015 (F)
($000s)

	2009	2010	2011	2012	2013	2014	2015F	Total
Programs								
Residential	1,386	2,322	3,473	3,436	3,921	4,277	5,188	24,003
Commercial	79	95	216	214	355	926	1,388	3,273
Industrial	57	226	103	173	89	1,244	19	1,910
Total Programs	1,522	2,643	3,791	3,823	4,365	6,447	6,595	29,186
General	1,303	1,121	1,156	1,052	1,149	1,779	2,054	9,614
Total	**2,825**	**3,764**	**4,947**	**4,875**	**5,514**	**8,226**	**8,649**	**38,800**

The Utilities' costs related to conservation programs have increased from approximately $2.8 million in 2009 to $8.6 million in 2015. This primarily reflects the addition of new customer energy conservation programs in 2013, specifically the Small Technologies Program and the Business Efficiency Program. This also reflects the increased levels of customer participation and rebates related to the joint takeCHARGE program portfolio. The expansion of customer programs has also resulted in increasing energy savings.

[25] This cost summary does not include (i) costs related to programs offered independently by the Utilities prior to June 2009; (ii) costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management); and (iii) costs related to Hydro's interruptible service arrangements with its Industrial Customers.

Details of the Utilities' customer energy conservation program and general costs are provided in Schedule C.

The Utilities each bear the costs related to the provision of customer energy conservation programming in their own service territory. General conservation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising, are split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[26]

Cost Recovery

Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through the annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred.

Hydro's current customer rates, as approved by the Board in Order No. P.U. 8 (2007), include recovery of approximately $0.4 million in costs related to management and planning of conservation programming. In each year from 2009 to 2014, inclusive, Hydro has deferred recovery of direct program costs related to the expansion of customer energy conservation programming under the 2008 Plan and 2012 Plan.[27] As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014,

[26] This approach to division of jointly incurred costs reflects the proportion of customers served by each utility.

[27] The deferred recovery of these costs in 2009, 2010, 2011, 2012, 2013, and 2014 were approved by the Board in Order Nos. P.U. 14(2009), P.U. 13(2010), P.U. 4(2011), P.U. 3(2012), P.U. 35(2013), and P.U. 43(2014), respectively.

the Consumer Advocate, Newfoundland Power, the Industrial Customer Group and Vale, with participation by Board Hearing Counsel, have engaged in negotiations with Hydro. As a result, these parties agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."[28]

3.0 PLAN: 2016-2020

3.1 Conservation Potential & Program Selection

The programs included in the 2016 Plan have been selected based on a number of considerations. Opportunities identified in the 2015 CPS are a key input and these have been further assessed by the Utilities in terms of engineering, market and economic viability. Consideration has also been given to the experience of the Utilities and others in the local marketplace, feedback from customers, as well as experience shared from other Canadian jurisdictions.

Conservation Potential Study

In June 2015, a comprehensive study was completed of electricity conservation and demand management potential for the province.[29] This Conservation Potential Study estimated the potential for electrical energy and demand savings by sector and by electricity system from 2015-2029. It also identified specific technologies available to assist in achieving that potential. The CPS essentially provides a framework, consistent with current North American practices, within which to assess conservation programming. The findings enabled the Utilities to quickly focus on cost effective technologies and begin assessment of market characteristics to guide program concept development.

[28] Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015.

[29] ICF International (previously called Marbek) conducted Conservation Potential Studies for the Utilities in 2007 and 2015. ICF International is a leading environmental and energy management consultancy and has extensive experience conducting Conservation Potential Studies in Canada.

Electrical system marginal costs of supply are used in the CPS to screen the economic viability of more efficient technologies.[30] For the current CPS, these costs were based on the most recent marginal cost forecast as projected by Hydro in February 2015.[31] These estimates are currently under review. Once Hydro's marginal cost study is completed, the CPS results will be reassessed. If such a review results in changes to the list of cost effective technologies with conservation potential, these will be considered in future updates to the 2016 Plan.

Figure 1 shows the baseline provincial energy usage forecast which was input to the 2015 CPS (the reference case), and the upper and lower achievable potentials estimated by the Potential Study.[32]

[30] Technologies are considered to be economically viable when the cost of saving one kWh or kW of electricity is equal to, or less than, the marginal cost of supplying the electricity.

[31] The 2015 CPS included an analysis of the sensitivity of potential technologies to changes in marginal costs. The analysis was based on a range of + 30% to – 10% of the February 2015 forecast marginal costs. It indicated a modest level of variability in technology viability and resulting conservation results. Please see CPS, section 7.5 Energy Efficiency Supply Curve, filed with the Board September 15, 2015.

[32] The reference case is based on the provincial energy usage forecast from 2014. After this study was completed the energy usage forecast decreased due to the economic downturn, mainly in the industrial sector. The achievable potential is defined as the portion of the economic conservation potential that is achievable through utility interventions and programs given institutional, economic and market barriers. The upper achievable potential is considered to be the best case scenario with all market barriers removed, such as capital cost and product accessibility. The lower achievable potential is considered a business as usual scenario with the existing market barriers remaining in place.

Figure 1
Conservation Potential Study Results
Provincial Electrical Consumption
2014-2029

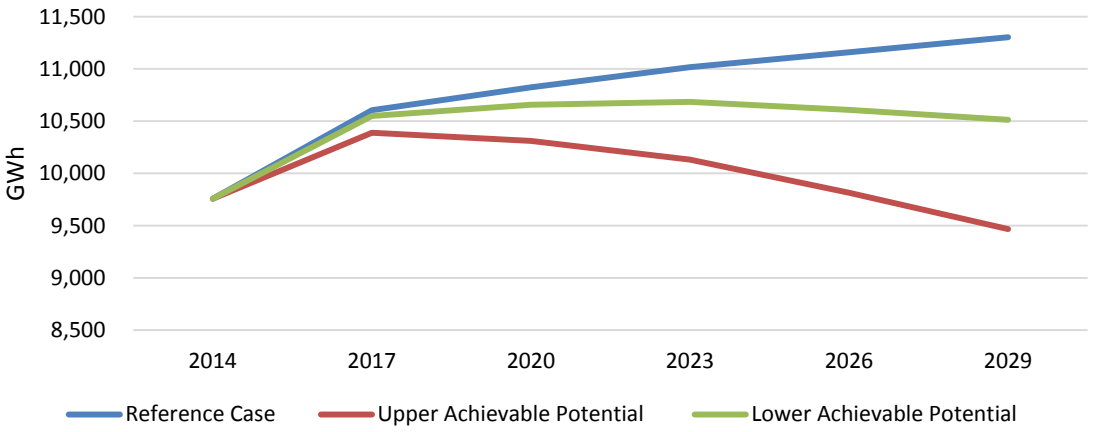


Figure 1 shows that, over time, the cumulative effects of implementing cost effective efficient technologies can significantly reduce forecast growth in electricity usage.[33]

Figures 2 and 3 show the results of the CPS regarding achievable demand reduction potential from energy efficiency measures ("Energy Efficiency") and from demand response specific measures ("Demand Response") by 2020.[34]

[33] At the end of the first estimation interval, in 2017, the CPS shows a range of 55 GWh for the lower achievable potential savings and 215 GWh for the upper achievable potential savings. This compares with annual savings of approximately 116 GWh currently estimated in the Plan for the same timeframe.

[34] The Commercial and Industrial sector includes Hydro's large transmission level Industrial customers as well as Newfoundland Power's general service customers.

Figure 2
Lower Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)

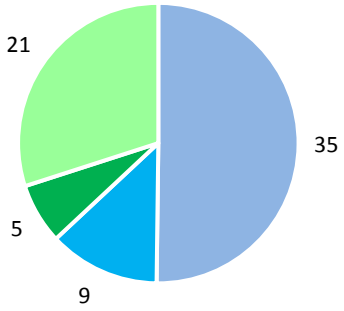
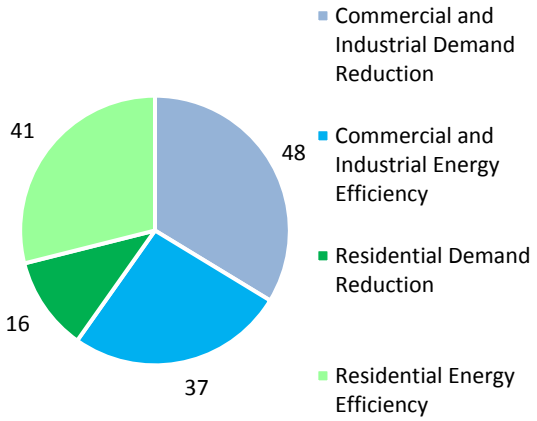


Figure 3
Upper Achievable Demand
Reduction Potential
Island Interconnected System
2020
(MW)



Figures 2 and 3 show 70 MW for the lower potential and 142 MW for the upper potential demand reduction on the Island Interconnected System.[35] Installation of energy efficiency measures that reduce consumption during times of peak demand account for approximately 43% and 55% of the lower and upper achievable demand reduction, respectively, by 2020.[36]

The majority of the demand reduction potential was identified in the Commercial and Industrial sectors. Specifically, the Industrial sector represents about 87% and 74% of the total lower and upper achievable demand reduction, respectively. The demand reduction technologies identified through the CPS as having the most potential included curtailable load arrangements with commercial and industrial customers and direct load control of residential hot water tanks.

[35] 21+35+9+5=70 and 41+16+37+48= 142
[36] (21+9)/70=43% and (37+41)/142=55%.

Selection

The technologies that passed the economic screening of the CPS were reviewed in detail to assess their possible inclusion in the 2016 Plan. Local market research was conducted to identify barriers to broader adoption of more efficient technologies, such as capital cost, market availability and awareness. This included consultation with market stakeholders and trade allies, as well as discussions with other utilities.

Once existing market barriers were identified, a program strategy was then developed to attempt to overcome those barriers. Costs associated with the program were considered and the cost effectiveness of the program determined.[37] This more detailed review of program costs and benefits can cause a technology that had passed economic screening in the CPS to fail the economic tests required of CDM programs.

Economic Screening

The Utilities' economic screening of the customer energy conservation programs has previously required a positive result for both the Total Resource Cost ("TRC") and Ratepayer Impact Measure ("RIM") cost-benefit tests.[38] Recent research indicates Canadian and U.S. utility practice has changed to focus on the TRC and Program Administrator Cost ("PAC") tests.[39]

The Utilities recommend adoption of the TRC as the primary means of program economic screening, and the PAC as a secondary means. This is consistent with current North American practice, and is appropriate based on the electrical system marginal costs and program objectives in this jurisdiction. Based on this recommendation the programs included in the 2016 Plan passed economic screening

[37] Program cost estimates include marketing, delivery and administration, incentives, measurement and verification, and evaluation.

[38] In Order No. P.U.7 (1996-97), the Board required customer conservation programs to be evaluated with respect to rate impact, as well as the total resource costs. The Utilities' have interpreted this Order to require a TRC of 1.0 and a RIM of 0.8 as described in *Newfoundland Power Inc. – 2009 Conservation Cost Deferral Application, Section 2: Proposed Customer Program Portfolio* filed with the Board October 29, 2008.

[39] See Section 2.1, page 4, and Schedule B.

based on the TRC and PAC.[40] The Utilities' will continue to monitor changes to economic screening practices to appropriately reflect evolving program characteristics and electrical system costs.

3.2 Conservation & Demand Management Programs

The 2016 Plan builds on the outcomes of the 2012 plan as well as the experience of the Utilities. Programs included in the 2016 Plan address conservation opportunities in all three sectors: residential, commercial, and industrial. The 2016 Plan includes a new behavioural-based program for the residential sector, expansion of existing commercial programs, and the reshaping or discontinuation of several programs. These conservation programs are broadly consistent with programs offered by utilities in other jurisdictions.

Table 9 shows, by sector, the portfolio of programs to be offered under the 2016 Plan.

Table 9
Conservation Programs
By Sector

Residential	**Commercial**	**Industrial**
Insulation	Business Efficiency Program	Industrial Energy Efficiency Program
Thermostat	Isolated Business Efficiency Program	
HRV		
Small Technologies		
Isolated Systems Community Program		
Benchmarking		

[40] Application of the RIM test would result in elimination of a number of programs, including Benchmarking, HRV, and Small Technologies.

Residential Programs

Insulation, Thermostat and HRV Programs

These existing joint incentive programs primarily target space heating energy savings, and will continue to be offered as part of the 2016 Plan. The remaining eligible market for the Insulation and Thermostats programs has been declining in recent years. The HRV program has had limited participation due to barriers related to customer understanding and market complexity. These programs will be continuously evaluated to ensure program cost effectiveness.

Small Technology Program

The jointly offered Small Technologies program will continue to use different marketing approaches for the two different groups of energy efficient products.

The Instant Rebate component will continue to offer relatively small incentives instantly at-the-cash on a variety of low cost, every day energy efficient products for the home. As part of the 2016 Plan, Instant Rebates will include additional technologies.[41] It is anticipated that this component will end during 2018 as LED lighting becomes the norm in the residential lighting market.[42] Most of the energy savings benefits in this program are related to customers' early adoption of LED lighting from less efficient technologies, and energy savings from non-lighting products are not expected to be sufficient to offset the program delivery costs.

Incentives for the Appliance and Electronics component will continue to be available through 2017. At that time, anticipated reductions in marginal costs on the electricity system will effectively reduce the value of energy saving benefits, causing the program to fail economic screening.

[41] As part of the 2016 Plan, Instant Rebates will include additional technologies, such as faucet aerators, door bottom weather stripping, door adhesive weather stripping, window insulation kits, electrical outlet gaskets, and caulking.

[42] The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Isolated Systems Community Program

The existing format for this program will continue to be offered to customers in Hydro's isolated system communities through 2017. Information and feedback collected in 2014 and 2015, particularly for the direct install component, will be used to evaluate and plan for the Isolated Systems Community Program beyond 2017.

An Appliance Retirement component will be added to this program beginning in 2016, targeting at least one community. Older inefficient appliances will be removed from participating homes and routed for appropriate disposal.[43]

Benchmarking

This new joint program will promote customer behaviour changes to encourage more efficient energy use. Benchmarking involves using social norms to encourage neighbourly competition to reduce electricity consumption. This program will include comparison of participant households' energy consumption with their energy history and that of similar households. Participants will also receive personalized home energy reports that provide household specific electricity usage information and savings tips to help them reduce energy use and lower their electricity bills. This program will be available to customers from 2016 to 2019.

Commercial Programs

Lighting Program

Beginning in 2016, existing commercial lighting program products will become prescriptive rebates under the Business Efficiency Program, including the fluorescent high bay, high performance T8 fluorescent lamp and LED exit sign. This change will allow for more specific marketing initiatives and increased awareness of the rebates available for these technologies.

[43] This component will be evaluated to determine whether a broader program would be cost effective.

Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts have become the market standard. Industry partners indicate that approximately 55% of ballasts sold in the province in 2014 meet the program efficiency criteria.[44]

Business Efficiency Program

The Business Efficiency Program, offered jointly by the Utilities, will continue to provide custom and prescriptive incentives to commercial customers for energy efficiency improvements. Continued growth in customer participation and energy savings are anticipated for this program. The Utilities will increase the customer education and awareness component of this program to include sector-based identification of energy efficiency opportunities. New technologies will also be added to the program's list of prescriptive incentives.[45]

Isolated Systems Business Efficiency Program

This program will continue through 2020, and will be offered to Hydro's commercial customers located in isolated system communities. The program will continue to provide incentives based on the energy savings of customer projects, similar to the Business Efficiency Program.

Industrial Programs

Industrial Energy Efficiency Program

Through 2020, this customized program will continue to offer support and financial incentives based on energy savings for retrofit of industrial process equipment for Hydro's transmission level industrial customers.[46]

[44] Note that U.S. Federal Regulations are now equivalent to this ballast efficiency specification.
[45] These include: LED screw-in lamps, high bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems, and low flow pre-rinse spray valves.
[46] The Industrial Energy Efficiency Program's cost effectiveness and potential energy savings will be evaluated on a year to year basis.

Customer Energy Savings

Table 10 shows forecast customer energy reduction estimates for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 10
2016 Plan Energy Reduction Estimates
2016 through 2020
(GWh)

	2016	2017	2018	2019	2020	Total
Residential	80.4	102.7	118.1	123.5	111.7	536.4
Commercial	18.7	27.6	37.5	48.6	61.4	193.8
Industrial	30.6	30.6	30.6	30.6	30.6	153.0
Total	129.7	160.9	186.2	202.7	203.7	883.2

The programs in the 2016 Plan will result in estimated aggregate customer energy savings of approximately 883.2 GWh from 2016 through 2020. Customer energy savings are forecast to increase annually through 2020, due to expansion of the program portfolio and the addition of program technologies for the residential and commercial sectors.

Several program offerings are expected to be concluded during the planning period. These include the Small Technologies program and the Benchmarking program. Design of alternate programming for the residential sector is anticipated through the Utilities' program planning in 2018.

Demand Management

The previous conservation and demand management plans have focused primarily on energy conservation.[47] However, the Utilities' customer energy conservation programs have resulted in quantifiable demand savings.

The technologies identified through the CPS as having the most potential for demand reduction included direct load control of residential hot water tanks and curtailable load arrangements with commercial and industrial customers. Recent research has identified issues with the cost effectiveness of residential load control on the Island Interconnected System. As a result, this measure is not included in the 2016 Plan.[48] The Utilities will continue to pursue curtailment opportunities with their larger customers.[49]

A new component will also be added to the Business Efficiency Program ("BEP") to include a custom incentive for demand reduction measures that are economically viable and that provide measureable demand reduction during peak times.[50]

[47] This reflected the relatively high marginal energy costs (predominantly due to fuel costs at Hydro's Holyrood Thermal Station) which justified such a focus.

[48] Although residential load control on the Island Interconnected System does not make economic sense, Hydro's isolated communities served by diesel generation have higher marginal costs which may make the program cost effective.

[49] Hydro currently has interruptible load arrangements with its Industrial Customers which have potential for more than 90 MW of capacity assistance. Newfoundland Power currently has 16 customers participating in its Curtailable Rate Option, providing 10.4 MW of potential load reduction.

[50] More information on the custom demand component of the BEP can be found in Schedule C.

Table 11 shows forecast customer demand reduction estimates for the customer energy conservation programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 11
2016 Plan Demand Reduction Estimates
2016 through 2020[51]
(MW)

	2016	2017	2018	2019	2020	Total
Residential	3.3	4.7	5.0	4.3	1.4	18.6
Commercial	2.1	2.0	2.3	2.5	2.8	11.7
Total	5.4	6.7	7.3	6.8	4.2	30.3

The Utilities' takeCHARGE customer energy conservation programs are forecast to achieve approximately 30.3 MW in peak demand reduction through 2020. This demand reduction will occur annually for the life of the installed technologies.[52]

[51] Hydro does not forecast demand reduction for their transmission level industrial customers.
[52] For example, a customer who installs basement insulation in 2014 will achieve approximately 0.9 kW of annual peak demand reduction for the next 20 years.

2016 Plan Program Costs

Table 12 shows forecast costs for the programs in the 2016 Plan, by sector, from 2016 through 2020.

Table 12
2016 Plan Program Costs Estimates
2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Residential	5,987	6,308	4,540	3,048	2,042	21,925
Commercial	1,628	1,906	1,933	2,258	2,301	10,026
Industrial[53]	667	10	10	10	10	707
Total	8,282	8,224	6,483	5,316	4,353	32,658

The Utilities' costs related to programs in the 2016 Plan are forecast to be approximately $32.7 million over the five-year planning period. Forecast changes in program costs primarily reflect the expansion of programs and additional technology offerings anticipated from 2016 to 2018, and the conclusion of certain programs through the planning period.

3.3 Education & Support

The Utilities' customer education and support activities will continue to evolve to support changes in customer energy conservation programs and in the broader conservation market. The Utilities will continue to provide customer support and be responsive to customer expectations. Current activities, including customer outreach events, the takeCHARGE website and partnerships with industry stakeholders will be key elements of customer education.

[53] Forecasted Industrial program costs after 2016 are associated with program promotion and customer engagement. Given the small number of transmission level customers in the province, there is a high degree of uncertainty for participation in the program year to year. The forecasted amounts after 2016 will increase if customers avail of the program for feasibility assessments or incentives for energy efficiency retrofits. Projects will continue to be screened based on cost effectiveness to ensure the program remains above minimum economic thresholds.

The Utilities' educational initiatives will be expanded to include a program promoting mini-split heat pumps. The program components will include financing, education and marketing initiatives directed towards customers, and direct engagement with certified installers and suppliers. A marketing campaign will be launched to raise customer awareness of the benefits of this technology, how to choose a high quality product, as well as the necessity of having the system installed by qualified contractors. The eligibility criteria for on-bill financing of these systems will encourage the installation of high efficiency units, installed by qualified contractors.[54]

The Utilities will continue to build upon their experience offering the takeCHARGE K-I-C Start School Program. Marketing will continue to build awareness of the program amongst school boards and teachers. Teaching aids will be developed and be made available on the takeCHARGE website to assist in furthering conservation education after presentations are conducted. Updates will also be made to strengthen the message of conservation for younger students, and awareness-building contests will be offered for all age groups.

Table 13 shows forecast costs for conservation education and support for the period 2016 to 2020.

Table 13
Conservation Education & Support
Costs 2016 through 2020
($000s)

	2016	2017	2018	2019	2020	Total
Education	770	791	827	851	873	4,112
Support	171	175	181	184	191	902
Total	941	966	1,008	1,035	1,064	5,014

[54] Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016.

3.4 Planning & Evaluation

Planning

The 2016 Plan incorporates research and analysis required for the next iteration of multi-year conservation portfolio planning by the Utilities.

Table 14 shows forecast planning costs included in the 2016 Plan.

Table 14
Conservation Planning
Costs 2016-2020(F)
($000s)

	2016	2017	2018	2019	2020	Total
Planning	527	596	767	863	644	3,397

Variability in annual planning costs reflects the Utilities' multi-year planning cycle for customer conservation programs.

The Utilities anticipate development of the next multi-year plan for customer energy and demand conservation programming in 2018. Further clarity regarding electrical system cost dynamics is expected to be a factor in the next planning cycle.[55] Further assessment and adjustments to the programming contained in the 2016 Plan may also be required within the next three years as marginal cost forecasts are updated.

Research

The next update of the study of conservation potential in the province is being planned for 2020. In advance of this study, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For the residential sector, customer surveys will gather details on

[55] An updated marginal cost study is expected to be a key input to the next conservation plan in 2018 and the next CPS in 2019-2020.

the type of electrical equipment that customers have in their homes, as well as their energy-related behaviour and motivation. Research for the commercial sector will include on-site facility audits to collect data on mechanical and electrical equipment being used.

The residential lighting market will be evaluated in 2017 to determine whether the Small Technologies program should continue. This research is expected to include a socket saturation study, with onsite inventories, as well as customer surveying. This will provide the Utilities with detailed data regarding the remaining potential for energy efficient lighting replacements.

Hydro is currently investigating the implementation of an Isolated System Direct Load Control Pilot in the community of Postville, Labrador.[56] The community of Postville is served by diesel generation. The objective of this pilot will be to reduce the peak load in the community and defer investment in electrical system upgrades. The Utilities will also continue to coordinate conservation planning with electrical system planning, and will evaluate potential for conservation initiatives targeted in specific areas or communities that may provide a lower-cost alternative to electrical system upgrades.

The Provincial Office of Climate Change Home Energy Monitoring Pilot Project is ongoing and the final report will be submitted to Government by end of March 2016. The results of this pilot project will be used to assess whether this type of technology may be considered as part of future energy conservation programming.

During this planning period, the Utilities will also monitor developments in North American practices for economic evaluation and screening of conservation programs.[57]

[56] The pilot will involve commercial and residential customers. It will include installing load controllers on hot water tanks, and commercial electric heating circuits, for commercial customers. Load controllers will only be activated during maximum system peak events. The customers that participate will receive incentives such as credits at the local store in Postville.

[57] While reliance on the TRC and PAC tests for primary economic screening is currently the norm in North American jurisdictions, modifications to the TRC methodology are being considered in a number of cases. These modifications primarily involve inclusion of customers' non-energy benefits from efficiency upgrade projects.

Evaluation

The customer program portfolio will continue to be evaluated in terms of its energy savings, market impacts and delivery process effectiveness. Additional review by third party evaluators is expected, reflecting the expanded program portfolio and delivery methods.[58] Program evaluation findings will be used to refine program design and implementation details on an ongoing basis, as well as support further planning.

Specific evaluation objectives in the 2016 Plan are to monitor market saturation of particular technologies as well as cost effectiveness of the programs. For example, the Instant Rebates component of the Small Technologies program will be evaluated and an exit strategy designed based on research into the pace and impact of LED sales growth in the local lighting market.

Similarly, the Utilities will continue to closely monitor the Insulation, Thermostat and HRV programs. These programs have unique challenges and barriers to program participation.[59] Evaluation of these programs will ensure they continue to satisfy cost effectiveness requirements.

In the case of new program introductions, post-implementation evaluations will be conducted within 12 months of program launch to ensure full assessment of program design assumptions, as well as marketing and delivery process effectiveness.

[58] Evaluation costs are primarily reflected in the costs for each specific program.

[59] For the Insulation and Thermostat Programs, these barriers primarily reflect the inherent difficulty in renovating existing living spaces and the remaining market being increasingly hard-to-reach. For the HRV program, this reflects the low level of customer understanding and slow adoption by the supply chain.

3.5 Costs & Cost Recovery

Table 15 provides a summary of the Utilities' customer energy conservation program and general costs from 2016 through 2020.[60]

Table 15
Conservation Costs
2016 through 2020
($000s)

	2016	2017	2018	2019	2020
Program					
Residential	5,987	6,308	4,540	3,048	2,042
Commercial	1,628	1,906	1,933	2,258	2,301
Industrial	667	10	10	10	10
Total Programs	8,282	8,224	6,483	5,316	4,353
Education	770	791	827	851	873
Support	171	175	181	184	191
Planning	527	596	767	863	644
Total General Costs	1,468	1,562	1,775	1,898	1,708
Total	9,750	9,786	8,257	7,214	6,061

Costs related to the customer energy conservation programs outlined in the 2016 Plan are forecast to be $9.8 million in 2016 and 2017.[61] This increase primarily reflects the addition of a new program, and enhanced program technology offerings. Costs begin to decrease in 2018 from $8.3 million to $6.0 million in 2020. This decrease primarily reflects the conclusion of the Small Technologies program in 2018 and the conclusion of the Benchmarking program in 2019.

[60] This cost summary does not include costs related to Newfoundland Power's demand management activities (Curtailable Service Rate Option and facilities management) and costs related to Hydro's interruptible load arrangements.

[61] All customer energy conservation programs outlined in the 2016 Plan are cost effective, and are justified on a cost of service basis.

Schedule E provides a summary of forecast energy savings, cost estimates and cost effectiveness analysis results for the programs in the 2016 Plan.[62]

Cost Recovery

The Utilities propose conservation cost recovery based on amortizing customer energy conservation program costs over seven years.[63] The amortization of program costs over a seven-year period is considered appropriate because of the extended nature of the energy savings benefits provided by program technologies.

The Utilities' annually recurring general conservation costs would continue to be expensed as incurred.[64]

4.0 OUTLOOK

The Utilities anticipate significant changes in the electrical system serving the province within the five years considered in this plan. The Muskrat Falls hydroelectric development and related interconnection to the North American grid will affect system operations and costs, as well as customer prices. The next iteration of multi-year conservation program planning is anticipated in 2018, to coincide with these events.

In the interim, the approach outlined in the 2016 Plan will remain flexible to address ongoing changes. The initiatives in the 2016 Plan are cost effective based on current information, and were assessed for sensitivity to changes in system costs. As the Utilities implement the program changes outlined in this Plan, they will continue to evaluate program offerings to ensure they create economic benefits and are responsive to evolving customer expectations and market conditions.

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62 Cost forecasts can be expected to be refined as detailed program design progresses in 2016.

63 Newfoundland Power has used this approach since 2013, based on Order No. P.U. 13 (2013). Hydro has proposed this approach in its ongoing general rate application, and the proposal has been agreed to by the parties to settlement negotiations in that matter.

64 While general customer energy conservation costs provide benefits to customers in terms of information, knowhow and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

With growing customer awareness of conservation, and of the takeCHARGE brand, the Utilities will continue to seek opportunities to partner with complementary organizations and trade allies for customers' advantage. Information sharing and policy coordination with the Province will also continue, primarily through the Office of Climate Change and Energy Efficiency.

Table A-1 shows most recent marginal cost forecast as projected by Newfoundland and Labrador Hydro in February 2015.

Table A-1
Marginal Cost Projection
for the
Island Interconnected System
2015 - 2035

	Energy ($/MWh)	Capacity ($/KW – Yr)
2015	108	51
2016	133	70
2017	134	74
2018	47	98
2019	50	99
2020	54	108
2021	56	112
2022	59	115
2023	62	119
2024	65	123
2025	68	126
2026	70	126
2027	73	125
2028	76	125
2029	78	124
2030	81	124
2031	85	121
2032	88	118
2033	92	116
2034	96	113
2035	100	110

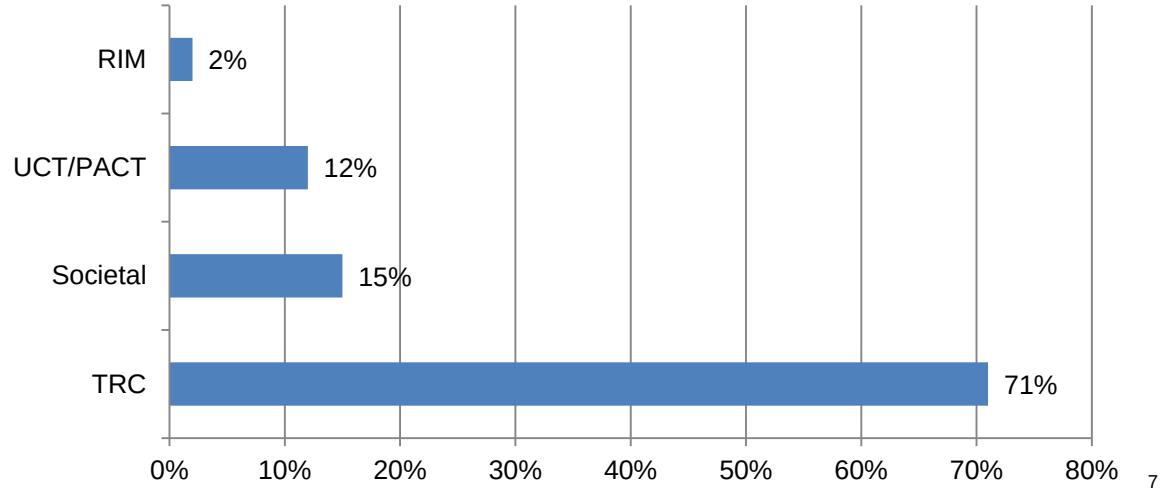
Notes:
1. Modeled as per NERA Economic Consulting marginal cost approach (2006).
2. Fuel costs per NLH corporate assumptions, January 2015.
3. Excludes transmission marginal costs.
4. Projection is at customer bulk delivery point.
5. Island Interconnected costs beyond 2017 reflect opportunity cost as per NERA approach.

Table B-1
Current Canadian
Utility Practice
Economic Evaluation Practices

Province	Economic Test				
	TRC	PAC	RIM	PCT[1]	SCT[2]
British Columbia	X[3]				
Ontario	X	X			
Nova Scotia	X	X			
Manitoba[4]	X		X	X	X
Saskatchewan	X	X			
Quebec	X		X[5]		
Prince Edward Island	X	X[6]		X	X[6]

1 Participant Cost Test ("PCT").
2 Societal Cost Test ("SCT").
3 British Columbia uses a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.
4 Manitoba also considers the levelized resource cost, net utility benefit, utility net present value, levelized utility cost, and simple customer payback calculation.
5 Quebec considers the RIM as a secondary test.
6 Prince Edward Island considers the PAC and SCT as secondary tests.

Chart B-1
Current American Utility Practice
Economic Evaluation Practices
(Percent of States)



[7]

n=43

[7] Research conducted by the American Council for an Energy Efficient Economy (February 2012) "A National Survey of State Policies and Practices for the Evaluation of Ratepayer-Funded Energy Efficiency Programs".

Insulation Program

Program Description
The objective of this program is to increase the insulation level in residential basements, crawl spaces and attics. Increasing the insulation R-value in a home will result in space heating energy savings. The program components include rebates and financing, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers completing retrofit projects. Changes to the National Building Code of Canada implemented in December 2012 mandated that all new homes install basement insulation and increased the R-Value requirements in the attic. As a result, this program is only offered to existing homes (i.e. connected to the electricity grid before January 1, 2014) to exclude minimum building code compliance in new homes. Eligibility will continue to be limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include insulation upgrades to basements, crawl spaces and attics. Technical requirements will be approximately aligned with National Building Code of Canada.
Delivery Strategy
Delivery of this program will continue to be bundled with Thermostat, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio. Marketing initiatives include partnering with retailers and trade allies in the renovation industry, and target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, website, tradeshows, community outreach and trade ally activities. Rebates and financing will be processed through mail and online customer applications.

Insulation Program

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the impact on space heating energy, the practical difficulties of renovating an existing living space and a decreasing number of eligible participants. Experience with the existing program has shown participation to be responsive to awareness-building marketing activities.

Incentive Strategy

Incentives for this program include rebates and financing. In August 2014, the rebate structure was simplified and increased. Customers can now get a rebate of 75% of the cost of materials installed in the basement and 50% of the cost of materials in the attic. Rebates amounts are capped at $1,000.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation and cost effectiveness. A representative sample of installations will be inspected. Formal external evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	1,187	1,207	1,202	1,197	1,223	6,018
Estimated Cumulative Energy Savings (GWh)	30.0	33.1	36.1	38.9	41.8	180
Total Resource Cost						**2.5**

Thermostat Program

Program Description

The objective of this program is to encourage installation of programmable and high performance electronic thermostats in homes. Programmable and high performance electronic thermostats allow customers to better control the temperature of their homes and to set back the temperature during the night or while away. The program components consist of rebates, financing options, and a variety of education and marketing tools. This program has been offered through takeCHARGE since 2009.

Target Market: Residential

This program targets residential customers, including home retrofit and new home construction. Eligibility will continue to be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include both programmable and high performance electronic thermostats. All thermostats must have a setting precision of +/- 0.5 degrees Celsius or less.

Delivery Strategy

The delivery strategy for this program remains unchanged. Delivery of this program will continue to be bundled with the Insulation, Instant Rebates, Appliance & Electronics and HRV programs as part of the takeCHARGE residential portfolio.

Marketing initiatives include partnering with retailers, electrical contractors, homebuilders and real estate professionals, to educate consumers regarding the energy savings and comfort benefits of programmable & high performance electronic thermostats. Tools and tactics include retail and model home point-of-sale materials, website, tradeshows, community outreach and trade ally activities. Rebates will be processed through mail and online customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high performance electronic thermostats include lack of awareness of the potential for energy savings, difficulty programming, and reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. This continues to reflect incremental cost of the more efficient options. A time limit is no longer required for incentive redemption.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, market saturation, and cost effectiveness, and a representative sample of installations will be inspected. Formal evaluations will be conducted every two years during program operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	517	555	539	557	552	2,720
Estimated Cumulative Energy Savings (GWh)	9.7	11.1	12.5	13.8	15.2	62
Total Resource Cost						**2.8**

Small Technologies Program

Program Description

The objective of this program is to increase home energy efficiency and awareness by offering instant rebates on a variety of energy efficient technologies as well as online and mail in rebates for eligible appliances and electronics. This program also includes promotional events to raise awareness of the technologies and to engage the public.

Target Market: Residential

This program is marketed toward all residential customers province wide. All customers are eligible to participate regardless of age of home or heat source. A variety of marketing techniques such as TV news sponsorships, print, radio, online, website, as well as social media channels are used to engage customers.

Eligible Measures

Eligible measures in this program will vary over time and will be selected based on cost effectiveness, energy saving potential and market conditions. Instant rebates are available for small energy efficient items such as LEDs and smart power bars, and online and mail in customer applications are required for qualifying models of full-size refrigerators, clothes washers, TVs and full-size Energy Star freezers.

Six new measures will be added to the technology list in 2016. They are:

- Faucet aerators
- Door bottom weather stripping
- Door adhesive
- Window insulation kit
- Electrical outlet gaskets
- Caulking

Small Technologies Program

Delivery Strategy

Partnerships have been made with both chain and independent retailers to offer instant rebates to customers on a number of energy efficient products. Efforts to engage both urban and rural retailers have been made in order to ensure rebated products are available in all areas of the province.

Campaigns are held in the spring and fall each year. During each campaign, the Utilities set up in-store events at the participating locations to raise customer's awareness of the rebates and encourage use of energy efficient products.

Market Considerations

The technologies included in the program do not involve a major renovation. This program will allow the Utilities to reach customers that may not have been able to participate in the other incentive programs.

Incentive Strategy

Incentives for this program include instant rebates for small energy efficient items that will vary by year and campaign. Online and mail in customer applications are available for eligible appliances and electronics. The rebate value will be different for each technology offered, and will reflect incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. Exit interviews will be conducted during selected retail events. Formal evaluations will be conducted after the first year of implementation, and biannually during operation.

It is anticipated that this program will end after 2018. The Utilities expect that LEDs will make up the majority of bulbs that are sold in the province. If this occurs, the economics of the program will no longer be cost effective. The uptake of LEDs will be monitored and evaluated to confirm the market saturation rate in 2017.

Small Technologies Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	3,113	2,879	1,578	-	-	7,570
Estimated Cumulative Energy Savings (GWh)	23.8	33.3	38.2	37.4	36.5	169
Total Resource Cost						**1.3**

HRV Program

Program Description

The objective of this program is to increase the installation of higher efficiency Heat Recovery Ventilators ("HRV"). The program components include rebates and financing, and a variety of education and marketing tools.

Target Market

This program targets all residential customers regardless of heat source or age of home. Eligibility is available to all homes that install or replace an HRV.

Eligible Measures

Eligible measures in this program include all HRV models that have an SRE of 70% or more and meet the minimum fan efficacy requirements.

Delivery Strategy

Delivery of this program will be bundled with other takeCHARGE residential programs as part of the overall portfolio. Marketing initiatives include partnering with trade allies in the home building and renovation industry, particularly Heating Refrigeration and Air conditioning Institute certified installers. Tools and tactics include website presence, tradeshows, and trade ally activities. Rebates and financing will be processed through customer application.

Market Considerations

The market includes new construction and existing HRV replacement with an emphasis on existing replacements. Early HRV installations of the 1990s are at or near the end of their useful life, so many of these require replacement.

This program has faced a number of barriers such as understanding of what a HRV is and its purpose in the home, initial cost, and awareness of the benefits of selecting more efficient HRVs.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $175 for qualifying HRV units. This reflects the incremental cost of the more efficient options.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. This program has experienced challenging barriers to program participation. Attempting to overcome these barriers can be administratively costly and may outweigh the benefits of program delivery. This program will be monitored to ensure that the participation goals are being met in each year to ensure the program remains cost effective. A representative sample of installations will be inspected. Formal evaluations will be conducted every two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	223	218	232	231	267	1,171
Estimated Cumulative Energy Savings (GWh)	0.7	1.0	1.3	1.6	2.0	7
Total Resource Cost						**1.3**

Benchmarking Program

Program Description

Energy social benchmarking is the analysis of a household's energy consumption and the comparison of its performance with its energy history and that of other similar households. Historic consumption information, tracking over time and comparisons with other households can encourage customers to reduce energy consumption. A printed paper report is delivered to participating customers via mail. These reports include a normative comparison that compares the customer to similar neighbors. The printed Home Energy Report is supplemented by access to an online web portal allowing for increased customer energy usage information and tips and resources to facilitate energy use reduction.

Target Market: Residential

The Benchmarking program is marketed to residential customers across the province. Customers will be selected into the program and can withdraw (opt-out) at any time.

Eligible Measures

A home's energy use is compared anonymously to the usage patterns of other homes in the vicinity that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide new information to help home owners understand their energy use and find ways to make the home more efficient.

Delivery Strategy

The program is delivered largely by a third party service provider that develops and issues the Home Energy Report and maintains the online web portal. takeCHARGE will oversee all aspects of the program to ensure greater customer insight into their home energy use. The program is available year round and will be supported with takeCHARGE marketing and communication efforts.

Benchmarking Program

Market Considerations

This program will allow the Utilities to reach customers that have not been able to participate in the other incentive programs. It will also allow takeCHARGE actively engage with customers using direct home energy consumption information. This program also allows for the cross promotion of existing takeCHARGE rebate programs as methods to reduce household consumption and to drive participation in these programs.

Incentive Strategy

No monetary incentive will be offered. It has been demonstrated that for this type of program that using social norm comparisons drives the greatest and longest lasting changes to household energy consumption.

Program Monitoring & Evaluation

The program is monitored for participation levels, service quality and cost effectiveness. Formal evaluation will be conducted very two years during operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	530	1,034	989	1,063	-	3,616
Estimated Cumulative Energy Savings (GWh)	0.3	8.0	13.8	15.6	-	38
Total Resource Cost						**1.0**

Mini Split Heat Pump Educational Initiative

Program Description

The objective of the program is to encourage customers to choose high efficiency mini split heat pumps (MSHP), installed by qualified contractors. When installed correctly, a high efficiency MSHP will provide space heating energy savings. The program components include financing, education and marketing initiatives directed towards customers, and direct engagement of certified installers. Financing has been offered by Newfoundland Power since the 1990s and Hydro will have financing available beginning in 2016, however the eligibility criteria for MSHP will be updated to support the uptake of high efficiency units.

Target Market

This program targets residential customers. New home construction and retrofit customers with electric baseboard heat are considered to have the greatest potential for participation, however customer eligibility to participate in financing will not be limited by heating fuel, age or type of dwelling.

Eligible Measures

Financing will now be limited to MSHP with an estimated Heating Seasonal Performance Factor (HSPF) of 9.6 or higher. This is aligned with the minimum HSPF required for certification of units meeting the “ENERGY STAR® Most Efficient 2015” designation. To qualify for financing the installation must be performed by a contractor that has the necessary permits and certification to perform electrical and refrigeration work in the province.

Delivery Strategy

Delivery will be a two pronged approach including marketing to customers and engaging eligible installers.

Marketing initiatives will include information on the takeCHARGE website as well as bill inserts and mass media advertising regarding the benefits of choosing the right heat pump and installer. Installer engagement will include information sessions, contests, and maintaining relationships with qualified installers.

Financing applications will be processed through customer application via the existing customer service channels (online or by phone).

An incentive could not be offered for this program because it does not pass the economic analysis.

Mini Split Heat Pump Educational Initiative

Market Considerations

One of the biggest barriers is a lack of customer awareness and availability of certified installers in rural areas. In order to achieve significant energy savings, the unit must be appropriate for the Newfoundland climate, properly installed and operated.

Other major barriers include identifying what to look for in an installer (i.e. what certification should be required) and difficulty of customers to find qualified installers. The upfront cost of highly efficient units is also a barrier for some customers.

Program Monitoring & Evaluation

This program will be monitored for participation level, and service quality. The criteria for eligible models and installers will also be continually reviewed to ensure the program is promoting units and installers that will provide customers the highest achievable energy savings at a reasonable cost.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	119	100	103	102	104	529

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers who have an interest in making their businesses more energy efficient. The program includes a custom project approach which appeals primarily to large commercial customers. In 2016, the program will also include rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting, which appeal to small and medium sized customers as well.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in electrical energy and demand savings. The program excludes alternative energy and fuel switching.

Beginning in 2016 the custom stream of the Business Efficiency Program will also include incentives for demand reduction based on the options available at the customer's facilities as well as the amount of demand they are able to reduce during peak times.

Also beginning in 2016, the existing fluorescent High Bay program and the current Commercial lighting program (including high performance T8 fluorescent lamps and LED exit signs) will become prescriptive rebates under the Business Efficiency Program.[1] Electronic ballasts will no longer be available for incentive as of 2016 because these ballasts are now considered to be the market standard.

The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, electrically commutated motors for evaporator fans, cold climate air source heat pump systems and low flow pre-rinse spray valves will be added to the prescriptive list of incentives.

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1 Prescriptive incentive program are customer energy conservation programs that have per unit rebates for installing certain defined technologies. For example, providing a predefined rebate amount for a LED light bulb;

Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A walk through audit can help customers identify efficiency opportunities.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, retail point-of-sale materials, website and advertising in trade publications. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the program and available incentives, budget & planning cycles, technical know-how, and customer time constraints.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period. Demand saving projects require a minimum of 50 kW savings and be sustainable over 5 years. Incentives of up to $50,000 per site help garner interest and lower customer project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy or demand savings achieved are consistent with incentives paid.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	1,519	1,791	1,813	2,133	2,171	9,427
Estimated Cumulative Energy Savings (GWh)	18.2	26.9	36.7	47.6	60.2	190
Total Resource Cost						**2.4**

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of the Newfoundland and Labrador industrial market, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally, with external engineering services used as required. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects.

This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

Industrial Energy Efficiency Program

Market Considerations

This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources.

The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.

Incentive Strategy

Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.

Program Monitoring & Evaluation

The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[2]						
	2016	**2017**	**2018**	**2019**	**2020**	**Total**
Estimated Costs ($000s)	667	10	10	10	10	707
Estimated Cumulative Energy Savings (GWh)	30.6	30.6	30.6	30.6	30.6	153
Total Resource Cost						**1.7**

[2] While Customer audits have confirmed that there are several potential projects at Hydro's customers' sites, savings for the Industrial Energy Efficiency Program (IEEP) have only been forecasted for 2016 because there are only five transmission level industrial customers in Newfoundland and Labrador and participation depends on each company's capital budgets and focus for the year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. The costs from 2017-2020 are the fixed administration costs associated with program promotion and customer engagement in the IEEP. The majority of costs are incurred after a project is submitted and passes economic screening. Projects for the Industrial EE Program will be evaluated on a yearly basis and projects with a TRC of 1.0 or greater will be completed.

Isolated Business Efficiency Program

Program Description

The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

Target Market: Commercial

This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as LED lighting, Air Source Heat Pumps and High performance T8 Lighting.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves will be added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentive. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro's program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	106	112	117	122	128	585
Estimated Cumulative Energy Savings (GWh)	0.5	0.7	0.8	1.0	1.2	4
Total Resource Cost						**1.6**

Isolated Systems Community Program

Program Description

The objective of this program is to provide a portfolio of technologies and opportunities to help residential and commercial customers in isolated diesel communities save electrical energy and to promote energy efficiency awareness.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.

Eligible Measures

Measures will range from efficient lighting products, hot water saving products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable.

An Appliance Retirement program is being planned for at least one community. Old inefficient appliances will be removed from participating homes and routed for appropriate disposal. This will save energy and money for the homeowner. This component will be evaluated to determine if it is economic to develop into a broader program.

The Isolated systems T12 replacement program will take place in 2-3 Isolated communities. This project will offer, free of charge to commercial customers, the supply and install of new High Performance T8 lamps and ballasts.

Delivery Strategy

Hydro has engaged Summerhill Group to deliver this program. They are using a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installs will be completed, whereby the customer receives the technology in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. There is a heavy electric hot water heating penetration and opportunities exist in plug load and behavior based areas.

Commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues; this program will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Following the 2015 direct install component, information collected in 2014 and 2015 will be used to plan for Isolated Systems Community programming beyond 2017. Costs and energy savings will be estimated once the technologies have been determined.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. Formal evaluations will be conducted after each year of operation.

Estimated Costs & Energy Savings

	2016	2017	2018	2019	2020	Total
Estimated Costs ($000s)	415	415	-	-	-	830
Estimated Cumulative Energy Savings (GWh)	5.2	5.5	5.5	5.5	5.5	27
Total Resource Cost						**2.7**

Table D-1
Conservation Programs
Energy Reductions: 2012 – 2015(F)
by Sector
(GWh)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	15.8	20.6	24.0	27.0	87.4
Thermostat Program	4.5	5.8	7.0	8.4	25.7
ENERGY STAR Window Program	6.1	8.6	10.1	10.1	34.9
Coupon Program	0.3	0.3	0.3	0.3	1.2
HRV	0.0	0.0	0.2	0.4	0.6
Small Technologies	0.0	0.0	5.5	14.4	19.9
Isolated Systems Community Program	1.7	2.8	4.1	4.8	13.4
Block Heater Timer Program	-	0.3	0.3	0.3	0.9
Total Residential Portfolio	**28.4**	**38.4**	**51.5**	**65.7**	**184.0**
Commercial					
Lighting Rebate Program	3.3	3.9	5.8	6.5	19.5
BEP	-	-	0.6	4.5	5.1
Isolated Systems Business Efficiency Program	-	-	0.1	0.4	0.5
Total Commercial Portfolio	**3.3**	**3.9**	**6.5**	**11.4**	**25.1**
Industrial					
Industrial Energy Efficiency Program	3.3	3.3	25.6	25.6	57.8
Total Portfolio	**35.0**	**45.6**	**83.6**	**102.7**	**266.9**

Table D-2
Conservation Programs
Program Costs: 2012 – 2015(F)
by Sector
($000s)

	2012	2013	2014	2015F	Total
Residential					
Insulation Program	882	1,092	796	1,039	3,809
Thermostat Program	492	253	227	454	1,426
ENERGY STAR Window Program	1,173	1,634	698	7	3,512
Coupon Program	-	-	-	-	-
HRV	-	59	56	225	340
Small Technologies	-	4	1,877	2,884	4,765
Isolated Systems Community Program	858	871	615	579	2923
Block Heater Timer Program	31	8	8	-	47
Total Residential Portfolio	**3,436**	**3,921**	**4,277**	**5,188**	**16,822**
Commercial					
Lighting Rebate Program	121	128	373	790	1,412
BEP	-	112	457	532	1,101
Isolated Systems Business Efficiency Program	93	115	96	66	370
Total Commercial Portfolio	**214**	**355**	**926**	**1,388**	**2,883**
Industrial					
Industrial Energy Efficiency Program	173	89	1,244	19	1,525
Total Portfolio	**3,823**	**4,365**	**6,447**	**6,595**	**21,230**

Table E-1
Conservation Programs
Energy Reduction Estimates: 2016 – 2020
by Sector
(GWh)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	30.0	33.1	36.1	38.9	41.8	179.9
Thermostat Program	9.7	11.1	12.5	13.8	15.2	62.3
ENERGY STAR Window Program	10.1	10.1	10.1	10.1	10.1	50.5
Coupon Program	0.3	0.3	0.3	0.3	0.3	1.5
Isolated Systems Community Program	5.2	5.5	5.5	5.5	5.5	27.2
Small Technology Program	23.8	33.3	38.2	37.4	36.5	169.1
HRV Program	0.7	1.0	1.3	1.6	2.0	6.6
Benchmarking	0.3	8.0	13.8	15.6	-	37.7
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**80.4**	**102.7**	**118.1**	**123.5**	**111.7**	**536.4**
Commercial						
Isolated Systems Business Efficiency Program	0.5	0.7	0.8	1.0	1.2	4.3
Business Efficiency Program	18.2	26.9	36.7	47.6	60.2	189.6
Total Commercial Portfolio	**18.7**	**27.6**	**37.5**	**48.6**	**61.4**	**193.8**
Industrial						
Industrial Energy Efficiency Program	30.6	30.6	30.6	30.6	30.6	153.0
Total Portfolio	**129.7**	**160.9**	**186.2**	**202.7**	**203.7**	**883.2**

Table E-2
Conservation Programs
Program Cost Estimates: 2016 – 2020
by Sector
($000s)

	2016	2017	2018	2019	2020	Total
Residential						
Insulation Program	1,189	1,207	1,202	1,197	1,223	6,018
Thermostat Program	517	555	539	557	552	2,720
Isolated Systems Community Program	415	415	-	-	-	830
Small Technology Program	3,113	2,879	1,578	-	-	7,570
HRV Program	223	218	232	231	267	1,171
Benchmarking Program	530	1,034	989	1,063	-	3,616
Total Residential Portfolio	**5,987**	**6,308**	**4,540**	**3,048**	**2,042**	**21,925**
Commercial						
Isolated Systems Business Efficiency Program	106	112	117	122	128	585
Business Efficiency Program	1,522	1,794	1,816	2,136	2,173	9,441
Total Commercial Portfolio	**1,628**	**1,906**	**1,933**	**2,258**	**2,301**	**10,026**
Industrial						
Industrial Energy Efficiency Program	667	10	10	10	10	707
Total Programs Portfolio	**8,282**	**8,224**	**6,483**	**5,316**	**4,353**	**32,658**

Table E-3
Conservation Programs
Total Resource Cost Test Results
by Sector

	TRC Results
Residential	
Insulation Program	2.5
Thermostat Program	2.8
Isolated Systems Community Program	2.7
Small Technology Program	1.3
HRV Program	1.3
Benchmarking	1.0
Commercial	
Isolated Systems Business Efficiency Program	1.6
Business Efficiency Program	2.4
Industrial	
Industrial Energy Efficiency Program	1.7