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hydro
a nalcor energy company

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November 10, 2014

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

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

Re: Newfoundland and Labrador Hydro's 2013 Amended General Rate Application

Background

Newfoundland and Labrador Hydro's (Hydro) last General Rate Application (GRA) received the Board's approval in Order No. P.U. 8 (2007) with new rates effective January 1, 2007. Industrial Customers' base rates have remained unchanged and have been approved on an interim basis since January 1, 2008. Newfoundland Power's rates have been subject to annual Rate Stabilization Plan (RSP) adjustments which have been passed on to their customers and, with the exception of those served from the Labrador Interconnected System, these rate changes have applied to Hydro's Rural Customers. Labrador Interconnected customers have also received rate changes over this period; rate changes approved in 2007 have been phased in as approved by the Board with the final implementation of standard Rural Labrador Interconnected rates on January 1, 2011.

On July 30, 2013, Hydro filed its General Rate Application (GRA) based on a 2013 Test Year, in accordance with a government directive, for new rates to be effective January 1, 2014. 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. The Board, thus far, has denied Hydro's requests for revenue relief in 2014 in Order No. P.U. 40(2013) and Order No. P.U.39(2014). As a result of not receiving approval for revenue relief for 2014, Hydro is forecasting a material revenue deficiency in 2014.

On June 6, 2014, Hydro notified 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 amend its 2013 GRA to derive rates based upon 2015 forecast costs. The amended GRA will ensure that new rates are sufficient to cover Hydro's costs and provide it with a reasonable rate of return. 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.

The calculation of rate base for 2014 and 2015 in the Amended Application 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: some 2014 capital projects (Holyrood combustion turbine, Western Avalon tap changer, Sunnyside transformer); 2014 Allowance for Unforeseen Items (Holyrood Unit 3 Fan and the Sunnyside and Holyrood Breakers); and other items such as the January 2013 Holyrood repairs, expenditures over budget on Labrador City Terminal Station and the Black Tickle Fire Repair costs. These items have been included in rate base in the Amended Application because Hydro believes that upon completion of further review, the Board will determine these projects were prudently incurred and completed in a least cost manner and, therefore, should be included in rate base.

Rate Stabilization Plan (RSP)

A surplus in the RSP has accumulated primarily due to fuel savings at Hydro's Holyrood Thermal Generating Station that resulted from the shutdown of significant pulp and paper production on the Island. On April 19, 2011, an Order in Council (OC) was issued under the *Electrical Power Control Act, 1994* directing the Board to consider the RSP issue in the context of Hydro's next GRA. Further OCs, (OC2013-089, OC2013-090 and OC2013-091, dated April 4, 2013, as amended by OC2013-207 and OC2013-208, dated July 16, 2013) provided guidance to the Board and Hydro as to the disposition of the RSP surplus and a phase-in of the Industrial Customer rate increase.

Hydro filed an RSP Application on July 30, 2013 to address the Industrial Customers' rate phase-in as well as related rule changes to the RSP. Changes to the RSP Rules were subsequently implemented based on a series of Board Orders. Hydro is currently appealing the Board's ruling regarding the disposition of the Newfoundland Power RSP Surplus. Current proposals relating to the RSP are outlined in this GRA.

The Amended General Rate Application

The Amended Application, pre-filed evidence and supporting information are organized as follows:

Volume 1 – Amended Application and Evidence

This Volume includes the Amended Application, proposed rates rules and regulations and company evidence.

Volume 2 – Exhibits

This Volume contains exhibits to support the evidence, and other exhibits required to be filed with Hydro's GRA.

Hydro's 2013 Amended GRA is written so that all the evidence reflects the 2015 Test Year information and assumptions. The first section of the evidence is titled Reconciliation to Original GRA Filing and provides a comparison of the main proposals of the Amended Application (noted below) to those filed with the original Application. Key data is also summarized for the 2007, 2013, 2014 and 2015 Test Years.

In the coming weeks, Hydro will file revised responses to Requests for Information where required to provide data and information that are updated and current with the Amended filing.

Access to Materials Filed

An Adobe portable document format (pdf) copy of this application will be available to all Parties listed below and will be posted to Hydro's website at www.nlh.nl.ca. In addition, hard copies will be made available for viewing at Hydro's Regional offices.

We trust you will find the enclosed Amended General Rate Application to be in order.

Should you have any questions, please do not hesitate to 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
Stephanie Kearns – Olthuis, Kleer, Townshend LLP
Thomas Johnson – Consumer Advocate
Yvonne Jones, MP Labrador
Ed Hearn, Q.C. – Miller & Hearn

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IN THE MATTER OF the Public
Utilities Act, RSNL 1990, Chapter P-47
(the Act), and

IN THE MATTER OF a General Rate Application
(the Amended Application) by Newfoundland and
Labrador Hydro for approvals of, under Sections 70
and 75 of the Act, changes in the rates to be charged
for the supply of power and energy to Newfoundland
Power, Rural Customers and Industrial Customers; and
under Section 71 of the Act, changes in the Rules and
Regulations applicable to the supply of electricity to
Rural Customers.

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

THE AMENDED 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, 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.

BACKGROUND

3. On July 30, 2013, Hydro filed a General Rate Application (GRA) based upon a 2013 Test Year. Due to the duration of the on-going GRA process, Hydro determined that rates would be more properly set based upon updated financial information and forecast Test Years of 2014 and 2015. As such, Hydro is filing the present Amended Application.

4. By Order No. P.U. 13(2014), the Board did not approve Hydro's application for interim rates for certain customers and a deferral account for others, and amendments to the Rate Stabilization Plan.

5. By Order No. P.U. 39(2014): i) the Board did not approve Hydro's application for the transfer of, an interim basis, $29.4 million to be recognized as revenue; and ii) changes to Island Industrial customer rates and rules.

<u>Rates Orders</u>

6. By Order No. P.U. 8(2007) the Board approved the forecast average rate base for 2007 at $1,489,323,000, allowed a rate of return on rate base (based on the 2007 Test Year) of 7.44% within a range of 7.29% to 7.59%, and approved a Schedule of Rates charged by Hydro to its customers.

7. Under the authority of the *Electrical Power Control Act, 1994*, the Lieutenant Governor in Council directed that the Board adopt a policy for Hydro's Non-Government Rural Isolated Domestic and General Service customers which effectively deferred, until the present Amended Application, the 2007 rate increase required for these customers.

8. By Order No. P.U. 21(2007) the Board approved a rates rebate for domestic customers served from the Labrador Isolated and L'Anse au Loup (Labrador Straits) systems.

9. By Order No. P.U. 33(2010) the Board approved changes to rates to be charged to Labrador Interconnected Customers following an adjustment to the Rural Rate Alteration, effectively completing the phase in of 2007 Test Year rates for these customers.

10. By Order No. P.U. 39(2010) the Board approved, on an interim basis, rates to be charged to Newfoundland Power as well as the Rate Stabilization Plan.

11. By Order No. P.U. 39(2012) the Board approved changes to the Utility Rate Schedule including updates to the weather adjustment calculation.

12. By Order No. P.U. 24(2013) the Board approved a change in rates to be charged to Island Interconnected and Isolated Rural customers.

13. By Order No. P.U. 19(2014) the Board approved the rates to be charged by Hydro to Newfoundland Power as set out in the Rate Stabilization Plan Adjustment.

14. By Order No. P.U. 22(2014) the Board approved a change in rates to be charged by Hydro to its Island Interconnected and Isolated Rural customers.

<u>Accounting and Revenue Requirement</u>

15. By Order No. P.U. 20(2009) the Board approved the recovery of Hydro's costs of burning 0.7% sulphur content No. 6 fuel at the Holyrood Thermal Generating Station.

16. Under the authority of the *Electrical Power Control Act, 1994*, on March 17, 2009, the Lieutenant Governor in Council directed that the Board, upon Hydro's next General Rate Application, approve a return on rate base calculated using the rate of return on equity last approved for Newfoundland Power in a general rate application or through Newfoundland Power's Automatic Adjustment formula, that Hydro would earn a return on equity on its entire rate base including amounts related to rural assets, and that Hydro would be permitted to have the proportion of equity in its capital structure up to a maximum of the same approved for Newfoundland Power.

17. By Order No. P.U. 13(2012) the Board approved, with certain exceptions, Hydro's adoption and use of International Financial Reporting Standards (IFRS) accounting standards for financial reporting for regulatory purposes.

18. By Order No. P.U. 29(2012) the Board determined that Hydro should appropriately recognize and record asset retirement obligations in accordance with IFRS, but approval of the regulatory treatment of the proposed asset retirement obligations was denied at that time.

19. By Order No. P.U. 40(2012), the Board approved, among other things, changes in Hydro's depreciation methodology and asset service lives.

20. By Order No. P.U. 27(2014) the Board approved and fixed Hydro's 2011 average rate base and Hydro's 2012 average rate base.

Rate Stabilization Plan

21. By Order No. P.U. 40(2003) the Board approved amendments to the Rate Stabilization Plan, *inter alia*, to add provisions to deal with the Historical Plan Balance.

22. By Order No. P.U. 11(2008) the Board approved, among other things, modifications to the fuel rider component of the Rate Stabilization Plan.

23. By Order No. P.U. 1(2011) the Board approved a modification to the Load Variation provision of the Rate Stabilization Plan rules and the repayment to Government from the Rate Stabilization Plan of $10,000,000.

24. By Order No. P.U. 17(2013) the Board approved, on an interim basis, rates to be charged to Newfoundland Power under the Rate Stabilization Plan.

25. By Order No. P.U. 26(2013), the Board approved the Rate Stabilization Plan rules and components of the rates to be charged to Island Industrial customers.

26. By Order No. P.U. 29(2013) the Board approved, on an interim basis, the Rate Stabilization Plan rules and components of the rates to be charged to Island Industrial customers.

27. By Order No. P.U. 32(2013) the Board approved, on an interim basis, the Rate Stabilization Plan rules.

28. By Order No. P.U. 34(2013) the Board approved, on an interim basis, changes to the Rate Stabilization Plan rules.

29. By Order No. P.U. 9(2014) the Board approved amendments to the Rate Stabilization Plan rules and a refund to Newfoundland Power's customers and certain Hydro Rural customers.

30. By Order No. P.U. 18(2014) the Board approved, on an interim basis, amendments to the Rate Stabilization Plan Rules.

Energy Conservation Program Costs

31. By Order Nos. P.U. 14(2009), P.U. 13(2010), P.U. 4(2011) and P.U. 3(2012), the Board, among other things, approved deferral accounts to allow for the recovery by Hydro of certain 2009, 2010, 2011 and 2012 costs associated with an energy conservation program.

32. By Order No. P.U. 21(2013) the Board did not approve Hydro's application to defer its 2013 costs related to the energy conservation program.

33. By Order Nos. P.U. 35(2013) and P.U. 43(2014) the Board approved the deferred recovery of Hydro's 2013 and 2014 costs associated with its energy conservation program.

Industrial Customers

34. By Order No. P.U. 18(2007) the Board amended the Corner Brook Pulp and Paper Limited Service Agreement.

35. By Order No. P.U. 34(2007) the Board approved, on an interim basis, rates to be charged by Hydro to its Island Industrial Customers.

36. By Orders No. P.U. 37(2008) and No. P.U. 6(2009) the Board, among other things, continued on an interim basis the rates, rules and regulations for the Island Industrial Customers.

37. By Order No. P.U. 17(2009) the Board, among other things, approved, for a period of two years, amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

38. By Order No. P.U. 6(2011) the Board, among other things, approved an extension of the amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

39. By Order No. P.U. 15(2011) the Board, among other things, approved a further extension of the amended rules and regulations of service for Corner Brook Pulp and Paper Limited.

40. By Order No. P.U. 4(2012) the Board, among other things, approved on a pilot basis the amended rules and regulations of service for Corner Brook Pulp and Paper Limited and further ordered that a proposal be made with Hydro's next general rate application as to these rules and regulations of service.

41. By Order No. P.U. 6(2012) the Board approved, among other things, rates and rules and regulations of service to Vale Newfoundland & Labrador Limited.

42. By Order No. P.U. 9(2013) the Board approved, among other things, rates and rules and regulations of service to Praxair Canada Inc.

43. By Order No. P.U. 2(2014) the Board approved revisions to Hydro's service agreement with North Atlantic Refining Limited to add a provision to limit Hydro's liability.

NEWFOUNDLAND AND LABRADOR HYDRO PROPOSALS

44. The Applicant makes this Amended Application under the Act, and specifically under Sections 58, 64, 70, 71, 75, 76, 78 and 80, proposes, effective January 1, 2014:

<u>Revenue Requirement</u>

(1) (a) that Hydro's 2014 Test Year Revenue Requirement of $562,855,000 be approved;

(b) that Hydro's 2015 Test Year Revenue Requirement of $662,475,000 be approved;

(2) (a) that Hydro's forecast average rate base for 2014 of $1,692,567,000 be approved;

(b) that Hydro's forecast average rate base for 2015 of $1,802,024,000 be approved;

(3) (a) that Hydro's forecast capital structure for 2014, as set out in the evidence in support of this Amended Application, be approved with a weighted average cost of capital of 7.32% be approved;

(b) that Hydro's forecast capital structure for 2015, as set out in the evidence in support of this Amended Application, be approved with a weighted average cost of capital of 6.82%;

(4) (a) that pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base, that the return on equity last approved by Order No. P.U. 13(2013), as a result of Newfoundland Power's general rate application, of 8.80% be approved for 2014;

(b) that pursuant to Order in Council OC2009-063, for purpose of calculating Hydro's return on rate base, that the return on equity last approved by Order No. P.U. 13(2013), as a result of Newfoundland Power's general rate application, of 8.80% be approved for 2015;

(5) (a) that Hydro be allowed a rate of return on forecast average rate base of 7.12% for 2014;

(b) that Hydro be allowed a rate of return on forecast average rate base of 6.82% for 2015;

(6) that the allowable range of return on rate base of +/- 20 basis points be approved;

Regulatory Accounting and Cost of Service

(7) that Hydro's treatment to include actuarial gains and losses on Employee Future Benefits of $1.6 million in the 2015 Test Year as part of Hydro's revenue requirement, as set out in the evidence in support of this Amended Application, be approved;

(8) that the proposed regulatory treatment of Hydro's Asset Retirement Obligations to include depreciation and accretion expenses associated with Asset Retirement Obligations of $3.1 million and $3.2 million for the 2014 and 2015 Test Years, respectively, in its revenue requirement, as outlined in the evidence in support of this Amended Application, be approved;

(9) that the total generation credit for Newfoundland Power be increased to 119,329 kW;

(10) that commencing January 1, 2014 the Rural Deficit be allocated by system based upon revenue requirement;

(11) that Hydro be permitted to exclude its Conservation and Demand Management ("CDM") costs as an expense in the determination of revenue requirement, as set out in the evidence in support of this Amended Application;

(12) (a) that an Isolated Systems Supply Cost Variance Deferral Account be approved as set out in the evidence in support of this Amended Application;

(b) that an Energy Supply Cost Variance Deferral Account be approved as set out in the evidence in support of this Amended Application;

(c) that a CDM Cost Deferral Account be approved as set out in the evidence in support of this Amended Application;

(13) that Hydro be permitted to amortize and recover costs associated with the Black Start diesel generating units in Holyrood of $1.0 million per year for five years commencing in 2015, as set out in the evidence in support of this Amended Application;

(14) that Hydro be permitted to amortize and recover costs associated with Extraordinary Repairs of $0.2 million per year for five years commencing in 2015, as set out in the evidence in support of this Amended Application;

(15) that Hydro be permitted to amortize and recover external regulatory costs of $0.3 million per year for three years commencing in 2015 as set out in the evidence in support of this Amended Application;

(16) that wind energy purchases be classified 100% energy-related in the Cost of Service, as set out in the evidence in support of this Amended Application;

(17) that in setting the Holyrood Capacity factor for Cost of Service purposes, the 2015 forecast Holyrood Capacity Factor be included in the five-year average, as set out in the evidence in support of this Amended Application;

(18) that the Regulatory treatment of Capacity Related Supply Cost Variances, as proposed in Hydro's application filed October 8, 2014, be amortized over a five-year period commencing in the 2015 Test Year, be approved;

(19) that Hydro's costs arising from Capacity Assistance Agreements be treated as a production demand costs in the 2015 Test Year Cost of Service, as set out in the evidence in support of this Amended Application;

<u>Rate Stabilization Plan (RSP)</u>

(20) that the proposed changes to the RSP rules as set out in Rates Schedule of the evidence in support of this Amended Application so that:

(a) the allocation of the load variation component be modified, effective September 1, 2013, such that the year-to-date net load variation for both NP and IC is allocated among the customer groups based upon energy ratios, as set out in the evidence in support of this Amended Application;

(b) the RSP Surplus Credit Adjustment be implemented whereby the Industrial Customer RSP Surplus balance is used to phase-in base customer rates from January 1, 2015 to August 31, 2016, as set out in the evidence in support of this Amended Application;

(c) the updated Teck Resources RSP Adjustment rate be implemented to comply with Government direction to phase-in base rates in three equal annual percentages, to a reasonable degree, as set out in the evidence in support of this Amended Application;

(d) the December 31, 2014 Industrial Customer RSP balance be recovered over a two-year amortization period starting January 1, 2015, as set out in the evidence in support of this Amended Application;

(e) Section D (2.2), by which the IC RSP Adjustment was suspended effective January 1, 2014, be removed;

(f) as there is no further Rural Labrador Interconnected Automatic Rate Adjustment, Section 1.3(b) be removed;

(g) changes be approved to the Rate Stabilization Plan so as to remove the previous Section E – Historical Plan Balance;

Interim Rates

(21) that rates for 2015 be approved on an interim basis for Island Industrial Customers effective January 1, 2015 in accordance with Order in Council OC-2013-089, as amended, as set out in the evidence in support of this Amended Application;

(22) that rates for 2015 be approved on an interim basis for Newfoundland Power and Hydro Rural Customers, effective February 1, 2015, with the revenue shortfall associated with the delayed implementation to be recovered through a rate rider, as set out in the evidence in support of this Amended Application;

2014 Revenue Deficiency

(23) (a) that the RSP credit balance be used, where appropriate, to offset the 2014 Revenue Deficiency attributable to the Island Interconnected System;

(b) that the portion of the 2014 Revenue Deficiency not recovered using the RSP credit balance be deferred for future recovery through a rate rider;

General Rate Proposals

(24) that the Island Industrial wheeling rate be set at 0.443 cents/kWh, as set out in the evidence in support of this Amended Application;

(25) that the Labrador Transmission demand-related rate be set at $1.25 kW/month, as set out in the evidence in support of this Amended Application;

(26) that the average system losses used in the calculation of the energy charge to Industrial Customers for non-firm service be increased to 3.47%, as stated on page 7 of the Rates Schedules attached to this Amended Application;

(27) that, as set out in the evidence in support of this Amended Application, Hydro's 2014 existing rates for all customers be made final;

(28) that the phase-in of Island Industrial Customer rates be completed by September 1, 2016 as set out in the evidence in support of this Amended Application;

(29) that the rules and regulations of service for Corner Brook Pulp and Paper Limited, as set out in Schedule A to this Amended Application, and as set out in evidence in support of this Amended Application, be approved as final;

(30) that the Rules and Regulations for service to all Hydro Rural Customers as set out in the Rates Schedule to this Amended Application, and as set out in evidence in support of this Amended Application, be approved;

(31) that, generally, the Board approve the rates set out in the attached Schedule B to this Amended Application;

(32) that Hydro use its most recent Test Year Cost of Service Study, as opposed to a forecast Cost of Service Study, for the purpose of its annual Key Performance Indicator (KPI) reports, as set out in the evidence in support of this Amended Application; and

(33) that, upon hearing this Amended Application, the Board grant such alternative, additional or further relief as the Board shall consider fit and proper in the circumstances.

45. Communications with respect to this Amended Application should be directed to the attention of Geoffrey P. Young, Counsel to Newfoundland and Labrador Hydro.

DATED at St. John's in the Province of Newfoundland and Labrador this 10th day of November 2014.

NEWFOUNDLAND AND LABRADOR HYDRO

Geoffrey P. Young
Counsel for
Newfoundland and Labrador Hydro
P.O. Box 12400 Columbus Drive
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<u>IN THE MATTER OF</u> the Public
Utilities Act, RSNL 1990, Chapter P-47
(the Act), and

<u>IN THE MATTER OF</u> a General Rate Application
(the Amended Application) by Newfoundland and
Labrador Hydro for approvals of, under Sections 70
and 75 of the Act, changes in the rates to be charged
for the supply of power and energy to Newfoundland
Power, Rural Customers and Industrial Customers; and
under Section 71 of the Act, changes in the Rules and
Regulations applicable to the supply of electricity to
Rural Customers.

AFFIDAVIT

I, Robert J. Henderson, Professional Engineer, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am Vice-President, Newfoundland and Labrador Hydro, the Applicant named in the attached Amended Application.
2. I have read and understand the foregoing Amended 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 10th day of)
November, 2014,)
before me:)

Barrister – Newfoundland and Labrador

Robert J. Henderson

THIS SERVICE AGREEMENT made at St. John's, in the Province of Newfoundland and Labrador on the day of .

<u>BETWEEN</u>: **<u>NEWFOUNDLAND AND LABRADOR HYDRO</u>**, a corporation and an agent of the Crown constituted by statute, renamed and continued by the <u>Hydro Corporation Act, 2007</u>, Revised Statutes of Newfoundland and Labrador, Chapter H-16, (hereinafter called "Hydro") of the first part;

<u>AND</u> **<u>CORNER BROOK PULP AND PAPER LIMITED</u>**, a company organized under the laws of Newfoundland and Labrador (hereinafter called the "Customer") of the second part.

WHEREAS Hydro has agreed to sell Electrical Power and Energy to the Customer and the Customer has agreed to purchase the same from Hydro according to the Rates, Rules and Regulations set by the Board of Commissioners of Public Utilities for the Province of Newfoundland and Labrador and by the terms of this Agreement;

AND WHEREAS the Customer has hydro-electric generating capability which the parties wish to be operated in a manner which optimizes energy production;

THEREFORE THIS AGREEMENT WITNESSETH that the parties agree as follows:

<u>ARTICLE 1</u>
<u>INTERPRETATION</u>

1.01 In this Agreement, including the recitals, unless the context otherwise requires,

(a) "**Amount of Power on Order"** means the Power contracted for in accordance with Article 2;

(b) "**Approved Planned Outage**" means an outage or reduction of capacity of the Customer's generation or transmission system undertaken by the Customer for scheduled maintenance and approved by Hydro not less than one week in advance of the start of that outage;

(c) **"Billing Demand"** means the components of the Customer's monthly Power consumption for which Demand charges apply as determined in accordance with Articles 3 and 10;

(d) “**Board”** means the Board of Commissioners of Public Utilities for Newfoundland and Labrador;

(e) “**Capacity Request**” means Hydro’s request to the Customer to provide an amount of capacity equal to its Generating Capacity;

(f) “**Customer’s Total 60 Hz Demand**” means the Demand at any particular time determined by adding the amount of the Generation Output, and the amount supplied to the Customer at the Hydro Delivery Points, less the amount received by Newfoundland Power at the Delivery Points to Newfoundland Power;

(g) “**Delivery Points to Newfoundland Power**” means the 66,000 Volt terminals of the station power transformers at Marble Mountain and Pasadena, both of which are serviced from Deer Lake Power’s L1 transmission line or at such other location or locations that Hydro and the Customer mutually agree in writing;

(h) **“Demand”** means the amount of Power averaged over each consecutive period of fifteen minutes duration, commencing on the hour and ending each fifteen minute period thereafter and measured by a demand meter of a type approved for revenue metering by the appropriate department of the Government of Canada;

(i) **“Electricity”** includes Power and Energy;

(j) **“Energy”** means the amount of electricity delivered in a given period of time and measured in kilowatt hours;

(k) **“Firm Energy**” means the Energy supplied during a month at the Hydro Delivery Points net of the Energy supplied at the Delivery Points to Newfoundland Power less Interruptible Energy, Generation Outage Energy, Oil-fired Boiler Replacement Energy and Secondary Energy. The Firm Energy exclusive of Frequency Converter Replacement Energy can in no case exceed the Amount of Power on Order for the period multiplied by the hours in that month;

(l) **“Firm Power”** means, except as varied by paragraph 3.02(a) and subject to Clause 3.03, the Demand normally associated with the Amount of Power on Order;

(m) “**Frequency Converter Replacement Energy**” means the reduced capability of Hydro’s 50/60 Hz frequency converter multiplied by the duration, in hours, of the outage or reduction in capability to Hydro’s 50/60 Hz frequency converter;

(n) "**Frequency Converter Replacement Power**" means the Power taken by the Customer in excess of the Amount of Power on Order due to an outage or reduction in capability to Hydro's 50/60 Hz frequency converter to a maximum of 18,000 kW, which is the normal maximum capability of Hydro's 50/60 Hz frequency converter;

(o) **"Generating Capacity"** means 99,100 kW, being the amount of Power the Customer is able to generate at 60 Hz from its hydraulic generating resources, or to generate at 50 Hz from its hydraulic generating resources and have converted to 60 Hz, but does not include capacity from generating facilities dedicated to the generation of power and energy for sale or transfer to Hydro or to a third party;

(p) **"Generation Outage"** means an outage or reduction of the Customer's Generating Capacity due to equipment failure, Approved Planned Outages or natural causes beyond the control of the Customer including but not limited to frazil ice and low intake water, but not including an outage to those facilities dedicated to the generation of power and energy for sale to Hydro or to a third party and not including an outage or reduction caused by Hydro's 50/60 Hz frequency converter;

(q) **"Generation Outage Demand"** means the Power taken by the Customer during a period of Capacity Request which exceeds the Amount of Power on Order and which is required to temporarily replace that Generating Capacity which is rendered unavailable to the Customer due to a Generation Outage;

(r) **"Generation Outage Energy"** means the Energy associated with Generation Outage Demand;

(s) **"Generation Output"** means the total amount of 60 Hz Demand supplied by the Customer at any time as measured at the generator terminals of its 60 Hz generators plus the amount of Demand measured at the 60 Hz terminals of the 50Hz – 60Hz frequency converter;

(t) **"Hydro Delivery Points"** means: (i) Hydro's 66,000 volt bus in its Massey Drive Terminal Station at Corner Brook, (ii) the line side insulators of the Customer's terminal structure near the east end of its Deer Lake Power Plant being the termination point of Hydro's 66,000 volt line, and (iii) the 66,000 volt 60 cycle bus and 50 cycle buses in the No. 1 and No. 2 Substation of the Customer, or at such other location or locations that Hydro and the Customer mutually agree in writing;

(u) **"Interruptible Demand**" means, that part of the Customer's Total 60 Hz Demand in any 15 minute interval, which exceeds the sum of

(i) The greater of the Generation Output and the Generation Capacity, and

(ii) The Amount of Power on Order,

and which may be interrupted, in whole or in part, at the discretion of Hydro, is supplied in accordance with Clause 4.01, and, for greater certainty, Interruptible Demand does not include any Demand associated with Oil-Fired Boiler Replacement Power, Frequency Converter Replacement Power or Secondary Energy;

(v) **"Interruptible Energy"** means the Energy associated with Interruptible Demand;

(w) **"Maximum Demand"** means the greatest amount of Power during the appropriate Month or part of a Month, as the case may be, averaged over each consecutive period of fifteen minutes duration commencing on the hour and ending each fifteen minute period thereafter, and measured by a demand meter of a type approved for revenue metering by the appropriate department of the Government of Canada;

(x) **"Month"** means a calendar month;

(y) **"Non-Firm Energy"** means Energy associated with Interruptible Demand, Generation Outage Demand, Oil-Fired Boiler Replacement Power and Supplemental Energy;

(z) "**Oil-Fired Boiler Replacement Power**" means the Power taken by the Customer during a period of a Capacity Request which exceeds the amount of Power on Order up to 15,000 kW, being the amount of Power the Customer requires from Hydro for use in its electric boiler to produce process steam, a load that the Customer is normally able to displace by using its No. 7 oil-fired steam boiler;

(aa) **"Power"** means the amount of electrical power delivered at any time and measured in kilowatts;

(bb) **"Province"** means the the Province of Newfoundland and Labrador;

(cc) **"Rate Schedules"** means the schedules of rates that are approved by the Board for the sale and purchase of Power and Energy;

(dd) **"Secondary Energy"** means that Energy Hydro is willing to sell, according to Clause 5.06, at a rate approved by the Board and which would be surplus to its needs and, if not sold, would likely result in spillage at one or more of Hydro's hydraulic generating stations;

(ee) **"Specifically Assigned Charge"** means the payment made by the Customer in each Month, calculated according to a method approved by the Board, for the use of Specifically Assigned Plant;

(ff) **"Specifically Assigned Plant"** means that equipment and those facilities which are owned by Hydro and used to serve the Customer only;

(gg) "**Supplemental Energy**" means all energy taken in a Month in excess of Firm Energy, Generation Outage Energy, Interruptible Energy, Oil-Fired Boiler Replacement Energy and energy supplied to the electric boiler for Secondary Energy.

1.02 Hydro and the Customer agree that they are bound by this Agreement and by the agreements and covenants contained in the Rates Schedules. In the event of a conflict between this Agreement and the Rates Schedules, the Rates Schedules shall have priority.

1.03 In this Agreement all references to dollar amounts and all references to any other money amounts are, unless specifically otherwise provided, expressed in terms of coin or currency of Canada which at the time of payment or determination shall be legal tender herein for the payment of public and private debts.

1.04 Words in this Agreement importing the singular number shall include the plural and vice versa and words importing the masculine gender shall include the feminine and neuter genders.

1.05 Where a word is defined anywhere in this Agreement, other parts of speech and tenses of the same word have corresponding meanings.

1.06 Wherever in this Agreement a number of days is prescribed for any purpose, the days shall be reckoned exclusively of the first and inclusively of the last.

1.07 The headings of all the articles are inserted for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

1.08 Any reference in this Agreement to an Article, a Clause, a subclause or a paragraph shall, unless the context otherwise specifically requires, be taken as a reference to an article, a clause, a subclause or a paragraph of this Agreement.

1.09 This Agreement may be executed in two or more counterparts, each of which when so executed shall be deemed to be an original, but all of such counterparts together shall constitute one and the same instrument.

ARTICLE 2
AMOUNT OF FIRM POWER

2.01 Subject to this Agreement, Hydro agrees to deliver to the Customer and the Customer agrees to purchase from Hydro the Amount of Power on Order. Aside from times when Hydro has made a Capacity Request, Hydro agrees to make reasonable efforts to make available Supplemental Energy, which the Customer may use to facilitate its efficient generation of Energy, subject always to Hydro's capability to deliver it which Hydro shall determine in its sole discretion.

2.02 The Customer shall declare to Hydro in writing, not later than October 1 of each calendar year, its Amount of Power on Order for the following calendar year. Such declarations may provide for an Amount of Power on Order to apply throughout the calendar year, or may provide for one or more successive increases at specified times during the calendar year, but subject to Clause 2.05, may not provide for a decrease other than a decrease to take effect on January 1st of that following calendar year. The Amount of Power on Order shall in no event be greater than 75,000 kilowatts.

2.03 Hydro will supply all future Power requirements requested by the Customer additional to the 75,000 kilowatts provided, however, that the Customer's requests for such additional Power be made upon adequate notice in order that Hydro may make suitable extensions or additions to its system.

2.04 If Hydro cannot fully comply with a declaration of Amount of Power on Order made in accordance with Article 2.02 it will, as soon as practicable and in any event not later than November 1 of the year in which the declaration was made, advise the Customer of the extent to which it can comply. If more than one industrial customer requests an increase in their Amount of Power on Order and Hydro cannot in its judgment provide enough Power to satisfy all of the timely requests it has received, Hydro will offer additional Amounts of Power on Order to the industrial customers who made those requests in such amounts as are prorated in accordance to the quantity of additional Amounts of Power on Order in the timely requests it has received from those customers.

2.05 If the Customer increases its Generating Capacity such that it can decrease or eliminate the amount of Power it requires from Hydro, then, provided the Customer gives Hydro thirty-six Month's written notice of the reduction, the Customer may reduce or eliminate its Amount of Power on Order and its Billing Demand effective on the date that the new generation is to go into service as indicated in that written notice.

ARTICLE 3
PURCHASE AND SALE OF POWER AND ENERGY

3.01 The sale and purchase of Power and Energy shall be at such prices and upon such terms and conditions as are set out in the Rate Schedules and this Agreement.

3.02 Subject to Clause 2.05 and Article 10, the Customer's Billing Demands, which shall each be charged at the applicable rates as approved by the Board, shall comprise the following:

(a) the Billing Demand for Firm Power, which in each Month shall be the greater of:

(i) the Amount of Power on Order,

(ii) the lesser of 75% of the Amount of Power on Order for the prior calendar year and, the Amount of Power on Order for the prior calendar year less 20,000 kW,

(iii) the Amount of Power on Order plus the maximum excess Demand taken up to that time in that calendar year determined by the application of paragraphs (b) and (c) of this Clause 3.02,

(b) During periods when Hydro has not issued a Capacity Request the excess Demand is the amount of Interruptible Demand supplied by Hydro in excess of the maximum allowable Interruptible Demand;

(c) During periods in which Hydro has issued a Capacity Request the excess Demand is the amount of Demand supplied by Hydro in excess of the Amount of Power on Order, the maximum allowable Interruptible Demand, and as applicable, for each 15-minute demand interval during that period the maximum available Generation Outage Demand, the maximum Frequency Converter Replacement Power, and the electric boiler Demand for Oil-Fired Boiler Replacement Power.

3.03 Notwithstanding that the Billing Demand for Firm Power shall have, by operation of Clause 3.02, exceeded the Power on Order declared for that calendar year in accordance with Article 2, Hydro is not obliged to provide any amount of Power in excess of the Power on Order.

3.04 Notwithstanding anything to the contrary herein, the Customer shall pay in each Month its Specifically Assigned Charge, its applicable Demand charges, and its Energy charges. Its Energy charges shall comprise its Firm Energy, Frequency Converter Replacement Energy, Interruptible Energy, Generation Outage Energy, Oil-fired Boiler Replacement Energy, Secondary Energy and Supplemental Energy taken in that Month.

3.05 Supplemental Energy shall be charged at the Non-Firm Energy Rate for the Month.

3.06 Frequency Converter Replacement Energy shall be charged at Firm Energy rates for the Month but without a demand charge.

ARTICLE 4
INTERRUPTIBLE POWER

4.01 The Customer may in any Month take an amount of Interruptible Demand and Energy in addition to the Amount of Power of Order which shall be billed at the Non-Firm Demand and Energy rates approved by the Board. Provided the Amount of Power on Order is equal to or greater than 20,000 kW, the amount of Interruptible Demand and Energy available shall be the greater of 10% of the Amount of Power on Order and 5,000 kW. If the Amount of Power on Order is less than 20,000 kW, the Amount of Interruptible Demand and Energy available shall be 25% of the Amount of Power on Order. If Hydro is willing and able to serve the Customer's Interruptible Demand, then the following shall apply:

(a) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Interruptible Demand requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Interruptible Power will be made available.

(b) If serving the Customer's Interruptible Demand would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Interruptible Demand and Energy at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(c) Notwithstanding anything contrary herein, if service of the Interruptible Demand is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive standby or emergency energy source (which for the purposes of this clause shall be deemed to be a reduction of Hydro of Interruptible Demand), the Billing Demand for Interruptible Power for the Month shall be determined as follows:

(i) If there is a total interruption of Interruptible Demand and Interruptible Energy by Hydro for a whole Month, the Customer shall not be required to make any payment for Interruptible Demand and Energy that Month.

(ii) If there is a total interruption of Interruptible Demand for part of a Month, the Billing Demand for that Interruptible Demand for that Month shall be reduced by a number of kilowatts bearing the same ratio to that Billing Demand as the number of hours during which the interruption occurs bears to the total number of hours in that Month.

(iii) If Hydro requires a reduction of Interruptible Demand for a whole Month, then, the reduced Billing Demand for Interruptible Demand for that Month shall be substituted for the Billing Demand for Interruptible Demand for the same Month, when determining the price of Power and Energy for that Month.

(iv) If Hydro requires the reduction of Interruptible Demand for part of a Month, then, subject to subparagraph (v) of this paragraph 4.01(c), there shall, when determining the price of Interruptible Power and Energy for the Months in which the reduction occurs, be substituted for the Billing Demand for Interruptible Demand for that Month, the number of kilowatts obtained by adding

(a) the reduced Billing Demand for Interruptible Demand for the part of the month during which the reduction was made, averaged over the whole of that Month;

to

(b) the Billing Demand for Interruptible Demand for the part of the Month during which no reduction was made, averaged over the whole of that Month.

(v) In any case arising under subparagraph (iii) or subparagraph (iv) of this paragraph 4.01(c), where a reduction of Interruptible Demand is made for a whole Month or part thereof and the Maximum Demand for Interruptible Demand over that same period is greater than the reduced Billing Demand for Interruptible Demand for that same period, then, instead of that reduced Billing Demand, that Maximum Demand for such period shall be substituted for the Billing Demand for Interruptible Demand for that period when determining the price of Power and Energy for the Month in which the reduction occurs, but, if in any period during which a reduction occurs, the Maximum Demand for Interruptible Demand is less than the reduced Billing Demand for Interruptible Demand, no account shall be taken of that Maximum Demand.

ARTICLE 5
GENERATION OUTAGE POWER
AND SECONDARY ENERGY

5.01 In the event that the Customer experiences or requires a Generation Outage, in addition to its Power on Order and any applicable Interruptible Power it may be taking, it may take an amount of Generation Outage Demand and Energy at Non-Firm Rates. The availability of Generation Outage Demand shall be subject to Hydro's capability to deliver it, which Hydro shall determine at its sole discretion. The Generation Outage Demand taken in any instance shall not exceed the amount of generating capacity rendered unavailable because of the Generation Outage. If Hydro is willing and able to provide the Customer with Generation Outage Demand and Energy, then the following shall apply:

(a) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Generation Outage Demand requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Generation Outage Demand will be made available. While requesting or taking Generation Outage Demand and Energy, the Customer shall notify Hydro of all circumstances and particulars as to the outage as soon as practicable and shall keep Hydro informed as those circumstances and particulars change. The Customer shall not make undue requests for Generation Outage Demand and Energy and it shall restore normal operating conditions as soon as reasonably possible.

(b) If serving the Generation Outage Demand would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Generation Outage Demand and Energy at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(c) Notwithstanding anything contrary herein, if service of the Generation Outage Demand is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive Energy provided from the standby or emergency energy source, the Billing Demand for the Generation Outage for that day shall be reduced in proportion to the number of hours in that day for which the more expensive energy was rejected.

(d) For billing purposes, a daily Generation Outage Demand shall be determined for each day which shall be calculated as the Maximum Demand taken during each day when Generation Outage Demand was taken, less the Billing Demand for Firm Power and less the Frequency Converter Replacement Power and Oil Fired Boiler Replacement Power taken during that fifteen minute interval and the maximum Interruptible Demand for that Month. The Generation Outage Demand billed shall be the amount calculated by totalling the daily Generation Outage Demands for the Month and dividing that total by the number of days in the Month.

Oil-Fired Boiler Replacement Power

5.02 In the event that the Customer experiences or requires an outage to its No. 7 oil-fired boiler, in addition to its Power on Order and any applicable Interruptible Power it may be taking, it may take an amount of Oil-Fired Replacement Power at Non-Firm Rates. The availability of Oil-Fired Boiler Replacement Power shall be subject to Hydro's capability to deliver it, which Hydro shall determine at its sole discretion. The Oil-Fired Boiler Replacement Power taken in any instance shall not exceed the amount of demand taken on the electric boiler needed to replace the amount of steam unavailable because of the No. 7 oil-fired boiler outage.

If Hydro is willing and able to provide the Customer with Oil-Fired Replacement Power, then the following shall apply:

(a) Subject to operational limitations, the Customer shall first maximize the amount of steam produced from all of its other oil-fired boilers during outages to the No. 7 oil-fired boiler so as to minimize the amount of demand taken on the electric boiler.

(b) The Customer shall, if practicable, make a prior request for, or otherwise as soon as practicable notify Hydro of its requirement, specifying the amount and duration of its Oil-Fired Boiler Replacement Power requirements. Such request or notification may be made by telephone and confirmed by facsimile transmission to Hydro's officials at its Energy Control Centre, who shall advise the Customer if such Oil-Fired Boiler Replacement Power will be made available. While requesting or taking Oil-Fired Boiler Replacement Power, the Customer shall notify Hydro of all circumstances and particulars as to the outage as soon as practicable and shall keep Hydro informed as those circumstances and particulars change. The Customer shall not make undue requests for Oil-Fired Boiler Replacement Power and it shall restore normal operating conditions as soon as reasonably possible.

(c) If serving the Oil-Fired Boiler Replacement Power would result in Hydro generating from, or increasing or prolonging generation from a standby or emergency energy source, then Hydro will so advise the Customer. If the Customer wishes to purchase Oil-Fired Boiler Replacement Power at such a time or times, that Power and Energy shall be charged for as calculated by the method or formula approved by the Board.

(d) Notwithstanding anything contrary herein, if service of the Customer's Electric Boiler is disrupted by Hydro or is curtailed by the Customer as a decision to reject the more expensive Energy provided from the standby or emergency energy source, the Billing Demand associated with the Oil-Fired Boiler Replacement Power for that day shall be reduced in proportion to the number of hours in that day for which the more expensive energy was rejected.

(e) For billing purposes, a daily Demand for the Oil-Fired Boiler Replacement Power shall be determined for each day which shall be calculated as the Maximum Demand taken during each day when Oil-Fired Boiler Replacement Power was taken, less the Billing Demand for Firm Power, the Generation Outage Demand and the Frequency Converter Replacement Power for that fifteen-minute interval and, the maximum Interruptible Demand for that Month. The Oil-Fired Boiler Replacement Demand billed, if applicable, shall be the amount calculated by totalling the daily Oil-Fired Boiler Replacement Demands for the Month and dividing that total by the number of days in the Month.

5.03 Generation Outage Energy and Oil-Fired Boiler Replacement Energy, and the associated Power, shall be charged at the Non Firm Energy Rate applicable during the period of the Capacity Request and Hydro shall notify the Customer of the applicable Non Firm Energy Rate at the time of the Capacity Request and shall give notice of any change in the rate which occurs during the Capacity Request period.

5.04 If the Customer is experiencing an unplanned Generation Outage or an unplanned outage to No. 7 oil-fired boiler during a Capacity Request period, then Hydro will supply the applicable Demand and Energy subject to Hydro's capability to deliver it which Hydro shall determine at its sole discretion. Hydro shall make reasonable efforts to supply such Demand and Energy.

5.05 The Customer shall by the end of each November verify its ability to provide the Generating Capacity by operating its generation so that the 60 Hz Generation Output and the Demand at the 60 Hz terminals of the frequency converter, simultaneously, equal or exceed the Generating Capacity for a period of one continuous hour. If the Generating Capacity is not verified the Customer's

Amount of Power on Order for the following calendar year shall increase by the amount of the shortfall.

5.06 If Hydro has surplus Energy capability and the Customer desires to purchase it, and provided that appropriate metering is in place, Hydro will deliver Secondary Energy to the Customer for use in its electric boilers. The quantity and availability of Secondary Energy shall be determined by Hydro in its sole discretion, however, once declared to be available, Secondary Energy shall remain available for a period of not less than 72 hours. The rate to be paid for Secondary Energy shall be determined by the Board.

ARTICLE 6
CHARACTERISTICS OF POWER SERVICE AND POINTS OF DELIVERY

6.01 The Power and Energy to be supplied under this Agreement will be delivered to the Customer at three (3) phase alternating current having normal frequencies of fifty (50) and sixty (60) cycles and at a voltage of approximately 66,000 and delivery will be made at the Hydro Delivery Points.

6.02 Hydro will exercise its best endeavours to limit variation from the normal frequency and voltage to tolerable values.

ARTICLE 7
POWER FACTOR

7.01 The Customer agrees to take and use the Power contracted for in this Agreement at a power factor of not less than ninety percent (90%) lagging at the point of delivery specified in this Agreement.

7.02 Should the power factor be consistently less than ninety percent (90%) lagging, the Customer, upon written notification from Hydro, agrees to install suitable corrective equipment to bring the power factor to a minimum of ninety percent (90%) lagging.

7.03 If the Customer should install static condensers to correct the lagging power factor, the equipment shall be so installed that it can be completely disconnected at the request of Hydro.

ARTICLE 8
METERING

8.01 The metering equipment and meters to register the amount of Demand and Energy to be taken by the Customer under this Agreement shall be furnished by Hydro and if required to be located on the Customer's premises will be installed by Hydro in a suitable place satisfactory to Hydro and provided by the Customer, and in such manner as to register accurately the total amount of Demand and Energy taken by the Customer under this Agreement.

8.02 If the metering is installed on the low side of transformers that are Specifically Assigned Plant or owned by the Customer, an appropriate adjustment will be made to account for losses in the transformers. Also, appropriate adjustments will be made to recognize the Power and Energy delivered to Newfoundland Power at Marble Mountain and Pasadena from the Customer's generation and transmission systems.

8.03 The Customer shall have the right, at its own expense, to install, equip and maintain check meters adjacent to the meters of Hydro.

8.04 Authorized employees of Hydro shall have the right of access to all such meters at all reasonable times for the purpose of reading, inspecting, testing, repairing or replacing them. Should any meter fail to register accurately, Hydro may charge for the Demand and Energy supplied during the period when the registration was inaccurate, either,

(a) on the basis of the amount of Demand and Energy charged for

(i) during the corresponding term immediately succeeding or preceding the period of alleged inaccurate registration, or

(ii) during the corresponding term in the previous calendar year; or

(b) on the basis of the amount of Demand and Energy supplied as established by available evidence,

whichever basis appears most fair and accurate.

ARTICLE 9
LIABILITY FOR SERVICE

9.01 Subject to the provisions of the Rate Schedules and this Agreement, the Power and Energy herein contracted for will be made available for use by the Customer during twenty-four (24) hours on each and every day of the term of this Agreement.

9.02 The obligation of Hydro to furnish Power and Energy under this Agreement is expressly subject to all accidents or causes that may occur at any time and affect the generation or transmission of such Power and Energy, and in any such event, but subject to Clause 9.04, Hydro shall have the right in its discretion to reduce or, if necessary, to interrupt the supply of Power and Energy under this Agreement.

9.03 Hydro agrees to take all reasonable precautions to prevent any reduction or interruption of the supply of Power and Energy or any variation in the frequency or voltage of such supply, and whenever any such reduction, interruption or variation occurs, Hydro shall use all reasonable diligence to restore its service promptly.

9.04 (1) Subject to Clause 9.04(2) hereof, Hydro shall be liable for and in respect of only that direct loss or damage to the physical property of the Customer caused by any negligent act or omission of Hydro its servants or agents. Customer agrees that for the purpose of this Clause 9.04, "direct loss or damage to the physical property of the Customer" shall not be construed to include damages for inconvenience, mental anguish, loss of profits, loss of earnings or any other indirect or consequential damages or losses.

9.04 (2) Hydro’s liability under subclause 9.04(1) applies only when the direct loss or damage to the Customer arising from a single occurrence exceeds the sum of $100,000.00. In no event shall the liability of Hydro exceed the sum of $1,000,000.00 for any single occurrence.

9.04 (3) Customer further agrees that any damages to which it may be entitled pursuant to clause 9.04(1) shall be reduced to reflect the extent to which such losses or damages could reasonably have been reduced if the Customer had taken reasonable protective measures.

9.05 Hydro shall have the right temporarily to interrupt its service hereunder in order to maintain or make necessary changes to its system, but, except in cases of emergency or accident, the service shall be interrupted only at such time or times as will be least inconvenient to the Customer, and Hydro shall use all reasonable diligence to complete promptly such repairs or necessary changes.

ARTICLE 10
REDUCED BILLING DEMAND

10.01 If at any time during the term of this Agreement the operation of the works of either party is suspended in whole or in part by reason of war, rebellion, civil disturbance, strikes, serious epidemics, fire or other fortuitous event, then, such party will not be liable to the other party to purchase or, as the case may be, to supply Power and Energy hereunder until the cause of such suspension has been removed and in every such event, the party whose operations are so suspended shall use all reasonable diligence to remove the cause of the suspension.

10.02 (1) For the purposes of this Clause 10.02,

a) the expression “reduced Billing Demand” means the number of kilowatts to which the Billing Demand is reduced in any of the circumstances referred to in subclauses (2) or (3) of this Clause 10.02, and

b) the expression Maximum Demand means

i. during periods where there is no Capacity Request, the Customer’s Total 60 Hz Demand less the Generation Capacity, and which in no instance can be less than zero.

ii. during a period for which a Capacity Request is in effect, the power delivered at the Hydro Delivery Points less power received by Newfoundland Power at the Delivery Points to Newfoundland Power.

(2) If the Customer is prevented from taking an amount of Power because of a suspension of its operations due to a reason listed in Clause 10.01, and any such interruption or reduction lasts for one hour or longer, then Hydro shall, on the request of the Customer, allow a proportionate reduction of the Billing Demand as calculated pursuant to subclauses (4) through (9) of this Clause 10.02, provided however that, except for reduced Billing Demands that occur pursuant to paragraphs 10.02(4)(b) or (c), in no such case shall the Billing Demand be reduced below 0.85 of the Amount of Power on Order unless Hydro is unable to deliver Power and Energy in accordance with this Agreement.

(3) If the supply of Power and Energy by Hydro is interrupted or reduced for any of the reasons referred to in Clause 9.02, 9.05 or 10.01, and any such interruption or reduction lasts for one hour or longer, then Hydro shall, on the request of the Customer, allow a proportionate reduction of the payment as calculated pursuant to subclauses (5) through (9) of this Clause 10.02.

(4) For those times when the Customer is prevented from taking an amount of Power because the Customer’s mill operations are suspended or curtailed due to a strike by the employees of the Customer, the Customer’s Billing Demand shall be calculated as follows:

(a) for the first 15 days of the strike and for that portion of the strike which exceeds 120 days, the Billing Demand shall be determined in the manner set out in subclauses (5) to (9) of this clause 10.02;

(b) for those whole Months during the period that commences following the first 15 days of the strike and ends not later than 120 days after the strike began, the reduced Billing Demand shall be the Customer's Maximum Demand in those Months;

(c) for those part Months that comprise periods that include;

(i) a period that commences following the first 15 days of the strike and ends not later than 120 days after the strike began,

together with one or both of

(ii) a period when the Customer is not affected by a strike or other suspension of its operations due to a reason listed in Clause 10.01,

and

(iii) a period where a strike has continued in excess of 120 days, or where the Customer is affected by any other suspension of its operations due to a reason listed in Clause 10.01,

the Customer's Billing Demand shall be determined by adding

(iv) the Maximum Demand for the part of the Month described in subparagraph (i) averaged over the whole of the Month,

(v) the greater of the Maximum Demand for Firm Power and the Amount of Power on Order for the part of the Month described in subparagraph (ii), if any, averaged over the whole of the Month

and

(vi) the reduced Billing Demand applicable to the period described in subparagraph (iii) averaged over the whole of the Month.

(5) If there is a total interruption of the supply of Power and Energy by Hydro for a whole Month, the Customer shall not be required to make any payment for that Month.

(6) If there is a total interruption of Power for part of a Month, the Billing Demand for that Month shall be reduced by a number of kilowatts bearing

the same ratio to that Billing Demand as the number of hours during which the interruption occurs bears to the total number of hours in that Month.

(7) If the reduction of Power is made for a whole Month, then, subject to clause (9) of this Clause 10.02, the reduced Billing Demand for that Month shall be substituted for the Billing Demand for the same Month, when determining the price of Power and Energy for that Month.

(8) If the reduction of Power is made for part of a Month, then, subject to subclause (9) of this Clause 10.02, there shall, when determining the price of Power and Energy for the Months in which the reduction occurs, be substituted for the Billing Demand for that Month, the number of kilowatts obtained by adding

(a) the reduced Billing Demand for the part of the month during which the reduction was made, averaged over the whole of that Month;

to

(b) the Billing Demand for the part of the Month during which no reduction was made, averaged over the whole of that Month.

(9) In any case arising under subclause (7) or subclause (8) of this Clause 10.02, where a reduction of Power is made for a whole Month or part thereof and the Maximum Demand for that same period is greater than the reduced Billing Demand for that same period, then, instead of the reduced Billing Demand, the Maximum Demand for such period shall be substituted for the Billing Demand for that period when determining the price of Power and Energy for the Month in which the reduction occurs, but, if in any period during which a reduction occurs, the Maximum Demand is less than the reduced Billing Demand no account shall be taken of that Maximum Demand.

(10) Where a Billing Demand, a reduced Billing Demand or a Maximum Demand for a part of a Month is to be averaged for the whole of that Month in accordance with subclause (8) of this Clause 10.02, the averaging shall be done by dividing the Billing Demand, the reduced Billing Demand or the Maximum Demand, as the case may be, by the total number of hours in the whole of that Month and multiplying the result by the number of hours to which the Billing Demand, the reduced Billing Demand or the Maximum Demand relates.

(11) In addition to the reductions in Billing Demand that may be made in accordance with this Article 10, Hydro may, in its sole judgment and discretion, make other Billing Demand adjustments from time to time to

decrease the Customer’s bill to reflect unusual or unanticipated conditions or to facilitate the testing of equipment or processes by the Customer.

ARTICLE 11
CONSTRUCTION OR INSTALLATION OF TRANSMISSION LINES OR APPARATUS

11.01 For the consideration aforesaid, the Customer hereby grants to Hydro the right to construct transmission lines and accessory apparatus on locations approved by the Customer on, under or over the property of the Customer for the purpose of serving the Customer and the other customers of Hydro, together with the right of access to the property of the Customer at all times for the construction of such lines and apparatus and for the repair, maintenance and removal thereof, provided that nothing in this clause shall entitle Hydro to construct transmission lines and accessory apparatus on or over the Customer’s property if such transmission lines are not directly connected with the Customer’s premises or some part thereof.

11.02 The Customer shall not erect any building, structure or object on or over any right-of-way referred to in Clause 11.01 without the written approval of Hydro, but subject to that limitation the Customer shall be entitled to make fair and reasonable use of all lands subjected to the said right-of-way.

11.03 Any changes that the Customer may request Hydro to make in the location of any lines or apparatus constructed pursuant to Clause 11.01, shall be made by Hydro, but the Customer shall bear the expense of any such changes to the extent that such lines or apparatus supply Power to the Customer.

11.04 All transmission lines and apparatus of Hydro furnished and installed by it on the Customer’s premises shall remain the property of Hydro, and Hydro shall be entitled to remove such transmission lines and apparatus on the expiry or termination of this Agreement.

11.05 For the purpose of using the power service of Hydro, the Customer shall install properly designed and suitable apparatus in accordance with good engineering practice, and shall at all times operate and maintain such apparatus so as to avoid causing any undue disturbance on the system of Hydro, and so that the current shall be approximately equal on all three of its phases.

11.06 If, at any time, the unbalance in current between any two of its phases is, in the judgment of Hydro, excessive to a degree that the power supply system of Hydro and/or the electrical equipment of any other customer of Hydro is adversely affected, then it shall be the responsibility of the Customer to take such reasonable remedial measures as may be necessary to reduce the unbalance to an acceptable value.

11.07 If, at any time during the term of this Agreement, Hydro desires to improve the continuity of power service to any of its customers, Hydro and the Customer will co-operate and use their best endeavours to carry out the improvements either by changes to existing equipment or additions to the original installations of either Hydro or the Customer.

11.08 The Customer shall not proceed with the construction of or major alterations of its equipment or structures associated with any terminal substation at which Power and Energy is being delivered until Hydro is satisfied that the proposals for such construction or alteration are in accordance with good engineering practice and the laws and regulations of the Province, provided that any examination of the Customer's proposals by Hydro shall not render Hydro responsible in any way for the construction or alteration proposed, even if electrical connection is made by Hydro, whether or not any changes suggested by Hydro shall have been made by the Customer.

ARTICLE 12
RESPONSIBILITY FOR DAMAGES

12.01 Beyond the point of delivery, the Customer shall indemnify and hold Hydro harmless with respect to any and all claims that may be made for injuries or damages to persons or property caused in any manner by electric current or by the presence or use on the Customer's premises of electric circuits or apparatus, whether owned by Hydro or by the Customer, unless and to the extent that such injuries or damages are caused by negligence on the part of the employees of Hydro.

12.02 Up to the point of delivery, Hydro shall indemnify and hold the Customer harmless with respect to any and all claims that may be made for injuries or damages to persons or property caused in any manner by electric current or by the presence or use on the Customer's premises of electric circuits or apparatus owned by Hydro and resulting from or arising out of the negligence of Hydro's employees or other persons for whom Hydro would in law be liable, unless and to the extent that such injuries or damages are caused by negligence on the part of the employees of the Customer.

12.03 If any of the transmission lines or apparatus installed by Hydro on the Customer's premises should be destroyed or damaged by the negligence of the Customer, its servants or agents, the Customer shall reimburse Hydro for the cost of their replacement or repair.

ARTICLE 13
PAYMENT OF ACCOUNTS AND NOTICE OF CLAIMS OF CUSTOMER

13.01 Hydro will render its accounts monthly and the Customer shall, within twenty (20) days after the date of rendering any such account, make payment in lawful money of Canada at the office of Hydro in St. John's, Newfoundland, or in such other place in the said Province as Hydro may designate, without deduction for any claim or counterclaim which the Customer may have to claim to have against Hydro arising under this Agreement or otherwise.

13.02 All amounts in arrears after the expiration of the period of twenty (20) days referred to in Clause 13.01 shall bear interest at the rate of one and one-half (1-1/2%) percent per Month.

13.03 If the Customer is in default for more than thirty (30) days in paying any amount due Hydro under this Agreement, then, without prejudice to its other recourses and without liability therefore, Hydro shall, upon ten (10) days written notice to the Customer of its intention so to do, be entitled to suspend the supply of Power and Energy to the Customer until the said amount is paid, and if the supply is so suspended, the Customer shall not be relieved of its obligations under this Agreement.

13.04 The Customer and Hydro will submit to the other in writing every claim or counterclaim which each may have or claim to have against the other arising under this Agreement within sixty days of the day upon which the Customer or Hydro has knowledge of the event giving rise to such a claim.

13.05 The Customer and Hydro shall be deemed to have waived all rights for the recovery of any claim or counterclaim that has not been submitted to the other party pursuant to and in accordance with Clause 13.04.

ARTICLE 14
ARBITRATION

14.01 If a settlement of any claim made by the Customer in accordance with Clause 13.04 is not agreed to by both parties, the matters in dispute shall be submitted, within three months from the time the claim was submitted, for decision to a board of arbitrators consisting of three members, one to be named by each party to this Agreement and the third to be named by the two arbitrators so chosen, and the decision of any two members of the board of arbitrators shall be final and binding upon both parties.

14.02 The charges of the third member of a board of arbitrators who shall be the chairman of that board, shall be borne by the losing party, and the parties shall bear the costs or charges of their own appointees. Any arbitration hearing commenced under this Article shall be held in St. John's or such other place as the parties mutually agree.

14.03 If the two appointees of the parties are unable to agree upon the third arbitrator or chairman, the chairman shall be appointed upon application of either party to the Trial Division of the Supreme Court of Newfoundland and Labrador or a judge of that Division.

14.04 The period of delay for appointment by the parties to this Agreement of their respective nominees shall be seven days after notification by the other party to this Agreement of its nominee, and the period for agreement by the two nominees on the chairman shall be ten days.

14.05 The provisions of the Arbitration Act, Chapter A - 14 of the Revised Statutes of Newfoundland and Labrador, 1990, as now or hereafter amended shall apply to any arbitration held pursuant to this Article 14.

ARTICLE 15
MODIFICATION OR TERMINATION OF AGREEMENT

15.01 Except, where otherwise specifically provided in this Agreement and only to the extent so provided, all previous communications between the parties to this Agreement, either oral or written, with reference to the subject matter of this Agreement, are hereby abrogated and this Agreement shall constitute the sole and complete agreement of the parties hereto in respect of the matters herein set forth.

15.02 At any time during the currency of this Agreement, the Customer may terminate it by giving to Hydro two years previous notice in writing of its intention so to do.

15.03 Any amendment, change or modification of this Agreement shall be binding upon the parties hereto or either of them only if such amendment, change or modification is in writing and is executed by each of the parties to this Agreement by its duly authorized officers or agents and in accordance with its regulations or by-laws.

15.04 Subject to Article 10, if the Customer voluntarily or forcibly abandons its operations, commits an act of bankruptcy or liquidates its assets, then, there shall, forthwith, become due and payable to Hydro by the Customer, as stipulated and liquidated damages without burden or proof thereof, a lump sum equal to:

(a) 0.85 of its then current Billing Demand for Firm Power, at the Firm Power Demand rate, multiplied by 24;

plus

(b) the remaining net book value of Specifically Assigned Plant, less its salvage value.

ARTICLE 16
SUCCESSORS AND ASSIGNS

16.01 This Agreement shall be binding upon and enure to the benefit of the parties hereto and their respective successors and assigns, but it shall not be assignable by the Customer without the written consent of Hydro.

ARTICLE 17
GOVERNING LAW AND FORUM

17.01 This Agreement shall be governed by and interpreted in accordance with the laws of the Province, and every action or other proceeding arising hereunder shall be determined exclusively by a court of competent jurisdiction in the Province, subject to the right of appeal to the Supreme Court of Canada where such appeal lies.

ARTICLE 18
ADDRESS FOR SERVICE

18.01 Subject to Clauses 18.02 and 18.03, any notice, request or other instrument which is required or permitted to be given, made or served under this Agreement by either of the parties hereto, except for notices or requests pertaining to Interruptible Demand, Generation Outages or Secondary Energy, shall be given, made or served in writing and shall be deemed to be properly given, made or served if personally delivered, or sent by prepaid telegram or facsimile transmission, or mailed by prepaid registered post, addressed, if service is to be made

(a) on Hydro, to

The Secretary
Newfoundland and Labrador Hydro
Hydro Place
P.O. Box 12400
St. John's, Newfoundland
CANADA. A1B 4K7
FAX: (709) 737-1782
or

(b) on the Customer, to

Mill Manager
Corner Brook Pulp and Paper Limited
P.O. Box 2001
Corner Brook, Newfoundland
A2H 6J4

18.02 Any notice, request or other instrument given, made or served as provided in Clause 18.01 shall be deemed to have been received by the party hereto to which it is addressed, if personally served on the date of delivery, or if mailed three days after the time of its being so mailed, or if sent by prepaid telegram or facsimile transmission, one day after the date of sending.

18.03 Except for notices for Interruptible Demand, Generation Outage Demand, or Secondary Energy, whenever this Agreement requires a notice to be given or a request to be made on a Sunday or legal holiday, such notice or request may be given or made on the first business day occurring thereafter, and, whenever in this Agreement the time within which any right will lapse or expire shall terminate on a Sunday or legal holiday, such time will continue to run until the next succeeding business day. Notices or requests pertaining to Interruptible Demand, Generation Outages or Secondary Energy may be given and received by and to the appropriate nominees of the respective parties by voice or electronic communication provided that it is confirmed in writing and transmitted or delivered by facsimile, courier or mail as soon as practicable.

18.04 Either of the parties hereto may change the address to which a notice, request or other instrument may be sent to it by giving to the other party to this Agreement notice of such change, and thereafter, every notice, request or other instrument shall be delivered or mailed in the manner prescribed in Clause 18.01 to such party at the new address.

<u>IN WITNESS WHEREOF</u> Newfoundland and Labrador Hydro and the Customer has each executed this Agreement by causing it to be executed in accordance with its by-laws or regulations and by its duly authorized officers or agents, the day and year first above written.

<u>THE CORPORATE SEAL</u> of
Newfoundland and Labrador
Hydro was hereunder
affixed in the presence of: ____________________________

____________________________ ____________________________
Witness

<u>DULY EXECUTED</u> by
Corner Brook Pulp and Paper Limited
in accordance with its Regulations
or By-Laws in the presence of:

____

____________________________ ____________________________
Witness

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* ....@ 11.622 ¢ 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**.. @ 5.151 ¢ 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
Historic Plan .... @ 0.722 ¢ per kWh
Fuel Rider .... @ 0.000 ¢ per kWh

Total RSP Adjustment – All kilowatt-hours .... @ 0.722 ¢ per kWh

Teck Resources RSP Adjustment.. @ (1.119) ¢ per kWh

Net Teck Resources RSP Adjustment.. @ (0.397) ¢ 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 January 1, 2015 to August 31, 2015 and subsequently reduce to a 35% credit effective September 1, 2015 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) x 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) x 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. It will be held in a separate account in the Plan, until its disposition is ordered by the Board of Commissioners of Public Utilities.

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

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

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)

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.

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Section E: Historical Plan Balance:

1. **Island Industrial Customer December 2014 Balance:**
The Island Industrial customer balance accumulated in the Plan (excludes the segregated load variation approved by the Board of Commissioners of Public Utilities in Order No. P.U. 29(2013) and the RSP Surplus defined in Section F), as at December 31, 2014 will be recovered over a 2-year collection period, with an adjustment rate to become effective January 1, 2015. Financing charges on the plan balance will be calculated monthly using Hydro's approved 2015 Test Year annual weighted average cost of capital.

The adjustment rate for each year of the two-year adjustment period will be determined as follows:

$$G = H \div I \div J$$

Where:

G = adjustment rate (₵ per kWh) for the 12-month period commencing the following January 1
H = Balance December 31
I = number of years remaining in the adjustment period
J = firm energy sales (kWh) to Industrial Customers, for the most recent 12 months ended December 31

Recovery and financing will be applied to the balance each month. At the end of the two-year recovery period, any remaining balance will be added to the plan then in effect.

Section F: 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

NEWFOUNDLAND AND LABRADOR HYDRO

RATE STABILIZATION PLAN (INTERIM) (Continued)

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.

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 January 1, 2015 to August 31, 2015 and subsequently reduce to a 35% credit effective September 1, 2015 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.

Teck Resources

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.

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 RECOVERY (Continued)

(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 .... @ 94.410 ¢ 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 .... @ 86.288¢ 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.. @ 64.094 ¢ 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)	15.96
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.

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

LABRADOR INDUSTRIAL – TRANSMISSION (INTERIM)

Availability:

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

Monthly Rate:

Demand Charge:

The rate for Firm Power shall be $1.25 per kilowatt of billing demand. The billing demand shall be equal to the customer's declared Power on Order.

Specifically Assigned Charge:

This rate may include a specifically assigned charge upon approval by the Board.

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.**

Reconciliation to Original GRA Filing

Purpose of this Document

The purpose of this document is to summarize the events and changes to evidence that have occurred from Hydro's initial 2013 General Rate Application (GRA) filing on July 30, 2013 to the current Amended GRA filing. This document provides the following:

- Brief background of events since Hydro's July 30, 2013 GRA filing;
- Summary of changes in Hydro's Amended Application;
- Comparison of 2013 and 2015 proposed rate changes;
- Summary of key information for the 2007, 2013, 2014 and 2015 Test Years;
- 2013 Test Year and 2015 Test Year Revenue Requirement Comparison; and
- 2013 Test Year and 2015 Test Year Rate Base Comparison.

Background

On July 30, 2013 Hydro filed its GRA based on a 2013 Test Year for new rates to be effective January 1, 2014. The GRA reflected a 2013 Test Year in accordance with Government directives.[1] Due to the duration of the ongoing GRA process, it was determined that rates would not likely be approved for implementation until well into 2014. Hydro subsequently filed two applications for interim relief recognizing that delayed rate implementation could deprive Hydro of the opportunity to earn a just and reasonable return on rate base for 2014. The Board, thus far, has denied Hydro's requests for revenue relief in 2014.[2] As a result of not receiving approval for revenue relief for 2014, Hydro is forecasting a material revenue deficiency.

[1] Refer to OC2013-089 and OC2013-091.
[2] See Order No. P.U. 40(2013) and Order No. P.U. 39(2014).

On June 6, 2014 Hydro notified 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 amend its 2013 GRA to derive rates based upon a 2015 Test Year. The Amended GRA would better ensure that new rates would be sufficient to cover Hydro's costs and provide it with a reasonable rate of return. Government has subsequently rescinded the Order in Council stipulation which required the use of a 2013 Test Year for the GRA.[3]

Amended Application

This section identifies changes in the Amended Application relative to the original Application filed in July 2013.

Test Year

- The Amended Application is proposing the Board test costs for 2014 and 2015 to determine revenue requirement. Hydro's costs and revenue forecasts have been updated to reflect this change. The 2014 forecast is based upon five months actuals and seven months forecast. The original Application was filed based upon a 2013 Test Year forecast which was comprised of a combination of actuals and forecast.
- The Amended Application is proposing to determine customer rates based upon a forecast 2015 Test Year Cost of Service Study in contrast to the 2013 Test Year Cost of Service Study which was comprised of a combination of actuals and forecast.

2014 Revenue Deficiency

- The forecast Revenue Deficiency for 2014 is $45.9 million, which excludes the deferral of approximately $10 million in increased 2014 supply costs applied for

[3] Refer to OC2014-319 and OC2014-320.

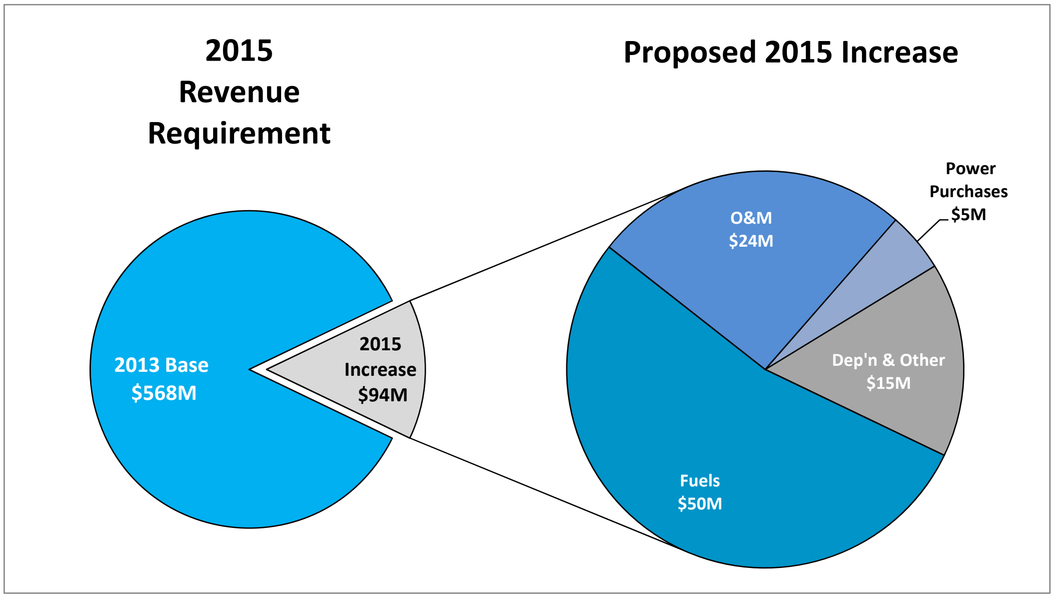
in a separate Application. Hydro proposes the use of a portion of the RSP credit balance, where appropriate, to offset the 2014 Revenue Deficiency. The portion of the 2014 Revenue Deficiency not recovered through the RSP is proposed to be recovered through future customer rates, through the application of a rate rider. The Board's approval of Hydro's proposal to recover additional revenue of $45.9 million in 2014 will ensure that Hydro continues to be provided a reasonable opportunity to earn a just and reasonable return on its investment in rate base.

- In November 2014, Hydro will be filing with the Board a 2014 Test Year Cost of Service Study to provide a basis for calculating the 2014 Revenue Deficiency by system and by class of service.
- Hydro proposes that the 2014 Revenue Deficiency to be recovered from customers will be based upon the difference between revenue from existing rates for 2014 and the 2014 revenue requirement as determined by the Board.
- If the Board requires further testing of the 2014 Test Year costs prior to approving recovery of the 2014 Revenue Deficiency, Hydro proposes that the Board approve a 2014 cost deferral to provide Hydro the opportunity to earn a reasonable return in 2014.

Revenue Requirement

- The proposed revenue requirement to be used in setting rates increased from the 2013 Test Year to the 2015 Test Year by $94 million, from $568 million to $662 million, as shown in Chart 1.

Chart 1: Change in Test Year Revenue Requirement



- The Amended Application is also seeking approval for the following changed or new proposals that impact the proposed 2015 Test Year Revenue Requirement. These include:
    - Five-year amortization of $1.2 million in additional operating and maintenance costs related to one-time costs for 2015 to complete a six-year plan initiated in 2010 to bring transformer and breaker maintenance in line with established preventative maintenance frequency.
    - Five-year amortization of Holyrood Black Start Diesel Units lease costs of $5.2 million commencing in 2015.
    - Increase in the range of allowable rate of return on Rate Base increase from +/- 15bps, as established by Board Order No. P.U.8(2007), to +/- 20 bps, which is a decrease from Hydro's original Application of +/- 25 bps.
    - Hydro proposes approval of the forecasted 2015 Test Year average Rate Base of $1,802.0 million, versus $1,564.1 million for the 2013 Test Year, for the purpose of setting rates in this proceeding.

Cost of Service Methodology

- The Amended Application is proposing changes to a number of Cost of Service methodologies which impact customer rates. These proposals include:
  - A change to the methodology to allocate the Rural Deficit by system revenue requirement; this proposal is made to address fairness concerns with the current methodology. The original Application reflected the methodology approved in 1993.
  - A change in the classification of the cost of purchasing wind generated energy to 100% energy-related; the original Application classified wind purchase costs based upon system load factor. The proposed change reflects that Hydro's system planners no longer assume wind generation will be available to meet system capacity requirements.
  - Updating the computation of the five-year average Holyrood capacity factor to include the 2015 forecast to better reflect the usage of Holyrood during the period rates are in effect. The original Application calculated the Test Year capacity factor using the five-year average ending with the year prior to the Test Year used in determining customer rates.
  - Classifying the costs for capacity assistance agreements with Island Industrial customers as 100% demand-related. This approach is consistent with the methodology used for the interruptible costs incurred for a previous contract with an Industrial Customer.

Customer Rate Changes

- The proposed rate impacts under the Amended Application compared to the original Application are presented in Table 1 below.

Table 1: Comparison of Customer Rate Impacts

Rate Class	2013 TY Average Increase (Decrease)	2015 TY Average Increase (Decrease)
ISLAND INTERCONNECTED		
Newfoundland Power (NP) wholesale rate impact	-4.8%	4.1%
Estimated end consumers' rate[1] impact	-3.2%	2.8%
Estimated Rural Customers' rate impact	-3.2%	2.8%
Industrial Customers (IC)	73.1%	39.2%
ISLAND ISOLATED SYSTEMS		
Domestic	0.9%	7.1%
General Service 0 - 10 kW	11.6%	18.5%
General Service Over 10 kW	11.5%	19.2%
Street and Area Lighting	-3.2%	2.8%
Government Departments		
General Service 0-10 kW	22.0%	24.7%
General Service Over 10 kW	27.5%	25.4%
Street and Area Lighting	16.8%	27.5%
LABRADOR INTERCONNECTED		
Domestic	26.0%	1.9%
General Service 0-10 kW	28.5%	1.9%
General Service 10-100 kW	16.6%	1.9%
General Service 110–1,000 kVA	16.9%	1.9%
General Service Over 1,000 kVA	22.0%	1.9%
Street and Area Lighting	42.8%	17.5%
LABRADOR ISOLATED SYSTEMS		
Domestic	0.9%	7.1%
General Service 0 - 10 kW	11.6%	18.5%
General Service Over 10 kW	11.5%	19.2%
Street and Area Lighting	-3.2%	2.8%
Government Departments		
Domestic	17.7%	21.5%
General Service 0 - 10 kW	22.0%	24.7%
General Service Over 10 kW	27.5%	25.4%
Street and Area Lighting	16.8%	27.5%
L'ANSE AU LOUP SYSTEM		
Domestic	-3.2%	2.8%
General Service	-3.2%	2.8%
Street and Area Lighting	-3.2%	2.8%

1 - Estimated pass through to retail level for 2013TY and 2015TY are 67% and 67.5% respectively.

Newfoundland Power (NP) Rate Design

- The Amended Application is proposing a Utility rate demand charge increase from $4.00 per kW to $5.50 per kW of billing demand. The demand charge of $5.50 per kW is less than the $9.12 per kW proposed in the original Application. The reduced demand charge gives consideration to system marginal capacity cost estimates. The demand charge of $9.12 per kW was based upon the average embedded demand cost from the 2013 Test Year Cost of Service Study.

- The Amended Application includes a Curtailable Credit in the determination of the NP billing demand. This approach was not reflected in the original Application. Hydro filed an application with the Board on September 19, 2014 to include a billing demand credit to provide for the efficient use of NP's curtailable load to meet system requirements. The approach in the Amended Application for the Curtailable Credit Application is consistent in approach to the one taken for NP's curtailable load.

Industrial Customer Rates

- The Amended Application proposes a phase-in of IC base rates concluding September 1, 2016 in accordance with Orders in Council OC2013-089 and OC2013-090, dated April 4, 2013. This matter was not addressed in the original Application as Hydro had filed a separate Application regarding this matter.

Labrador Industrial Rates

- The Amended Application proposes the implementation of a Labrador Industrial Customer Transmission Rate effective January 1, 2015. This proposal is in accordance with the requirements of legislation reflecting the Labrador Industrial Rates Policy. This matter was not required to be addressed in the original Application.
- Hydro is proposing a regulated transmission demand rate for Labrador Industrial customers of $1.25 per kW per month, to be implemented on an interim basis effective January 1, 2015.

Rate Stabilization Plan

- The Amended Application proposes a change in the load variation component of the RSP to reflect an energy allocation approach. This matter was not addressed in the original Application as Hydro had filed a separate application to address this matter. However, the proposal is consistent with Hydro's recommendation in the 2006 GRA.

- The Amended Application proposes the introduction of an RSP Surplus Credit Adjustment to apply in the phase-in of IC base rates in accordance with OC2013-089 and OC2013-090 dated April 4, 2013. This matter was not addressed in the original Application.
- The Amended Application proposes to re-activate the operation of the annual IC RSP Adjustment January 1, 2015. It has been suspended per Board Order No. P.U. 40(2013) since January 1, 2014. This matter was not addressed in the original Application.
- The Amended Application proposes to recover the forecast $8 million year-end 2014 current balance in the RSP to be recovered from Island IC over a two-year period to permit a reasonable phase-in approach to 2015 Test Year rates. The proposed RSP rules to become effective January 1, 2015 reflect this proposal. This matter was not reflected in the original Application as the balance accumulated as a result of the Board's suspension of the normal operation of the RSP effective January 1, 2014.

Interim Rates

- The Amended Application proposes to implement interim IC rates and start the IC rate phase-in beginning January 1, 2015.
- The Amended Application proposes 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.

Other Regulatory Matters

- In the original Application, Hydro proposed discontinuing one of the required KPI statistics. In the Amended Application, Hydro is proposing modifying the source of the data and continuing to report the KPI information.

Energy Supply

- The Amended Application includes a higher Island Interconnected System load forecast for the 2015 Test Year of 7,235 GWh compared to 6,681 GWh for the 2013 Test Year. The increase is driven by higher Utility and Industrial load requirements.
- The Amended Application includes a lower Labrador Interconnected System load forecast from recall purchases for the 2015 Test Year of 919 GWh, compared to 1,114 GWh for the 2013 Test Year. The decrease is driven by lower Industrial load requirements which have been partially offset by higher Rural Customer load.
- The Amended Application includes a 2015 Test Year fuel price of $93/bbl and a total of 2,624,371 bbls compared to $109/bbl and 1,842,112 bbls for the 2013 Test Year in the original Application. The increase in fuel usage is primarily driven by higher system load requirements.
- The Amended Application includes higher hydraulic generation of 4,604 GWh for the 2015 Test Tear compared to 4,533 GWh for the 2013 Test Year.
- The Amended Application proposes higher standby generation costs than those filed with original Application. There are peaking requirements assumed for the Island Interconnected System combustion turbines in order to maintain minimum generation reserve requirements in light of average forced outage rates and in consideration of the peak load forecasts. The units are also assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness.

- In its Amended Application, for generating unit capacities, Hydro is now using the gross continuous unit ratings. These ratings generally represent the maximum continuous power-generating capacity of a generating unit which it can be expected to provide during peak load periods.
- In its Amended Application, Hydro has modified the approach it uses to forecast the Holyrood fuel conversion rate. The forecast results from a five-year regression analysis of conversion factor versus Holyrood gross monthly average unit loading, adjusted for fuel heating content (in BTUs/bbl). There has been a decline in fuel conversion performance in recent years. A significant factor is the heating content in the low sulfur No. 6 fuel that Hydro is required to use at the plant. The result is a forecast fuel conversion rate of 607 kWh/bbl for the 2015 Test Year.

Newfoundland Power Generation Credit

- Hydro is proposing a generation credit of 119.33 MW for NP in the 2015 Test Year. This is 0.7% lower than that proposed for the 2013 Test Year as a result of a decrease in NP's generating capacity that is partially offset by a lower "reserve at criteria".

Corner Brook Pulp and Paper Demand Credit Contract

- In its Amended Application, Hydro has revised the report regarding the benefits relating to the Corner Brook Pulp and Paper Demand Credit Contract to include the period to the end of the 2015 Test Year. It is still recommended that the pilot agreement be made permanent.

TwinCo Assets

- The long standing TwinCo power arrangements will expire at the end of 2014. Hydro and CFLCo are finalizing a power purchase agreement which will allow Hydro to purchase the former TwinCo block of power and energy for resale to

Industrial customers in Labrador West. As these assets are critical to providing reliable service to Hydro's customers, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements. These arrangements will be in place by the end of 2014. Hydro's 2015 Test Year includes forecast operating and maintenance costs of approximately $2.8 million for the transmission lines and the terminal station. Hydro will subsequently be requesting Board approval of the asset acquisitions and will request approval of future required capital expenditures for the former TwinCo assets consistent with the capital budget expenditure guidelines established by the Board.

Exploits Assets Transfer

- The Amended Application continues to reference the letter to Hydro dated December 2, 2013[4] in which Government indicated its intention to transfer ownership of the Exploits generation facilities from Government to Hydro. While no further correspondence from Government has been received, the price for Exploits power purchases is assumed to equal the 4¢ per kWh for the 2015 Test Year.

Deferral Accounts

- The Amended Application proposes a number of deferral accounts that have changed from the original Application:
    - *Isolated Systems Supply Cost Variance Deferral Account*: in the original Application Hydro requested two deferral accounts to provide for cost recovery of diesel and purchase power cost variances. In the Amended Application, Hydro is proposing a single supply cost variance account.
    - *Energy Supply Cost Variance Deferral Account*: in the original Application, Hydro proposed an Energy Supply Cost variance recovery through the

[4] Refer to Hydro's response to PUB-NLH-008

RSP. In the Amended Application, Hydro is proposing the deferral account but is not proposing the recovery of that amount through the RSP.

- *Conservation Demand Management (CDM) Cost Deferral Account*: In the original Application, Hydro proposed a CDM deferral recovery over seven years based upon March balances and calculated annually based upon a rolling balance methodology. In the Amended Application, Hydro is proposing a seven-year, discrete amortization based upon year-end balances.

Data Summary

Tables 2 and 3 summarize key Test Year data for 2007, 2013, 2014 and 2015.

1 **Table 2: Key Data for 2007, 2013, 2014, and 2015 Test Years**

Newfoundland and Labrador Hydro Data Summary				
Particulars	**Test Year**	**Amount**	**% Change from 2007**	**Reference**
Load Forecasts (GWh)				
Island Interconnected				
	2007	6,444.4	-	Page 2.59, Table 2.14
	2013	6,680.8	3.7%	2013 Filing, Page 2.35, Table 2.14
	2014	7,096.4	10.1%	Page 2.59, Table 2.14
	2015	7,235.1	12.3%	Page 2.59, Table 2.14
Labrador Interconnected				
	2007	1,011.0	-	Page 2.61, Table 2.15
	2013	957.0	-5.3%	2013 Filing, Page 2.37, Table 2.15
	2014	853.5	-15.6%	Page 2.61, Table 2.15
	2015	918.6	-9.1%	Page 2.61, Table 2.15
Isolated Diesel including L'Anse Au Loup				
	2007	61.2	-	Page 2.64, Table 2.17
	2013	74.6	21.9%	2013 Filing, Page 2.39, Table 2.16
	2014	76.7	25.3%	Page 2.64, Table 2.17
	2015	77.5	26.6%	Page 2.64, Table 2.17
Expenses ($000)				
Fuels				
	2007	148,436	-	Finance Schedule III, Page 1, Line 27
	2013	219,390	47.8%	2013 Filing, Finance Schedule III, Page 1, Line 25
	2014	201,714	35.9%	Finance Schedule III, Page 1, Line 27
	2015	267,820	80.4%	Finance Schedule III, Page 1, Line 27
Power Purchases				
	2007	38,327	-	Finance Schedule III, Page 1, Line 29
	2013	58,674	53.1%	2013 Filing, Finance Schedule III, Page 1, Line 26
	2014	66,668	73.9%	Finance Schedule III, Page 1, Line 29
	2015	63,254	65.0%	Finance Schedule III, Page 1, Line 29
Operations and Maintenance				
	2007	93,418	-	Finance Schedule III, Page 1, Line 21
	2013	113,820	21.8%	2013 Filing, Finance Schedule III, Page 1, Line 20
	2014	126,068	35.0%	Finance Schedule III, Page 1, Line 21
	2015	138,179	47.9%	Finance Schedule III, Page 1, Line 21
Depreciation and Other				
	2007	40,191	-	Finance Schedule III, Page 1, Line 30 + 31 + 32
	2013	53,803	33.9%	2013 Filing, Finance Schedule III, Page 1, Line 27 + 28 + 29
	2014	58,134	44.6%	Finance Schedule III, Page 1, Line 30 + 31 + 32
	2015	68,744	71.0%	Finance Schedule III, Page 1, Line 30 + 31 + 32
Interest and Return				
	2007	110,707	-	Finance Schedule III, Page 1, Line 37
	2013	122,448	10.6%	2013 Filing, Finance Schedule III, Page 1, Line 34
	2014	120,563	8.9%	Finance Schedule III, Page 1, Line 37
	2015	122,810	10.9%	Finance Schedule III, Page 1, Line 37

Table 3: Other Key Data for 2007, 2013, 2014, and 2015 Test Years

Particulars	Test Year	Amount	% Change from 2007	Reference
Additional Key Data				
Rate Base ($ Millions)				
	2007	1,489.3	-	Finance Schedule III, Page 1, Line 39
	2013	1,564.1	5.0%	2013 Filing, Page 3.22, Table 3.6
	2014	1,692.6	13.6%	Finance Schedule III, Page 1, Line 39
	2015	1,802.0	21.0%	Finance Schedule III, Page 1, Line 39
Return on Rate Base (%)				
	2007	7.44%	-	Finance Schedule III, Page 1, Line 41
	2013	7.83%	5.2%	2013 Filing, Page 3.26, Table 3.8
	2014	7.12%	-4.3%	Finance Schedule III, Page 1, Line 41
	2015	6.82%	-8.3%	Finance Schedule III, Page 1, Line 41
Regulated Debt ($ Millions)				
	2007	1,243.7	-	2006 GRA, Finance Schedule I, Page 4, Line 4
	2013	984.9	-20.8%	2013 Filing, Page 3.9, Table 3.2
	2014	1,208.1	-2.9%	Finance Schedule I, Page 4, Line 7
	2015	1,441.8	15.9%	Finance Schedule I, Page 4, Line 7
Shareholder's Equity ($ Millions)				
	2007	217.7	-	2006 GRA, Finance Schedule I, Page 2, Line 27
	2013	364.7	67.5%	2013 Filing, Page 3.9, Table 3.2
	2014	361.9	66.2%	Finance Schedule I, Page 4, Line 14 + 16
	2015	395.1	81.5%	Finance Schedule I, Page 4, Line 14 + 16
Return on Equity (%)				
	2007	4.47%	-	Page 3.18, Table 3.8
	2013	8.80%	96.9%	2013 Filing, Finance Schedule I, Page 4, Line 37
	2014	8.80%	96.9%	Finance Schedule I, Page 4, Line 37
	2015	8.80%	96.9%	Finance Schedule I, Page 4, Line 37
Revenue at Existing Rates ($ Millions)				
	2007	431.1	-	Finance Schedule II, Page 1, Line 5
	2013	479.4	11.2%	2013 Filing, Finance Schedule II, Page 1, Line 4
	2014	516.9	19.9%	Finance Schedule II, Page 1, Line 5
	2015	522.8	21.3%	Finance Schedule II, Page 1, Line 5
Revenue Deficiency at Existing Rates ($ Millions)				
	2007	-	-	
	2013	88.7	-	2013 Filing, Finance Schedule I, Page 6, Line 4 less Schedule II, Page 1, Line 4
	2014	45.9	-	Page 3.7, Table 3.1
	2015	139.8	-	Page 3.8, Table 3.2
Revenue Requirement ($ Millions)				
	2007	431.1	-	Finance Schedule III, Page 1, Line 5
	2013	568.1	31.8%	2013 Filing, Page 3.18, Line 22
	2014	562.9	30.6%	Finance Schedule III, Page 1, Line 5
	2015	662.5	53.7%	Finance Schedule III, Page 1, Line 5
Net FTEs				
	2007	813	-	Page 3.40, Chart 3.5
	2013	815	0.2%	2013 Filing, Page 3.14, Chart 3.3
	2014	860	5.8%	Page 3.40, Chart 3.5
	2015	888	9.2%	Page 3.40, Chart 3.5

Revenue Requirement

Table 4 and 5 below provide a comparison of the 2013 and 2015 Test Year revenue requirement and rate base by component and explanations for significant variances.

Table 4: 2013 and 2015 Revenue Requirement and Variances Explanations

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Revenue Requirement Analysis - 2013 vs. 2015 Test Year
($000)

		Test Year 2013	Test Year 2015	Variance from 2013 to 2015	Reference
1	**Revenue requirement**				
2	Energy sales	565,737	659,967	94,230	
3	Revenue defeciency	-	-	-	
4	Other revenue	2,350	2,508	158	
5	**Total revenue requirement**	568,087	662,475	94,388	
6					
7	**Expenses**				
8	Operating expenses				
9	Salaries and fringe benefits	77,241	88,888	11,647	**1**
10	System equipment maintenance	21,495	26,825	5,330	**2**
11	Office supplies and expenses	2,571	2,804	233	
12	Professional services	7,022	9,494	2,472	**3**
13	Insurance	2,211	2,607	396	
14	Equipment rentals	1,731	3,066	1,335	**4**
15	Travel	3,156	3,717	561	**5**
16	Miscellaneous expenses	6,380	5,772	(608)	**6**
17	Building rental and maintenance	1,070	1,217	147	
18	Transportation	2,273	2,245	(28)	
19	Cost recoveries	(9,222)	(7,069)	2,153	**7**
20	Allocated to non-regulated customer	(2,108)	(1,387)	721	**8**
21	**Net operating expenses**	113,820	138,179	24,358	
22	Fuels				
23	No. 6 fuel	200,315	244,914	44,599	**9**
24	Rate stabilization plan deferral	(84)	(34)	50	
26	Diesel and other	19,159	22,940	3,781	**10**
27	Total fuels	219,390	267,820	48,430	
28	Fuel supply deferral	-	1,991	1,991	**11**
29	Power Purchases	58,674	63,254	4,580	**12**
30	Amortization	51,656	63,792	12,136	**13**
31	Accretion of asset retirement obligation	843	878	35	
32	Other income and expense	1,304	4,074	2,770	**14**
33	**Expenses before cost of service exclusions**	445,687	539,988	94,300	
34	less: Cost of service exclusions	(48)	(323)	(275)	
35		445,639	539,665	94,025	
36					
37	**Return on rate base**	122,448	122,810	363	
38					
39	**Average rate base**	1,564,085	1,802,023		
40					
41	**Rate of return on rate base**	7.83%	6.82%		

Table 5: 2013 and 2015 Rate Base and Variances Explanations

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate Base - 2013 Test year vs. 2015 Test year
($000)

	Test Year 2013	Test Year 2015	Variance from 2013 to 2015	Reference
1 **Capital assets**	1,633,080	1,870,275	237,195	
2 less: asset retirement obligation costs	(17,320)	(12,169)	5,151	
3 less: contributions in aid of construction	(22,269)	(17,936)	4,333	
4 less: accumulated depreciation	(140,043)	(203,834)	(63,791)	
5 **Capital assets - current year**	1,453,448	1,636,336	182,888	
6 **Capital assets - previous year**	1,387,986	1,615,796	227,810	
7 Unadjusted Capital assets - average	1,420,717	1,626,066	205,349	
8 less: Average net assets not in use	(3,005)	(2,605)	400	
9 **Capital assets - average**	1,417,712	1,623,461	205,749	
10				
11 Cash working capital allowance	5,336	7,037	1,701	
12 Fuel	50,885	66,633	15,747	**15**
13 Materials and supplies	24,701	27,402	2,701	
14 Deferred charges	65,451	77,491	12,040	**16**
15				
16 **Average rate base**	1,564,085	1,802,024	237,938	

Variance Explanations

Detailed variance explanations for the changes from the 2013 Test Year to the 2015 Test Year are summarized below:

1. Salaries and benefits have increased from the 2013 Test Year to the 2015 Test Year by $11.6 million. The primary driver is salary increases and FTE changes. In the 2015 Test Year, there are 895 operating FTEs[5], an increase of 71 FTEs over the 2013 Test Year of 824. There is also an increase in fringe benefits due to increased premiums and contributions to the Public Service Pension Plan (PSPP) in conjunction with the increase in salaries and FTEs. These increases are

[5] Operating FTEs are FTEs before any capital labour recharges.

partially mitigated by an increase capital labour due to the increase in the capital program.

2. System equipment maintenance has increased by $5.3 million from the 2013 Test Year to the 2015 Test Year primarily due to maintenance and warranty costs of the new Holyrood combustion turbine of $2.6 million and an increase in maintenance of transmission assets in Labrador of $2.8 million. This maintenance is associated with the transmission lines and terminal stations from Churchill Falls to Wabush that were previously incurred by TwinCo. Please refer to Section 2.2.5 for further information.
3. Professional services increased by $2.5 million due to an increase in regulatory filings and studies of $1.4 million and $0.8 million associated with system planning and other professional services.
4. Equipment rentals increased by $1.3 million primarily due to costs associated with the Holyrood black start diesel units. Hydro has proposed to defer and amortize these costs over a five year period commencing in 2015. The net amortization expense in 2015 is $1.0 million. Please refer to Section 3.8 for additional information regarding deferrals.
5. Travel costs increased by $0.6 million from the 2013 Test Year to the 2015 Test Year mainly due to increased travel fares.
6. Miscellaneous expenses decreased by $0.6 million from the 2013 Test Year to the 2015 Test Year. The decrease is primarily due to a reduction in CDM. This reduction is offset in cost recoveries and as a result, there is no impact on Revenue Requirement.
7. Cost recoveries decreased by $2.2 million mainly due to a $2.0 million decrease in CDM program costs deferrals.
8. Allocated to a non-regulated customer decreased by $0.7 million due to a reduction in recoveries related to generation supply in Labrador. Refer to Section 2.5.2 for further information.

9. No.6 fuel increased by \$44.6 million due to an increase in volume variance of \$85.1 million which was partially mitigated by a decrease in the price variance of \$40.5 million.
10. Diesel and other increased by \$3.8 million due to an increase in volume which was partially mitigated by a decrease in price.
11. Hydro has, in a separate application to the Board dated October 8th, 2014, requested a deferral of supply costs.
12. Power purchases increased by \$4.6 million from 2013 Test Year to 2015 Test Year primarily due to a \$2.9 million increase in Corner Brook Co-generation and a \$2.1 million increase in capacity assistance as outlined in Section 2.2.7.
13. There was an increase in Hydro's capital program from the 2013 Test Year to the 2015 Test Year resulting in an increase in depreciation of \$12.1 million.
14. Other income and expense increased from the 2013 Test Year to the 2015 Test Year by \$2.8 million primarily due to an increase in removal costs.
15. Fuel in inventory is comprised of a thirteen month average of No. 6 fuel, diesel, and gas turbine fuel. Fuel inventory increased from \$50.9 million in the 2013 Test Year to \$66.6 million in 2015 due to a higher volume of fuel storage due to load growth, particularly in the winter months.
16. Deferred charges increased from \$65.5 million in the 2013 Test Year to \$77.5 million in the 2015 Test Year. The increase primarily related to the Holyrood black start diesel units and the Supply Cost deferral of \$10 million reflected in the Amended Application.

Section 1: Introduction

SECTION 1: INTRODUCTION

1.1 OVERVIEW

1.1.1 General

Hydro's last General Rate Application (GRA) was filed in August 2006 with new rates becoming effective January 1, 2007. Since that time, there have been a number of factors affecting the cost to provide reliable electricity service. This impacts the price customers are required to pay for electricity.

Hydro's investment in the province's electricity system has been steadily increasing in order to replace aging infrastructure and to meet growing customer requirements to provide reliable service at least cost. As a result of the higher capital expenditure program, including the 123 MW combustion turbine at Holyrood, Hydro has incurred increased depreciation and financing costs. To ensure service reliability of its aging assets, Hydro is increasing staff levels to meet the growing operating and maintenance requirements. Many of Hydro's assets are approaching the end of their service lives and must be replaced or refurbished to ensure continued reliability.

Since 2007, on the Island Interconnected System, there has been a significant increase in the price of fuel used at the Holyrood Thermal Generating Station (Holyrood), increasing from $55/bbl in the 2007 Test Year to $93/bbl in Hydro's proposed 2015 Test Year. The 2015 Test Year proposed rates reflect these higher fuel costs. At this time, Holyrood remains a critical facility for the reliable supply of electricity, particularly during the winter period when the existing electrical service demand is high due to the level of electric heat required on the Island Interconnected System. In 2015, Hydro forecasts that Holyrood will be required to remain in use throughout the full year in response to continuing load growth, particularly as the new Vale facility comes on line.

Rates for Newfoundland Power (NP) and Island Interconnected System retail customers have been adjusted annually, on July 1, over the 2007 to 2014 period, through the Rate Stabilization Plan (RSP) fuel rider, and therefore reflect the impact of increased fuel prices. Rates for Island Industrial Customers (IC), however, have not been adjusted over that period and, therefore, these rates must be realigned to reflect the increased cost of providing service.

The new wind and hydraulic generation that Hydro has acquired since 2007 through power purchase agreements have had a positive impact on Island Interconnected electricity rates. It is estimated that in 2015, these renewable energy sources will result in approximately $74 million in fuel savings and a reduction in Greenhouse Gas Emissions (GHGs) of 555,000 tonnes. These savings are being passed directly on to customers in the proposed rates which would be higher, without these additional energy sources.

The Labrador Interconnected System has also required a significant increase in capital spending to ensure the continued delivery of safe and reliable electricity to customers. In total, over the 2007 to 2015 period, there will have been capital expenditures of approximately $59 million, related to both increasing customer usage and aging infrastructure. These expenditures, along with other cost increases, have put upward pressure on electricity rates.[1]

On the Labrador Interconnected System, the long standing Twin Falls Power Corporation (TwinCo) power arrangements will expire at the end of 2014. The Twinco assets include two transmission lines from Churchill Falls to Labrador West and the Wabush terminal

[1] If approved by the Board, cost increases on the Labrador Interconnected System will be mitigated to a large degree by Hydro's proposed change in the Rural Deficit allocation methodology. This proposal is described in Rates and Regulation evidence Section 4.3.1.

station. As these assets are critical to providing reliable service to Hydro's customers, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements. Also, based on legislative changes, transmission service and the related rate for the Industrial Customers on the Labrador Interconnected System is to be fully regulated by the Board effective January 1, 2015. The development of this rate is described in Hydro's current filing.[2]

Further evidence presented by Hydro in this filing addresses the following:

- Hydro's operating performance;
- The financial position and financial performance of the Company;
- The recovery of the Revenue Deficiency resulting from delayed implementation of customer rates beyond January 1, 2014; and
- The customer rates being proposed for implementation in 2015.

1.1.2 Amended Application

On July 30, 2013, Hydro filed its GRA based on a 2013 Test Year for new rates to be effective January 1, 2014.[3] However, as a result of the length of time that had elapsed in the GRA process, it became apparent to Hydro that due to changes in its cost levels, the prudent course of action was to advise the Board and Parties that it would file an amended Application.[4] Hydro's Amended Application is based on a 2014 Test Year and a 2015 Test Year.[5]

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[2] Refer to Regulated Activities Section 2.6.2 and Rates and Regulation Section 4.9.2.

[3] The use of a 2013 Test Year was in accordance with a Government directive (OC2013-089 and OC2013-091).

[4] On June 6, 2014 Hydro notified both the Board and the Parties that it would be filing an amended Application in the fall of 2014 based on updated financial information.

[5] On October 30, 2014, the Government rescinded the Order in Councils requiring the use of a 2013 Test Year.

1.1.3 2014 Revenue Requirement

Hydro filed its GRA on July 30, 2013 requesting new rates effective January 1, 2014. Due to the duration of the GRA process, Hydro applied for interim revenue relief recognizing that delayed rate implementation could deprive Hydro of the opportunity to earn a just and reasonable return on rate base for 2014. The Board, thus far, has denied Hydro's requests for revenue relief in 2014.[6] As a result of not receiving approval for revenue relief for 2014, Hydro is forecasting a material revenue deficiency for 2014 (2014 Revenue Deficiency).

In the Amended Application, Hydro is seeking to recover a 2014 Revenue Deficiency of $45.9 million.[7] In the absence of a recovery mechanism for the Revenue Deficiency, Hydro would realize a return on rate base of 4.41%. The 2014 forecast return is below the bottom of the approved range of return on rate base of 7.29%. The forecast return on rate base under existing rates is also lower than the proposed 2014 return on rate base of 7.12%.

Hydro proposes to use a credit balance that has accumulated in the RSP, where appropriate, to offset the 2014 Revenue Deficiency. Any portion of the 2014 Revenue Deficiency not recovered through the RSP is proposed to be recovered through future customer rates through the use of a rate rider.[8] A rate rider will be proposed for any of the 2014 Revenue Deficiency determined to be attributable to customers on the Labrador Interconnected System.

[6] See Order No. P.U. 40(2013) and Order No. P.U. 39(2014).
[7] An additional $10 million of supply costs have been requested to be recovered in a separate Application to the Board, dated October 8, 2014.
[8] Rate rider to become effective on a date to be determined by the Board pursuant to a final GRA Order.

If the Board determines it requires further testing of the 2014 Test Year costs prior to approving recovery of the 2014 Revenue Deficiency by Hydro, the Board can approve a deferral of 2014 costs to provide Hydro the opportunity to earn a reasonable return in 2014. The decision on the recovery approach to the 2014 Revenue Deficiency would then be addressed in a subsequent order of the Board following the testing of 2014 costs. Refer to Section 3.2 for further details on the components of the 2014 Revenue Deficiency and Section 4.4 for further details on the recovery of the 2014 Revenue Deficiency.

1.1.4 2015 Revenue Requirement

Hydro's costs have increased materially since base rates were last set based upon a 2007 Test Year. As shown in Table 1.1, Hydro's forecast 2015 Test Year Revenue Requirement is $231.5 million higher than the 2007 Test Year.[9]

Table 1.1

2015 Revenue Requirement Increase
($ Millions)

	2007 Test Year	2015 Test Year	Increase (Decrease)
Operating and Maintenance	93.4	138.2	44.8
Fuel	148.4	269.8	121.4
Power Purchases	38.3	63.3	24.9
Depreciation and Other	40.2	68.7	28.6
Return on Equity	8.0	33.2	25.3
Interest	102.7	89.3	(13.5)
Total Revenue Requirement	**431.0**	**662.5**	**231.5**

[9] Existing rates for NP would collect an estimated $90.4 million through the present RSP fuel rider were this rate to remain in place for 2015. Refer to Table 4.15.

The Amended Application 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, which is below the bottom of the approved range of return on rate base of 7.29%.[10] The 2015 forecast return on rate base under existing rates is also lower than the proposed 2015 return on rate base of 6.82%.

Hydro is proposing that rates for Industrial Customers become effective January 1, 2015 on an interim basis. To provide adequate time for rate implementation for retail customers, the Amended Application proposes that the Utility rate and retail rates become effective on an interim basis effective February 1, 2015. Hydro is also requesting approval to recover any 2015 revenue shortfall resulting from delayed implementation of proposed rates beyond January 1, 2015 and that the shortfall be deferred for future recovery through a rate rider.[11] Additional detail on 2015 rate implementation is provided in Section 4.4.3.

The basis and detailed justification for the increase in Hydro's revenue requirement and rate proposals are addressed in the evidence to the Amended Application.

1.2 KEY CHALLENGES

Hydro is the primary generator and transmitter of electricity in the Province. In 2013, Hydro supplied roughly 87% of the electrical energy used by approximately 294,000 customers throughout the Province. Hydro has $1.5 billion[12] of capital assets located across Newfoundland and Labrador.

[10] As shown in Schedule II, line 43, Finance evidence.
[11] The same rate rider can be used to recover a portion of the 2014 Revenue Deficiency and any revenue shortfall from 2015.
[12] Net book value as at December 31, 2013.

The Newfoundland and Labrador electrical grids were established principally in the late 1960s with the construction of the Bay d'Espoir Generating Station on the island and the Churchill Falls Generating Station in Labrador during the early 1970s. As such, most of Hydro's generation and transmission assets are now more than 40 years old and require increasing maintenance, refurbishment and replacement. This is the number one challenge faced by Hydro. Investment in Hydro's generation, transmission and distribution assets is essential to provide reliable electricity service to customers. Hydro is not unique in this matter; the Canadian Electricity Association (CEA) also indicates that infrastructure renewal and new build are among the top challenges facing the Canadian electricity industry.

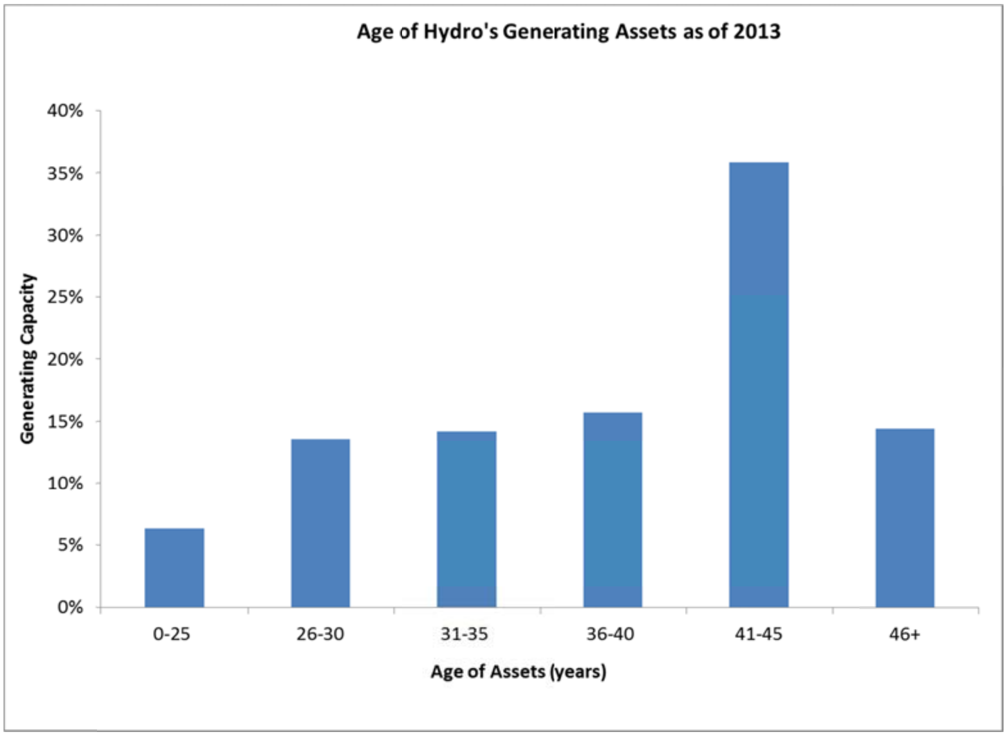
1.2.1 Infrastructure Renewal

Aging Assets

<u>Generation</u>

As shown in Chart 1.1, most of Hydro's generating assets are over 40 years old.

Chart 1.1



The hydraulic generating assets,[13] which form a large part of Hydro's Island Interconnected generating capacity, are now a high value, low cost source of clean renewable energy as their original cost represents a fraction of the replacement cost of hydraulic assets today. Therefore, they must be strategically maintained and refurbished to retain that value. Hydro's thermal plant at Holyrood, set to be retired within the next 5-7 years, is comprised of generating units and other infrastructure reaching the end of their service lives,[14] with Units 1, 2, and 3 having been placed in-service in 1970, 1971 and 1980, respectively. These units, until they are replaced by hydro generation from Muskrat Falls, are critical system assets. It is important to

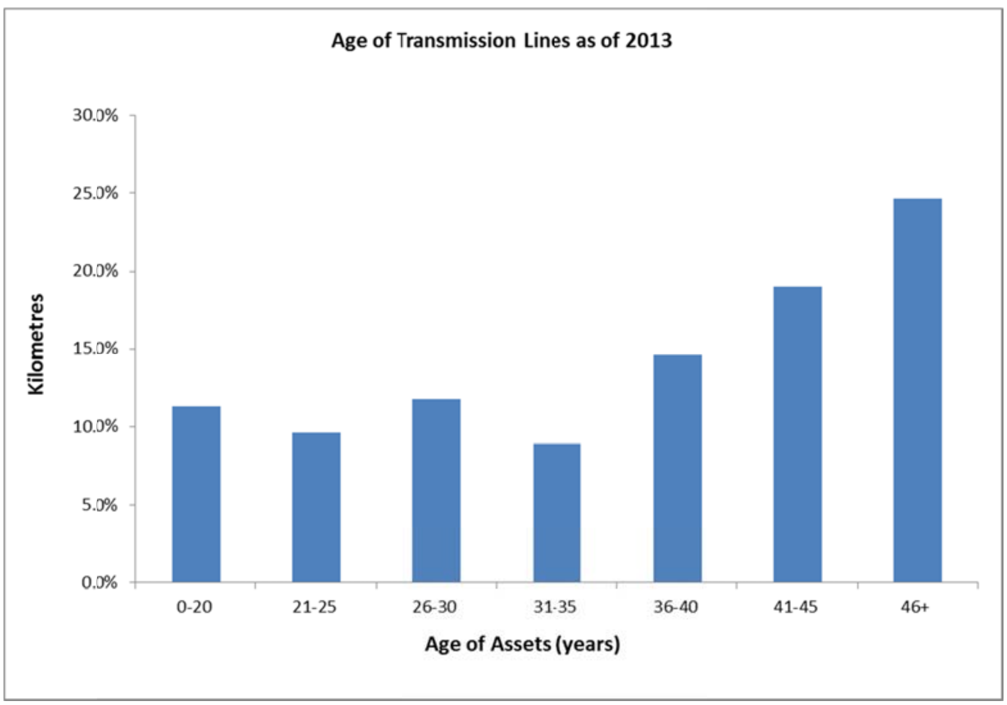
[13] Hydraulic asset components have service lives in the range of 45 to 100 years.
[14] Certain Holyrood thermal and marine assets have service lives ending in 2020.

maintain them effectively and as such, they are subject to a strategic and balanced approach to asset management until their retirement.

<u>Transmission</u>

The majority of Hydro's transmission system was constructed at the same time as the Bay d'Espoir facility in the late 1960s to connect generation to load centers across the province. As shown in Chart 1.2, many of Hydro's transmission lines are now greater than 40 years old and many components are reaching the end of their service lives.[15]

Chart 1.2

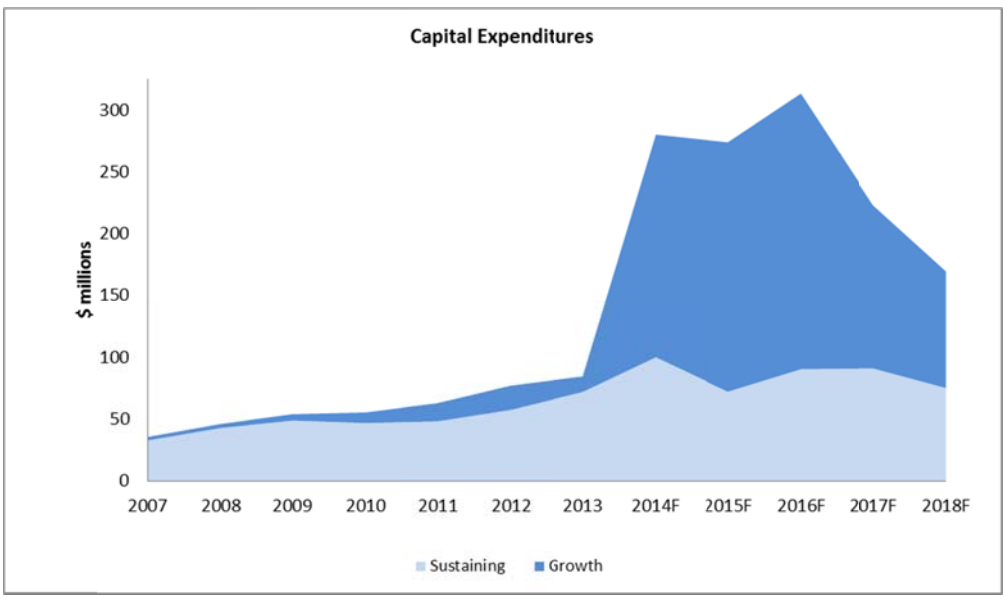


[15] Transmission asset components have service lives in the range of 30 to 65 years.

Increasing Expenditures

Aging assets require strategic operating and maintenance to optimize the useful life of the assets while maintaining operating expenses at the least cost consistent with reliable service. Capital replacements and refurbishment (sustaining capital) are required as normal deterioration of asset components occurs. Hydro has incurred to date, and is forecasting to incur, a significant increase in capital expenditures during the period from 2007 to 2018, as shown in Chart 1.3. This is predominantly a result of the need to rehabilitate and replace an aging asset base, and to provide new assets to meet growth in customer demand.

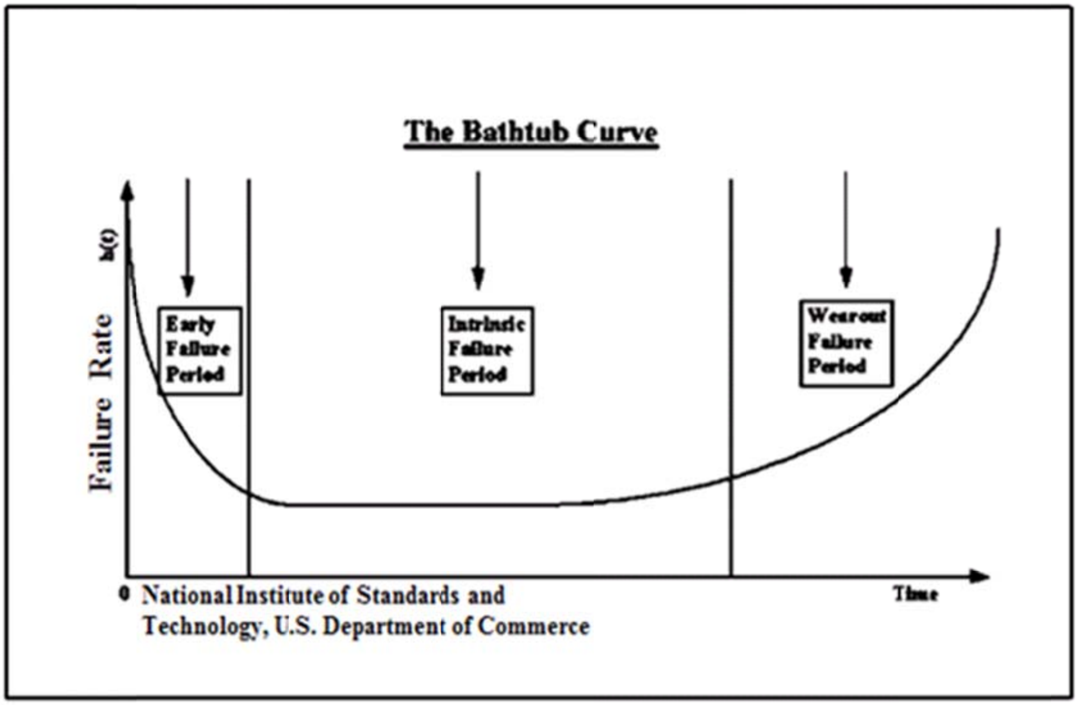
Chart 1.3



As previously stated, infrastructure renewal and replacement is the key challenge faced by Hydro. The significant increase in the capital program has required redeployment of Hydro’s workforce and increased engagement of contractors to meet the additional work requirements. Hydro’s focus remains on safely providing least cost, reliable power, while managing these upward cost pressures.

Chart 1.4 is a representative failure curve, called a bathtub curve, that demonstrates the challenges of managing Hydro's aging assets as they are approaching the last phase of their service lives.

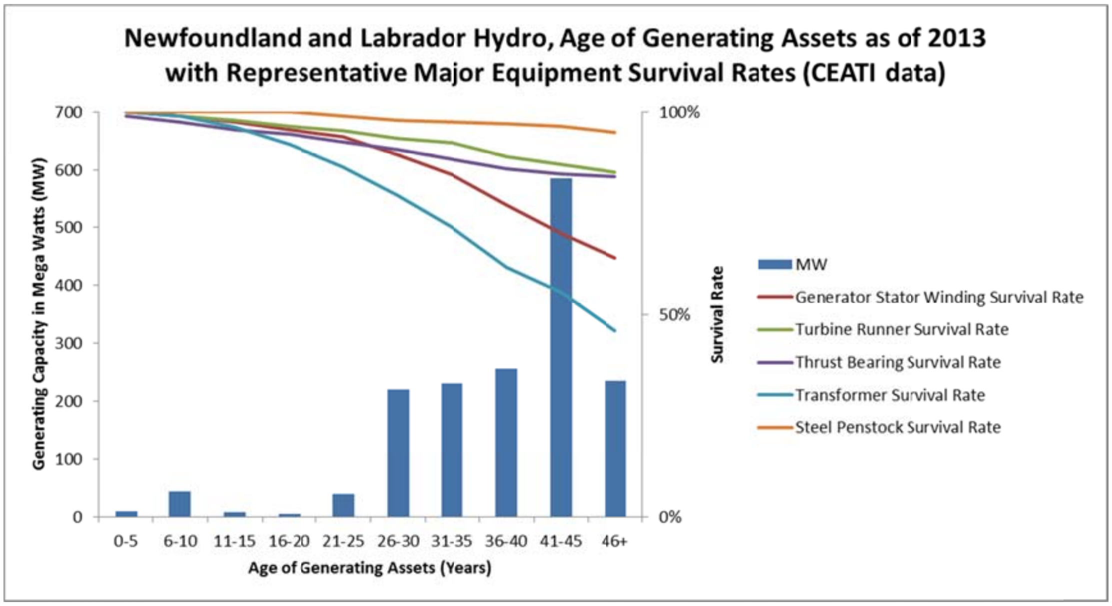
Chart 1.4



In the chart above, there is a short period known as the "Early Failure Period" when assets are first installed and a higher failure rate is encountered. Assets then move into the "Intrinsic Failure Period" where they enter a long period with stable reliability and relatively low operating and maintenance cost. As assets enter the "Wear-out Failure Period" and approach end of service life, they see steadily increasing failure levels of components and require increasing levels of inspections and prompt repairs until they ultimately reach the end of their useful life and are renewed or replaced.

Chart 1.5 shows representative survival rate curves for certain major assets superimposed over Hydro's generating assets age distribution bar chart. It demonstrates that a significant portion of Hydro's assets are entering the wear-out phase and approaching end of life. As the survival rates fall away, there is a corresponding increase in maintenance and inspection to detect the early onset of failures, and ultimately increased capital investments to renew and replace.

Chart 1.5



1.2.2 Supplying Least Cost Power

Securing economic, clean, renewable sources of electricity is one of the most effective means to mitigate customer rate increases. Since 2007, Hydro has achieved this through:

- New sources of wind energy installed at St. Lawrence and Fermeuse;
- A reduction in the cost of energy from the former Star Lake Hydro and Exploits River Hydro Partnerships; and
- Access to additional Exploits generation which was previously used to supply the Abitibi Consolidated Inc. paper mill operations at Grand Falls-Windsor.

Each of these supply sources has had a significant positive impact on reducing the cost to provide service and on reducing GHGs. It is estimated that in 2015, the combined benefit will total approximately $74 million, based on Test Year forecasts for energy production utilization, No. 6 fuel prices, and the Holyrood conversion rate. If Hydro had not achieved these savings for customers, it would have resulted in an incremental 13% increase in total revenue requirement on the Island Interconnected System.

In addition to meeting demand requirements on the island, the new 123 MW combustion turbine (CT) at Holyrood will facilitate a more efficient operation of the Holyrood Thermal Generating Plant. Availability of the CT will allow the Holyrood generating units to be shut down for longer periods. This is particularly important during shoulder seasons when these units are often required to operate at minimum loading for system reliability purposes resulting in inefficient fuel use.

New Wind Purchases

The wind farms at St. Lawrence and Fermeuse began commercial operation in the fall of 2008 and spring of 2009, respectively. In 2013, 2.9% of the Island Interconnected System's net energy generation needs were supplied by wind. An equivalent level of energy production at Holyrood requires the consumption of nearly 305,000[16] barrels of oil and creates more than 159,000 tonnes of GHGs. In 2015, it is estimated that the forecast level of wind energy production, if generated at Holyrood, would cost customers an additional $14.4 million.[17]

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[16] At the approved 2007 Test Year conversion factor of 630 kWh/bbl.
[17] At the 2015 proposed Holyrood conversion factor of 607 kWh/bbl and fuel costs of $93.32/bbl.

Exploits Generation

In 2008, the Government of Newfoundland and Labrador (the Government) passed the *Abitibi-Consolidated Rights and Assets Act* which included the expropriation of the Star Lake, Buchans, Grand Falls and Bishop's Falls generating stations and associated assets (Exploits Generation). Subsequent to the 2008 expropriation, on the direction of Government, Hydro continued to apply power purchase rates and terms that had been in place with Star Lake Hydro and Exploits River Hydro Partnerships. Commencing in 2011, the Government changed the terms of the purchase arrangements and an additional block of energy that was previously used by Abitibi Consolidated Inc. (ACI) was made available to Hydro from the Exploits Generation. In the 2015 Test Year, the Exploits Generation will continue to be made available to Hydro as a source of economical, clean, renewable energy to the benefit of ratepayers. The alternative source of this energy would be higher cost Holyrood oil-fired generation. Exploits also provides 63 MW of firm capacity with more available during times of excess flows without which Hydro would have had to acquire additional capacity support.

Conservation and Demand Management

Hydro and NP have jointly developed and executed a five-year Conservation and Demand Management (CDM) plan and filed an updated plan with the Board in 2012. Initiatives resulting from the plan include activities encouraging customers' behavioral change, the provision of rebates, marketplace promotions and other targeted efforts that promote lower reliance on electricity. Lower electricity use results in less fuel being burned and a reduction in GHGs, while providing economic benefits for customers.

Under the takeCharge brand, Hydro has CDM programs targeting its isolated diesel communities where the cost to serve is extremely high, and has implemented measures which are estimated to have achieved total energy savings of 2.8 GWh in 2012 and 2013.

Hydro has also implemented energy efficiency initiatives in many of its facilities across the province and at its head office in St. John's. At Hydro Place, for example, energy conservation initiatives have focused on control of heating, ventilation and air conditioning that has resulted in an estimated 0.9 GWh of energy savings from 2007 to 2013.

1.2.3 Employee Retention and Recruitment

In 2006, based on an analysis of its workforce and the external labour market, Hydro identified the importance of focusing on its ability to recruit and retain the necessary skilled employees. Retirements were continuing to increase as greater numbers of employees approached retirement age, and at the same time expected labour shortages were imminent, particularly in the technical/trades occupations. The following factors dictated the need for a focused strategy for recruitment and retention:

- Significant anticipated retirements during the coming five to ten years;
- Large-scale construction projects within the province, as well as a very active and increasing construction program in Western Canada;
- Changing labour force demographics, specifically an aging population and fewer labour market entrants; and
- Stable or declining participation trends in the trades and engineering occupations.

Over the period from 2007 to August 31, 2014, Hydro had 238 retirements and between 2014 and 2022, it is anticipated that 40% of the Company's current workforce will be eligible to retire. This will have a significant impact on key operational roles.

These levels of turnover have had, and will continue to have, a major impact on recruitment activity at Hydro. Given that the employees leaving are often among the most experienced and knowledgeable, the Company's focus from a retention and business sustainability standpoint, has been to minimize voluntary turnover.

Hydro has been proactive in ensuring the availability of a stable and qualified workforce to position the Company for success in carrying out its mandate. Several actions and initiatives, as described in Section 2, have been taken in the last several years to strengthen recruitment and retention at Hydro. However, a continuing focus will be required to meet new challenges in this area in the future.

1.3 ECONOMIC ENVIRONMENT

Hydro's forecasted financial performance is based on specific planning criteria and the following market factors and economic assumptions:

- The provincial economy which determines the level of Hydro's sales;
- World oil markets impacting delivered fuel prices, primarily No. 6 fuel used at Holyrood, and diesel fuel;
- General levels of inflation and pricing impacts due to supply and demand variables;
- Borrowing costs and access to capital markets; and
- Provincial and regional labour markets.

1.3.1 Provincial Economy

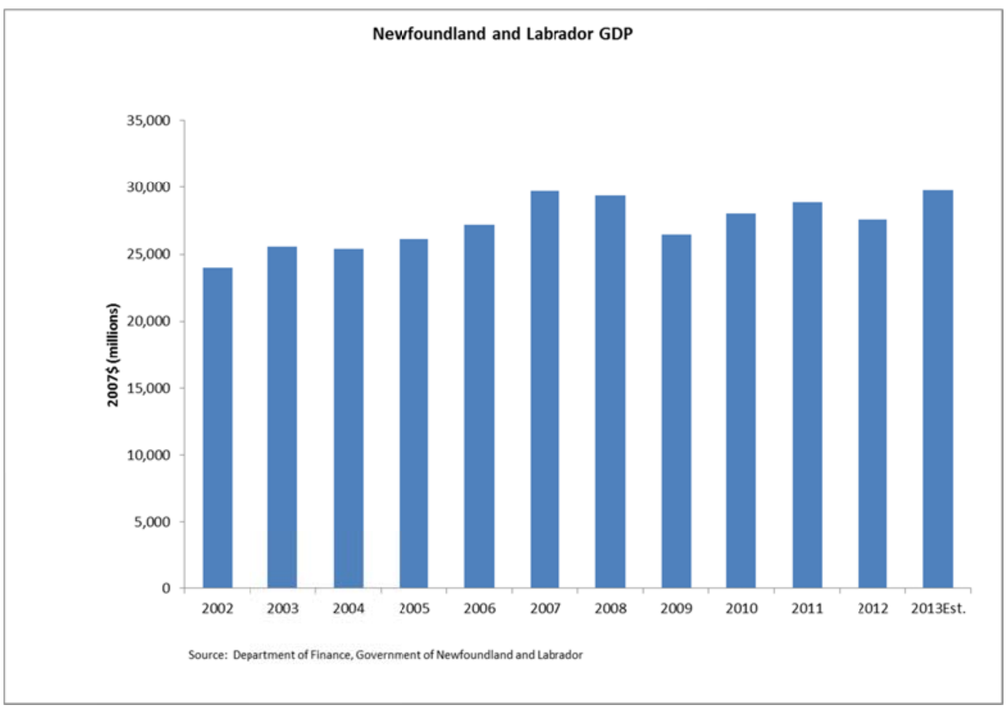
The general levels of economic activity in the province, including the operating level of locally based firms and labour competition in internal and external markets, directly affect Hydro.

Medium-Term Outlook[18]

The province posted a return to solid economic growth in 2010 and 2011 following a moderate decline in 2009 associated with the global recession.

In 2012, economic conditions in the province remained robust despite the marginal decline in real Gross Domestic Product (GDP). The decline in real GDP in 2012 was primarily a result of lower oil production which more than offset gains in both investment and consumption. In 2013, economic conditions in the province were robust with substantial growth in real GDP, which was a result of gains in investment, consumption and exports.

Chart 1.6



[18] Five to ten-year outlook from the Department of Finance of Newfoundland and Labrador.

Gains in capital investment spending in 2013 over 2012 were a result of the continued development of major projects, led by Hebron and Muskrat Falls, along with Vale's nickel processing facility in Long Harbour. Commercial and residential expenditures also contributed to high levels of investment spending. Consumer retail spending was strong in 2013 with the value of sales increasing over 2012. Employment and wage gains, combined with high levels of consumer confidence continued to support consumer spending. Employment grew by 1.0 percent and led to growth in the provincial personal income level and a decline in the unemployment rate to 11.4%, the lowest rate since 1973.

Over the next few years, the economic environment in the Province is expected to be positive with GDP growth dependent on the timelines of major projects as well as natural resource production. Increased exports, investment and consumption are expected to more than offset a decline in government spending. Despite near term softening in global fossil fuel prices, the projected trend in longer term fossil fuel prices will continue to encourage offshore exploration and development options. Capital investment will remain at high levels due to major projects being developed as well as residential and non-resource commercial investment. It is anticipated that provincial economic conditions will continue to support consumer confidence and result in net in-migration and a stable population through the medium-term.

The underlying local market conditions for electric power requirements suggest continuous growth through the medium-term. In summary, the outlook for medium-term electricity requirements in the Province remains largely positive.

Hydro's 2015 Forecast Electricity Sales

Due to the anticipated load growth from the 2007 Test Year to 2015, overall customer energy requirements are forecast to increase by 8.7%, despite the significant reduction[19] in industrial use by the pulp and paper industry on the island.

The energy requirements on the Island Interconnected System are forecast to increase by 791 GWh or 12.3% in the 2015 Test Year forecast compared to the 2007 Test Year. Demand requirements on the Island Interconnected System are also forecast to increase from 1540 MW in 2007 to 1744 MW in 2015 or 13%, to be supplied from both Hydro's and customers' resources. Demand growth has created the requirement for the installation of a new combustion turbine at Holyrood in 2014 as well as the Capacity Assistance arrangements with Industrial Customers. The overall increase is a result of higher utility customer requirements partially offset by an overall decrease in IC load. Lower IC load is associated with the closure of the ACI paper mill in Grand Falls-Windsor and reduced load at the Corner Brook Pulp and Paper (CBPP) mill due to the shutdown of two of its four paper machines in recent years. This reduced load will be offset somewhat by the new customer requirements at the Vale nickel processing facility at Long Harbour. The Vale terminal station was energized in June 2012 with first power taken by the customer in December 2012. It is anticipated that Vale will continue to increase its levels of demand and energy consumption until it reaches full production by the end of 2016. In October 2013, another Industrial Customer, Praxair, began taking power from Hydro. Praxair will provide the oxygen requirements for the Vale nickel processing facility.

[19] Since the 2007 Test Year, the pulp and paper industry energy requirements have decreased by 93%.

On the Labrador Interconnected System, Hydro's total 2015 Test Year load forecast has increased 1.7 TWh (165%) from the 2007 Test Year. This is due primarily to Hydro supplying the industrial energy requirements that had previously been supplied by TwinCo and higher Hydro Rural Customer requirements associated with normalized weather, community load growth and the load associated with addition of the Muskrat Falls construction sites.

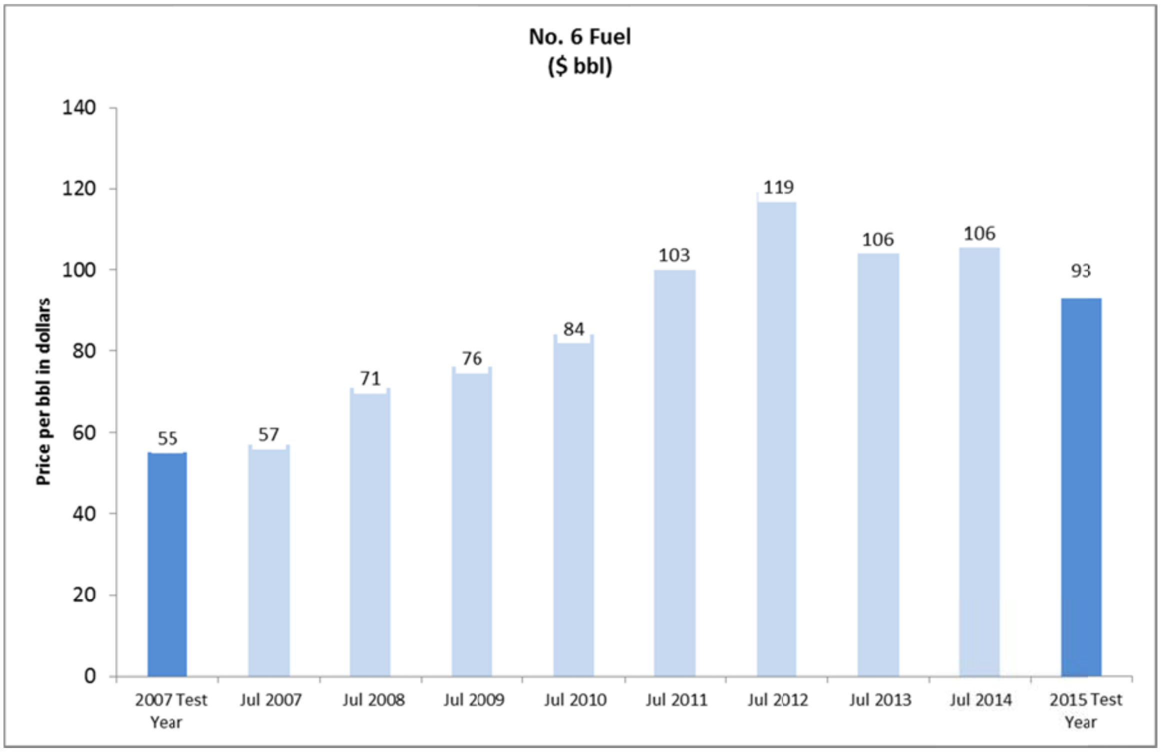
The net electricity requirements for isolated diesel systems are projected to increase by 16.3 GWh or 26.6% in the 2015 Test Year relative to the 2007 Test Year. The primary driver is the increasing customer load in Labrador, in particular, on the L'Anse au Loup System. The L'Anse au Loup System has experienced strong electricity sales growth following the introduction of lower electricity rates as a result of the interconnection of the L'Anse au Loup System to Hydro Québec's Lac Robertson System. Approximately one half of the homes on the L'Anse au Loup System now have electricity as the main heating source whereas prior to the rate change very few homes were heated by electricity. Given the cost to consumers of heating fuel compared to electricity costs, further conversion to electric heat is anticipated and additional capital expenditures will likely be required.

Detailed explanations of the load forecasts are found in the Regulated Activities evidence of this Application.

1.3.2 World Fuel Prices

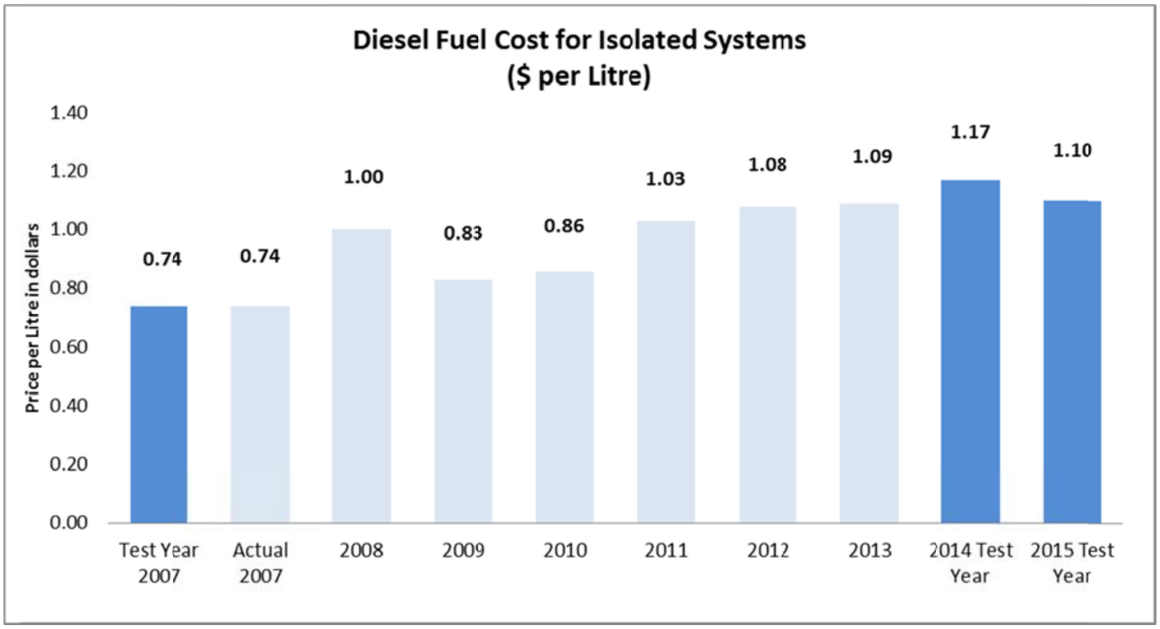
Since 2007, the costs of No. 6 and diesel fuels have risen sharply, as illustrated in Charts 1.7 and 1.8.

Chart 1.7



Note: July values are those values upon which the fuel rider is based. Prices are based upon the fuel in use at the time, which varied in sulphur content.

Chart 1.8



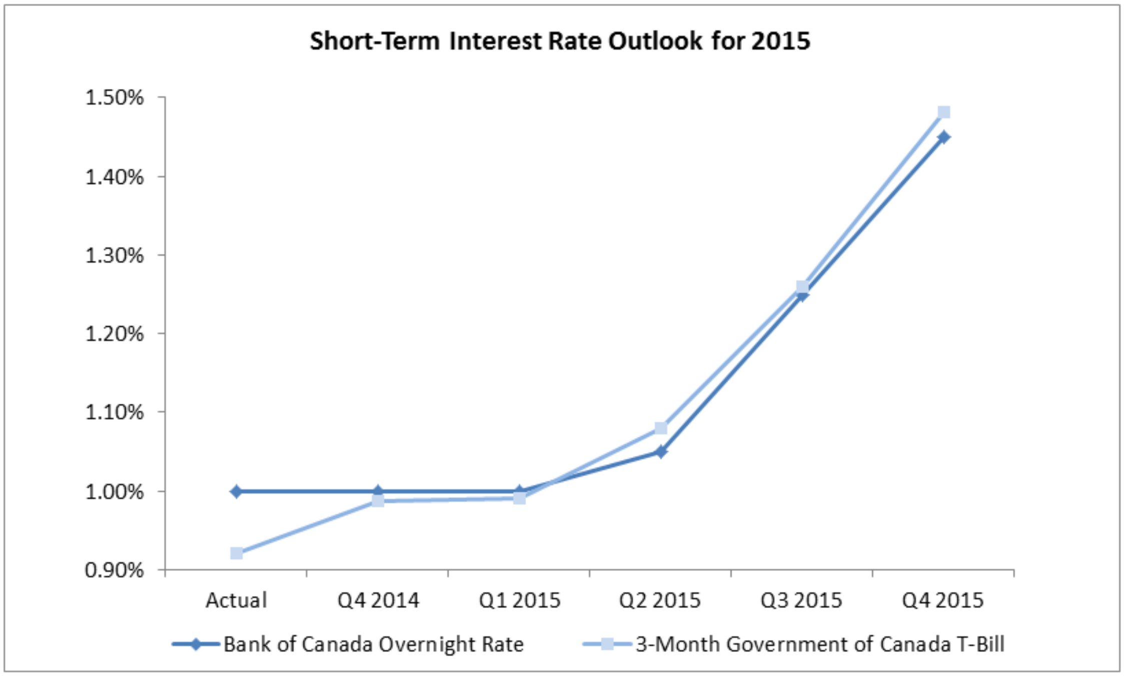
Rate impacts from monthly variances in the price of No. 6 fuel are smoothed for Hydro's customers through the RSP which reduces short-term volatility by establishing an annual adjustment in customer rates. Forecast fuel prices are reflected annually in the fuel rider on customers' rates.[20] Diesel fuel prices included in the 2015 Test Year are $0.36/litre higher at $1.10/litre for 2015 compared to $0.74/litre in the 2007 Test Year. While there is no recovery mechanism currently in place for diesel fuel, Hydro is proposing such a mechanism in this Application.

1.3.3 Borrowing Costs

An overview of the forecast for key short-term benchmark rates for 2015 is shown in Chart 1.9.

[20] Since January 1, 2007, the IC have not received annual RSP rate adjustments.

Chart 1.9[21]

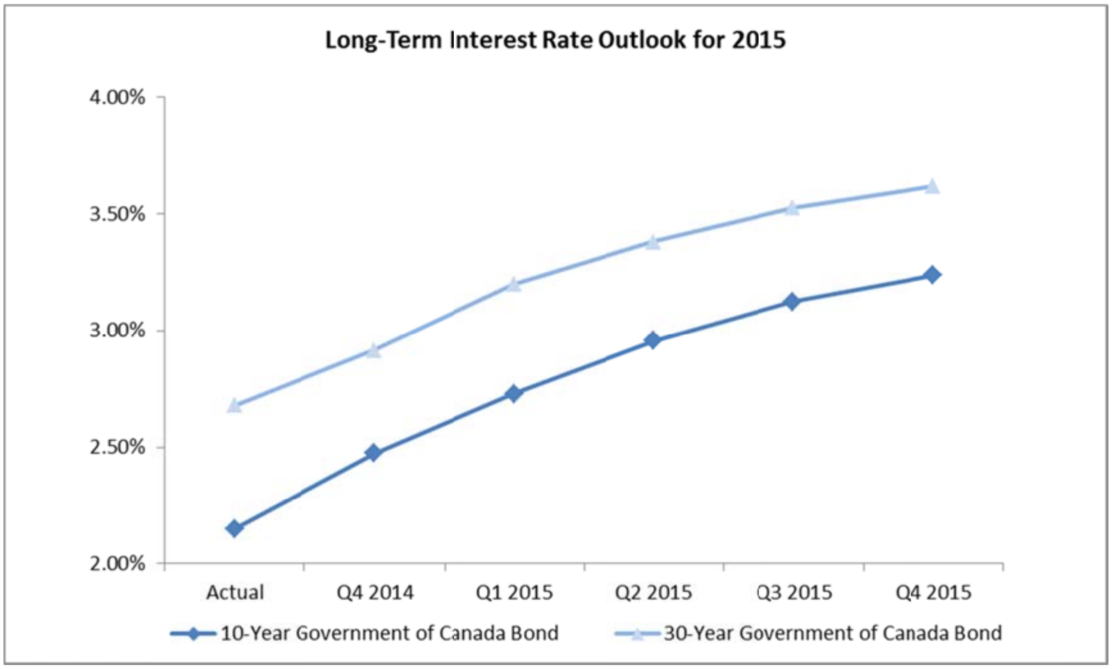


To the extent that Hydro has short-term borrowing requirements, interest expense will be directly impacted by prevailing rates in the short-term money markets which determine Hydro's borrowing cost under its $300 million promissory note program and, to a lesser extent, the rate which Hydro pays on funds borrowed through its $50 million operating line of credit.

An overview of the forecast for key long-term benchmark rates for 2015 is shown in Chart 1.10.

[21] Current data obtained from Bank of Canada as of September 2014. Data points for Q4 2014 to Q4 2015 represent the average of the forecasts published by RBC Economics (September 2, 2014), Scotiabank (August 28, 2014), BMO Capital Markets (September 12, 2014), CIBC World Markets (September 17, 2014) and TD Economics (September 25, 2014).

Chart 1.10[22]



In contrast, because Hydro's outstanding bond issues all have fixed interest rates, prevailing market rates for longer-term issues will only impact interest expense and the embedded cost of debt to the extent that new debt is issued. Hydro issued $200 million in new debt in 2014 at a rate of 3.6%, and plans to issue up to $400 million of additional debt in 2015. Therefore, these prevailing long-term rates will have an impact on future interest expense and the embedded cost of debt.

[22] Current data obtained from Bank of Canada as of September 2014. Data points for Q4 2014 to Q4 2015 represent the average of the forecasts published by RBC Economics (September 2, 2014), Scotiabank (August 28, 2014), BMO Capital Markets (September 12, 2014), CIBC World Markets (September 17, 2014) and TD Economics (September 25, 2014).

1.3.4 Provincial Labour Markets

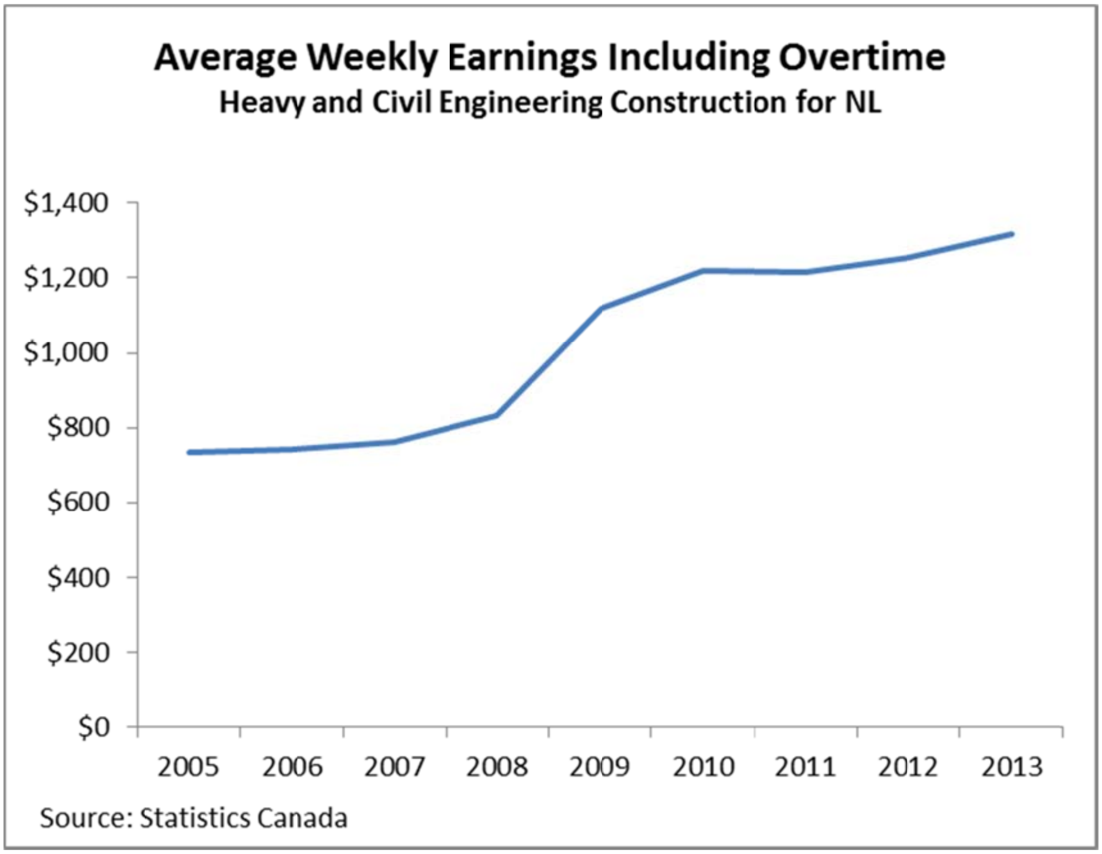
Provincial employment levels have generally been increasing since the mid-1990s. In 2009 employment declined by 2.9%, linked to the 2009 global recession. The recovery of job losses in the Province between 2009 and 2010 marked the shortest employment recovery from a recession since the mid-1970s and is indicative of the momentum in the provincial economy. More recent employment growth is largely driven by major project developments, increased consumer expenditures and public sector spending.

Employment growth continued from 2011 to 2013 with job gains in both full-time and part-time employment. Employment grew to a record level in the Province in 2013 and the unemployment rate declined to the lowest annual unemployment rate since 1973.

Accompanying the provincial labour market changes are signals that labour market conditions have "tightened."[23] Chart 1.11 shows the trend in average weekly earnings for heavy and civil engineering construction work in the province since 2005. These wage increases, in excess of 60% over the period, illustrate some of the external cost pressures Hydro has recently experienced.

[23] Government of Newfoundland and Labrador, Department of Finance: Used in the context of this evidence, a tight labour market refers to a labour market where the availability of jobs is greater than the supply of workers causing employers to compete for employees.

Chart 1.11



Provincial labour markets are expected to continue to tighten in the next ten years and beyond due to an aging population and a shrinking labour supply. The demand for skilled workers has been increasing and employment is expected to grow through the medium-term due to current and planned major project developments. Other occupations that are expected to grow quickly in the medium-term include occupations required for processing, manufacturing, and utilities.

1.4 HYDRO'S BUSINESS STRATEGY

Hydro's business strategy for meeting its mandate of providing least cost, reliable power to customers is based on the following objectives:

- To pursue operational excellence in safety, environmental responsibility and reliability;

- To strengthen and maintain its financial performance;
- To develop and maintain a highly-skilled and motivated team of employees who are strongly committed to Hydro's success; and
- To provide, through operational excellence in asset and financial management, exceptional value to all energy consumers.

1.4.1 Financial Performance

Over the period 2014 to 2018, Hydro estimates that its total capital program will be approximately $1.3 billion. As Hydro returns to the capital markets to fund its infrastructure renewal and new asset construction program, it is critical that it is in a sound financial position.

Prior to 2009, Hydro had the second highest percentage of debt in its capital structure of any major electric utility in Canada. Hydro also had the lowest approved return on equity (ROE) amongst its peer utilities. In order to reduce the debt level of Hydro, the Government, in its 2008 – 2009 Budget, included a $100 million equity injection that would "*bring Hydro more in line with similar utilities in Canada.*"[24] Also in 2009, the Government directed that Hydro would earn the same ROE as NP following Hydro's next GRA. These actions by Government have improved, and will continue to improve the financial position of the Company.

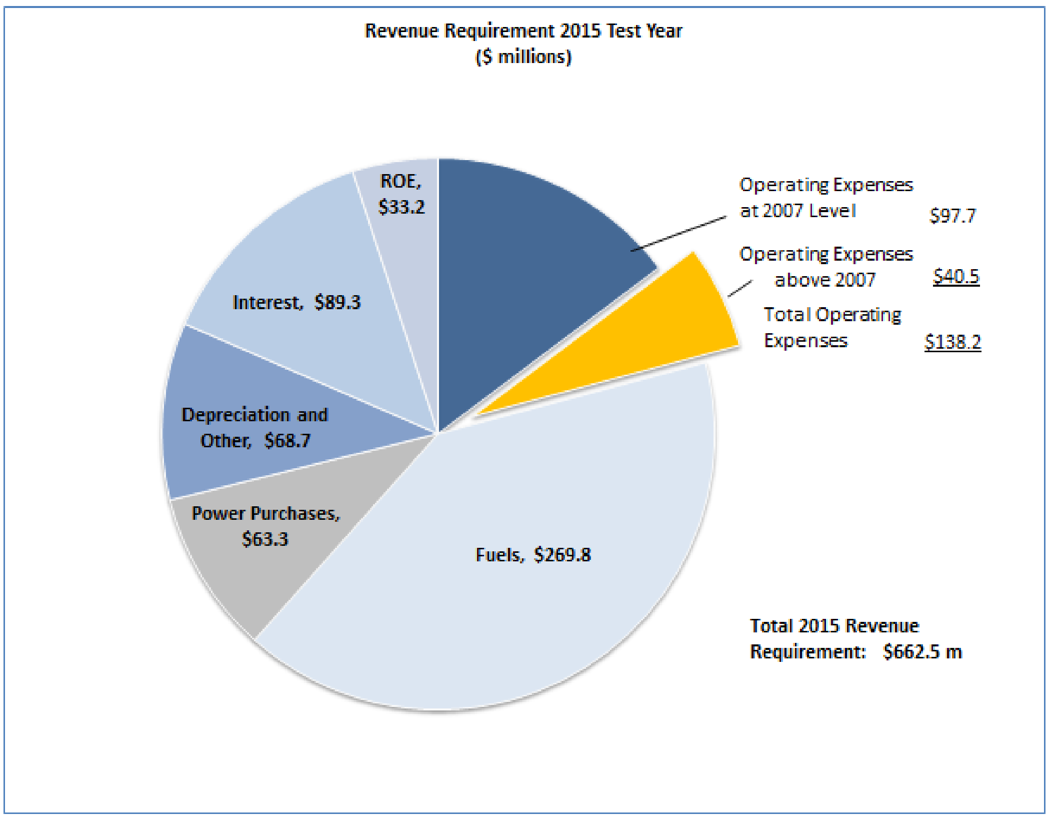
Cost Management

Fuel and interest costs, which comprise 54% of Hydro's 2015 Test Year revenue requirement, are subject to variability driven by global economic conditions and markets. Fuel volumes are largely uncontrollable in the short and medium-term as they are reflective of the provincial generation supply mix available to meet customers'

[24] Government of Newfoundland and Labrador Budget Speech, April 29, 2008.

requirements. In addition, a significant portion of remaining costs (e.g. interest, depreciation and power purchases) are driven by previous capital program and power supply decisions which result in long-term financial commitments. The primary area where Hydro exercises cost management in the short-term is Operating Expenses[25] which have increased by $40.5 million from 2007 to 2015.

Chart 1.12

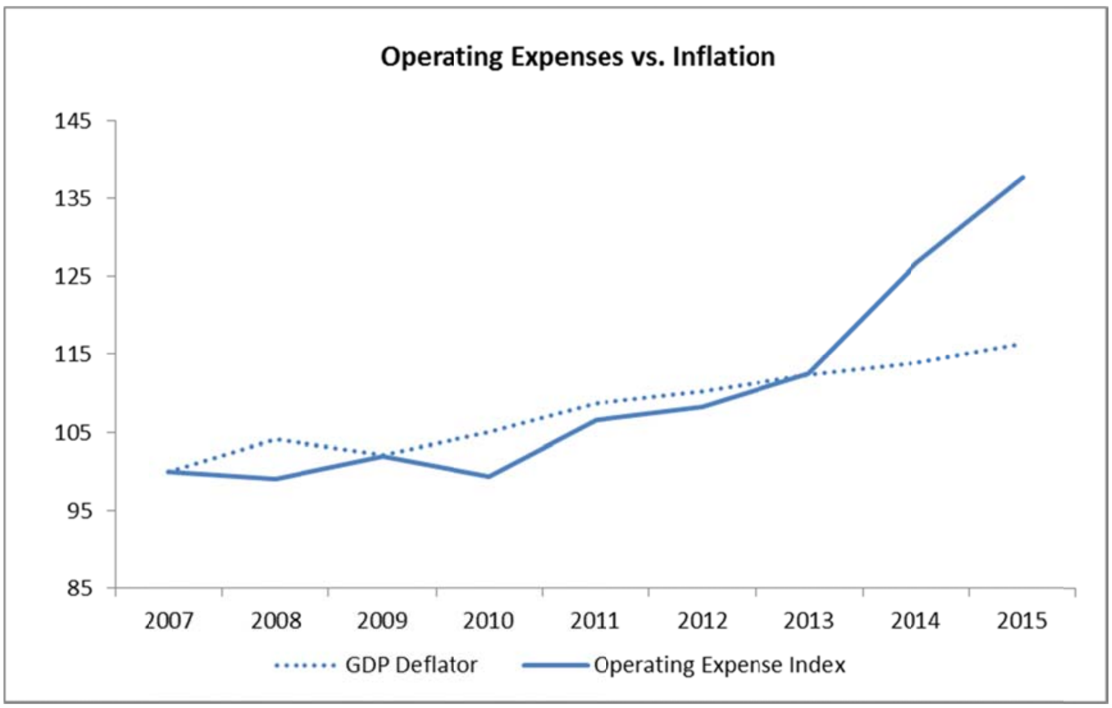


As shown in Chart 1.12, over the period 2007 to 2013, the increases in Hydro's Operating Expenses have been maintained at inflationary levels, with inflation averaging 2.0% annually over the period, while the increase in Operating Expenses have also

[25] Operating Expenses include salaries and benefits, system equipment maintenance, professional fees, travel and other costs and cost recoveries.

averaged 2.0% annually. During this period, Hydro also increased its competitiveness in a tightening labour market and expanded its engineering workforce to meet the infrastructure asset management challenge. In addition, since 2007 Hydro has prudently incurred and managed expenditures and also achieved economies of scale through sharing services with Nalcor Energy (Nalcor).

Chart 1.13[26]



The work load associated with maintaining, refurbishing and replacing aging infrastructure continues to grow. Additional staff in critical operational roles are required to support the increasing capital investment in the renewal of the power system. Also, many of the assets in operation, which have not yet been replaced or

[26] For comparative purposes, the Operating Expense index excludes the effects of the impacts of accounting changes as approved in Order No. P.U. 13(2012). The period from 2007 to 2013 excludes major repairs and inspections at Holyrood. Both Operating Expenses and inflation are presented for comparison purposes indexed to the 2007 base.

refurbished, require additional and more frequent maintenance intervals to provide a reliable electricity supply to Hydro's customers. This additional work requires additional planning and skilled trades workers to ensure appropriate and efficient work execution.

Beginning in 2014, and continuing to 2015, Hydro is making adjustments in its operating expenses, and in particular staffing levels, to reflect changing circumstances in its business to ensure cost effective and reliable service to customers. The details and justification for changes in Hydro's cost levels for 2014 and 2015 Test Years is included in Hydro's Regulated Activities evidence.[27]

Shared Service Structure

Hydro has a long history of involvement with non-regulated activities, such as the administration of Churchill Falls (Labrador) Corporation (CF(L)Co) since 1985 and its involvement in the Lower Churchill Project since the 1970s. Policies and procedures governing the accounting for non-regulated activities are in place and have been subject to external review. With the establishment of Nalcor, intercompany activity increased and it was recognized that intercompany guidelines, processes and costing methodologies would need to evolve.   In order to ensure that Hydro's customers pay the appropriate amount for electrical service, Hydro has an obligation to ensure that costs not associated with non-regulated activities are clearly separated and that Hydro's regulated customers pay only for those costs incurred in order to meet their electricity requirements.

Since 2007, there has been continual review of intercompany processes within the Nalcor companies, including Hydro, resulting in a number of enhancements. Intercompany guidelines, processes and costing methodologies were updated to ensure

[27] Refer to Regulated Activities, Section 2.4.

they were appropriate and reflective of cost-based pricing. A number of positions and business operations were transferred from Hydro to Nalcor in order to more closely reflect organizational changes. In 2010, mandatory time sheets for all employees were introduced requiring employees to record all paid hours. Prior to this change, many of Hydro's employees used an exceptional time sheet[28] recording basis. In October 2012, at the request of Nalcor, Deloitte & Touche LLP, an independent third party, completed a review of the processes and procedures used by Nalcor to recover costs among affiliates. A copy of this review was previously filed with the Board. Additionally, the report of the Board's expert, Mr. Brad Rolph, regarding Newfoundland and Labrador Hydro's intercompany charges entitled "Evaluating the Pricing Policy for Affiliate Common Services, Common Services and Corporate Services"[29] found Hydro's pricing policies to be reasonable in all significant areas. Further details on intercompany guidelines, processes and results are included in the Finance evidence.

With the expansion of Nalcor, there has been an opportunity to share services among Nalcor and its subsidiaries. Some employees have been transferred to Nalcor and there has been an overall achievement of economies of scale which Hydro has benefited from. Hydro's evidence outlines how its workforce remuneration has changed and how it has been restructured to meet increasing challenges, while providing least cost electricity supply to meet customers' increasing energy needs.

1.4.2 Employees

Hydro's mandate is carried out by a highly-skilled workforce of trades workers, engineers and business professionals. As the population of rural Newfoundland and Labrador continues to decline, coupled with an anticipated shortage of workers in the

[28] Employees were not required to report hours unless on leave or doing work for capital jobs or other lines of business.
[29] Grant Thornton report filed with the Board on April 25, 2014.

engineering, trades and technical fields, not only in the province, but nationally and internationally, there is increasing pressure on employee retention and recruitment in Hydro. In addition, the demographics of Hydro's workforce are such that, in some key areas, there is increasing retirement eligibility.

Recognizing these growing workforce pressures and the importance of a stable workforce, Hydro has been actively seeking ways to ensure success in employee retention, recruitment and replacement. Since its last GRA in 2006, Hydro increased its wage and benefits package to become more competitive with industry and the other Atlantic Canada region electric utilities. This became particularly necessary after Hydro's wages were frozen in 2005 and then in 2006 employees received a general increase of 1.5% after which Hydro's wages were still not competitive. In an increasingly competitive labour market, it is critical that the Company provide a competitive compensation package for its employees to ensure that it continues to have a skilled and motivated workforce to carry out operations and meet the increasing demands of an expanding capital program. As part of a multifaceted approach to its recruitment and retention strategy, Hydro also employs other non-compensation initiatives. These include apprenticeship and training programs, redeployment of staff and a focus on employee engagement.

1.4.3 Asset Management[30]

Asset Management Objectives

Hydro is proactively managing its $1.5 billion in capital assets. Successful management of these assets today, through appropriate infrastructure renewal and replacement, will optimize the value of assets for customers now and into the future.

Hydro's Asset Management objectives include:

- Condition and performance of all key assets are known;
- Critical assets do not fail unexpectedly;
- Critical spare parts are identified and available;
- Condition inspections proactively identify the onset of failure;
- Key performance measures are in place for asset performance and the asset management process; and
- Key stakeholders understand and have confidence in the quality and integrity of Hydro's Asset Management approach and support or approve the investments required to meet service and customer expectations.

As outlined in Section 1.2, infrastructure renewal and replacement is the number one challenge faced by Hydro. The Company is addressing Asset Management from two perspectives: the physical assets themselves and the organization of personnel who are responsible for the assets.

In recognizing the need to increase its focus on the assets to maintain reliable service to its customers, Hydro implemented a comprehensive Asset Management Strategy in

[30] Asset management is the comprehensive management of asset requirements, planning, procurement, operations, maintenance, and evaluation in terms of life extension or rehabilitation, replacement or retirement to achieve maximum value for the stakeholders based on the required standard of service for current and future generations. It is a holistic, cradle-to-grave or lifecycle view on how Hydro manages its assets.

2010. This included reorganization of the operations and engineering functions, establishing a comprehensive 20 year capital plan and establishing an Office of Asset Management to provide strong oversight of asset management practices and standards throughout the organization. This has led to the planned increase in capital investment through replacements and refurbishment. In addition, Hydro completed an asset maintenance review of much of its equipment using original equipment manufacturer recommendations as well as the practices of other utilities to determine appropriate levels of maintenance.

Also, as part of its asset management strategy, Hydro continually monitors the performance, condition and increasing age of its assets and their components to detect the early onset of failure. Hydro has prioritized the acquisition of internal and external resources in order to quickly meet the growing repair and maintenance needs of its aging assets, and to avoid increasing potential for failure that is inherent in older assets. The details of the changes since 2007 which Hydro has undertaken to execute its asset management strategy are outlined in Hydro's Regulated Activities evidence.

1.5 CONCLUSION

Hydro continues to focus on improving the service reliability for its customers through capital investments and sound asset management practices. Similar to many other utilities, Hydro faces the challenge of an aging asset base, while at the same time experiencing continued growth in demand for electrical service. Many of Hydro’s assets have now reached the end of their expected service lives and many others are approaching that point. The maintenance, refurbishment and replacement of its aging asset base, along with providing new assets to meet growth in customer demands have resulted in continued growth in Hydro’s capital investments. This level of investment is expected to be sustained at a higher level in the near term.

Since 2007, strategic steps have been taken to improve Hydro's capital structure. Additionally, effective with the current GRA, the Province has directed that Hydro target the ROE granted to NP, and that this return would apply to Hydro's entire rate base. The results of these measures will align Hydro with other regulated utilities and will strategically position the Company to face the challenge of funding its increasing capital program and provide increased financial stability.

Hydro's evidence also outlines how its workforce has changed since 2007. The establishment of Nalcor in 2007 has enabled the sharing of services among the Nalcor companies resulting in cost savings to Hydro. Hydro has a more competitive wage and benefit package to help enhance retention of its existing skilled workforce and to be competitive in attracting new workers to help meet the asset management challenges and provide reliable service to customers. This evidence will demonstrate that the costs to be recovered in the proposed rates are appropriate to ensure that continued safe, environmentally responsible, reliable and least cost electricity supply is available to customers to meet current demand and future growth.

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SECTION 2: REGULATED ACTIVITIES

2.1 OVERVIEW

Hydro's service territory encompasses a broad geographic area with challenging operating and environmental conditions such as high winds from severe cold, corrosive coastal areas and remote customer and facility locations. Maintaining, refurbishing and replacing the extensive power system infrastructure in a manner which provides safe, reliable and least cost service to its customers is the number one challenge faced by Hydro. Hydro has incurred, and is estimating a significant increase in capital expenditures during the period from 2007 to 2018, predominantly as a result of the need to rehabilitate and replace an increasingly aged asset base, as well as provide new assets to meet growth in customer demand. This requires Hydro to be diligent in the execution of its asset management strategy and the deployment of its workforce to be able to implement all aspects of the strategy. In addition, Hydro continues to rely on a significant amount of fossil fuel burning generating sources to meet customer requirements. The use of these sources will increase significantly in the short term as customer demand grows.

There are a number of factors which have created upward pressure on the cost of meeting customer electricity requirements since the last GRA:

- Increasing customer demand has created the requirement for capacity additions in order to increase generation reserves and provide reliable service on the Island Interconnected System. To address this requirement, Hydro is proceeding with the installation of a 123 MW combustion turbine at Holyrood and is also proposing capacity assistance agreements with two of its industrial customers.
- The cost of fuel has increased significantly.
  - At Holyrood, the forecast price of No. 6 fuel for 2015 has increased by more than 60 percent from the 2007 Test Year.

- There has been a decline in fuel conversion rate at Holyrood in recent years due to lower production requirements, attributable to a number of factors, as well as a lower fuel heating content in the fuel since the switch to 0.7% sulfur in 2009.
- The overall cost increase has been reduced from what it otherwise would have been by the purchase of lower priced energy from the two wind farms at St. Lawrence and Fermeuse and from the former Abitibi Consolidated generating assets that were used to supply the paper mill in Grand Falls-Winsor. These energy additions have helped to maintain Holyrood at nearly the same level of production as in the 2007 Test Year, despite significant customer load growth on the Island Interconnected System.
- Fuel costs on the Isolated Systems have increased due to higher fuel prices and overall load growth experienced on the Labrador systems.

- Many of Hydro's assets have now reached the end of their expected service lives and many others are approaching that point. This has required increasing capital and O&M expenditures as well as increase in operations FTEs in order to provide reliable service to customers.
- There have been a number of salary and wage increases since the last GRA for both union and non-union employees. The increases help to ensure that Hydro is competitive in a tightening labor market and to improve its position from a recruitment and retention standpoint.
- On the Labrador Interconnected System, the long standing TwinCo arrangements are set to expire at the end of 2014. As the TwinCo assets are critical in providing reliable service to Hydro's customers in Labrador West, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements. Hydro has included

operating and maintenance costs for the former TwinCo transmission lines and Wabush Terminal station in its 2015 forecast.

The Regulated Activities evidence will provide further detail regarding these upward cost pressures as well as describe other activities under the following areas:

- The success Hydro has had in obtaining new renewable energy sources that have significant cost and environmental benefits through lower fuel consumption;
- Hydro's pursuit of operational excellence in safety, environmental responsibility, and reliability;
- Hydro's approach to asset management and the resulting changes in organizational structure;
- Workforce demographics and employee recruitment and retention initiatives;
- Operating expenses overview for the 2007 to 2015 period; and
- Hydro's load forecast and power supply arrangements.

2.2 NEW SOURCES OF ELECTRICITY AND OPTIMIZATION OF RESOURCES

2.2.1 Wind Power

The Province of Newfoundland and Labrador has a world-class wind regime that is being utilized on both the Island Interconnected and Isolated systems. Since 2007, Hydro has entered into new Power Purchase Agreements (PPAs) for wind energy on the Island Interconnected System. The PPA with Frontier Power for wind energy in Ramea remains in place. In addition, Hydro is now receiving energy from the Nalcor experimental Wind Hydrogen diesel plant in Ramea.

On the Island Interconnected System, wind energy has been generated at St. Lawrence since October 2008 and at Fermeuse since April 2009. There is a PPA in place with NeWind Group Inc. for the St. Lawrence wind energy and a PPA with Elemental Energy for the Fermeuse wind energy. At each site, there are nine 3 MW wind turbines, for a total installed capacity of 27 MW. In each full year of operation, the St. Lawrence site has produced, on average, more than 102 GWh, while the site at Fermeuse has produced more than 89 GWh. In 2013, the total Island Interconnected wind generation purchased was nearly 192 GWh. This level of energy production at Holyrood would require the consumption of nearly 305,000 barrels of oil, creating nearly 159,000 tonnes of GHGs.

On the Island Isolated System, Hydro has a PPA with Frontier Power for wind generation at Ramea. Frontier Power has six 65 kW wind turbines installed for a total capacity of 390 kW. From 2006 to 2013, the wind generation from Frontier Power has produced, on average, 10% of Ramea's annual energy requirements. In 2013, 637 MWh or 14.4% of Ramea's total energy requirements of 4,438 MWh were produced from Frontier Power's wind turbines. This resulted in a reduction of diesel fuel usage at Ramea of approximately 178,000 litres with a displacement of 550 tonnes of GHGs.

2.2.2 Exploits Generation

In December of 2008, the Government expropriated the generating assets at Grand Falls, Bishop's Falls, Buchans and Star Lake following the announced closure of the paper mill in Grand Falls-Windsor. Nalcor received the license to operate the assets, and, in February of 2009, cessation of paper-making operations resulted in there being surplus power and energy from the Grand Falls, Bishop's Falls and Buchans generating facilities. As directed by Government, the energy from Star Lake and the Incremental Generation[1] at Grand Falls and Bishop's Falls continued to be available to Hydro under the terms of the PPAs which were with the Star Lake Hydro Partnership and the Exploits River Hydro

[1] Generation in excess of 54 MW at Grand Falls and Bishop's Falls.

Partnership, respectively. The surplus power and energy resulted from the Base Generation[2] which was previously used by ACI to supply the paper mill operations.

Hydro continued to purchase the Incremental Generation and Star Lake energy at the rates specified in the PPAs up to December 31, 2010. The Base Generation energy was not purchased by Hydro because it held no value due to 1) the significant load reductions at the Grand Falls and Corner Brook paper mills, and 2) new wind energy sources at St. Lawrence and Fermeuse. The combined effect of these Industrial Customer load reductions and new wind energy sources was sufficient for Holyrood to be reduced to minimum output.

Subsequent to the paper mill closure, Nalcor Energy was unable to reduce the flow of water in the Exploits River to store the water in the Red Indian Lake reservoir for later production, as this reservoir did not have sufficient space. Furthermore, it had to meet minimum flow requirements in the Exploits River. As a result, Hydro took receipt of the Base Generation rather than having the generating plants on the Exploits River shut down and the energy lost. This was done by displacing Hydro's hydraulic production, resulting in increased water levels in Hydro's reservoirs. This action, in effect, enabled the storage of the Base Generation for potential future disposition unless it caused water spillage from Hydro's reservoirs. If there was water spillage from Hydro's reservoirs, the equivalent energy in the spilled water would be deemed to be from the Base Generation and would no longer be available for future use. Spillage did occur in 2010 and 2011, resulting in all of the Base Generation energy produced up to the end of 2011, except 448 GWh, being spilled.

On July 25, 2011, Hydro received Government direction to pay for energy received from the Grand Falls, Bishop's Falls, Buchans and Star Lake facilities at 4¢/kWh, effective

[2] Generation up to 54 MW at Grand Falls and Bishop's Falls and generation from the Buchan's hydroelectric plant.

January 1, 2011. In a letter to Hydro dated December 2, 2013, Government indicated its intention to transfer ownership of the Exploits generation facilities from Government to Hydro. While no further correspondence from Government has been received, until the end of the 2015 Test Year the price for purchases is assumed to equal the 4¢ per kWh, as previously directed by the Government.

The following table outlines the purchases from these facilities since February 12, 2009. The 2015 production level from the Exploits Generation is forecast to be 776 GWh. A detailed description of the methodology and assumptions used in the 2015 hydraulic generation forecast is in Section 2.7.

Table 2.1

Energy Purchases from Exploits Generation
February 12, 2009 - December 31, 2015 (Forecast)

			Exploits River Project	Star Lake	Nalcor Grand Falls, Bishops Falls and Buchans[1]	Totals
2009	Energy	(GWh)	161	126	-	287
	Cost	($000)	12,427	8,674	-	21,101
2010	Energy	(GWh)	112	140	-	252
	Cost	($000)	8,664	11,232	-	19,896
2011	Energy	(GWh)		130	511	641
	Cost	($000)		5,193	20,425	25,618
2012	Energy	(GWh)		144	586	730
	Cost	($000)		5,778	23,436	29,214
2013	Energy	(GWh)		141	600	741
	Cost	($000)		5,624	23,989	29,613
2014F	Energy	(GWh)		145	612	757
	Cost	($000)		5,893	24,384	30,277
2015F	Energy	(GWh)		142	634	776
	Cost	($000)		5,687	25,340	31,027

Notes:
[1] The base energy from the Nalcor operated generation at Grand Falls, Bishops Falls and Buchans became available to the Island Interconnected System following shutdown of the paper mill on February 12, 2009.

2.2.3 Conservation and Demand Management

During its 2006 GRA, Hydro outlined its planned approach regarding energy conservation. As described in Exhibit 1 of this evidence, an energy efficiency team has been established with a mandate to develop and implement demand and energy conservation programs both internally for Hydro and externally for customers. The following is a summary of the energy savings related to the activities completed as of December 31, 2013, and forecast for 2014.

Table 2.2

Hydro Customer and Internal Annual Energy Savings (MWh)						
Customer Energy Conservation Programs	**2009**	**2010**	**2011**	**2012**	**2013**	**2014(F)**
Windows	13	37	61	136	99	75
Insulation	35	126	404	382	794	114
Thermostats	9	35	30	53	24	13
Coupon Program	-	64	256	-	-	-
Commercial Lighting	3	10	227	95	99	73
Block Heater Timer					288	-
Isolated Systems Energy Efficiency Program				1,676	1,096	600
Isolated Systems Business Efficiency Program				3	27	50
High Efficiency HRV					1	6
Business Efficiency Program						64
Small Technologies Program						65
Residential & Commercial Customer Energy Savings	**60**	**272**	**978**	**2,345**	**2,428**	**1,060**
Industrial Customer Energy Savings	-	-	165	3,172	-	15,000
Total Customer Program Energy Savings	**60**	**272**	**1,143**	**5,517**	**2,428**	**16,060**
Hydro Internal Energy Savings	1,391	453	232	279	851	350
Total Customer and Hydro Internal Energy Savings	**1,451**	**725**	**1,375**	**5,796**	**3,279**	**16,410**

CDM activities since 2007 include:

- Participation, along with NP, in the production of two five-year CDM plans;
- Participation in and promotion of rebate programs related to energy efficient products;
- Participation in government sponsored conservation activities;

- Establishment, in partnership with NP, of the takeCHARGE brand for energy efficiency programs;
- Participation in trade shows and presentations;
- Establishment of customer and class-specific programs; and
- Establishment of internal energy efficiency activities at Hydro's facilities to improve lighting and HVAC efficiency.

2.2.4 Ramea Wind-Hydrogen-Diesel Facility

The Ramea Wind-Hydrogen-Diesel facility is a Research and Development (R&D) project, the capital costs for which were not incurred by the ratepayer. The construction and installation of the wind-diesel system was approved by Board Order No. P.U. 31(2007). The scope of the project involved the supply, installation and commissioning of the following major components:

- Energy Management System;
- Hydrogen (H_2) Electrolyser;
- H_2 Internal Combustion Engine Genset – five 50 kW Units;
- H_2 Storage;
- System Integration components; and
- Wind Farm – three 100 kW Units.

The purpose of this R&D effort is to lay the groundwork for further study of the potential to provide a cost-effective, renewable energy alternative to remote diesel systems. Since 2007, the project has had a number of technical challenges that have delayed its completion. Most of the delays have been associated with late deliveries of specialized equipment or were a result of the challenges associated with this new technology. Nalcor will continue to study the economics of operating and maintaining this system while considering the environmental benefits of reduced diesel fuel consumption. The study will also provide for technical learning opportunities to develop techniques to fully optimize project components for possible future installations.

Despite delays and integration issues, the first energy was produced from the wind generation on December 12, 2009. Over the course of its operation, and up to December 31, 2013, 616 MWh of energy have been produced for the community. This has resulted in a total reduction in diesel fuel usage at Ramea of approximately 172,000 litres and a displacement of 530 tonnes of GHGs.

Hydro is forecasting 145 MWh and 200 MWh of production in 2014 and 2015, respectively, from the Nalcor Ramea wind generation facility which will help to offset diesel fuel usage and result in a further displacement of greenhouse gas emissions.

2.2.5 Labrador TwinCo Power and Assets

The Twin Falls Power Corporation (TwinCo) Block of power is produced by Churchill Falls Labrador Corporation (CF(L)Co) at the Churchill Falls Generating Station and delivered to TwinCo at a delivery point near Churchill Falls. It is a firm 225 MW, 100% capacity factor block of power and energy, resulting in 1,971 GWh per year. It is currently resold by TwinCo to Wabush Mines[3] and the Iron Ore Company of Canada (IOCC) for their iron mining operations in Labrador West.

The transmission lines from Churchill Falls to Labrador West are constructed and operated on land which is subleased from CF(L)Co by TwinCo. There are two parallel lines (Lines 23 and 24) which are operated at a nominal 230 kV voltage with a total length of approximately 470 km. These transmission lines serve both the iron ore mines of IOCC and Wabush Mines as well as Hydro Rural Customers in Labrador West. The lines are maintained by CF(L)Co on behalf of TwinCo with no costs passed on to Hydro. The long standing sublease expires at the end of 2014 at which time the transmission lines will become the assets of CF(L)Co.

[3] In October 2014, Cliff Natural Resources announced its plans to officially close Wabush Mines.

The transmission assets in Labrador West also include the equipment in the Wabush Terminal Station. Most of these assets are also owned by TwinCo and reside on land that is currently being leased from Wabush Mines. This lease also expires at the end of 2014. The major equipment generally consists of eight 230 kV/46 kV power transformers, three synchronous condensers and ancillary equipment (for voltage support), 13 - 230 kV circuit breakers, 18 – 46 kV circuit breakers, 230 and 46 kV disconnect switches, station service equipment and protection and control equipment. This equipment, with the exception of the third synchronous condenser[4], is also maintained by CF(L)Co on behalf of TwinCo. The capital and operating and maintenance costs associated with the two original synchronous condensers are shared between IOCC and Hydro under an agreement which expires at the end of 2014, with Hydro's portion recovered from Hydro Rural Customers. The Labrador Interconnected System - Plant Assignment drawing in Exhibit 3 of this GRA illustrates the configuration of this equipment.

As these assets are critical to providing reliable service to Hydro's customers, Hydro is in the process of acquiring the rights to these transmission assets either through purchase or leasing arrangements from the three parties involved. The arrangements for either lease or purchase will be in place by the end of 2014. For the purpose of determining 2015 proposed rates for Hydro Rural and Labrador Industrial Customers, Hydro's 2015 Test Year includes forecast operating and maintenance costs of approximately $2.8 million for the transmission lines and the terminal station. Once discussions with the parties are finalized, Hydro will be requesting Board approval of any asset acquisitions and will request approval of future required capital expenditures for the former TwinCo assets consistent with the capital budget expenditure guidelines established by the Board.

[4] This unit is installed and owned by IOCC.

2.2.6 Expanded Generation Capacity to meet Customer Demand

Customer demand for electricity has been growing due to the economic growth within the Province. This has led to the requirement for capacity to be added to the existing Island Interconnected System generation capacity before the end of 2015 in order to provide reliable service to customers. To address these requirements Hydro is placing in service a 123 MW combustion turbine late in 2014 and is also proposing the implementation of capacity assistance agreements with its Industrial Customers as outlined below.

2.2.7 Capacity Assistance Arrangements

The proposed agreement with Corner Brook Pulp and Paper Limited (CBPP) will allow Hydro to call on CBPP for its ability to provide up to 60 MW capacity assistance to Hydro during winter peak demand periods by both reducing its firm demand supplied by Hydro, and by providing capacity to Hydro's system from the CBPP hydraulic generating facilities. Hydro is also discussing a capacity assistance agreement with Vale. Under the arrangements with this customer, it is anticipated that Vale will provide up to 15.8 MW of capacity support from its local diesel generation at Hydro's request. The 2015 Test Year forecast assumes an annual cost of $2.1 million for these arrangements.

2.2.8 New Combustion Turbine

Hydro is proceeding with the addition of a combustion turbine (CT) generator with an early in-service of late 2014 to provide additional reserve capacity earlier than originally planned. Work is currently ongoing to install a 123 MW unit and auxiliary equipment at Holyrood with a planned in-service in December 2014. The unit will serve several functions:

- Additional long term generation capacity and increased generation reserves for the Island Interconnected System;
- Additional generation capacity on the Avalon Peninsula to mitigate local generation supply and transmission contingencies; and

- Local generation at the Holyrood Generating Station for the provision of Black start and station service requirements.

The capital cost of the project is $119 million and approval for construction was received under Board Order No. P.U. 16(2014).

2.3 OPERATIONAL EXCELLENCE

Hydro is focused on delivering value to the electricity consumers of the Province through operational excellence.

2.3.1 Safety and Health

Foremost among Hydro's goals is the safety of its employees, contractors, and the general public. The Company has a targeted approach towards injury prevention, communication and awareness, and visible leadership and support at all levels. There is also a focus on supporting and recognizing the areas with exceptional safety performance to enable continued motivation and sustain a positive and strong safety culture.

A company-wide process for collecting and reporting hazards, near misses and both safe and unsafe practice observations remains a key component of Hydro's safety program. This Safe Workplace Observation Program (SWOP) focuses on reporting safety observations. This data is used to identify actions to continually improve safety for employees, contractors and the public. Hydro continues to strengthen its focus on the Work Protection Code[5], Work Methods[6] and Grounding and Bonding[7] which are

[5] The Work Protection Code is a document containing rules which must be followed by all individuals required to perform work on transmission and distribution systems, auxiliary metering circuits, and at generating facilities. The rules and procedures ensure protection for individuals working in an environment into which harmful energy can be introduced.

[6] Work Methods are documents that instruct employees on how to properly perform critical tasks in a safe manner.

[7] The Grounding and Bonding Program identifies practices for temporary grounding of electricity generation equipment and transmission and distribution lines to provide maximum protection for workers.

fundamental components of a utility's safety program. Hydro's safety program has been a joint union and company effort, and its current success can be attributed to the broader involvement by both union and non-union workers. As a result of the data collected from the SWOP database, Hydro increased its engagement in enabling contractor safety, promoting public safety around electrical equipment, and standardizing and increasing awareness of permits required to complete work near a transmission or distribution line. These efforts contribute to overall safety.

Hydro also has wellness programs for employees which have focused mainly on heart health, with initiatives including wellness clinics, stress management sessions, and fitness reimbursement programs for certain wellness related activities.

2.3.2 Environmental Performance and Air Emissions

Over the past few years, Hydro has improved its environmental performance, while maintaining the safe and reliable delivery of energy to residents of the Province. Hydro's commitment to the environment helps ensure a healthy and sustainable environment for future generations of Newfoundlanders and Labradorians. To facilitate this environmental performance, Hydro continues to use the ISO 14001 Certified Environmental Management Systems, which provide a framework for an organization's environmental responsibilities and is an integral component of the organization's business operations and continuous improvement focus.

The environmental commitment to sustainable practices in its operations is demonstrated throughout the Company's activities. Hydro has integrated initiatives in alternative energy, energy conservation and community partnerships into its operations throughout the Province. Hydro also takes its responsibility to preserve sensitive habitats and vegetation very seriously and makes every effort to ensure minimal environmental impacts through its operations.

Environmental Management Areas

Currently there are four Environmental Management areas[8] within Hydro with identified environmental aspects. Environmental aspects are elements of a department's activities, products, or services that can interact with the environment. Significant environmental aspects are managed either through Environmental Management Programs or standard operating procedures.

In 2013, Hydro completed 95% of its Environmental Management Systems targets, which are initiatives undertaken to improve environmental performance.

Emissions

In 2013, approximately 82% of the net electricity supplied by Hydro was generated from clean hydroelectric power. However, to reliably meet all the electricity demand each year, and to supplement Hydro's hydroelectric generation and purchases, a portion of the Island Interconnected System electricity still must come from fossil-fuel fired generation at Holyrood and at times from gas turbines. From 2007 to 2013, 13 to 20% of the Island Interconnected System net energy requirements were supplied by Holyrood. Hydro also owns and operates 25[9] diesel plants across the Province, primarily to supply isolated communities. In 2013, approximately 72% of the supply in these isolated areas was from fossil fuel generation.

Since 2007, the Company has incorporated additional alternative sources of energy into the Province's energy supply to reduce emissions from burning fossil fuels and the related costs. As stated previously, in 2013, Hydro purchased nearly 192 GWh of clean energy from the two Island Interconnected wind projects.

[8] Services Management, Thermal Generation, Hydro Generation and Transmission and Rural Operations.
[9] Includes 21 Isolated diesel plants, and diesel units in St. Anthony, Hawkes Bay, Happy Valley-Goose Bay and Mud Lake. Hydro operates and maintains the diesel plant in Natuashish on behalf of the Mushuau Innu First Nation.

Overall, thermal production at Holyrood increased in 2013 by 11.7% from 2012, primarily due to increased requirements from the plant for Avalon transmission support and higher system peaking requirements. This was primarily driven by colder temperatures and increased customer demand. The Holyrood plant produced just over 14% of the energy supplied by Hydro in 2013, up slightly from 13% in 2012. The increased energy production from the Holyrood plant in 2013 resulted in a 10.9% increase in carbon dioxide (CO_2) emissions. The increase in CO_2 emissions is directly attributed to more fuel being consumed in 2013, relative to 2012. The sulphur dioxide (SO_2) emissions from the plant in 2013 were 8.1% higher than those experienced in 2012.

Total emissions for CO_2, and SO_2 for Holyrood, gas turbine facilities and isolated diesel generating stations are calculated using formulas approved by the provincial Department of Environment and Conservation. Hydro's overall air emissions are dominated by those resulting from production at the Holyrood Generating Station.

Emissions for the Island Interconnected System, including Holyrood, and interconnected gas turbines and the standby diesel plants are outlined in the following charts:

2 **Chart 2.1**

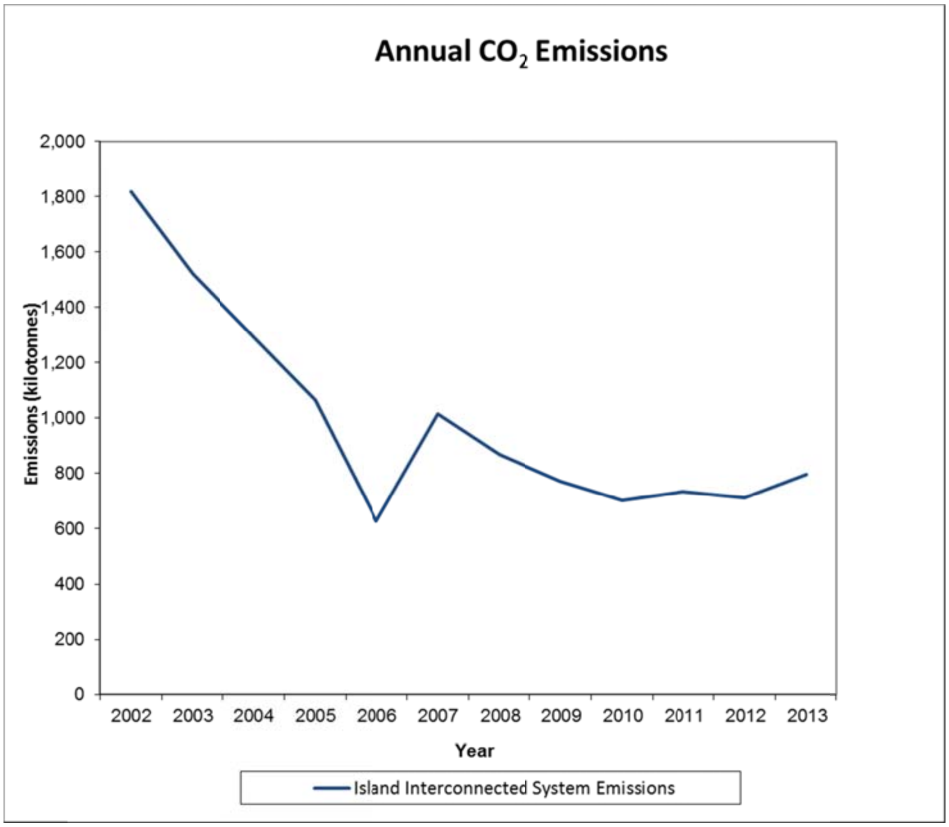
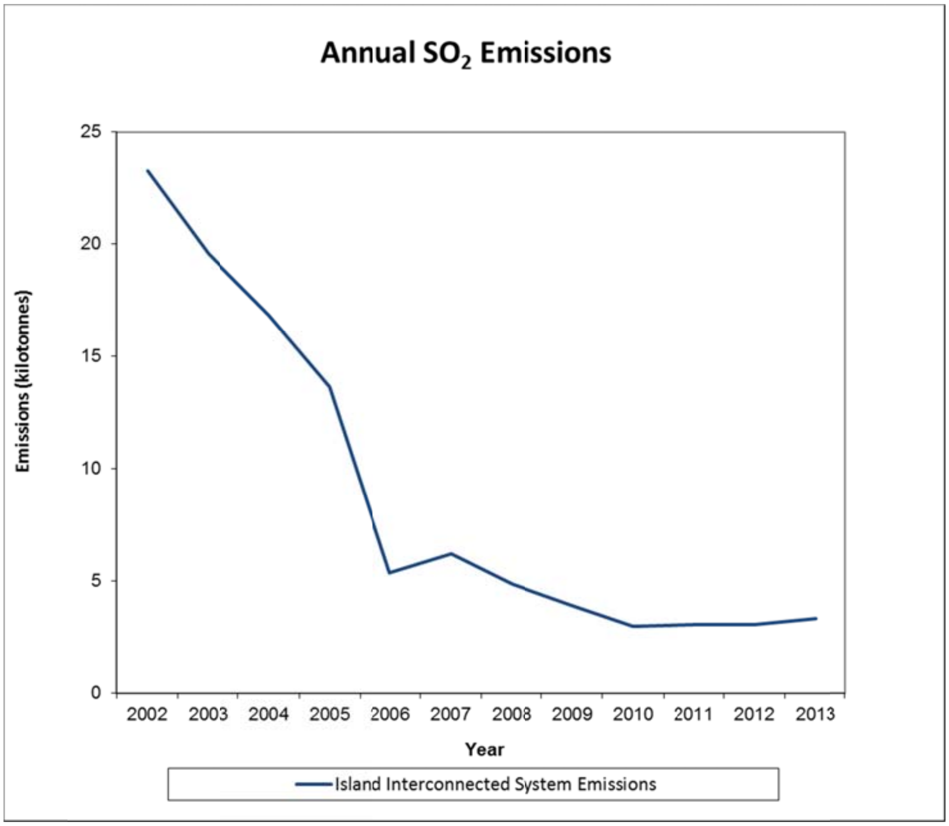

Annual CO_2 Emissions
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
Emissions (kilotonnes)
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
Island Interconnected System Emissions

Chart 2.2



Emissions of CO_2 and SO_2 for Hydro's other systems in 2013 were calculated to be approximately 47.8 and 0.06 kilotonnes, respectively.

2.3.3 Asset Management and Capital Investment with an Aging Asset Base

Hydro's responsibility to provide reliable and least cost service to meet the needs of its customers is a challenging balance which is addressed through sound asset management. This approach requires that assets are kept in reliable working condition through a structured preventative maintenance program, with the required corrective maintenance and replacement or refurbishment when necessary. Asset replacements are planned based on condition assessments, maintenance and operating history, changing technology, expected service lives and knowledge of individual assets. Asset additions and upgrades are also determined through analysis of options to address the long-term, least cost supply of electricity.

The current condition of Hydro's asset base is a reflection of the history of the electricity industry in general and, in particular, the Province. In the 1960s, there was a significant expansion in assets to fulfill the mandate of the Newfoundland and Labrador Power Commission, Hydro's predecessor, which was to bring electricity to many areas of the Province and to build an infrastructure which connected the many diverse and isolated electrical systems in the Province. Many of the assets constructed during that time have now reached the end of their expected service lives and many others are approaching that point. Other major assets, such as hydroelectric plants like the Bay d'Espoir Generating Station, have not reached the end of their expected service lives, however, some of the components, auxiliary equipment and systems are at, or near, the end of their service lives. This, along with increasing upward pressure on labour and material market costs, has resulted in growth of Hydro's capital investments which is expected to be sustained at a higher level for the near term.

In 2006, Hydro undertook an assessment of its asset management process in recognition of its aging asset base. Figure 2.1 summarizes the progression of this assessment and action items.

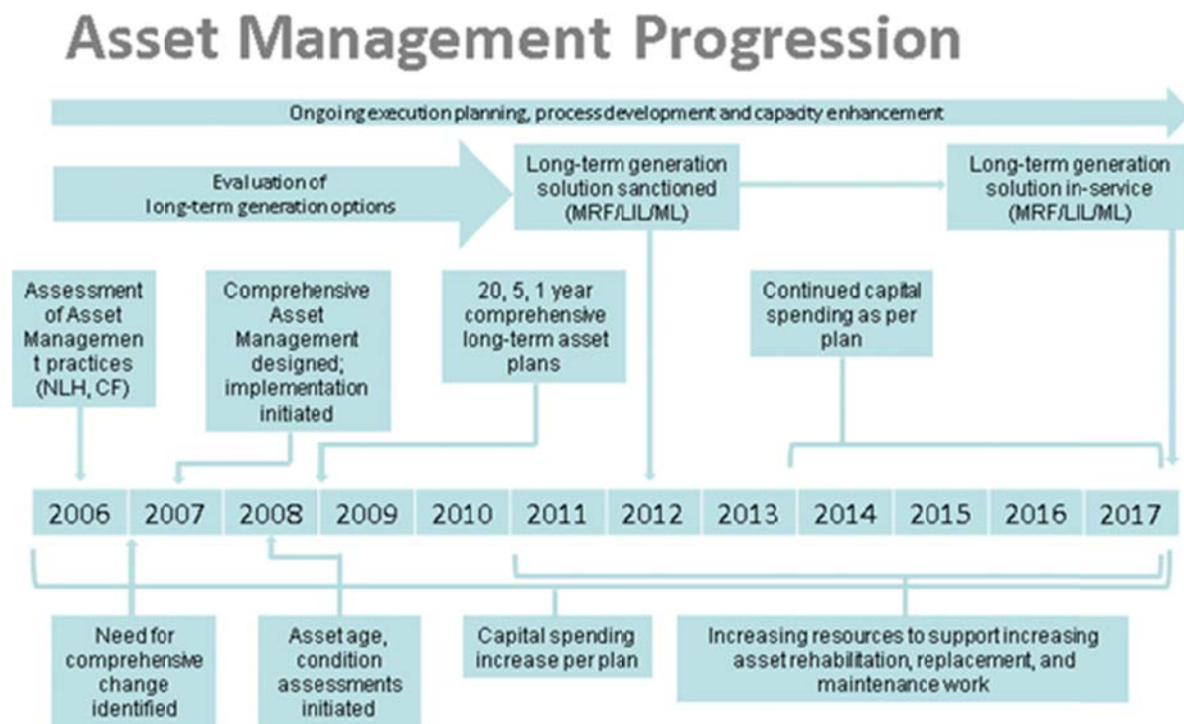


Figure 2.1 - Asset Management Progression

Asset management activities have focused on:

- Reviewing the five year capital plan, updating both the content and timing of projects based on knowledge gained from inspections (e.g. onsite physical inspections as well as feedback from hands-on operators and maintainers) and targeted formal condition assessments;
- Updating the full 20 year capital plan;
- Preparing and executing plans to update:
  - o critical spare requirements; and
  - o standards, planning criteria and operating parameters;
- Updating metrics for asset management;
- Developing a consistent approach to performing root cause failure investigation; and

- Process improvements for Project Execution and Short Term Work Planning and Scheduling, including integrated resource planning and standardized progress tracking.

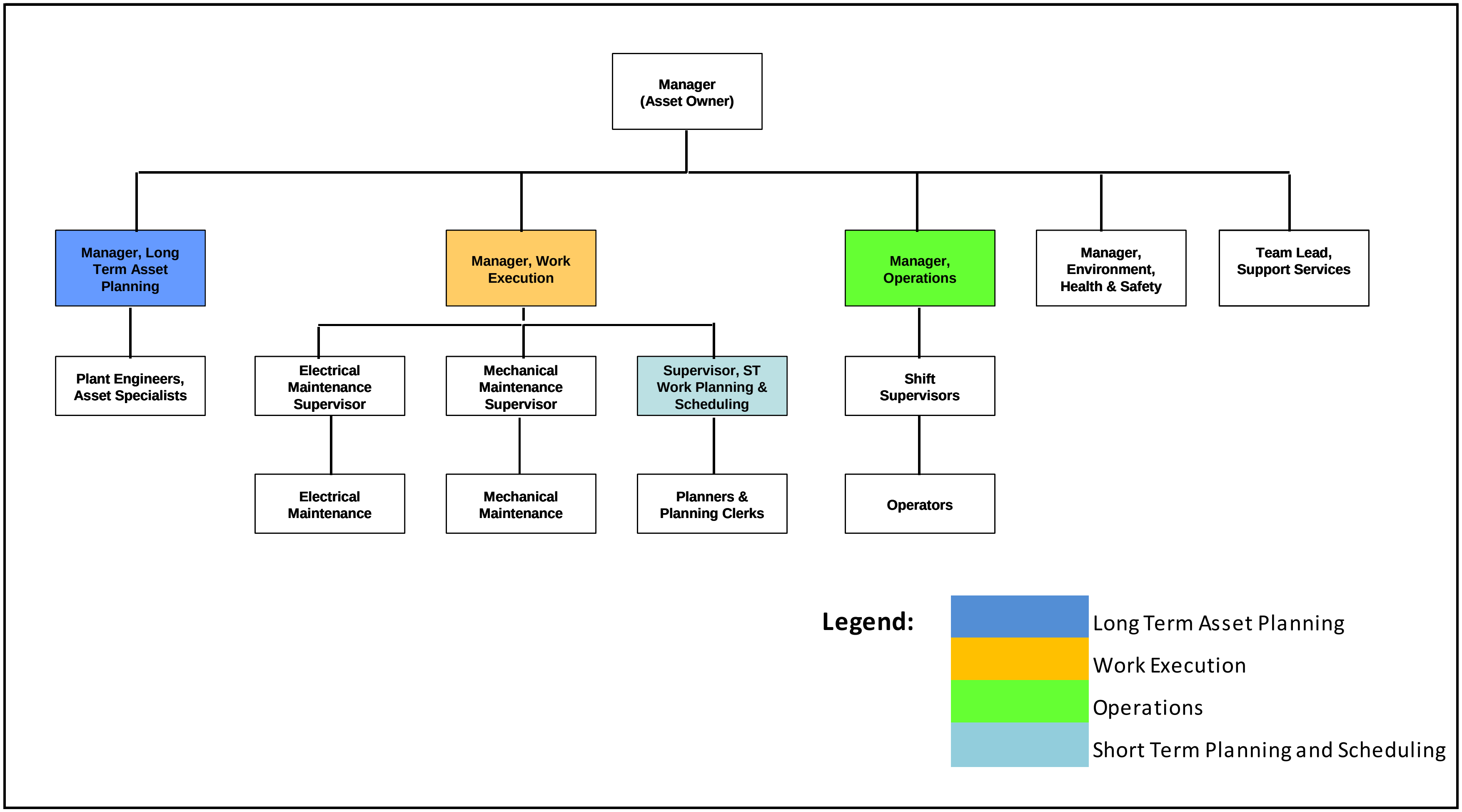
In 2010, Hydro updated its organizational structure to support a renewed Asset Management Strategy which aligns with:

- Asset performance expectations;
- Consistent maintenance practices for similar assets; and
- Asset renewal or replacement programs.

As a result of this reorganization, five key functions have been established consistently throughout all operating departments.

1. Long-Term Asset Planning;
2. Short-Term Work Planning and Scheduling;
3. Work Execution;
4. Operations; and
5. Support Services.

Figure 2.2 shows a representative organizational structure reflecting these functions.



1 **Figure 2.2 - Asset Management Representative Organizational Structure**

In addition to the changes in the operating departments, a centralized Office of Asset Management (OAM) was created in the Project Execution and Technical Services division. The OAM has responsibility for oversight and direction for asset management and provides support to the operating departments, ensuring a consistent implementation of asset management best practices throughout the Company.

These changes in roles are included in Exhibit 1, Organizational Responsibility.

As part of its ongoing asset management strategy Hydro reviews its workforce capacity to address any changes required to meet the challenges of both an aging and growing asset base. In 2014 and 2015 it has made adjustments to staffing levels in a number of key areas to meet growing customer demand, an increasing capital program and a greater requirement for execution of required preventative and corrective maintenance relating to Hydro's aging assets. There has been an increase in Full Time Equivalents (FTEs) throughout the Company with particular focus in Operations areas. In 2014, there are 861 operating FTEs, an increase of 44 FTEs over the 2007 Actual. In 2015, there is a further increase of 34 FTEs for a total of 895 operating FTEs. The planned increases in the Operations area provide for additional execution capacity and enhanced planning and scheduling to complement the increased capital program and increasing maintenance requirements resulting from aging assets and their replacements. These positions are critical for the delivery of sustained reliable service to customers. The additions are further described and explained in the Section 2.4 functional area cost reviews.

Holyrood

Holyrood is the second largest generating plant on the Island Interconnected System, and, as a thermal plant, is significantly more complex than its hydroelectric counterparts. Units 1, 2 and 3 were put in service in 1970, 1971, and 1980, respectively. Each has passed the normal 30-year design life for such a facility and has undergone life extension activities. Units 1 and 2 were modified in the late 1980s to increase their capacity from 150 to 170 MW each. This was achieved by availing of the overcapacity inherently designed in equipment of that vintage and by modifying the plant's auxiliary systems. Units of a similar age in other electric utilities have been retired or have been subjected to life assessment and extension studies. Those not retired received costly major refurbishments to extend their useful lives.

Maintaining Holyrood as a reliable source of energy and capacity for the Island Interconnected System is essential prior to the Labrador interconnection. The closure of the paper mill at Grand Falls-Winsor, the reductions in load at CBPP and the development of two wind farms have resulted in reduced energy requirements from Holyrood in recent years. However, Holyrood remains a vital generation asset for capacity and energy, particularly in light of growing customer demand due to utility load increases and the ramp up of operations at the Vale nickel processing facility. It should also be noted that during a repeat of the critical dry sequence, annual required production from Holyrood would be significant, up to 3,000 GWh per year. In addition to ensuring reliability, environmental issues with the plant and various legislative and regulatory requirements contribute to ongoing significant expenditures at the facility.

To enhance the reliability of supply from Holyrood, Hydro has recently installed and commissioned eight mobile Black start diesel units at the facility. Installation took place during the winter of 2014 with the final plant interconnection occurring in early April 2014. The units were fully commissioned in July 2014 when a Black start test could be performed. The diesel units provide for several functions:

- Black start capability of Holyrood in the event of an extended transmission outage that separates the Avalon Peninsula from the remainder of the Island Interconnected System grid;

- In the event of an extended transmission outage into the facility, pre-warming capabilities and other essential and auxiliary services for the plant which will reduce the overall outage time once transmission is restored; and
- Peaking capacity of up to 10 MW to the grid.

The total lease and capital costs associated with this project were $6.5 million and approval for construction was received under Board Order No. P.U. 38(2013). The leased diesel units will be returned to the supplier at the end of June 2015 as they will be no longer required at that time due to the installation of the new Holyrood CT.

2.3.4 Recent Reliability Performance

As part of its asset management strategy, Hydro continually monitors the performance, condition and increasing age of its assets and their components to detect the early onset of failure. To enable a rapid response to failures Hydro continues to increase its capacity to repair and maintain through additions of both internal and external resources, as appropriate for the assets' position on their life cycle curves and the increased potential for failure. Also, as part of Hydro's asset management strategy, Hydro reviews significant asset failure incidents to determine root causes and to implement improvements to prevent recurrence.

In 2013, there were a number of severe weather related events that negatively impacted Hydro's reliability performance. The events of January 11, 2013, which were initiated by high winds and salt contaminated snow at the Holyrood switchyard, resulted in widespread customer outages in many areas of the Province. Following the events of January 2013, Hydro undertook a review of the power system response and identified and implemented a number of recommendations that primarily targeted enhancements to and replacements of high voltage and protection and control equipment, power system studies and a review of preventative maintenance and operating procedures.

The events of January 2014 were driven by an abnormal combination of generation equipment problems followed by transmission breaker failures during an extended period of cold weather. Hydro recognizes the significant impact these events had on customers and is committed to reducing the impact and likelihood of it reoccurring. Hydro has subsequently made changes to improve reliability. The more significant initiatives are as follows:

- Enhanced senior leadership and oversight of critical operations, namely a General Manager for gas turbines and diesels;
- Accelerated the addition of the combustion turbine generator to 2014 from 2015 to provide additional reserve capacity a year earlier than originally planned;
- Following from the work initiated in 2013 to update previous critical spares reviews, an accelerated review and update to include all generation equipment was undertaken in 2014;
- Modified the established air blast circuit breaker replacement program to have an earlier completion with more replacements in 2015;
- Specific focus on identified protection and control improvements;
- Completion of the remaining circuit breaker and transformer preventive maintenance work that was included in the six year recovery plan (2010 to 2015), by completing approximately 50% of the remaining work in 2014 and the remainder in 2015; and
- Obtained an agreement with CBPP for 60 MW of capacity assistance. Hydro is also working on a capacity assistance agreement with Vale for up to 15.8MW of capacity support.

Also, the following actions which Hydro had previously planned and/or which were identified during ongoing asset management activities in 2014 were undertaken:

- Upgrading of two transformers at Oxen Pond for load growth;

- Installation of three Labrador Island Link related 230 kV breaker upgrades at the Holyrood Terminal Station;
- Planned refurbishment of the Stephenville Gas Turbine;
- Initiation of a program of scheduled battery discharge testing to ensure that protection and control systems will operate reliably when required;
- Execution of recommended modifications to electrical grid protection and control systems;
- Replacement of insulators on TL201 and TL203 to address age related deterioration;
- Implementation of an enhanced winter readiness program in all operating areas to build on existing activities in place for preparing for the high winter demand period; and
- Advancement of the excitation transformer replacement program at Bay d'Espoir.

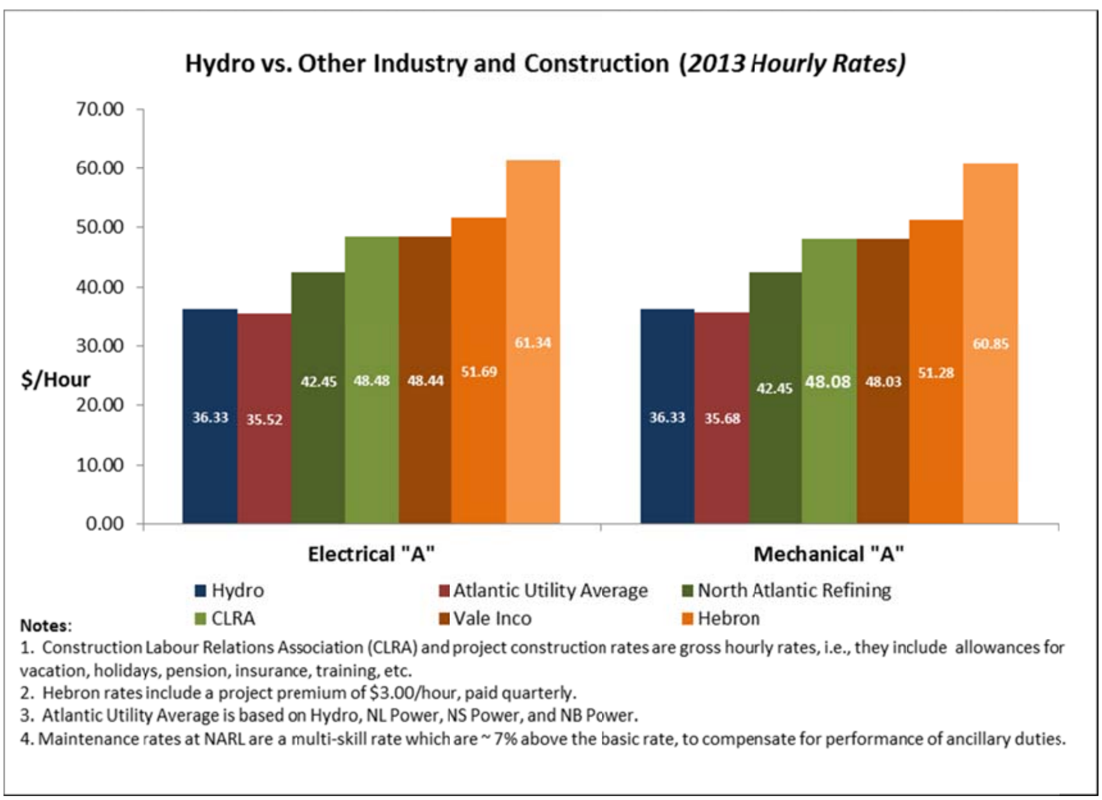
2.3.5 Maintaining a Skilled Workforce

A skilled and motivated workforce is critical for ensuring safe and reliable service to Hydro's customers. In 2006, a focus on recruitment and retention was initiated as there was increasing incidence of voluntary resignations. A key aspect of Hydro's recruitment and retention strategy has been to ensure the Company is competitive on salaries and wages in an increasingly tight labour market. Hydro has expended considerable effort to ensure its compensation is adequate to both attract and retain quality employees, while maintaining cost control on behalf of customers. There still remain additional challenges to incent resources to work in rural areas.

With respect to its unionized groups, Hydro negotiated two series of special wage adjustments in order to bring its employees' wages in line with NP and the average wages of other Atlantic Canada electric utilities. Over the period 2007-2009, trades and technology employees, who represent the significant majority of Hydro's operations group, received an additional $1.65/hour wage and benefit increase to help close this gap. In 2010, a further trades adjustment of approximately 4.8%, plus annual general adjustments of 6.5%, 4%, 4%, and 4% over the period 2010 to 2013 were negotiated in order to completely close the gap and achieve parity and competitive positioning with other Atlantic Canada electric utilities to aid in recruitment and retention efforts.

An additional factor for Hydro in applying these changes has been the rates paid in the provincial construction industry. Chart 2.3 presents a comparison of 2013 rates between Hydro, the average across the Atlantic Canada electric utilities and the provincial construction rates, using Electrical "A" and Mechanical "A" as reference points. While it is not necessary to fully match the construction rates in order to be competitive, it is imperative that the Company wage rates are in reasonable proximity from a recruitment and retention standpoint. Hydro will continue to monitor its positioning relative to these sectors.

Chart 2.3



In its non-union group, annual general economic adjustments mirrored those that were provided to the Company's unionized employees over the period 2010 to 2013. In addition, in 2007 it was necessary to re-establish the historical wage differential between front-line supervisors and their trades and technology employees. In the absence of this adjustment, the differential of between 17% and 20% which existed before market adjustments initiated in 2007 would have eventually eroded to below 10%, causing difficulties from an internal recruitment and retention standpoint in relation to front-line supervisors.

Additionally, in 2012 a number of non-union salary scales were adjusted upwards by 1.3% to 7.9% based on an analysis of non-union salaries. The adjustments were required to ensure Hydro is more competitive with the external labour market.

All of the above compensation measures resulted in annual wage and salary increases which have been above the rate of inflation. However, in all cases, they have been implemented for sound recruitment and retention reasons, and to help ensure the sustainability of Hydro's operations. Increased recruitment needs driven by retirements, in the context of an increasingly tight and changing labour market, have compelled the Company to take the steps necessary to ensure it can minimize the loss of knowledge and skills. The electric utility industry is highly specialized and Hydro has taken action to compete for the people and skills it requires to maintain operations and complete its increasing capital program.

As in the past, Hydro will continue to take a multi-faceted approach to its recruitment and retention strategy, by emphasizing non-compensation initiatives as well as compensation-based approaches. This will include a continuing focus on Apprenticeship and Engineer in Training programs, assessing the possible redeployment of FTEs when vacancies occur, focusing on employee engagement, and implementing organizational and process efficiencies where appropriate.

Hydro does anticipate that the challenge of maintaining wage and salary costs within inflationary levels will continue. High levels of recruitment, driven by retirements, high levels of construction and major project activity in the Province and elsewhere, and a shrinking labour force will continue to place pressure on wage and salary competitiveness.

The collective agreements for Hydro's unionized employees expired as of March 31, 2014. Hydro and the IBEW are currently in negotiations for new collective agreements.

2.4 OPERATING EXPENSES

This section provides an overview of Hydro’s Operating Expenses for the 2014 and 2015 Test Years with variance explanations to the 2007 actuals. Operating expenses are shown by both cost category and functional areas. Cost category is comprised of three major classifications: Salaries and Benefits, System Equipment Maintenance (SEM) and Other Operating Expenses, shown in Schedule 1, page 9 of 11 in Section 3 of this evidence. Functional areas include Operations and Corporate Services. Operations is comprised of Transmission and Rural Operations (TRO), Generation, and System Operations and Planning. Corporate Services includes Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services, and Corporate Relations. An overview of operational expenses by functional area is provided in Schedule 1 of this evidence.

Cost recoveries related to operating expenses are also discussed in this section. Cost recovery is related to services provided by Hydro to other Nalcor lines of business or external parties as well as cost deferrals associated with the CDM program. The cost recovery methodology is explained in Section 3.4.2.

2.4.1 Operating Expenses by Cost Category

A breakdown of operating expenses by cost category is shown in Table 2.3.

Table 2.3

Operating Expense by Cost Category ($millions)						
Cost Category	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Salaries and Benefits	58.3	73.3	78.0	19.7	85.8	27.5
System Equipment Maintenance	23.1	21.4	22.4	(0.7)	26.3	3.2
Other Operating Expenses	19.2	21.8	29.6	10.4	28.6	9.4
Total Operating Expenses Before Other Cost Recoveries	**100.6**	**116.5**	**130.0**	**29.4**	**140.7**	**40.1**
Other Cost Recoveries	(2.9)	(4.7)	(3.9)	(1.0)	(2.5)	0.4
Total Operating Expenses	**97.7**	**111.8**	**126.1**	**28.4**	**138.2**	**40.5**

Total operating expenses in the 2014 Test Year of $126.1 million are $28.4 million higher than the 2007 Actual of $97.7 million. Costs in the 2015 Test Year of $138.2 million are $40.5 million higher than the 2007 Actual. Detailed explanations of the increases in costs are outlined in the following sections.

Salaries and Benefits

As indicated in Table 2.3, the 2014 Test Year salaries and benefits expense of $78.0 million is $19.7 million higher than the 2007 Actual costs of $58.3 million. The 2015 Test Year costs of $85.8 million are $27.5 million higher than the 2007 Actual. A further breakdown of the changes in salaries and benefits by cost type is shown in Table 2.4 and an explanation of the major changes follows.

Table 2.4

Salary and Benefit Expenses ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Salaries	49.5	66.6	73.2	23.7	77.9	28.4
Overtime	6.2	12.3	12.2	6.0	10.1	3.9
Gross Salaries	55.7	78.9	85.4	29.7	88.0	32.3
Capital Labour Costs	(11.3)	(20.2)	(22.0)	(10.7)	(22.6)	(11.3)
Total Salaries	44.4	58.7	63.4	19.0	65.4	21.0
Fringe Benefits	6.5	8.4	8.8	2.4	12.5	6.1
Employee Future Benefits	5.9	6.8	6.8	0.9	8.4	2.5
Group Insurance	2.2	2.4	2.5	0.3	2.6	0.4
Total Benefits	14.5	17.6	18.1	3.6	23.5	9.0
Total Salaries and Benefits, before cost recoveries	58.9	76.3	81.5	22.6	88.9	30.0
Cost Recoveries	(0.6)	(3.0)	(3.5)	(2.9)	(3.1)	(2.5)
Total Salaries and Benefits, net of Cost Recoveries	**58.3**	**73.3**	**78.0**	**19.7**	**85.8**	**27.5**

Salaries

As shown in Table 2.4, the 2014 Test Year salary costs of $73.2 million are $23.7 million higher than the 2007 Actual of $49.5 million. The primary drivers of this increase include cost of living salary adjustments of $16.8 million. Changes in FTEs also contributed to cost increases. In the 2014 Test Year, there are 861 operating FTEs[10] in Hydro, an increase of 44 FTEs over the 2007 Actual of 817. This results in additional costs of $6.0 million.

Costs in the 2015 Test Year of $77.9 million are $28.4 million higher than 2007 Actual. The primary drivers of this increase include cost of living increases of $20.2 million. In the 2015 Test Year, there are 895 operating FTEs, an increase of 78 FTEs over the 2007 Actual resulting in additional salary costs of $8.6 million.

[10] Operating FTEs are FTEs before any capital labour recharges.

Hydro also reports net FTEs[11], as outlined in Section 3.7.3 of the evidence which includes operating FTEs and FTEs who charge to capital. In the 2014 Test Year, net FTEs are 860, a decrease of one from the operating FTEs of 861. In the 2015 Test Year, net FTEs are 888, a decrease of 7 from the operating FTEs of 895.

Further details of the changes in salaries and FTEs by functional area are discussed in Section 2.4.2.

As discussed in Section 1 of the evidence, there is a tightening labour market in the Province, which has resulted in changes to the compensation packages offered to Hydro employees. Furthermore, during union negotiations in 2010, it was recognized that there were differentials in the wages offered by Hydro compared to NP and other Atlantic Canadian utilities, primarily due to Government's prior wage restraints, which also applied to Hydro. In order to attract and retain a qualified workforce, Hydro has provided wage and benefit increases over the 2007 to 2015 period, enabling Hydro to be competitive with market.

Since 2007, Hydro has negotiated two union agreements which have resulted in general salary increases and a number of hourly rate increases. The first negotiated union agreement resulted in increases of 3.0% effective April 1, 2007, 2008, and 2009 for each year and 6.5% effective April 1, 2010. The second resulted in increases of 4.0% on April 1, 2011, 2012, and 2013. Non-union personnel also received similar wage and benefit increases. Adjustments were also made to front line supervisor's wage rates, to maintain wage differentials between them and their direct reports. The agreement expired on March 31, 2014 and is currently being negotiated.

[11] Net FTEs are operating FTEs plus or minus operating and capital labour recharges from and to other Nalcor lines of business.

See Regulated Activities Section 2.3.5 for additional discussion on workforce management and salaries.

Overtime

Annual overtime costs are necessary to provide least cost reliable service. Overtime varies based on circumstances such as emergencies, which may arise due to weather and equipment related outages, labour shortages and capital project requirements. Overtime is also necessary at times to minimize customer outages or to minimize customer service interruption risks. Overtime also occurs as a result of compensation paid to shift workers who must work statutory holidays. Overtime is minimized where possible through work planning and promptly addressing vacancies.

The 2014 Test Year costs of $12.2 million are $6.0 million higher than the 2007 Actual costs of $6.2 million. In addition, the 2014 Test Year includes $5.4 million of capitalized overtime, an increase of $3.7 million over the 2007 Actual of $1.7 million. The net impact of these variances is an increase in operating overtime costs of $2.3 million. During 2014, overtime was driven by incremental work requirements identified as a result of the January outage as well as emergency call outs. The overall increase in capital overtime is primarily due to an increase in Hydro's capital program and higher salary costs over the period.

The 2015 Test Year costs of $10.1 million are $3.9 million higher than the 2007 Actual. In addition, the 2015 Test Year includes $5.2 million of capitalized overtime, an increase of $3.5 million over the 2007 Actual of $1.7 million. The net impact of these variances is an increase in overtime costs of $0.4 million. Overtime of $10.1 million in the 2015 Test Year is $2.1 million less than the 2014 Test Year of $12.2 million. This reduction in overtime is primarily a result of the additional FTEs. Additional information by functional area is presented in Section 2.4.2.

Capital Labour Costs

As noted previously, internal labour and overtime costs associated with Hydro's capital projects are capitalized. Table 2.5 shows the breakdown of capital labour costs.

Table 2.5

Capital Labour ($millions)						
Cost Type	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Capital Labour	(7.6)	(14.5)	(16.6)	(9.0)	(17.4)	(9.8)
Capital Overtime	(1.7)	(5.7)	(5.4)	(3.7)	(5.2)	(3.5)
Overhead Allocation	(2.0)	-	-	2.0	-	2.0
Total Capital Labour	**(11.3)**	**(20.2)**	**(22.0)**	**(10.7)**	**(22.6)**	**(11.3)**

The 2014 Test Year capitalized costs of $22.0 million are $10.7 million higher than the 2007 Actual capital labour recharges of $11.3 million. The increases in capital labour are primarily attributable to an increase in Hydro's capital program which has more than doubled since 2007, coupled with salary and benefit increases. This is partially mitigated by the discontinuation of the allocation of overhead to capital labour in 2012, as approved in Board Order No. P.U. 2(2012).

Capitalized labour in the 2015 Test Year of $22.6 million is $11.3 million higher than the 2007 Actual. The increase in capitalization is related to salary increases as well as growth in the capital program discussed previously.

Fringe Benefits

Fringe benefits include Canada Pension Plan (CPP), Employment Insurance (EI), Public Service Pension Plan (PSPP), and Workers Compensation premiums and contributions paid by Hydro. The $8.8 million of fringe benefits included in the 2014 Test Year is $2.4 million more than 2007 Actual costs of $6.4 million, mainly due to increased premiums for EI and CPP and increased contributions to the Public Service Pension Plan (PSPP) in combination with salary increases previously described in this Section. The 2015 Test Year costs of $12.5 million are $6.1 million higher than the 2007 Actual. Costs increases have been consistent with the increases in 2014 as well as an estimated $2.5 million additional expense associated with PPSP reform[12].

Employee Future Benefits

Employee future benefit (EFB) costs relate to severance payments upon retirement and health benefits provided to retirees on a cost-shared basis. These costs are forecasted using actuarial methods and include assumptions as to future benefit costs and interest rate expectations. The EFB costs of $6.8 million, included in the 2014 Test Year, are $0.9 million higher than the 2007 Actual costs of $5.9 million. This increase is primarily due to increases in current service costs and is partially mitigated by the exclusion of actuarial losses in the 2014 Test Year expense in accordance with Order P.U. 13(2012). In the 2015 Test Year, there is an increase of $2.5 million over the 2007 Actual for total costs of $8.4 million. This increase includes actuarial losses of $1.6 million. This is a proposed change from the accounting treatment outlined in Board Order P.U. 13 (2012) and is described in further details in Section 3.9.2.

Group Insurance

Group insurance benefits provide Hydro employees with health, dental, life insurance and accidental death and dismemberment coverage. Insurance costs for the 2014 Test Year of $2.5 million are $0.3 million higher than the 2007 Actual cost of $2.2 million. This increase is mainly due to higher employee salaries and associated life insurance premiums and self-insured experience claim increases for health and dental insurance. The 2015 Test Year costs of $2.6 million are $0.4 million higher than the 2007 Actual consistent with the reasons noted for the 2014 Test Year.

[12] In September 2014, the Government announced changes to the Public Service Pension Plan that resulted in increased employer contributions.

Cost Recoveries

As shown in Table 2.4, cost recoveries related to salaries and benefits for the 2014 Test Year of $3.5 million are $2.9 million higher when compared to the 2007 Actual cost recoveries of $0.6 million. In 2007, Hydro recovered salary and benefit costs mainly from CF(L)Co. Subsequent to 2007, additional salary and benefit costs were recovered from other Nalcor lines of business through the Administration fee (Admin fee), primarily related to Safety and Health, Human Resources, Information Systems, and Supply Chain services. Cost recoveries also include $0.3 million in labour costs associated with the CDM program that are deferred as outlined in Section 3.8.2 of this evidence. Cost recoveries for the 2015 Test Year are $3.1 million which is a slight decrease from the 2014 level of recoveries.

System Equipment Maintenance (SEM)

As shown in Table 2.3, costs of $22.4 million in the 2014 Test Year are $0.7 million less than the 2007 Actual cost of $23.1 million. The primary reasons are an increase in costs in TRO of $3.2 million as described in Section 2.4.2, more than offset by a cost decrease of $3.9 million in Generation as described in Section 2.4.2.

The 2015 Test Year costs of $26.3 million are $3.2 million higher than the 2007 Actual. The primary drivers of the increase relate to the additional costs in TRO of $7.3 million which are further outlined in Section 2.4.2 offset by a reduction in SEM costs in Generation of $4.1 million as described in Section 2.4.2.

Other Operating Expenses

As shown in Table 2.3, Other Operating Expenses included in the 2014 Test Year of $29.6 million are $10.4 million higher than the 2007 Actual costs of $19.2 million. The 2015 Test Year costs of $28.6 million are $9.4 million higher than the 2007 Actual. A breakdown of the changes in other operating expenses is shown in Table 2.6 and an explanation of the major changes follows.

Table 2.6

Other Operating Expenses ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY - 2007A Change**	**2015 Test Year**	**2015TY - 2007A Change**
Professional Services	3.8	4.3	10.6	6.8	8.4	4.6
Miscellaneous	4.2	4.7	5.2	1.0	5.2	1.0
Travel	2.9	3.2	3.6	0.7	3.6	0.7
Equipment Rentals	1.1	1.8	1.8	0.7	3.0	1.9
Insurance	1.7	2.4	2.7	1.0	2.6	0.9
Transportation	2.0	2.1	2.4	0.4	2.2	0.2
Office Supplies	2.3	2.2	2.2	(0.1)	2.5	0.2
Building Rental	1.2	1.1	1.1	(0.1)	1.1	(0.1)
Total Other Operating Expenses	**19.2**	**21.8**	**29.6**	**10.4**	**28.6**	**9.4**

Professional Services

As shown in Table 2.6, professional services have increased by $6.8 million from $3.8 million in 2007 Actual costs to $10.6 million in the 2014 Test Year. The 2015 Test Year costs of $8.4 million are $4.6 million higher than the 2007 Actual. A detailed breakdown of professional services is provided in Table 2.7.

Table 2.7

Professional Services ($millions)						
Cost Type	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Consultants	2.2	3.2	7.2	5.0	5.6	3.4
GRA and Board Related Costs	0.6	1.2	3.5	2.9	2.3	1.7
Software Costs	1.0	1.3	1.4	0.4	1.5	0.5
Audit and Legal	0.1	0.2	0.1	-	0.1	-
Cost Recoveries	(0.1)	(1.6)	(1.6)	(1.5)	(1.1)	(1.0)
Total Professional Services	**3.8**	**4.3**	**10.6**	**6.8**	**8.4**	**4.6**

The increase of $6.8 million in the 2014 Test Year over the 2007 Actual is primarily due to:

- Higher consulting costs of $5.0 million primarily due to costs associated with the Outage Inquiry of $2.0 million, CDM programs of $0.9 million (offset in cost recoveries), $0.9 million associated with environmental work and safety and health related programs, $0.7 million in condition assessments, $0.3 million in engineering related initiatives and $0.3 million in environmental remediation at Sunnyside Terminal Station;
- GRA and Board related costs of $2.9 million associated with an increased volume of applications and regulatory activity;
- Software costs have increased by $0.4 million, primarily due to vendor price increases and additional software programs; and
- An increase of $1.5 million in cost recoveries, primarily related to the deferral of CDM costs of $0.9 million and $0.7 million recovered from the Admin fee.

The increase of $4.6 million in the 2015 Test Year over the 2007 Actual is primarily due to:

- Consulting costs increased by $3.4 million primarily due to regulatory studies and filings of $1.0 million, $0.9 million associated with environmental work and safety and health related programs, $0.7 million in condition assessments, CDM programs of 0.3 million (offset in cost recoveries) and $0.3 million in engineering related activities;
- GRA and Board related costs increased by $1.7 million associated with an increased volume of applications and regulatory activity. The variance includes $0.3 million in amortization of hearing related costs which is $0.1 million higher than the amortization of hearing costs in 2007. Hearing related costs and deferrals are detailed in Section 3.4.2.
- Software costs have increased by $0.5 million, primarily due to vendor price increases and additional software programs; and

- Cost recoveries increased by $1.0 million primarily related to $0.7 million recovered through the Admin fee and $0.3 million related to the deferral of CDM costs.

Miscellaneous Expenses

Miscellaneous costs include training, payroll and municipal taxes. The 2014 Test Year costs of $5.2 million are $1.0 million higher than 2007 Actual. This is mainly attributable to higher municipal and employer payroll taxes of $0.9 million and an increase of $0.1 million in other costs. The 2015 Test Year costs of $5.2 million are on par with the 2014 Test Year levels.

Travel

Travel costs of $3.6 million in the 2014 Test Year are $0.7 million higher than 2007 Actual of $2.9 million. This increase is primarily related to increased travel fares. The 2015 Test Year costs of $3.6 million are on par with the levels in the 2014 Test Year.

Equipment Rentals

Equipment rental costs are comprised of telecommunication costs, equipment rentals, computer bandwidth costs as well as costs associated with the lease of black start diesel units at Holyrood. The 2014 Test Year equipment rental net cost of $1.8 million is $0.7 million higher than the 2007 Actual costs of $1.1 million of which, $0.4 million is recovered from third parties. The 2015 Test Year costs of $3.0 million are $1.9 million higher than the 2007 Actual. One of the primary drivers of this increase also relates to costs associated with the black start diesel units in Holyrood. The total cost of the lease from January 2014 to June 30, 2015 is $5.2 million. Hydro has proposed to defer and amortize these costs over a five year period beginning in 2015. The net amortization expense in 2015 is $1.0 million. Please refer to Section 3.4.2 for additional information regarding deferrals.

Insurance Costs

Insurance costs, which cover property/boiler and machinery, liability and excess, directors' and officers' liability, brokerage fees and other miscellaneous insurances, have increased by $1.0 million from the 2007 Actual costs of $1.7 million to the 2014 Test Year amount of $2.7 million. This increase is primarily a result of property coverage due to loss ratio, overall value increase and industry rate increase. The 2015 Test Year costs of $2.6 million are $0.9 million higher than the 2007 Actual primarily for the reasons previously mentioned.

Other Cost Recoveries

Other cost recoveries as outlined in Table 2.3, includes recoveries from external parties and from the provision of generation supply to Labrador industrial, a portion of which is non-regulated. The 2014 Test Year recoveries of $3.9 million are $1.0 million higher than the 2007 Actual recoveries of $2.9 million. This increase is mainly attributable to $ $1.1 million in recoveries of depreciation and interest costs from other Nalcor lines of business through the Admin fee. These increased cost recoveries are offset by a reduction of $0.8 million in recoveries from Labrador Industrial customer generation supply. The recoveries in the 2015 Test Year of $2.5 million are $0.4 million lower than the 2007 Actual. The primary driver for the increase in recoveries is $0.7 million from the Admin fee for depreciation and interest offset by a decrease of $1.3 million from Labrador Industrial Generation supply.

2.4.2 Operating Expenses by Functional Area

The major functional areas are Operations and Corporate Services as shown in Schedule 1 of this evidence. Within Operations, costs are grouped into Transmissions and Rural Operations (TRO), Generation, and System Operations and Planning. Corporate Services includes Leadership and Associates, Human Resources and Organizational Effectiveness (HROE), Finance, Project Execution and Technical Services (PETS) and Corporate Relations.

Table 2.8 shows the total operating expenses for the 2014 and 2015 Test Years in comparison to the 2007 Actual.

Table 2.8

Operations and Corporate Services Operating Expenses
Net of Cost Recoveries
($millions)

Operations	2007 Actual	2013 Actual	2014 Test Year	2014TY vs. 2007A Change	2015 Test Year	2015TY vs. 2007A Change
Generation (Thermal & Hydraulic)	32.1	32.2	34.5	2.4	37.3	5.2
Systems Operations and Planning	3.0	3.7	3.6	0.6	5.8	2.8
Transmission and Rural Operations (TRO)	34.5	48.2	51.8	17.3	57.0	22.5
Total Operations	**69.6**	**84.1**	**89.9**	**20.3**	**100.1**	**30.5**
Corporate Services	28.1	27.7	36.2	8.1	38.1	10.0
Total Operating Expenses	**97.7**	**111.8**	**126.1**	**28.4**	**138.2**	**40.5**

Operations

Transmission and Rural Operations (TRO)

TRO has responsibility for providing safe, reliable service to customers through the Application of sound practices on asset management of transmission and distribution systems and associated high voltage terminal stations, 21 isolated diesel systems, diesel units at Hawkes Bay, St. Anthony and Happy Valley-Goose Bay, four gas turbines including the new combustion turbine, the telecommunications network and the mobile fleet.

A summary of operating expenses by cost category for TRO is noted in Table 2.9.

Table 2.9

Transmission and Rural Operations Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY vs. 2007A Change	2015 Test Year	2015TY vs. 2007A Change
Salaries and Benefits	20.8	31.6	33.5	12.7	34.9	14.1
SEM Expenses	7.5	9.7	10.7	3.2	14.8	7.3
Other Operating Costs	6.4	7.7	8.7	2.3	7.9	1.5
Cost Recoveries	(0.2)	(0.8)	(1.1)	(0.9)	(0.6)	(0.4)
Total Operating Expenses	**34.5**	**48.2**	**51.8**	**17.3**	**57.0**	**22.5**

Operating expenses in the 2014 Test Year for TRO of $51.8 million have increased $17.3 million from 2007 Actual costs of $34.5 million. The 2015 Test Year costs of $57.0 million are $22.5 million higher than 2007 Actual costs. The details of the increase are discussed in the following sections.

Salaries and Benefits

Salaries and benefits in the 2014 Test Year of $33.5 million are $12.7 million higher than the 2007 Actual of $20.8 million. In 2007, there were 309 operating FTEs compared to 343 in the 2014 Test Year, an increase of 34 FTEs. This increase includes a transfer of 8 employees formerly grouped with the Finance department, related to warehousing as well as wage increases since 2007. The additional FTEs are associated with increased maintenance activity and growing capital work due to aging terminal station equipment as well as initiatives undertaken to improve reliability. Additional staff includes protection and control technologists in 2014 to sustain completion of critical power system maintenance and one safety and health resource to sustain and improve safety performance in the Northern and Labrador regions.

The main components of the salary and benefits increases are:

- Salary increases of \$6.7 million;
- \$3.5 million increase in costs associated with changes in FTEs;
- \$2.1 million increase in costs related to employee benefits;
- \$1.9 million in net[13] overtime costs; and
- Partially offset by an increase of \$2.5 million in capitalized labour which reduces the above noted increases.

Salaries and benefits in the 2015 Test Year of \$34.9 million are \$14.1 million higher than the 2007 Actual of \$20.8 million. In the 2015 Test Year there are 350 operating FTEs, an increase of 41 over 2007 Actual. The new FTEs, beyond those in 2014, are required to sustain full completion of the annual preventative maintenance program, to enhance planning and scheduling driven by increased capital support, to provide improved maintenance efficiency, to enhance financial governance, to meet increased requirements due to customer growth in Labrador and to operate and maintain the new CT at Holyrood. The main components of the salary and benefits increases are:

- Salary increases of \$8.0 million;
- Increases in costs of \$4.1 million associated with new FTEs;
- An increase of \$2.7 million in costs primarily related to public service pension reform;
- An increase of \$1.2 million of costs associated with employee future benefits;
- An increase of \$0.5 million in net overtime costs;
- Partially offset by an additional \$2.8 million charged to capital jobs.

System Equipment Maintenance

System Equipment Maintenance expenses in the 2014 Test Year of \$10.7 million are \$3.2 million higher than the 2007 Actual of \$7.5 million. The primary drivers of the

[13] Net of time charged to capital due to implementation of enhanced maintenance practices and to address emergency call outs.

increase are vegetation management of $1.4 million and $1.8 million related to improving transmission and distribution reliability performance and maintenance work. This increase is primarily related to the completion of preventative and corrective maintenance backlog[14] work associated with critical power transformers, air blast circuit breakers and protection and control systems. This work effort contributes to improved reliability of key assets in the transmission system and as a result enhanced service to customers.

System Equipment Maintenance expenses in the 2015 Test Year of $14.8 million are $7.3 million higher than the 2007 Actual of $7.5 million. In 2015, there is a further increase of $4.1 million from 2014 primarily related to:

- Costs of $1.0 million associated with the new CT and an additional $1.6 million to provide for the extended (two year) warranty to cover the provision of technical oversight and coaching from the Engineering, Procurement and Construction contractor related to the operation and maintenance of the unit;
- An increase of $2.8 million related to the maintenance of transmission assets in Labrador which are associated with the transmission lines and terminal stations from Churchill Falls to Wabush that were previously incurred by TwinCo;
- A further increase of $0.5 million related to vegetation management;
- Costs associated with the continuation of the work associated with preventative and corrective maintenance backlog reduction initiatives of $1.0 million are anticipated to be incurred in 2015. As these costs are not considered to be reflective of normal operating costs, Hydro has proposed a deferral of these costs with a five year amortization period beginning in

[14] Backlogs are a collection of maintenance work which is approved to be completed in future and is dependent on planned system outages for completion. In 2009, Hydro identified a six-year plan to bring large power transformer and breaker preventative maintenance in line with a six year cycle. This has resulted in an increase in SEM through the use of contractors.

2015. The 2015 Test Year includes $0.2 million of related amortization. The deferral of costs is discussed in greater detail in Section 3.4.2; and
- A reduction of $0.7 million in maintenance related costs associated with the incremental corrective and preventative backlog work completed 2014.

Other Operating Expenses

This category of costs includes all other operating costs associated with the activity in TRO. The 2014 Test Year costs of $8.7 million are $2.3 million higher than the 2007 Actual of $6.4 million. The primary drivers of the increase are:

- Consulting related costs of $0.7 million associated with condition assessments to provide information to determine appropriate maintenance strategies and timing of equipment replacements to ensure sustained reliable service;
- Telecommunications equipment costs associated with mobile radio rentals of $0.7 million. This is partially offset by cost recovery of $0.4 million for a net increase of $0.3 million.
- Aircraft rental expenses of $0.5 million due to higher rental rates; and
- Travel related costs of $0.4 million associated with inflationary impacts on travel costs.

The 2015 Test Year costs of $7.9 million are $0.8 million less than the 2014 Test Year. They reflect a return to a more normal level of activity and costs related to consulting, travel and transportation costs upon completion of increased maintenance of breakers and transformers. These costs were required to bring all breaker and transformer maintenance to the established frequency and remove this preventative maintenance from the year end maintenance backlogs.

<u>*Cost Recoveries*</u>

The TRO cost recoveries forecast has increased by $0.9 million from $0.2 million in 2007 to $1.1 million in 2014 largely due to third party cost sharing of mobile radio equipment. The 2015 Test Year recoveries of $0.6 million are on par with the 2014 Test Year recoveries.

Generation

Hydro's two primary sources of electricity generation on the Island Interconnected System are thermal and hydraulic. These generating plants are operated and maintained by two separate departments, Thermal Generation (Holyrood) and Hydro Generation (hydraulic generation) and the costs are reported separately. These departments ensure the safe, efficient and reliable delivery of electricity to the grid as required to meet customer demands.

Changes in operating expenses from 2007 Actual costs to 2014 and 2015 Test Years are shown in Table 2.10.

Table 2.10

Generation Operating Expenses
($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Thermal Generation						
Salaries and Benefits	9.2	12.3	13.1	3.9	14.6	5.4
SEM Expenses	12.3	8.1	8.2	(4.1)	8.2	(4.1)
Other Operating Expenses	1.5	0.8	1.3	(0.2)	2.2	0.7
Thermal Generation	**23.0**	**21.2**	**22.6**	**(0.4)**	**25.0**	**2.0**
Hydraulic Generation						
Salaries and Benefits	6.6	8.5	8.7	2.1	9.3	2.7
SEM Expenses	1.7	1.5	1.9	0.2	1.7	-
Other Operating Expenses	0.8	1.0	1.3	0.5	1.3	0.5
Hydraulic Generation	**9.1**	**11.0**	**11.9**	**2.8**	**12.3**	**3.2**
Total Operating Expenses	**32.1**	**32.2**	**34.5**	**2.4**	**37.3**	**5.2**

Total Generation operating expenses have increased by $2.4 million from 2007 Actual costs to the 2014 Test Year and $5.2 million in the 2015 Test Year primarily due to the following:

Salaries and Benefits

Salaries and benefits of $21.8 million in the 2014 Test Year are $6.0 million higher than 2007 Actual costs of $15.8 million. In the 2014 Test Year, there are 195 operating FTEs, an increase of 16 over the 2007 Actual FTEs of 179. In Hydro Generation, from 2007 to 2014, there was an increase in FTEs primarily due to asset growth and associated support as well as an increase of two FTEs from the transfer of warehouse personnel from Finance. In Thermal, there was an increase in FTEs over this period, including the addition of on-site emergency response personnel as well as seven FTEs relating to the transfer of warehouse personnel from Finance. Cost increases are primarily due to:

- Salary increases of $4.1 million;
- An increase of $1.1 million associated with changes in FTEs;
- An increase of $1.4 million in employee benefits;
- Partially offset by an increase in the amount of labour capitalized of $1.1 million.

Salaries and benefits of $23.9 million in the 2015 Test Year are $8.1 million higher than 2007 Actual costs of $15.8 million. In the 2015 Test Year, there are 208 FTEs, an increase of 29 over the 2007 Actual. Cost increases are primarily due to:

- Salary increases of $4.9 million;
- An increase of $2.2 million associated with changes in FTEs;
- An increase of $1.3 million in fringe benefits primarily associated with PPSP reform;
- An increase in other employee benefits of $1.1 million; and
- Partially offset by a $1.0 million increase in the amount of labour capitalized.

The additional FTEs in 2015 have been added to address increasing maintenance requirements due to the aging assets, particularly at Holyrood, and to improve scheduling in light of the increased capital and maintenance activities.

System Equipment and Maintenance

SEM costs in the 2014 Test Year of $10.1 million are $3.9 million less than the 2007 Actual of $14.0 million. The primary reasons for the reduction in costs relates to the completion of amortization of costs associated with extraordinary repairs and expenses in Holyrood as follows:

- A reduction of $2.1 million associated with the amortization of the Asbestos Abatement program and the amortization of costs associated with Unit 2 boiler repairs at Holyrood included in 2007 but have since been fully amortized; and
- A reduction in SEM overhaul expenses from the 2007 Actual costs due to capitalization of major overhauls as approved by the Board in Order No. P.U. 2(2012).

SEM costs in the 2015 Test Year of $9.9 million are $4.1 million less than the 2007 Actual of $14.0 million. The primary reasons for the reduction in costs relates to the completion of amortization of costs associated with extraordinary repairs and expenses in Holyrood as well as the discontinuation of overhauls costs as noted in the 2014 variance explanation above.

Other Operating Costs

Other operating costs of $2.6 million in the 2014 Test Year are $0.3 million higher than the 2007 Actual costs of $2.3 million. The primary driver of the cost increase relates to consulting costs of $0.2 million associated with operating projects and condition assessments of equipment to determine asset maintenance requirements and the timing of asset replacements to ensure ongoing reliable operation of the assets.

The 2015 Test Year costs in this category of $3.5 million are $1.2 million higher than the 2007 Actual. One of the primary drivers of this increase relates to costs associated with the black start mobile diesel units in Holyrood. The total cost of the lease from January 2014 to June 30, 2015 is $5.2 million. Hydro has proposed to defer and amortize this cost over a five year period beginning in 2015. The net amortization expense in 2015 is $1.0 million. Please refer to Section 3.4.2 for additional information regarding deferrals.

System Operations and Planning

System Operations, comprised of the Energy Control Centre (ECC) and engineering support, manages the dispatch of energy across the provincial electrical systems, both on the Island and in Labrador, to ensure safe, reliable and efficient delivery of power to customer delivery points. System Planning staff include engineers and economists responsible for establishing the additions and modifications to generation, transmission and distribution facilities required to economically meet forecast changes in customer electricity requirements while adhering to established reliability criteria.

Changes in System Operations and Planning operating expenses from the 2007 Actual costs to the 2014 and 2015 Test Years are noted in Table 2.11.

Table 2.11[15]

System Operations and Planning Operating Expenses ($millions)

Cost Category	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007A Change	2015 Test Year	2015TY - 2007A Change
Salaries and Benefits	2.6	3.5	3.3	0.7	4.7	2.1
SEM Expenses	0.1	-	-	(0.1)	-	(0.1)
Other Operating Costs	0.3	0.2	0.3	-	1.1	0.8
Total Operating Expenses	**3.0**	**3.7**	**3.6**	**0.6**	**5.8**	**2.8**

[15] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.11 have been restated for comparative purposes to include this group.

Operating Expenses in the 2014 Test Year have increased $0.6 million from the 2007 Actual and increased $2.8 million in the 2015 Test Year. The change in expenses is outlined below:

Salaries and Benefits

Salary and benefits expense in the 2014 Test Year of $3.3 million are $0.7 million higher than the 2007 Actual costs of $2.6 million primarily due to salary increases. In the 2014 Test Year, there are 27 operating FTEs, a decrease of two from the 2007 Actual of 29 FTEs.

The 2015 Test Year costs of $4.7 million have increased by $2.1 million over the 2007 Actual. In 2015, there is a total of 36 operating FTEs forecast, an increase of seven FTEs over the 2007 Actual. Additional staff is required to accommodate system growth and planning. Hydro's electrical system will be interconnected to the North American grid for the first time in 2017/2018 and the way the system is planned and operated, as well as its cost structure, will fundamentally change. Hydro will begin undertaking the work necessary to ensure it is prepared for these significant changes in order to successfully integrate a large new source of generation and transmission infrastructure into the current electrical system. While Hydro has included some costs related to this in its 2015 Test Year, the Board may want to consider the deferral of these costs for future recovery upon the in-service of the Labrador Island Link. Salary costs associated with the new positions are $1.0 million and $1.0 million associated with normal salary increases. In addition, there is an increase of $0.4 million associated with employee benefits, primarily related to PPSP reform.

Other Operating Costs

Other operating costs in the 2014 Test Year of $0.3 million are on par with the 2007 Actual. In the 2015 Test Year, there is an increase of $0.8 million from the 2007 Actual.

This increase is primarily related to consulting costs associated with system planning studies related to the integration of additional generation sources.

Corporate Services

Changes in Corporate Services Operating Expenses by cost category from 2007 Actual costs to the 2014 and 2015 Test Years are shown in Table 2.12.

Table 2.12[16]

Corporate Services Operating Expenses ($millions)						
Cost Category	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY - 2007A Change**	**2015 Test Year**	**2015TY - 2007A Change**
Salaries and Benefits	19.7	20.4	22.9	3.2	25.4	5.7
SEM Expenses	1.9	2.7	2.1	0.2	2.1	0.2
Other Operating Costs	10.4	14.9	21.6	11.2	18.4	8.0
Cost Recoveries	(3.9)	(10.3)	(10.4)	(6.5)	(7.8)	(3.9)
Total Operating Expenses	**28.1**	**27.7**	**36.2**	**8.1**	**38.1**	**10.0**

2014 Test Year operating expenses of $36.2 million are $8.1 million higher than 2007 Actual costs. The 2015 Test Year costs of $38.1 million are $10.0 million higher than 2007 Actual. A further explanation by cost category and department follows.

Salaries and Benefits

Salaries and benefits expense in the 2014 Test Year in Corporate Services has increased by $3.2 million over 2007 Actual costs. Costs in the 2015 Test Year of $25.4 million are $5.7 million higher than the 2007 Actual. The change by department is shown in Table 2.13.

[16] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.12 have been restated for comparative purposes to include this group.

Table 2.13[17]

Corporate Services Salaries & Benefits ($millions)						
Cost Category	**2007 Actual**	**2013 Actual**	**2014 Test Year**	**2014TY vs. 2007A Change**	**2015 Test Year**	**2015TY vs. 2007A Change**
Executive Leadership	2.2	1.1	1.7	(0.5)	1.6	(0.6)
HROE	3.9	5.0	5.6	1.7	6.3	2.4
Finance	7.4	8.6	9.5	2.1	10.3	2.9
Project Execution and Technical Services	3.7	2.2	2.4	(1.3)	3.0	(0.7)
Corporate Relations	2.5	3.5	3.7	1.2	4.2	1.7
Total Operating Expenses	**19.7**	**20.4**	**22.9**	**3.2**	**25.4**	**5.7**

Leadership and Associates

Leadership and Associates is comprised of Executive, General Counsel/Corporate Secretary, and Internal Audit. Salaries and benefits expenses in the 2014 Test Year for the Executive Leadership group is forecast to decrease by $0.5 million from the 2007 Actual costs of $2.2 million. In 2014, there is a total of 7 operating FTEs forecasted, a decrease of 7 FTEs from the 2007 Actual of 14 FTEs. This decrease is primarily due to a net reduction in FTEs and the associated salaries and benefits transferred to Nalcor during the period.

The 2015 Test Year costs of $1.6 million are $0.6 million lower than the 2007 Actual. This reflects the transfer of FTEs to Nalcor for a total of 6 operating FTEs in the 2015 Test Year.

Human Resources and Organizational Effectiveness

Salaries and benefits expense for HROE in the 2014 Test Year of $5.6 million is $1.7 million higher than the 2007 Actual costs of $3.9 million. In 2014, there are a total of 76 operating FTEs, an increase of 16 over the 60 FTEs in the 2007 Actual. These FTEs

[17] In 2013, the System Planning group moved from Project Execution and Technical Services to Systems Operations and Planning. Costs in Table 2.13 have been restated for comparative purposes to include this group.

include apprentices who charge time by region based on work activity. Cost increases are due to normal salary increases of $1.2 million and the addition of FTEs of $0.6 million. This increase is partially offset by capitalized labour of $0.3 million, primarily due to apprentices.

Salaries and benefits expense for HROE in the 2015 Test Year of $6.3 million is $2.4 million higher than the 2007 Actual costs. In the 2015 Test Year there are 69 operating FTEs, an increase of nine over 2007 Actual. The primary drivers of the cost increase include salary and FTE increases. There was also an increase of $0.9 million associated with employee benefits including pension reform as well as changes in employee future benefits. Consistent with the 2014 Test Year, these costs increases were partially offset by capitalized labour of $0.3 million.

Finance

Salaries and benefits expense for Finance is forecast to increase by $2.1 million from the 2007 Actual costs of $7.4 million to the 2014 Test Year amount of $9.5 million. In the 2014 Test Year, there are 89 operating FTEs, a decrease of 29 over 2007 Actual of 118 FTEs. This decrease includes a transfer of warehouse personnel from Finance to operations as well as the transfer of positions to Nalcor. Over this time period, positions have been added in Hydro Finance as part of a re-organization and to address financial reporting requirements. The primary drivers of the salary and benefits increase include:

- Salary increases of $1.8 million;
- A decrease of $0.8 million associated with FTE changes; and
- An increase of $1.0 million due to the discontinuation of capitalizing salaries as per Board Order P.U. 2(2012).

The 2015 Test Year costs of $10.3 million are $2.9 million higher than the 2007 Actual. In the 2015 Test Year, there are 95 operating FTEs, a decrease of 23 from the 2007 Actual. This decrease includes the transfer of positions as noted previously as well as additional

FTEs resulting from the re-organization and to address regulatory and financial reporting requirements. In the 2015 Test Year, changes are as noted above and also include an additional $0.5 million associated with employee benefits.

Project Execution and Technical Services

Salaries and benefits expense in the 2014 Test Year of $2.4 million is $1.3 million less than the 2007 Actual. From 2007 to 2014 an additional 15 operating FTEs were hired for a total of 85 operating FTEs in the 2014 Test Year. This additional staffing is to address growth in the capital program for sustaining Hydro assets and to provide reliable service as the assets reach the end of their service lives. The FTE additions and salaries and benefits increases for all employees were more than offset by higher capitalization of labour charges of $4.5 million resulting from growth in the capital program since 2007.

The 2015 Test Year costs of $3.0 million are $0.7 million less than the 2007 Actual. In the 2015 Test Year, there is an increase of 19 operating FTEs over 2007 Actual for a total of 89 operating FTEs. The increased costs associated with the additional FTEs are more than offset by an increase in capitalized labour of $5.1 million. In addition, there is an increase of $1.0 million related to employee benefits primarily associated with PPSP reform.

Corporate Relations

Corporate Relations include Corporate Communications and Shareholder Relations, Customer Service, and Energy Efficiency. Salaries and benefits for Corporate Relations in the 2014 Test Year as noted in Table 2.13 of $3.7 million are $1.2 million higher than the 2007 Actual of $2.5 million. In the 2014 Test Year, there is no change in operating FTEs of 39 from the 2007 Actual. Over this time period, salary increases were $1.0 million.

The 2015 Test Year costs noted in Table 2.13 of $4.2 million are $1.7 million higher than the 2007 Actual. In 2015 there are 43 operating FTEs, an addition of 4 FTEs over the 2007 Actual. Normal salary increases over this time period contributed to the increase as well as an increase of $0.4 million associated with the additional FTEs. The change includes a reduction in FTEs through the implementation of Automatic Meter Reading through many areas of Hydro's rural services territory, the transfer of FTEs to Nalcor, offset by an increase in personnel associated with the Energy efficiency programs. As well, in 2015 there is an increase of $0.5 million related to employee benefits expenses due to public service pension plan reform and the inclusion of costs associated with employee future benefits.

System Equipment Maintenance

SEM costs related to Corporate Services as outlined in Table 2.12 in the 2014 Test Year of $2.1 million are $0.2 million higher than the 2007 Actual costs of $1.9 million, mainly due to an increase in material related costs in the Information Systems (IS) Department. This increase is partially offset by the Administration fee recovery as the IS department is a common service department. For additional information on the Administration fee, please refer to Section 3.7.4. Costs in the 2015 Test Year of $2.1 million are comparable to 2014 costs.

Other Operating Costs

Other operating costs related to Corporate Services as outlined in Table 2.12 are forecast to increase by $11.2 million from the Actual costs in 2007 of $10.4 million to $21.6 million in the 2014 Test Year. The primary drivers of this increase are:

- An increase in consulting costs of $3.2 million which consists of $2.0 million associated with the Outage Inquiry, an increase of $0.9 million associated with environmental work and safety and health related programs and $0.3 million in engineering related initiatives.

- An increase in regulatory related costs of $2.9 million primarily due to Hydro consultant costs related to the GRA and other regulated activities of $1.2 million, Board and intervener costs of $1.0 million, an increase in the Board Annual Assessment of $0.4 million and capital supplemental applications of $0.3 million;
- Program costs of $2.1 million associated with the CDM program. These costs have been deferred and are proposed to be amortized as outlined in Section 3.4.2 of this Amended Application;
- Increase in insurance premiums of $1.0 million primarily related to property coverage due to loss ratio, overall value increase and industry rate increase;
- An increase of $0.9 million related to payroll taxes; and
- An increase in software related costs of $0.5 million.

Costs in the 2015 Test Year of $18.4 million are $8.0 million higher than the 2007 Actual as outlined in Table 2.12. The primary drivers are:

- An increase in consulting costs of $2.5 million which is primarily due to an increase in regulatory studies and filings of $1.0 million, an increase of $0.9 million associated with environmental work and safety and health related programs and $0.2 million in engineering related initiatives;
- An increase of $1.7 million related to regulatory activity primarily due to consulting services related to the GRA and other regulated activities of $0.7 million, an increase in the Board Annual Assessment of $0.4 million, depreciation and other applications of $0.4 million;
- An increase of $1.1 million related to payroll taxes;
- An increase in insurance premiums of $0.9 million primarily related to property coverage due to loss ratio, overall value increase and industry rate increase;
- Software costs have increased by $0.5 million, primarily due to vendor price increases and additional software programs; and

- CDM costs increased by $0.5 million. These costs have been deferred and will be amortized as outlined in Section 3.4.2 of this Application.

Cost Recoveries

Cost recoveries for the 2014 Test Year of $10.4 million as shown in Table 2.12 have increased by $6.5 million from the 2007 Actual recoveries of $3.9 million. This is primarily attributable to Admin fee recoveries of $4.4 million from other Nalcor lines of business and the deferral of CDM costs of $2.4 million. The 2015 Test Year cost recoveries of $7.8 million are $3.9 million higher than 2007 Actual primarily due to Admin fee recoveries of $4.5 million and CDM program cost deferrals of $0.7 million partially offset by a reduction in recoveries of $1.3 million related to generation supply in Labrador.

2.5 LOAD FORECASTS AND NEW POWER SUPPLY

The 2014 and 2015 load forecasts used in this updated submission were prepared in the same manner as previous submissions to the Board. They reflect a combination of direct input from the IC and NP, and Hydro's analysis for the interconnected and isolated systems. The total load requirement is determined from an analysis of overall system losses and demand diversity.

2.5.1 Island Interconnected Load Forecast

The 2007 Test Year load forecast, along with the actual power and energy requirements from Hydro for the Island Interconnected System for 2007-2013, and the operating load forecasts for 2014 and 2015, are provided in Schedule II. Table 2.14 presents the annual changes in Hydro's electricity requirements for that period.

Table 2.14

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Island Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
Newfoundland Power	4,925.8	34.0	148.2	(91.8)	301.3	41.8	246.4	357.1	(38.7)	5,924.1
Industrial Customers	930.2	(203.9)	(332.1)	(24.7)	(58.6)	98.7	(58.3)	82.1	188.0	621.4
Rural and Losses	588.4	19.3	3.1	6.0	41.4	13.5	28.9	(0.4)	(10.6)	689.6
Total Island Interconnected	6,444.4	(150.6)	(180.8)	(110.5)	284.1	154.0	217.0	438.8	138.7	7,235.1

In 2008, electricity requirements on the Island Interconnected System declined by 2.3% relative to the 2007 Test Year, primarily because of reduced consumption at CBPP. CBPP's No. 1 paper machine was shut down in November 2007. In 2009, there was a further decline in electrical requirements (2.9% relative to 2008) due to the closure of the Grand Falls newsprint mill in February 2009 and the shutdown of No. 4 paper machine at CBPP in March 2009. The load reduction for these ICs was partially offset by increased utility load in 2009. In 2010, there was a further decline in electricity requirements by 1.8% relative to 2009, primarily because of warmer weather patterns which reduced the requirements of NP's and Hydro's residential and general service customers (the Utility load).

In 2011, there was an increase in electricity requirements by 4.7% relative to 2010. This reflects a return to normal weather patterns and higher Utility load. The increase was partially offset by lower IC requirements, particularly at CBPP and North Atlantic Refining Limited (NARL).

The Vale terminal station was energized in June 2012, with first power taken by the customer in December 2012. It is anticipated that Vale will continue to increase its levels of demand and energy consumption until it reaches full production levels by the end of 2016. In 2012 there was an increase in Island Interconnected load requirements of 2.4% over 2011. This load growth reflects the level of Utility load requirements and increased industrial consumption at CBPP and NARL.

In October 2013, another IC, Praxair, began taking power from Hydro. Praxair will provide the oxygen requirements for the Vale nickel processing facility and it is expected to increase operations through to the end of 2014. In 2013, there was an increase in total Island Interconnected load requirements of 3.4% relative to 2012. This increase is primarily due to increased Utility load, partially offset by decreased Industrial requirements at CBPP and NARL.

For 2014, Hydro is forecasting a 6.6% increase in load requirements, relative to 2013. This is due to increased Utility requirements resulting from the colder temperatures and increased demand experienced during the winter/early spring period and the increased IC requirements at Vale and Praxair.

For 2015, Hydro is forecasting a 2.0% increase in load requirements, relative to 2014. This is due to increases in requirements at Vale and Praxair which is nearly offset by decreased Utility requirements, with the expected return to normal weather. Beginning in June 2015 it is expected that Teck Resources will no longer require power and energy from Hydro.

The Island Interconnected System's total electrical requirements in 2015 are expected to be 12.3% above the 2007 Test Year requirements primarily due to the Utility load increase which has been partially offset by an overall decrease in industrial loads.

Customer peak demand requirements exhibit the same general growth pattern as energy requirements with lower industrial peak demands and offsetting increases in utility requirements. Peak demand requirements for NP and Hydro Rural for 2015 reflect both weather normalization and expected growth.

2.5.2 Labrador Interconnected Load Forecast

The 2007 Test Year load forecast, the actual power and energy supplied to the Labrador Interconnected System by Hydro for 2007-2013, and the operating load forecasts for 2014 and 2015 are provided in Schedule III. Table 2.15 outlines the changes in Hydro's electricity delivery requirements for that period.[18]

Table 2.15

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Labrador Interconnected System (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
Hydro Rural	505.5	(6.9)	4.6	(33.0)	60.5	14.8	29.4	55.0	58.2	688.1
CFB Goose Bay	77.4	(16.7)	(41.3)	37.0	(5.0)	(33.8)	(14.4)	5.5	1.5	10.2
IOCC	312.5	24.7	(175.3)	141.0	(174.0)	51.3	20.4	(61.2)	8.8	148.2
Wabush Mines and Losses	115.6	(23.5)	(26.3)	15.4	(11.9)	6.5	4.0	(4.3)	(3.4)	72.1
Total Labrador Interconnected	1,011.0	(22.4)	(238.3)	160.4	(130.4)	38.8	39.4	(5.0)	65.1	918.6

Hydro's overall electricity supply for the Labrador Interconnected System in 2008 declined by 2.2% relative to the 2007 Test Year, primarily due to reduced secondary energy consumption at CFB Goose Bay and lower system losses. The overall decline in 2008 was partially offset by increased consumption at IOCC.

In 2009, the electricity supply declined sharply by 24.1% from the requirements in 2008 due to significantly reduced consumption at IOCC and lower secondary energy loads at CFB Goose Bay. IOCC experienced a lengthy shutdown in the summer of 2009 and reduced consumption for significant periods during the remainder of the year.

In 2010, the electricity supply increased over 2009 by 21.4%. This was primarily driven by loads that had increased again at IOCC and CFB Goose Bay. The overall increase was partially offset by lower Hydro Rural requirements. The Hydro Rural load, with a high

[18] Schedule III and Table 2.15 present the actual and forecast requirements from the recall power only and do not include TwinCo requirements for industrial.

concentration of electric space heating, declined due to warmer overall weather patterns in the area.

In 2011, the total electricity requirements for the system were 14.3% lower than in 2010. This decrease is primarily driven by significantly reduced consumption at IOCC, partially offset by a return to normal weather patterns which resulted in increased Hydro Rural requirements.

In 2012, Labrador Interconnected load requirements increased by 5.0% over 2011. This increase is primarily due to increased consumption levels at IOCC and increased Hydro Rural requirements, partially offset by less reliance on secondary energy by CFB Goose Bay during 2012. CFB Goose Bay's electric boilers have been in operation since the 1980s. The customer has advised that it has installed oil fired boilers as a primary source of energy.

In 2013, Labrador Interconnected load requirements increased by 4.8% over 2012. This increase is primarily due to a further increase in requirements at IOCC supplied by Hydro and increased Hydro Rural requirements, partially offset by lower energy consumption at CFB Goose Bay. This customer has advised that it intends to continue taking small amounts of secondary energy for its electric boilers through to mid-2018.

In 2014 there is forecast to be a modest decrease of 0.6% in Labrador Interconnected load requirements relative to 2013. This is due to a decline in IOCC requirements from Hydro which has been nearly offset by increased Hydro Rural requirements. In June 2014 arrangements were put in place that allowed IOCC to use the excess TwinCo demand and energy that became available as a result of the decline in Wabush Mines operations. This has, in turn, lowered the requirements for IOCC purchases from Hydro.

For 2015, Hydro is forecasting an overall increase in energy requirements of 7.6% relative to 2014. This is due to a further increase in Hydro Rural requirements.

For 2015, Hydro's load forecast for the Labrador Interconnected System has decreased 9.1% from the 2007 Test Year. This reflects lower requirements supplied by Hydro to IOCC which is partially offset by higher Hydro Rural requirements associated with normalized weather, community load growth and load associated with the addition of the Muskrat Falls construction site.

TwinCo Power

As indicated previously in Section 2.2.5 the TwinCo block of power is produced by CF(L)Co at the Churchill Falls Generating Station and delivered at a delivery point near Churchill Falls. It is a firm 225 MW, 100% capacity factor block of power and energy, resulting in 1,971 GWh. The long standing TwinCo power arrangements will expire at the end of 2014.

For 2015, Hydro's total load forecast for the Labrador Interconnected System has increased 1.7 TWh (165%) from the 2007 Test Year. This is due primarily to Hydro supplying the industrial energy requirements that had previously been supplied by TwinCo and higher Hydro Rural requirements associated with normalized weather, community load growth and the load associated with addition of the Muskrat Falls construction sites.

The following table provides an indication of the total industrial requirements (recall power and TwinCo) since 2007, including the forecast for 2015.

Table 2.16

Summary of Total IOCC and Wabush Mines Electricity Requirements GWh

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast(1)	2015 Forecast
IOCC	1,520	1,726	1,398	1,680	1,458	1,544	1,549	n/a	1,720
Wabush Mines	420	412	365	399	390	380	339	n/a	70
Total Industrial Load	1,940	2,138	1,763	2,079	1,848	1,924	1,888	n/a	1,790

2.5.3 Isolated Diesel Systems Load Forecasts

The 2007 Test Year load forecast, the actual power and energy requirements for Hydro's isolated systems for 2007-2013, and the operating load forecasts for 2014 and 2015 are provided in Schedule IV. Table 2.17 presents the changes in Hydro's electricity requirements for that period.

Table 2.17

Summary of Year-Over-Year Changes in Electricity Requirements 2007 to 2015 Isolated Diesel Systems (GWh)

	2007 Test Year	Change in 2008	Change in 2009	Change in 2010	Change in 2011	Change in 2012	Change in 2013	Change in 2014	Change in 2015	2015 Forecast
L'Anse Au Loup	16.9	1.6	1.9	0.5	2.4	(1.3)	2.1	0.6	0.3	25.0
Other Labrador Diesel	35.7	0.7	1.2	(0.3)	1.5	(0.6)	1.3	4.8	0.6	44.9
Island Diesel	8.6	0.1	0.2	(1.4)	0.4	(0.3)	0.2	(0.1)	(0.1)	7.6
Total Isolated	61.2	2.4	3.3	(1.2)	4.3	(2.2)	3.6	5.3	0.8	77.5

Electricity production across the Labrador Isolated diesel systems was higher in 2008 relative to the 2007 Test Year by 4.4%. There was a further increase of 5.6% in 2009 relative to 2008. The annual load increases are primarily driven by increased requirements in the L'Anse au Loup system caused by the construction of electrically heated homes and the conversion of existing homes to electric heat. The L'Anse au Loup system has experienced strong energy consumption growth as a result of a reduction in electricity rates upon the interconnection to Hydro-Québec's Lac Robertson system in 1996.

In 2007, the Government introduced an electricity rebate program[19] for domestic customers in isolated Labrador coastal communities, including the communities on the L'Anse au Loup system. The Labrador rebate reduces customer electricity costs on the first block of energy and basic customer charge to the equivalent of costs paid by customers on Labrador Interconnected Systems. In 2011, the total production requirements for the Labrador Isolated diesel systems were 6.6% higher than that experienced in 2010. In 2012, the requirements were 2.9% lower, relative to 2011. For 2013, requirements were 5.5% higher relative to 2012 primarily due to increased requirements for the L'Anse au Loup system. For 2014 Hydro is forecasting an increase of 8.5% in energy requirements relative to 2013. This is owing to the addition of several large general service accounts in communities along the north coast of Labrador, increased fish processing load and increased consumption for domestic customers. For the 2015, Hydro is forecasting a modest increase of 1.3% relative to 2014.

Hydro's load forecast for the Labrador Isolated diesel systems for 2015 has increased by 32.9% from the 2007 Test Year. This reflects the overall increased requirements in the L'Anse au Loup system and the underlying load growth trend for many of the other Labrador Isolated Systems.

Across the Island Isolated Systems, the load has not exhibited the same growth pattern as in the Labrador Isolated Systems. There was a 15.7% decline in 2010 relative to 2009. The decline in 2010 is partly due to milder weather during 2010 and no production at the fish plant in Little Bay Islands. The fish plant and associated services had an annual consumption of approximately one GWh.

In 2011, the total production requirements for the Island Isolated diesel systems were 4.6% higher than in 2010. In 2012 they were 3.2% lower, relative to 2011. In 2013 requirements were 2.3% higher relative to 2012, primarily due increased load in Ramea,

[19] Northern Strategic Plan.

mainly related to weather. The forecasts for 2014 and 2015 reflect a continued slow decline in the isolated communities.

2.5.4 New Power Supply

In order to ensure that the future capacity and energy requirements of the Island Interconnected System are met in a reliable and cost effective manner, Hydro regularly prepares long-term forecasts for the provincial power system and maintains a portfolio of projects with various levels of engineering feasibility.

The Company's assessment on the timing of the requirement for new investment for the Island Interconnected power supply and associated facilities is based on previously established generation planning criteria. These criteria set the minimum level for reserve capacity and firm energy to ensure an adequate power supply to meet the grid's firm load requirements. These criteria are:

- Energy: The Island Interconnected System should have sufficient generating capability to supply all of its firm energy requirements with firm system energy capability; and
- Capacity: The Island Interconnected System should have sufficient generating capacity to satisfy a LOLH[20] expectation target of not more than 2.8 hours per year.

To ensure that the future capacity and energy requirements are met for the Labrador Interconnected System, the Industrial firm requirements are compared with the 225 MW block of TwinCo power, with the remaining requirements (additional Industrial and the Hydro Rural) compared with the 300 MW block of recalled power and associated energy, all available from CF(L)Co.

[20] Loss of Load Hours is a standard reliability measure in the utility industry.

Island Interconnected System

Table 2.18 presents the long-term planning load forecast and energy balances for the Island Interconnected System through to 2018. The load forecast reflects the longer-term view for the economy and incorporates the expected Utility load growth and the ramp up and sustained operation of the Vale nickel processing facility.

Table 2.18

Island Interconnected System
Load Forecast and Energy Balances
(GWh)

		Existing System	
Year	**Load Forecast**	**Firm Capability**	**Energy Balance**
2014	8,416	8,940	524
2015	8,549	8,940	391
2016	8,829	8,940	111
2017	8,924	8,940	16
2018	9,011	8,940	-71

Note: Firm energy reflects system as of August 2014 and does not include energy capability of installed combustion turbines.

The system firm energy capability[21] has been increased by 119 GWh since the 2007 Test Year to reflect the firm output of the two wind farms (167 GWh), partially offset by a reduction at the CBPP Co-Generation unit (48 GWh). Production at this unit has been reduced in recent years due to the reduction of operations at the CBPP mill and the resultant decrease in process steam requirements. The firm energy capability of the system does not include energy capability on installed gas turbines. Future supply requirements, including the negative energy balance in 2018 will be offset by the Muskrat Falls hydroelectric plant and the Labrador Island Link coming in-service in 2017-2018.

[21] Refer to Exhibit 3 of this Application for the breakdown of firm energy capability.

As outlined in Exhibit 3, the generating capacity of the Island Interconnected System is 2,050 MW. For calculations that involve unit capacity, it has been recognized that the nameplate capacity of the unit may need some adjustment to best reflect the actual usable capacity of the system, especially during peak periods. Thus, Hydro is now using the gross continuous unit ratings, where applicable. Nameplate ratings for generating units are taken from manufacturer design data and information supplied from non-utility or customer owned generators. These ratings generally represent the maximum continuous power-generating capacity of a generating unit. The gross continuous unit ratings for Hydro's units are generally reflective of the nameplate ratings but may be adjusted due to known permanent limitations or unavailability. For Hydro purchases and customer owned generation, gross continuous unit ratings reflect the output that is assumed during peak times and may be adjusted to account for available prime mover supply (i.e. wind, water or steam) or load restriction.

The existing system capacity has been adjusted to reflect the following:

- The capacity values provided in 2014 by NP for their generating units;
- Rating adjustments, a removal from service, and an addition to Hydro's gas turbine fleet; and
- The addition of capacity assistance arrangements with CBPP.[22]

There has been a total increase in NP's capacity of 3.9 MW which results from an increase in hydraulic generation of 5.9 MW and a decrease in diesel generation of 2.0 MW. Since the 2007 Test Year, the capacity of each of the gas turbines at Hardwoods and Stephenville has been reviewed and has been adjusted down by 4 MW for a total of 8 MW and the 10 MW gas turbine at Holyrood has been removed from service. A new 123 MW combustion turbine is planned to be in-service at Holyrood in December 2014.

[22] At the time of calculating the total Island Interconnected System generating capacity for this Amended GRA, discussions with Vale were very preliminary. Therefore, the proposed capacity assistance of 15.8 MW from this IC has not been included.

Hydro is proposing capacity assistance arrangements of 60 MW with CBPP for the upcoming winter period and potentially another 15 .8 MW from Vale.

Labrador Interconnected System

Hydro supplies the firm and secondary load requirements of the Labrador Interconnected grid with its purchased 300 MW recall block from CF(L)Co. Energy available from recall that is surplus to the requirements on the Labrador Interconnected System is exported from the Province. The energy requirements forecast for Hydro's recall power supply to the Labrador Interconnected grid through to the year 2018 is shown in Table 2.19.

Table 2.19

Labrador Interconnected System
Energy Forecast and Available Surplus
(GWh)

Year	Forecast	Recall	Surplus
2014	854	2,416	1,562
2015	906	2,416	1,510
2016	920	2,416	1,496
2017	1,090	2,416	1,326
2018	1,172	2,416	1,244

Note: Forecast, recall and surplus reflect energy volumes at Churchill Falls.

The load forecast includes the requirements of Hydro's rural retail customers, CFB Goose Bay secondary load and the share of Labrador west mining operations load which is more than that is available to these large industrial operations through the former TwinCo block. Under the existing load growth forecast, the 300 MW recall capability will satisfy the firm and secondary requirements of the Labrador Interconnected well beyond 2018.

Changes in Island Interconnected System Reserve and Newfoundland Power Generation Credit

"Reserve at" criteria is calculated to determine NP's generation credit. Reserve at criteria is not the same as system reserve. To calculate the reserve at criteria, the peak demand (while maintaining the forecast load factor for the year in question) is adjusted until the LOLH for the system becomes 2.80 (Hydro's criteria). Using this "demand at" criteria and the net capacity (Gross Continuous Unit Rating) of the system, the percent reserve at criteria is calculated. The reserve at criteria of the Island Interconnected System has changed, from 15.0% to 13.3%. When applied to NP's revised generation capability forecast for 2015, the generation credit becomes 119.33 MW. The calculation of NP's generation credit is shown in Table 2.20.

Table 2.20

NP Generation Credit (kW)	
Hydraulic Capacity	94,200
Thermal Capacity	41,000
Total	135,200
Reserve at Criteria	1.133
NP Generation Credit	119,329

Corner Brook Pulp and Paper Demand Credit Contract

In April 2009, the Board issued Order No. P.U. 17(2009) approving, on a pilot basis for a two-year period, a demand credit rate structure to be applied to Hydro's service agreement for CBPP. This service agreement format was intended to provide a price signal that would facilitate more efficient use of that customer's hydraulic generating resources in coordination with its pulp and paper mill operations.

In June and December 2011, Hydro completed assessments of the demand credit rate structure for the CBPP Service Agreement and determined that it provides hydraulic energy production efficiencies that permit lower energy production from Holyrood. The rate structure achieves these energy savings by providing an incentive for CBPP to operate its hydraulic generation resources in a manner which provides more efficient energy production rather than have CBPP maintain power production at levels that avoid incurring additional capacity charges. Reports with Hydro's findings were submitted to the Board requesting that the pilot agreement be permanently put in place.

In subsequent Order Nos. P.U. 15(2011) and P.U. 4(2012), the Board approved extensions of the service agreement on a continued pilot basis until a further Order of the Board. Contained in Exhibit 4 of this Application, is an updated request for approval of the service agreement with the following considerations as outlined by the Board:

> *…analysis in relation to potential and actual fuel savings at Holyrood, the efficiency factor at the Holyrood Thermal Generating Station, the Rate Stabilization Plan, and the allocation of costs in revenue requirement*.

With this Application, Hydro is recommending that the pilot agreement be made permanent.

2.6 ENERGY SUPPLY EXPENSES

2.6.1 Island Interconnected System

The actual energy supply sources and fuel expenses for 2007-2013 and the forecast for the 2014 and 2015 are summarized in Schedule V.

Hydraulic Production Forecast

Hydraulic production for 2015 is forecast to be 4,603.6 GWh. This is the average expected production for 2015 using the methodology consistent with that previously approved by the Board and further described in Section 2.7.

Energy Purchases and Related Costs

Energy purchases in 2007 and 2008 were above the 2007 Test Year forecast of 415 GWh by 39 GWh and 36 GWh, respectively. The increase in 2007 was primarily due to higher secondary energy receipts from the ACI generation. In 2008, the increase was primarily attributable to increased production from the Exploits River Hydro Partnership and the start of commercial production in September of 2008 at the wind farm at St. Lawrence. In 2009, 2010, 2011, 2012 and 2013 energy purchases and receipts were above the 2007 forecast by 567 GWh, 534 GWh 490 GWh, 579 GWh, and 597 GWh respectively. This is primarily due to Exploits Generation that was previously used in the Grand Falls paper mill and the production from the St. Lawrence and Fermeuse wind farms, the latter of which started operation in April of 2009. The high levels of energy purchases and receipts in 2009 to 2013 were partially offset by decreased production at the CBPP co-generation unit. Generation from this unit has been reduced due to the shutdown of two of the four paper machines and the resulting decrease in process steam available to drive the co-generation unit. For 2014, the energy purchases are forecast to be 603 GWh above the 2007 Test Year forecast, due to the same factors mentioned previously.

The forecast energy purchases for 2015 are 1,031 GWh, which is based on Hydro's hydraulic generation model (VISTA) output for the Exploits Generation, the historical average data for Rattle Brook and design estimates for the wind farms. This is 616 GWh higher than the 2007 Test Year forecast. The 2015 forecast generation for the CBPP co-generation unit has been reduced from the 2007 Test Year to reflect experience since the shutdown of the paper machines. The purchase costs from all sources in 2015 are forecast to increase to $57.4 million from $33.5 million in 2007 Actual costs. This overall increase results from the inclusion of the wind projects and purchase of the Exploits Generation which has been partially offset by lower production levels at the CBPP co-generation unit. The 2015 costs also include the total fixed fees ($2.1 million) associated with the Capacity Assistance arrangements with CBPP and Vale for the 2014/2015 winter period.

The suppliers and related expenses for power purchases are presented in Schedule VI. Holyrood meets the energy supply requirements beyond Hydro's hydraulic production and energy purchases. The primary factors affecting the plant's fuel expenses are its production level, fuel to energy conversion rate and fuel purchase price. These factors for 2007 to 2015 are included in Schedule V.

Holyrood Energy Production and Related Costs

Energy production from Holyrood in 2007 and 2008 was 1,256 GWh and 1,080 GWh, respectively. In 2009 and 2010, production levels were at 940 GWh and 803 GWh, respectively. In 2011 and 2012, the output levels from the station were 885 GWh and 856 GWh, respectively. In 2013, the output level from the Holyrood generating station was 957 GWh. The forecasts for 2014 and the 2015 Test Year are 1,373 GWh and 1,593 GWh, respectively. The changes from the 2007 Test Year are due to load, power purchases and hydraulic production variances.

The actual fuel conversion factors for 2007 and 2008 were 614 kWh/bbl and 625 kWh/bbl, respectively. In 2009 and 2010, the conversion performance was 612 kWh/bbl and 589 kWh/bbl, respectively. In 2011 and 2012, the performances were 603 kWh/bbl and 599 kWh/bbl, respectively. The actual energy conversion factor for 2013 was 594 kWh/bbl. In 2014, the conversion performance is forecast to be 588 kWh/bbl.

The decline in fuel conversion performance in recent years is primarily due to changes external to the operation of the Holyrood thermal generating station and therefore cannot be affected by the manner in which the plant is operated. There have been lower production requirements at Holyrood as a result of reduced system loads, higher energy purchases and higher levels of hydraulic generation. All things being equal, a thermal unit operates most efficiently at higher levels of generation. Performance has also deteriorated due to a lower heating content in the fuel used at Holyrood since the switch to 0.7% sulfur content in 2009.

A change in the approach to forecasting Holyrood conversion rate is necessary in this updated GRA filing due to the financial impact incurred by Hydro resulting from the low conversion rate in recent years. Table 2.21 outlines the losses to Hydro since 2009.

Table 2.21

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

Under the current mechanism of the RSP, there is no provision for Hydro to recover the additional fuel consumption costs due to lower fuel conversion rate at the prevailing Test Year fuel price. Hydro is only able to recover the additional fuel costs related to additional consumption and any change from the Test Year fuel price.[23] Hydro will be presenting further evidence and a proposal regarding the stabilization of costs relating to the fuel conversion rate.[24]

The forecast conversion factor for the 2015 Test Year is 607 kWh/bbl. This forecast results from a five-year regression analysis of conversion factor versus Holyrood gross monthly average unit loading, adjusted for fuel heating content (in BTUs/bbl). There is a station service factor of 6.6% applied to the gross energy production. The station service factor is based on the average experience over the past five year period (June 2009 - May 2014). The improvement in conversion rate to 607 kWh/bbl above recent experience is due to anticipated higher production requirements and a reduction in

[23] The cost related to the additional consumption at the actual fuel price minus the Test Year fuel price.
[24] In Vale's Expert Report (April 25, 2014) and in subsequent RFI response to NLH-V-002, it was proposed that changes in Holyrood fuel conversion efficiency should be accounted for in the RSP.

minimum operating time which will be enabled by the new CT at Holyrood. This is obtained through higher levels of average output for the Holyrood units. However, improvements in the fuel heating content are not anticipated.

The actual average fuel purchase prices for 2007 to 2013 and forecasts for 2014 and 2015 are indicated in Table 2.22.

Table 2.22

Holyrood No. 6 Fuel
($/bbl)

	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Average No. 6 Fuel Purchase Price	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85

The forecast prices assume 0.7% sulfur content. The detailed monthly actual and forecast purchase prices are provided in Schedule VII. The fuel prices for June to September 2014 are referenced to the June 2014 Corporate forecast which is based on the May 2014 forecast of PIRA Energy Group. The fuel prices for October 2014 to December 2015 are referenced to the October 2014 Corporate forecast which is based on the September 2014 forecast of PIRA Energy Group.

The actual total Holyrood fuel expense was $107.4 million in 2007 and is forecast to rise to $244.9 million in 2015, a 128% increase over the eight-year period and a 79% increase from the 2007 Test Year, primarily driven by the increasing purchase prices.

Standby Generation Requirements and Related Costs

For the winter periods of 2014/2015 and 2015/2016 there are peaking requirements assumed for the Island Interconnected System CTs in order to maintain minimum generation reserve requirements. The requirements for the CTs are determined based on average forced outage rates of 10% for the Holyrood thermal units and 1% for Hydro's hydraulic units, and in consideration of the peak load forecast and Hydro's typical load duration curve.

The Island Interconnected System gas turbine and diesel production also assumes that each plant is exercised at rated output for one hour per month during the non-winter period for testing and for ensuring availability. These units are assumed to be exercised for four hours during each winter month (approximately once per week) for winter readiness and storm preparedness.

The total energy forecasted to be produced at the Island Interconnected System gas turbine and diesel generating plants is 11.4 GWh for the 2015, at an associated fuel cost of $3.6 Million.

2.6.2 Labrador Interconnected System

The majority of all energy consumed on the Labrador Interconnected System is purchased from CF(L)Co. The only exception is when the gas turbine and diesel generation in Happy Valley-Goose Bay are operated for Labrador Interconnected System outages or system support. The actual power purchase costs from CF(L)Co ranged from $1.9 million to $2.4 million for each of the years from 2007 to 2013. The costs are forecast to be $2.1 million and $1.9 million for 2014 and the 2015, respectively.
The other power purchase expenses for the Labrador Interconnected System relate to the annual costs for Hydro's share of expenses related to TwinCo's Wabush Terminal Station. These expenses were $0.76 million in 2007 and $0.27 million in 2008. In 2009 costs were $0.35 million and $0.49 million in 2010. In 2011 the costs were $0.58 million, while in 2012 they were $0.40 million. In 2013 the costs were $0.21 million. Costs are forecast to be $0.71 million in 2014. The variability of these costs is caused by variances in the major maintenance and equipment replacements undertaken by CF(L)Co on behalf of TwinCo.

As indicated in Section 2.2.5, at the end of 2014 the long-standing TwinCo arrangements expire and, as such, no costs related the Wabush Terminal Station are included in Hydro's Labrador Interconnected System power purchase costs for the 2015 Test Year. The costs for this equipment will now be part of the station costs as outlined in Section 2.4.2.

2.6.3 Isolated Systems

The primary source of power supply for Hydro's isolated systems throughout the Province is diesel generation. The Company has also availed of opportunities to supplement or displace diesel generation. On the L'Anse au Loup system, the Company displaces diesel generated energy by purchasing secondary energy from a regional Hydro-Québec hydroelectric plant. On the Ramea diesel system, Hydro continues with its energy receipts from wind generation. On the Mary's Harbour diesel system, until 2007, Hydro purchased energy from an independent hydro generator; however, the plant was shut down in 2007 and is in need of refurbishment. Schedule VIII presents Hydro's 2007 Test Year budgets, the actual diesel fuel and purchased power expenses for its isolated systems for 2007 to 2013, along with the forecast expenses for 2014 and 2015. Diesel fuel and purchased power expenses have increased from $12.1 million in the 2007 Test Year to $19.7 million in 2013. This increase reflects higher electricity requirements for isolated systems and the prices for petroleum in world markets. In 2014, expenses are forecast to increase to $23.2 million, primarily due to increasing supply requirements but also due to higher fuel prices. For 2015, the Company's isolated systems fuel and purchased power costs are forecast at $21.9 million.

2.7 HYDROELECTRIC PRODUCTION FORECAST

2.7.1 Introduction

This section describes the methodology used by Hydro to estimate its average annual hydroelectric energy production in the 2015 Test Year.

For the 2004 Test Year, Hydro prepared the average annual energy production forecast for hydraulic generation facilities using the 30 years of inflows from 1973 to 2002. However, during the 2003 GRA, Hydro's consultant, Hatch (formerly SGE Acres), provided evidence to confirm that it would be better to use the full hydrological record (dating back to 1950) after certain inconsistencies in the record had been resolved. In addition, Hatch recommended the use of a simulation model (SYSSIM), rather than a spreadsheet, to prepare the estimate. Hydro worked with Hatch to make the required adjustments to the hydrological record and to select and implement the SYSSIM model. The average energy value provided for the 2007 Test Year was based on the revised record and the SYSSIM modeling.

In addition to its use in preparation of the 2006 GRA, Hydro used the SYSSIM model to estimate hydroelectric production for budgeting, fuel forecasting, and other planning activities. However, over time, the model seemed less able to accurately determine the contribution of the hydraulic resources compared to the required thermal production. The model still provided results, but changes to the input, for example adding new wind resources, did not have the anticipated effect on the hydroelectric and thermal production estimates. This problem seemed to have been caused, or at least worsened, by the decrease in industrial load as a result of the paper mill closures and paper machine shutdowns on the island.

In anticipation of this GRA, Hydro again retained Hatch to provide advice on how to proceed – whether changes were possible to improve the SYSSIM model of the Hydro system or whether a new methodology was required. Hatch's advice was to switch to the VISTA DSS model. A letter from Hatch, describing the evolution of their modeling techniques and outlining their recommended approach for use in the GRA is attached as Exhibit 5.

2.7.2 Vista DSS Model

Background

Hydro first implemented the Vista DSS in the 1990s. Initially, only the LT (long-term) Vista module was implemented; LT Vista provides guidance on optimized unit dispatch on a weekly time step. In the 2008-2009 period, Hydro implemented the ST (short-term) Vista module which provides more detailed optimized dispatch on an hourly time step. Part of the implementation of the ST module was to add inflow forecasting capability to the model. Currently, Hydro uses seven-day hourly precipitation and temperature forecasts to produce inflow forecasts for use in hourly modeling.

Use of Vista for GRA

When planning for the 2006 GRA, Hydro worked with Hatch to assess the best methodology for determining the average hydroelectric capability of its system. At that time, the use of Vista was considered, but not chosen. Since 2006, various changes as noted in Exhibit 5 have been made to Vista which makes it more suitable for use in studies and budget forecasts. In particular, in preparation for Hydro's use of Vista for this GRA, Hatch added a new option which allows a value to be assigned to water in storage at the end of the simulation period. This means target water levels do not have to be set and Vista can make more realistic decisions at the end of the simulation period.

2.7.3 System Assumptions

Hydrology

As per Board Order No. P.U. 14(2004), simulations for this updated GRA were completed using all available hydrology from 1950 through 2013 inclusive, 64 years in total.

Inflows to each of Hydro's reservoirs are calculated daily from measured water levels and estimated outflows. At the end of each year, Hydro reviews the calculated inflows and makes any necessary adjustments. Adjustments include:

- Smoothing to remove calculated negative inflows, a common problem when back calculating inflows from water level changes; and
- Adjustments to the distribution of inflows between two reservoirs when the estimates of flow in the connecting canals are not well known.

Inflow data for recent years was added according to the methodologies recommended by Hatch during the last GRA.

Exploits Generation

Hydro's Vista model has always included generating plants on the Exploits River but prior to 2010 the generation was modeled as one pseudo plant of 92 MW for the combined output of Buchans, Grand Falls and Bishop's Falls. Star Lake was modeled separately, but still in a simplified form.

In 2010, Hatch was asked to develop a more realistic and complete representation of the Exploits plants in the Vista model. The Vista model now has realistic representations of each watershed and power plant. The total forecast generation included for the Exploits generation in 2015 is 776 GWh, as shown previously in Table 2.1.

Newfoundland Power and Non-Utility Generators (NUGS)

All hydroelectric generation sites on the Island Interconnected System are modeled in Vista.

NP's sites are modeled as one pseudo site with characteristics and input hydrology that result in a reasonable estimate of its generation. Several other small plants (Snook's Arm, Venam's Bight, Rattle Brook, and Roddickton mini-hydro) are included with NP's sites as they are too small to warrant modelling separately and have similar characteristics to NP's sites.

Deer Lake Power's plant on Grand Lake is modeled to a level of detail similar to that of Hydro's own system.

Estimates of generation from each wind farm and from CBPP's co-generation plant are included in the model as purchase contracts.

Thermal Generation

Holyrood was modeled similarly to the previous Application. It has a minimum production level set for each week of the year, reflecting the requirements for meeting peak loads and transmission constraints.

2.7.4 Impact on the Hydraulic Production Forecast

The hydraulic production forecast determined from the Vista model and used for 2015 in this updated Application is 4,604 GWh compared with the final forecast used in the 2007 Test Year of 4,472 GWh. The changes are due to an extension in the record of inflows to incorporate the data up until 2013, improvements in methodology and enhanced representation of the non-Hydro owned hydroelectric generation sources. The increase in hydraulic production is also due to improved utilization of inflows during the wetter sequences which is facilitated by the higher load and reduced spill. The combined impact results in an increase in the annual average hydroelectric production estimate for 2015 of 132 GWh. It should be noted that Exploits Generation as described in Section 2.7.3 is included in power purchases as Hydro does not currently own these assets.

2.8 RURAL DEFICIT

Revenues from Hydro's Rural Customers, with the exception of those on the Labrador Interconnected System, do not fully recover the cost to serve, resulting in a deficit (Revenue Deficit). The Rural Deficit has grown from $40.8 million in the 2007 Test Year to a forecast of $64.1 million in the 2015 Test Year, primarily due to increased supply costs. Controllable costs, primarily operating expenses, remain relatively consistent from year to year, despite increasing wages, general inflationary pressure on material supply costs and other costs.

Hydro's mandate to provide least-cost, safe and reliable power to all its customers remains its primary focus. Hydro continues to control its operating expenses using measures such as the CDM program which is mandated to develop and implement demand and energy conservation programs both internally and externally for customers. Such efforts reduce Hydro's costs and assist in reducing and/or limiting growth in supply costs.

Other dedicated efforts which are aimed at controlling the Rural Deficit include operating and capital initiatives such as capturing waste heat, monitoring diesel system fuel efficiency, utilizing commercial air flights rather than helicopter use, use of fuel efficient mix of engines to supply load, more effective planning and scheduling to minimize outages and delays, life cycle cost analysis for diesel engines, automatic meter reading, install of in-line heaters at diesel plants, e-billing, and in-house printing of customer bills. Hydro will continue to undertake initiatives to manage its costs of serving its Rural Customers in a manner that is consistent in providing reliable service and in minimizing the Rural Deficit.

List of Schedules:

SCHEDULE I	OPERATING EXPENSES BY FUNCTIONAL AREA
SCHEDULE II	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
SCHEDULE III	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - LABRADOR INTERCONNECTED SYSTEM
SCHEDULE IV	ACTUAL AND FORECAST ELECTRICITY REQUIREMENTS FOR 2007 TO 2015 - ISOLATED SYSTEMS
SCHEDULE V	ENERGY SUPPLY AND FUEL EXPENSE FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
SCHEDULE VI	ENERGY PURCHASES BY SUPPLIER FOR 2007 TO 2015 - ISLAND INTERCONNECTED SYSTEM
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SCHEDULE VIII	ISOLATED FUEL AND PURCHASED POWER COSTS FOR 2007 TO 2015

Newfoundland and Labrador Hydro
Operating Expenses by Functional Area
($000's)

	2007 Actual	2013 Actual	2014 Test Year	2014TY - 2007 Actual Change	2015 Test Year	2015TY - 2007 Actual Change
Operations						
Thermal Generation	20,870	21,220	22,644	1,774	23,984	3,114
Deferred Major Extraordinary Repairs	2,109	-	-	(2,109)	-	(2,109)
Deferred Regulatory Costs	-	-	-	-	1,044	1,044
Hydro Generation	9,112	10,959	11,871	2,759	12,438	3,326
Generation	32,091	32,179	34,515	2,424	37,466	5,375
System Operations and Planning[1]	2,920	3,753	3,604	684	5,765	2,845
Deferred Regulatory Costs	50	-	-	(50)	-	(50)
System Operations and Planning	2,970	3,753	3,604	634	5,765	2,795
Transmission & Rural Operations	34,541	48,210	51,756	17,215	56,660	22,119
Deferred Major Extraordinary Repairs	-	-	-	-	249	249
Transmission & Rural Operations	34,541	48,210	51,756	17,215	56,909	22,368
Total Operations	69,602	84,142	89,875	20,273	100,140	30,538
Corporate Services						
Project Execution and Technical Services[1]	4,186	2,949	3,661	(525)	4,176	(10)
Deferred Regulatory Costs	61	-	-	(61)	-	(61)
Finance	11,908	11,753	17,561	5,653	16,881	4,973
Deferred Regulatory Costs	223	-	-	(223)	333	110
Allocation to non-regulated customer	(2,679)	(2,021)	(1,926)	753	(2,271)	408
Human Resources & Organizational Effectiveness	6,608	7,346	8,153	1,545	9,398	2,790
Leadership & Associates	2,762	1,534	2,031	(731)	1,986	(776)
Corporate Relations	5,022	6,109	6,713	1,691	7,536	2,514
Total Corporate Services	28,091	27,670	36,193	8,102	38,039	9,948
Operating Expenses	**97,693**	**111,812**	**126,068**	**28,375**	**138,179**	**40,486**

[1] Tables and certain numbers have been restated to reflect the transfer of Systems Planning Group formerly in Project Execution and Technical Services to Systems Planning.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Island Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Newfoundland Power	1,121.5	4,925.8	1,083.0	4,990.7	1,109.4	4,959.8	1,168.1	5,108.0	1,146.3	5,016.2	1,186.3	5,317.5	1,177.9	5,359.3	1,276.3	5,605.7	1,233.4	5,962.8	1,295.0	5,924.1
Hydro Rural Interconnected	84.8	392.0	79.9	400.0	88.9	411.7	87.5	415.3	81.7	406.5	95.5	437.6	88.8	445.6	95.8	458.0	95.4	467.5	95.2	463.9
Industrial Customers	126.9	930.2	135.8	816.2	106.1	726.3	104.6	394.2	65.7	369.5	61.9	310.9	64.7	409.6	64.1	351.3	79.0	433.4	81.5	621.4
Total Deliveries	1,307.6	6,248.0	1,258.4	6,206.9	1,264.0	6,097.8	1,332.7	5,917.5	1,245.2	5,792.2	1,329.0	6,066.0	1,313.3	6,214.5	1,410.0	6,415.0	1,382.5	6,863.7	1,448.3	7,009.4
Transmission Losses	39.9	196.4	64.6	182.1	59.0	196.0	57.3	195.5	59.8	210.3	69.8	220.6	71.9	226.1	90.8	242.6	48.4	232.7	50.7	225.7
Hydro Island Requirement	1,347.5	6,444.4	1,323.0	6,389.0	1,323.0	6,293.8	1,390.0	6,113.0	1,305.0	6,002.5	1,398.8	6,286.6	1,385.2	6,440.6	1,500.8	6,657.6	1,430.9	7,096.4	1,499.0	7,235.1

Notes:
1. The 2014 and 2015 Forecasts are sourced to the June 25, 2014 Island Operating Load Forecast.
2. Required NLH Net Generation MW's are NLH system coincident MW's and include customer firm demand requirements only. MWs in 2014 are December forecast values. MWs in 2015 are January
3. Demands for Total Deliveries and Transmission Losses are coincident with system peak. Actual transmission losses include station services.
4. Actuals reflect rounded values to the nearest tenth of a GWh.
5. Teck Resources is anticipated to cease operations in June 2015.
6. Industrial MW's for 2007-2013 reflect sum of annual maximum customer demands.

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Labrador Interconnected System

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh	MW	GWh
Hydro Rural Interconnected																				
Happy Valley - Goose Bay	57.5	235.0	55.0	228.0	59.0	230.0	59.8	230.8	57.8	216.3	62.1	243.8	61.1	250.6	67.8	268.0	73.5	298.7	78.4	325.4
Churchill Falls	0.3	1.5		1.4		1.3		1.1		1.2		1.4		1.3		1.4	0.3	1.8	0.3	1.5
Wabush	15.1	62.0	15.7	63.8	17.6	66.1	17.5	67.6	16.1	62.7	17.5	72.8	18.0	77.4	21.7	83.4	20.5	93.4	22.6	100.0
Labrador City	50.6	207.0	49.0	201.5	49.0	201.2	51.5	203.7	48.5	190.0	50.8	212.7	50.5	216.2	53.5	222.1	51.7	236.0	58.7	261.2
Total	123.5	505.5	119.7	494.7	124.3	498.6	128.8	503.2	122.4	470.2	130.4	530.7	129.7	545.5	143.0	574.9	146.0	629.9	160.0	688.1
Department of National Defence	-	77.4	-	62.9	-	60.7	-	19.4	-	56.4	-	51.4	-	17.6	-	3.2	-	8.7	-	10.2
Iron Ore Company of Canada	82.0	312.5	88.8	257.1	95.4	337.2	82.6	161.9	90.8	302.9	83.2	128.9	63.4	180.2	84.9	200.6	76.6	139.4	57.0	148.2
Wabush Mines	-	0.2	-	0.2	-	0.2	-	0.1	-	0.1	-	0.1	-	0.1		-	-	-	4.0	6.0
Total Deliveries	170.4	895.6	162.4	814.9	173.9	896.7	165.0	684.6	171.0	829.6	182.1	711.1	182.6	743.4	194.6	778.7	204.8	778.0	195.4	852.6
Transmission Losses	21.6	115.4	22.3	75.0	25.8	91.9	44.1	65.7	24.2	81.1	39.7	69.2	21.3	75.7	27.2	79.8	25.8	75.5	24.6	66.1
Hydro Labrador Requirement	192.0	1,011.0	184.7	889.9	199.7	988.6	209.1	750.3	195.2	910.7	221.8	780.3	203.9	819.1	221.8	858.5	230.6	853.5	220.0	918.7

Notes:
1. The 2014 and 2015 Forecasts are sourced to the June 26, 2014 Labrador Operating Load Forecast.
2. Actual customer peaks are annual maximums. System peak excludes interruptible and secondary load. MWs in 2014 are December forecast values. MWs in 2015 are January forecast values.
3. Demands for Total Deliveries and Transmission Losses are coincident with system peak.
4. Sales to CFB Goose Bay and Wabush Mines are secondary sales.
5. Actuals reflect rounded values to the nearest tenth of a GWh.
6. In 2013 Happy Valley - Goose Bay includes the Muskrat Falls Contruction Site consumption (3.456 GWh).

Newfoundland and Labrador Hydro
Actual and Forecast Electricity Requirements for 2007 to 2015
Isolated Systems

	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh	kW	MWh
Labrador Isolated																				
Davis Inlet	1,468	6,629	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
L'Anse au Loup	3,740	16,884	3,974	17,556	4,451	18,495	4,463	20,363	4,688	20,912	4,931	23,292	5,043	22,049	5,756	24,073	5,669	24,661	5,736	24,953
Others	8,661	35,700	8,539	35,340	9,536	36,421	9,050	37,644	9,421	37,296	9,208	38,754	8,814	38,207	9,281	39,504	10,310	44,316	10,448	44,911
Total (excluding Davis Inlet)	12,401	52,584	12,513	52,896	13,987	54,916	13,513	58,007	14,109	58,208	14,139	62,046	13,857	60,256	15,037	63,577	15,979	68,977	16,184	69,864
Island Isolated	2,844	8,577	2,323	8,043	2,664	8,707	2,623	8,934	2,221	7,528	2,293	7,876	2,277	7,621	2,200	7,797	2,274	7,679	2,263	7,645
Total Isolated		61,161		60,939		63,623		66,941		65,736		69,922		67,877		71,374		76,656		77,509

Notes:

1. Forecast source is NLH Spring 2013 Rural Operating Load Forecast.
2. Peaks are non-coincident net annual maximums.
3. Net production excludes station services.
4. Operations ceased at Davis Inlet in early 2006, when the community moved to Natuashish.
5. Natuashish is operated by Hydro for the Department of Indian and Northern Affairs with full cost recovery.

Newfoundland and Labrador Hydro
Energy Supply and Fuel Expense for 2007 to 2015
Island Interconnected System

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Total Energy Requirement (GWh)[3]	6,444.4	6,389.0	6,293.7	6,113.0	6,002.4	6,286.6	6,440.7	6,657.6	7,096.4	7,239.0
Hydraulic Production (GWh)	4,472.1	4,689.4	4,771.0	4,199.5	4,273.8	4,512.4	4,595.0	4,688.3	4,702.6	4,603.6
Energy Receipts and Purchases (GWh)[1][2][4]	414.9	453.9	450.6	981.6	948.4	905.3	994.2	1,012.3	1,017.8	1,031.0
Gas Turbine/Diesels Production (GWh)	3.0	(10.0)	(8.1)	(7.9)	(10.6)	(8.5)	(4.3)	(0.5)	3.0	11.4
Holyrood Production (GWh)	1,554.5	1,255.6	1,080.2	939.9	803.1	885.3	855.8	957.4	1,373.0	1,593.0
Holyrood No. 6 Fuel Conversion Factor (kWh/bbl)	630	614	625	612	589	603	599	594	588	607
Holyrood No. 6 Fuel Consumption (bbl)	2,467,396	2,044,648	1,728,681	1,534,707	1,363,179	1,469,169	1,428,337	1,610,966	2,334,546	2,624,371
Average No. 6 Fuel Purchase Price ($/bbl)	56.71	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85
No. 6 Fuel Production Cost ($000)	136,867	107,369	123,734	80,585	100,674	135,136	164,001	171,786	255,841	244,913
Gas Turbine/Diesel Production Cost ($000)	528	420	1,370	840	1,120	687	596	1,255	6,417	3,561

Notes:

1. After February 12, 2009, data includes Nalcor Exploits base generation at Grand Falls, Bishop's Falls and Buchans originally used for Grand Falls paper mill operations.
2. Energy received from Nalcor Exploits base generation was stored, rather than purchased, prior to 2011.
3. Total energy requirements excludes transferred energy amounts transferred from Hydro to CBPP of 8.55 GWh, 12.30 GWh, and 30.34 GWh, in 2009, 2010 and 2011, respectively.
4. Total energy receipts and purchases excludes energy amounts transferred from CBPP to Hydro of 8.55 GWh and 22.36 GWh, in 2009 and 2011, respectively.

Newfoundland and Labrador Hydro
Energy Purchases by Suppliers for 2007 to 2015
Island Interconnected System

Supplier	2007 Test Year		2007 Actual		2008 Actual		2009 Actual		2010 Actual		2011 Actual		2012 Actual		2013 Actual		2014 Forecast		2015 Forecast	
	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000	GWh	$000
NP at Hydro Request	-	-	0.05	-	0.46	108	0.52	119	0.20	15	0.09	7	0.10	114	0.97	533	3.26	733	-	-
CBPP Secondary(1)	-	-	0.39	11	0.08	2	6.96	207	4.46	(74)	3.92	-	6.25	321	8.24	80	9.20	-	-	-
ACI-GF Secondary(2)	20.59	689	64.12	2,282	29.58	1,361	7.41	237	-	-	-	-	-	-	-	-	-	-	-	-
Star Lake(4)	142.45	10,432	147.79	10,813	147.69	10,940	148.50	10,255	135.83	11,232	129.82	5,193	144.45	5,778	140.61	5,624	144.99	5,893	142.18	5,687
Rattle Brook	14.59	1,128	11.91	913	13.69	1,131	15.59	1,202	17.42	1,380	18.66	1,490	14.63	1,181	14.76	1,229	13.70	1,127	15.00	1,254
Corner Brook Cogen	100.24	10,086	92.54	8,632	74.09	7,956	55.74	5,525	51.54	5,469	50.50	5,917	47.84	6,906	55.89	9,260	48.93	9,805	51.07	10,281
Exploits River Project	137.00	10,757	137.13	10,801	177.19	13,798	179.95	14,006	112.40	8,664	-	-	-	-	-	-	-	-	-	-
St. Lawrence Wind	-	-	-	-	7.82	536	100.64	7,248	100.46	7,072	110.00	7,777	103.84	7,383	96.38	6,876	99.54	7,117	104.80	7,514
St. Lawrence Wind Ecoenergy Incentive Credit(3)		-		-		-		(620)		(620)		(685)		(586)		(632)		(588)		(638)
Fermeuse Wind	-	-	-	-	-	-	53.74	4,443	82.80	6,255	87.96	6,674	91.20	6,952	95.52	7,313	81.72	6,268	84.41	6,488
Fermeuse Wind Ecoenergy Incentive Credit		-		-		-		(386)		(620)		(663)		(683)		(715)		(534)		(632)
Nalcor Grand Falls, Bishops Falls and Buchans(4)	-	-	-	-	-	-	-	-	-	-	510.63	20,425	585.90	23,436	599.73	23,989	611.94	24,384	633.50	25,340
CBPP Capacity Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.21	80	7.71	6,126	-	1,680
Vale Capacity Assistance	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	442
Total Power Purchases	414.87	33,092	453.93	33,452	450.60	35,832	569.05	42,236	505.11	38,773	911.58	46,135	994.21	50,802	1,012.31	53,637	1,020.99	60,331	1,030.96	57,416

Notes:
1. Adjustment required in 2010 to account for June, 2009 metering issue
2. ACI-GF secondary ceased on February 12, 2009
3. Ecoenergy Incentive Credits are paid to Hydro quarterly at $0.0075/kwh on the eligible production (up to a maximum of 82.78 GWh annually)
4. Energy purchased from Nalcor generation at Grand Falls, Bishop's Falls, Buchans and Star Lake in 2011, 2012, 2013 2014, and 2015 is at $0.04/kWh.

Newfoundland and Labrador Hydro
Monthly No. 6 Fuel Purchase Prices for 2007 to 2015
($/bbl)

	2007		2008	2009	2010	2011	2012	2013	2014	2015
	Forecast	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Actual(1)	Forecast(1)(2)	Forecast
January	56.40	43.65	73.98	45.52	75.99	82.71	110.99	103.39	111.97	92.00
February	55.25	46.81	71.41	45.80	72.73	92.02	116.71	112.64	118.69	90.10
March	57.35	48.63	72.43	46.75	72.53	102.20	127.24		120.93	91.70
April	55.95						120.63	100.96	117.53	92.90
May	54.50	57.10							110.59	91.50
June	53.75		104.86						112.80	93.00
July	52.85	56.23							114.40	90.90
August	53.10	57.56							118.00	92.90
September	52.70								116.40	92.70
October	54.65					107.03			93.20	94.00
November	57.35	71.44	49.01	78.66	79.27	114.70	103.46	105.89	92.30	90.80
December	60.65	73.43	43.30	74.75	82.74			103.89	90.00	88.80
Weighted Purchase Price	56.71	56.86	70.23	55.11	75.74	96.72	115.26	105.58	106.46	90.85

Notes:
1. There were no purchases in months with a blank.
2. In 2014 actual fuel purchase prices are indicated to the end of May.

Newfoundland and Labrador Hydro
Isolated Fuel and Purchased Power Costs for 2007 to 2015
($000)

	2007 Test Year	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Forecast	2015 Forecast
Diesel Fuel										
Davis Inlet	1,564									
Other Hydro Diesel	10,391	10,340	14,937	12,522	12,266	15,642	15,791	16,430	19,667	18,592
Total (excluding Davis Inlet)	10,391	10,340	14,937	12,522	12,266	15,642	15,791	16,430	19,667	18,592
Purchased Power										
L'Anse au Loup	1,567	1,586	2,254	1,643	2,054	2,890	2,931	3,056	3,329	3,055
Ramea	121	60	101	94	114	108	296	221	221	232
Mary's Harbour	44	18	-	-	-	-	-	-	-	-
Total	1,732	1,664	2,355	1,737	2,168	2,998	3,227	3,277	3,550	3,287
Total	**12,123**	**12,004**	**17,292**	**14,259**	**14,434**	**18,640**	**19,018**	**19,707**	**23,216**	**21,879**

Notes:
1. L'Anse Au Loup fuel purchases include deferred fuel savings.
2. 2014 and 2015 Forecast sourced to October 2014 Isolated Fuel and Power Purchase budgets.

SECTION 3: FINANCE

3.1 OVERVIEW

Hydro's Amended Application is based on a 2014 Test Year for the purposes of recovery of a 2014 revenue deficiency (2014 Revenue Deficiency) and is based on a 2015 Test Year for the purpose of setting rates for customers. Hydro's base rates were last set effective January 1, 2007. These existing rates would result in a 2014 and 2015 return on rate base of 4.41% and 3.33% respectively,[1] which is below Hydro's approved return on rate base for rate making purposes of 7.44%, with a range of 7.29% to 7.59%. This return on rate base is also considerably lower than the 2014 and 2015 proposed return on rate base of 7.12% and 6.82% respectively. The return proposed is based on an embedded cost of debt for 2014 and 2015 of 7.33% and 6.67% respectively and a Return on Equity (ROE) of 8.8%[2] for both 2014 and 2015.

2014 Test Year

On May 12, 2014 Hydro filed an Application ("Second Interim Rates Application") with the Board seeking interim relief for 2014 in advance of the conclusion of its GRA. Hydro's Application stated that addressing Hydro's 2014 forecast net income shortfall prior to conclusion of the GRA would enable Hydro to forecast reasonable cost recovery in 2014 and to provide more certainty to lenders and other stakeholders that it will have an opportunity to earn a reasonable return in 2014. Hydro proposed that the revenue shortfall be dealt with either through a revenue transfer from the RSP or alternatively, the approval on an interim basis of a cost deferral account with recovery to be determined following the testing of 2014 costs. The Board did not approve this

[1] As shown in Schedule II of the Finance evidence.
[2] Based on NP's return on equity of 8.8% which was approved in Board Order No. P.U. 13(2013).

Application and stated “The Board finds that Hydro has not demonstrated that it is appropriate in the circumstances to set aside the proposed revenue shortfall in a deferral account at this time.”[3]

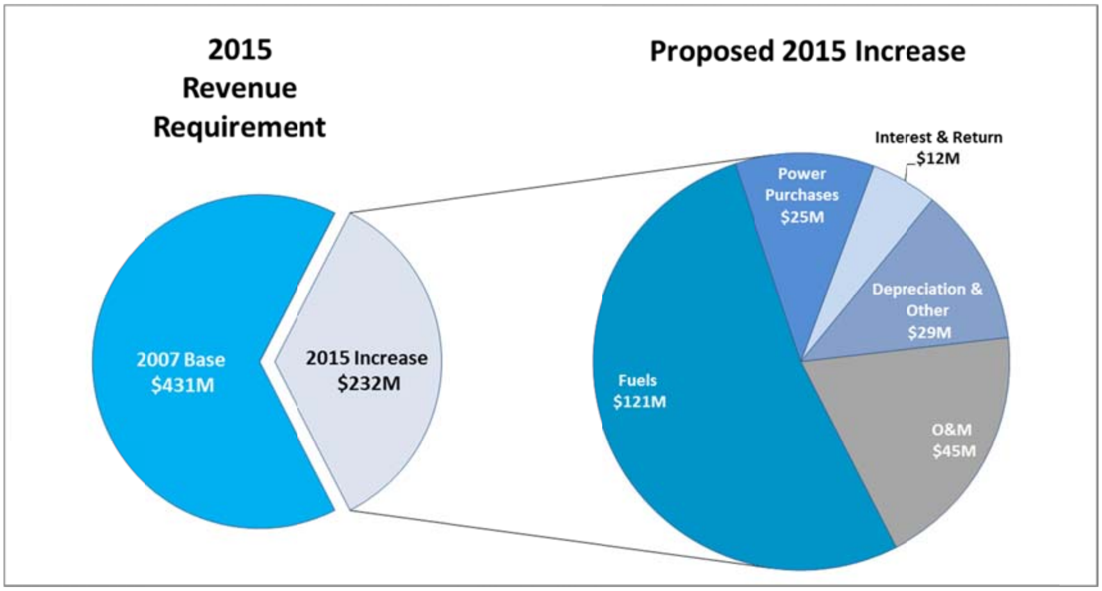
The 2014 Test Year filed in this Amended Application identifies a 2014 Revenue Deficiency of $45.9 million. Hydro’s 2014 revenue requirement has increased by $131.8 million since 2007 and is contributing to the Revenue Deficiency of $45.9 million. In the Amended Application, Hydro is requesting the recovery of this amount. Refer to Section 3.2 of this evidence.

2015 Test Year

Hydro’s revenue requirement for the provision of safe, reliable electrical service is the sum of the return on rate base and other reasonable costs, which include operating expenses, fuels, power purchases and depreciation. Based on existing rates, it is estimated that Hydro would incur a net loss of $34.9 million[4] in 2015.

[3] Refer to Order No. P.U. 39(2014), Page 11.
[4] Schedule II, page 1,line 21 of the Finance evidence.

Chart 3.1



As shown in Chart 3.1 above, Hydro's 2015 revenue requirement in this Application represents an increase of approximately $232 million over the 2007 Board approved revenue requirement since base rates were last set on January 1, 2007. The increase in revenue requirement since 2007 primarily results from inflation, fuel price increases, higher power purchases costs, depreciation costs related to ongoing capital investments in Hydro's aging infrastructure and a higher return on equity. These increases were partially offset by lower interest costs.

Beginning in 2014 and continuing to 2015, Hydro is increasing staffing levels in a number of key areas to meet growing customer demand, an increasing capital program and for execution of required preventative and corrective maintenance relating to Hydro's aging assets. Details on Hydro's 2014 and 2015 revenue requirement are found in Section 3.3.

The purpose of the Finance evidence is to outline the following:

- Hydro's 2014 Revenue Deficiency;
- Details of Hydro's 2014 and 2015 revenue requirement;
- Hydro's return on rate base;
- Hydro's financial position and performance;
- Financial objectives and targets;
- Intercompany charges and shared services;
- Regulatory deferral and recovery mechanisms; and
- Other cost and accounting matters.

3.2 2014 REVENUE DEFICIENCY

A revenue deficiency occurs when existing rates are not adequate to recover the prudently incurred costs of operating a utility. Hydro has not adjusted its base rates since 2007. However, Hydro's costs have been steadily increasing since 2007 and therefore, 2014 revenue based on existing rates is not sufficient to cover the current cost of supplying electricity to customers. The inadequacy of revenues to cover current costs has resulted in a revenue deficiency of $55.9 million for 2014 as shown in Table 3.1.

Table 3.1

2014 Revenue Deficiency $ Millions				
Cost Type	**2007 Test Year**	**2014 Test Year**	**Increase (Decrease)**	**Evidence Reference**
Operating and Maintenance	93.4	126.1	32.7	Section 2.4, 3.3.1
Fuel	148.4	283.7	135.3	Section 3.3.2
Less: RSP Recovery	-	(81.9)	(81.9)	Section 1, Table 1.1
Recovery of Additional Supply Costs	-	(10.0)	(10.0)	Hydro Application, October 8, 2014
Net Fuel Costs	148.4	191.8	43.4	
Power Purchases	38.3	66.7	28.4	Section 3.3.3
Depreciation and Other	40.2	58.0	17.8	Section 3.3.4
Return on Equity	8.0	30.5	22.5	Section 3.3.7
Interest	102.7	89.7	(13.0)	Section 3.3.5
Total Revenue Requirement	430.0	562.8	131.8	
Less: Revenue at Existing Rates		(516.9)		Finance Schedule II, Page 1, Line 4
2014 Revenue Deficiency		45.9		Applied for in the Current Application
Supply Costs Revenue Deficiency		10.0		Applied for in the October 8, 2014 Application
Total 2014 Revenue Deficiency		**55.9**		

In this present Application, Hydro is seeking to defer and recover a 2014 Revenue Deficiency of $45.9 million. An additional $10 million of supply costs have been presented in a separate Application to the Board, dated October 8, 2014. Hydro is of the opinion that, consistent with other regulatory jurisdictions in Canada, supply costs are normally a direct pass-through to customers.[5]

The key drivers of the $45.9 million Revenue Deficiency are the changes to Hydro's 2014 revenue requirement since 2007. Table 3.2 provides the details of Hydro's 2014 revenue requirement increase of $131.8 million. Explanations of these changes can be found in Section 3.3 of this evidence.

[5] Currently cost recovery or flow through mechanisms have been approved for supply cost or margin variations for utilities in all provinces except Manitoba and Saskatchewan.

Table 3.2

2014 Revenue Requirement Changes from 2007		
Cost type	**$ Millions**	**Evidence Reference**
Operations and Maintenance Expenses	32.7	Section 3.3.1
Depreciation and Other	17.8	Table 3.5
Return on Rate Base	9.5	Section 3.3.6
Fuel Costs		
Holyrood Thermal Generating Station (TGS) Fuel Costs	28.4	Table 3.3 [1]
Holyrood TGS Fuel Conversion Costs	8.6	Section 3.3.2
Diesel and Gas Turbine Fuel	16.4	Table 3.3
Fuel Supply Deferral	(10.0)	Table 3.3
Power Purchases		
Wind Energy Purchases	12.3	Table 3.4
Exploits Power Purchase	9.1	Table 3.4
Corner Brook Pulp and Paper Capacity Assistance	6.1	Table 3.4
Other Power Purchases	0.9	Table 3.4
Total	**131.8**	

[1] Holyrood TGS Fuel Costs are calculated as follows:

	2014 TY - 2007 TY
No. 6 fuel per Table 3.3	118.9
RSP per Table 3.3	(81.9)
Holyrood TGS Fuel Conversion Costs Table 3.2	(8.6)
Holyrood TGS Fuel Costs	**28.4**

As detailed above, Hydro's 2014 revenue requirement has increased by $131.8 million since 2007 and is contributing to a revenue deficiency of $45.9 million for Hydro. The vast majority of cost increases since 2007 primarily result from inflation, fuel price increases, higher power purchases costs, depreciation costs related to ongoing investments in Hydro's aging infrastructure and a higher return on equity. These increases were partially offset by a reduction in interest costs. These cost increases would have been significantly higher had new wind and hydraulic supply sources not been secured.[6]

[6] Refer to Section 2.2.

It is important that Hydro receive approval for the recovery of its 2014 Revenue Deficiency. The majority of the costs that comprise the $131.8 million shown in Table 3.1 will be incurred as a result of past capital budget decisions approved by the Board, fuel costs, which are influenced by world oil prices, and wind and hydraulic power purchases which are beneficial for customers (see Section 2.2). However, the 2007 base rates do not provide Hydro with the opportunity to earn a just and reasonable return in 2014.

Hydro's operations, plant assets, and the number and scale of projects both planned and underway are materially larger than in 2007, while rates charged to customers have remained the same. In July 2013, Hydro applied to the Board for rate adjustments to be effective January 1, 2014 to reflect these increases and to enable a reasonable return on rate base. Hydro acted prudently to request the rate adjustment and had a reasonable expectation of a rate change in 2014. Despite this request and subsequent interim rate applications and due to extenuating events, the reasonably expected rate adjustments have not yet occurred.

Section 4.4 of the Rates and Regulation evidence presents Hydro's proposal for recovery of the 2014 Revenue Deficiency. Hydro understands and respects the desire of interested parties and the Board to review and fully test the evidence in this proceeding. However, if the Board requires further testing of the 2014 Test Year costs prior to approving recovery by Hydro, the Board can approve a cost deferral to provide Hydro the opportunity to earn a reasonable return in 2014. The 2014 costs in the revenue requirement are being incurred prudently to allow Hydro to provide reliable service to its customers. The decision on the recovery approach to the 2014 Revenue Deficiency could be addressed in a subsequent order of the Board following the testing of 2014 costs.

3.3 2014/2015 REVENUE REQUIREMENT

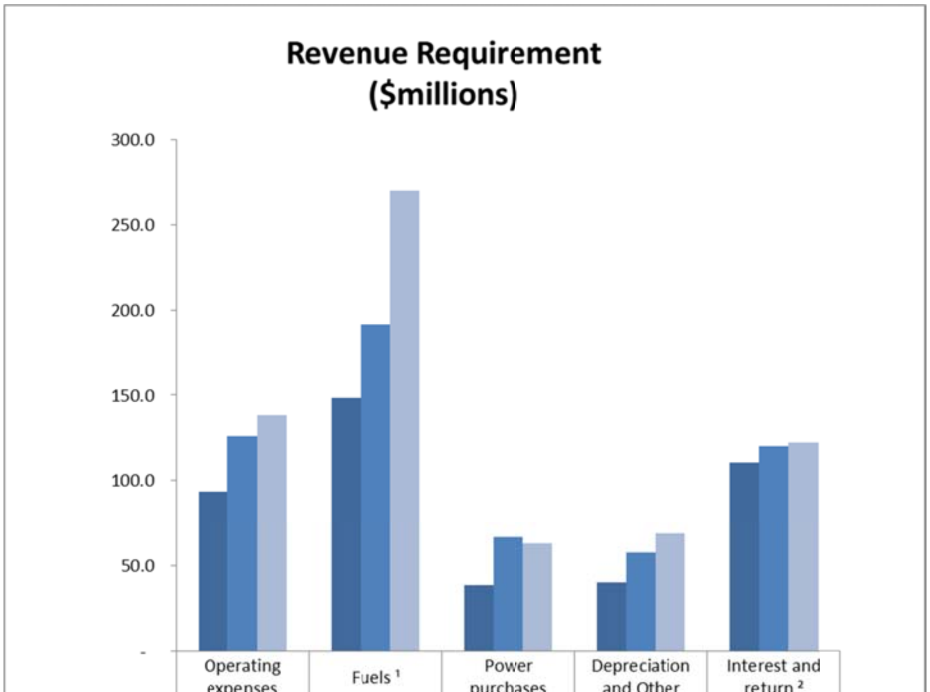
As stated above, Hydro's amended filing is based on a 2014 Test Year for the purpose of recovery of a 2014 Revenue Deficiency and is based on a 2015 Test Year for the purposes of setting rates for customers. Hydro's revenue requirement is the sum of the required return on rate base and other costs, which include operating expenses, fuels, power purchases and depreciation. The total revenue requirement for the 2014 Test Year is $562.9 million and for the 2015 Test Year is $662.5[7] million. Based on existing rates, this would result in a return on rate base of 4.41%[8] and 3.33%[8] for 2014 and 2015 respectively. These rates of return are below Hydro's approved return on rate base for rate making purposes of 7.44%, with a range of 7.29% to 7.59% and the return on rate base of 7.12% for 2014, and 6.82% for 2015 proposed in the Amended Application.

Since 2007, the revenue requirement has increased $131.8 million to 2014, and $231.4 million to 2015. The components of the revenue requirement are outlined in Chart 3.5. The following section of the evidence provides the basis of 2014 and 2015 cost changes since 2007.

		($ Millions)
Total Revenue Requirement per Finance Schedule 1, Page 6	$	662.5
Less: Expense Credits		(2.5)
Add: IOCC Cost Recovery		1.4
[7] **2015 Revenue Requirement per Cost of Service**	**$**	**661.4**

[8] Schedule II, page 1, line 43, Finance evidence.

Chart 3.2



	Operating expenses	Fuels [1]	Power purchases	Depreciation and Other	Interest and return [2]
2007 Test Year	93.4	148.4	38.3	40.2	110.7
2014 Test Year	126.1	191.8	66.7	58.0	120.2
2015 Test Year	138.2	269.8	63.3	68.7	122.5

[1] Net of RSP and fuel supply deferrals.
[2] Prior to cost of service exclusions of $0.4 million in 2014 and $0.3 million in 2015 which primarily relate to the depreciation of assets not in service.

3.3.1 Operating Expenses

Operating costs of $126.1 million in 2014 are $32.7 million higher than the 2007 Test Year costs of $93.4 million. The 2015 Test Year costs of $138.2 million are $44.8 million higher than the 2007 Test Year. Salary and benefit costs are the primary driver of this variance for the 2014 and 2015 Test Years. Please refer to Section 2.4 of the evidence for additional information.

3.3.2 Fuel Expense

Hydro's fuel expense consists of No. 6 fuel used at Holyrood, gas turbine and diesel fuel and other costs. The 2014 Test Year fuel costs, net of the RSP and the fuel supply deferral, are $191.8 million or $43.4 million higher than the 2007 Test Year costs of

$148.4 million. The 2015 Test Year fuel costs of $269.8 million are $121.4 million higher than the 2007 Test Year. The primary driver of the increase in fuel expense is No. 6 fuel costs as shown in Table 3.3 below.

Table 3.3

Fuel
($ millions)

	2007 Test Year	2014 Test Year	2014 TY - 2007TY	2015 Test Year	2015 TY - 2007TY
No. 6 fuel	$ 136.9	$ 255.8	$ 118.9	$ 244.9	$ 108.0
Diesel and gas turbine	11.5	27.9	16.4	22.9	11.4
Total fuel	148.4	283.7	135.3	267.8	119.4
Less:					
Fuel supply deferral	-	(10.0)	(10.0)	2.0	2.0
RSP	-	(81.9)	(81.9)	-	-
Net Fuel	**$ 148.4**	**$ 191.8**	**$ 43.4**	**$ 269.8**	**$ 121.5**

No. 6 fuel

The price for No. 6 fuel consumption in the 2007 Test Year averaged $55.47 per barrel compared to $109.59 in the 2014 Test Year which resulted in an increase of $118.9 million. In addition, there has also been an increase in fuel expense as a result of a decline in fuel conversion performance at Holyrood as described in Section 2.6.1. In 2014, it is estimated that the decline in fuel conversion performance will result in $8.6 million in additional costs. Overall, the net number of barrels used at Holyrood in 2014 decreased by 132,850 barrels relative to the 2007 Test Year which resulted in a net decrease of $7.4 million in costs. Fuel expense in 2014 was reduced by $81.9 million relative to the 2007 Test Year as a result of normal RSP activity. This amount was recorded in the RSP deferral account for future recovery from customers. Similarly, fuel expense was reduced by $10.0 million as a result of Hydro's fuel supply deferral application.

In the 2015 Test Year, the consumption price is $93.32 per barrel which results in an increase of $99.3 million over the 2007 Test Year. The volume of fuel in 2015 is forecast to increase by 156,975 barrels resulting in an increase in costs of $8.7 million, for a total increase of $108.0 million over the 2007 Test Year.

Diesel and Gas Turbine

Diesel and gas turbine fuel costs of $27.9 million in the 2014 Test Year are $16.4 million higher than the 2007 Test Year. This increase reflects higher electricity requirements for isolated systems and higher petroleum prices in world markets. Diesel and gas turbine fuel costs of $5.7 million were incurred in early 2014 as a result of the January supply outage. The 2015 Test Year costs are $22.9 million, an increase of $11.4 million over the 2007 Test Year.

3.3.3 Power Purchases

Hydro purchases energy from non-utility generators to supply customers both on the Island and in Labrador. In the 2014 Test Year, power purchases are $66.7 million, an increase of $28.4 million over the 2007 Test Year of $38.3 million as shown in Table 3.4.

Table 3.4

Power Purchases ($ millions)					
	2007 Test Year	2014 Test Year	2014 TY - 2007TY	2015 Test Year	2015 TY - 2007TY
Exploits	$ 21.2	$ 30.3	$ 9.1	$ 31.0	$ 9.8
Wind	-	12.3	12.3	12.7	12.7
Capacity Assistance	-	6.1	6.1	2.1	2.1
Other	17.1	18.0	0.9	17.5	0.4
Total Power Purchases	$ 38.3	$ 66.7	$ 28.4	$ 63.3	$ 25.0

The primary drivers of the increase relate to the acquisition of wind generation as a supply source with the addition of 181 GWh at a cost of $12.3 million. The Exploits arrangements have also contributed an additional 477 GWh of generation resulting in an increase in power purchase costs of $9.1 million. In 2014, there is an additional cost of $6.1 million from Capacity Assistance related to arrangements with Corner Brook Pulp and Paper. This latter cost increase was primarily incurred during the supply outage in January 2014. Hydro has submitted a separate application to the Board dated October 8, 2014 for the recovery of this cost.

The 2015 Test Year costs of $63.3 million for power purchases are $25.0 million higher than the 2007 Test Year. The increased costs are as noted for 2014 with a $4.0 million reduction in costs associated with Capacity Assistance. A summary of the major increases are noted in Table 3.4. Please refer to Schedules VI and VIII of the Regulated Activities evidence for additional information.

3.3.4 Depreciation and Other

Depreciation expense is calculated on the basis of rates of depreciation assigned to each class of Hydro's assets. In 2011, a depreciation study was conducted by Gannett Fleming. The methodology, classes and rates were approved per Board Order No. P.U. 40(2012).

Table 3.5

Depreciation ($ millions)	2007 Test Year	2014 Test Year	2014 TY - 2007TY	2015 Test Year	2015 TY - 2007TY
Depreciation	$ 38.8	$ 55.2	$ 16.4	$ 63.8	$ 25.0
Other[1]	$ 1.4	$ 2.8	$ 1.4	$ 4.9	$ 3.5
Total	$ 40.2	$ 58.0	$ 17.8	$ 68.7	$ 28.5
Average Ratebase	**$ 1,489.3**	**$ 1,692.6**	**$ 203.2**	**$ 1,802.0**	**$ 312.7**

[1] Other expenses include loss on disposal of assets, removal costs and ARO accretion.

In Table 3.5 above, depreciation expense in the 2014 Test Year of $55.2 million is $16.4 million higher than the 2007 Test Year. Depreciation expense in the 2015 Test Year of $63.8 million is $25.0 million higher than 2007 Test Year. The primary driver of these increases is the growth in Hydro's capital program which increased from $42.3 million in capital expenditures in 2007 Test Year to $268.0 million in the 2014 Test Year and $282.1 million in the 2015 Test Year. The vast majority of this significant capital investment by Hydro has been reviewed and approved by the Board.

Other expenses include loss on disposal of assets, removal costs and Asset Retirement Obligation (ARO) accretion. The increase in both 2014 and 2015 is primarily due to the increase in removal costs which are estimated to be $1.7 million in the 2014 Test Year and $2.2 million in the 2015 Test Year.

3.3.5 Interest and Return

Interest and return are based on a function of both the weighted average cost of capital and the rate base. The interest and return in the 2014 Test Year of $120.2 million[9] is $9.5 million higher than the 2007 Test Year of $110.7 million. The 2015 Test Year of $122.5 million is $11.8 million[10] higher than the 2007 Test Year. Additional information on the components of the increase is outlined in Section 3.4.3.

The forecasted interest expense for 2014 and 2015 represents a decrease of $13.5 million and $14.0 million, respectively, compared to the 2007 Test Year amount of $110.7 million. This is primarily due to reductions in the 2014 and 2015 debt guarantee fees ($9.4 million and $8.7 million, respectively) lower interest on long-term debt ($15.2 million and $6.1 million, respectively) and higher interest during construction ($5.1 million and $9.9 million, respectively) partially offset by increases in the 2014 and 2015 RSP Interest expense of $17.0 million and $11.3 million respectively.

3.3.6 Forecast Return on Rate Base

The total forecast return on rate base for 2014 and 2015 is $120.6 million, and $122.8 million respectively as outlined in Table 3.7.

The 2014 and 2015 forecasted returns on rate base are outlined in Schedule I, Page 5 of 11. Table 3.6 below summarizes the rate of return on rate base from 2007 to 2015.[11]

[9] Prior to cost of service exclusions of $0.4 million which primarily relate to the depreciation of assets not in service. Net of cost of service exclusions the 2014 Test Year would have increased by $9.9 million over the 2007 Test Year.
[10] Prior to cost of service exclusions of $0.4 million which primarily relate to the depreciation of assets not in service. Net of service exclusions the 2015 Test Year would have increased by $12.1 million over the 2007 Test Year.
[11] 2014 and 2015 are returns based upon proposed rates.

Table 3.6

Return on Rate Base										
	Test Year	**Actual**							**Test Year**	**Test Year**
	2007	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014[1]**	**2015[1]**
Rate of Return on Rate Base	7.44%	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	6.01%	7.12%	6.82%

[1] Based on proposed rates presented in this GRA Amended Application.

Hydro is requesting the Board's approval of an allowable range of return on rate base of +/- 20 basis points based on a recommendation by Ms. Kathleen C. McShane[12] of Foster Associated Inc. The calculation of the rate of return on rate base is outlined in Table 3.7.

Table 3.7

Return on Rate Base (RORB)
Year ended December 31
($000)

	2007 Test Year	**2014 Test Year**	**2015 Test Year**
Net Income	7,979	30,504	33,232
Interest	102,728	89,723	89,255
Total Interest and Return	110,707	120,227	122,487
Add: Cost of Service Exclusions	-	336	323
Return on Rate Base	110,707	120,563	122,810
Average Rate Base	1,489,323	1,692,567	1,802,024
Rate of Return on Average Rate Base	**7.44%**	**7.12%**	**6.82%**
Allowable RORB Range (+/- 0.15)	7.29% to 7.59%	7.29% to 7.59%	
Allowable RORB Range (+/- 0.20)			6.62% to 7.02%

3.3.7 Return on Equity

The return on rate base set by the Board in Order No. P.U. 8(2007) reflected a return on equity of 4.47% as shown in Table 3.8.

[12] See Exhibit 6 of this evidence.

Table 3.8

Return on Equity (ROE)								
	Test year	Actual						
	2007	2007	2008	2009	2010	2011	2012	2013
Board Approved	4.47%	4.47%	4.47%	4.47%	4.47%	4.47%	4.47%	4.47%
Hydro	4.47%	1.30%	4.12%	6.18%	2.03%	6.59%	5.25%	0.06%
NP - Allowed ROE	-	9.75%	8.69%	9.00%	8.38%	8.38%	8.38%	8.80%

Hydro's actual ROE, shown in Table 3.8, ranges from a low of 0.06% in 2013 to a high of 6.59% in 2011, significantly less than NP's ROE. Hydro's ROE over this time period would have been lower if not for the reduction in the debt guarantee fee amount. In 2009, the Government directed in Order in Council OC2009-063, that Hydro would be allowed to earn ROE equal to that of NP which is currently 8.8%. That rate represents a significant increase over Hydro's current ROE of 4.47%, which is one of the lowest in the country compared to other similar utilities. Hydro's Amended Application for 2014 and 2015 Test Years reflect an 8.8% ROE. Based on existing rates (and in the absence of approval of the 2014 Revenue Deficiency) Hydro's ROE would be -4.76%[13] in 2014 and -11.69%[13] in 2015.

[13]

	2014 ($ Millions)	2015 ($ Millions)
Net Loss	(15.4)	(34.9)
Average Shareholder's Equity	323.7	298.5
ROE at Existing Rates	**-4.76%**	**-11.69%**

3.3.8 Hydro's Application

Hydro is requesting approval of the following:

- Revenue Requirement of $562.9 million for 2014 Test Year and $662.5 million for 2015 Test Year.

3.4 RATE BASE

3.4.1 Average Rate Base

Hydro's rate base is comprised of its investment in capital assets in use, unamortized balances of deferred charges, fuel inventory, materials and supplies inventory and cash working capital allowances. Schedule I, Page 5 of 11, provides details of the rate base elements from 2007 to 2015. The average rate base for 2014 and 2015 is forecasted to be $1,692.6 million and $1,802.0 million respectively.[14] This compares to an average rate base in 2007 of $1,489.3 million. Table 3.9 shows the changes in the components of rate base relative to 2007 Test Year.

[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. These items have been included in rate base because Hydro believes that upon completion of further review, the Board will determine these projects were prudently incurred and completed in a least cost manner and, therefore, should be included in rate base.

Table 3.9

Changes in Components of Rate Base Years ended December 31 ($000)					
	2007 Test Year	2014 Test Year	2014TY - 2007TY Change	2015 Test Year	2015TY - 2007TY Change
Capital Assets - Average	**1,355,590**	**1,521,224**	**165,634**	**1,623,461**	**267,871**
Other Components of Rate Base					
Cash Working Capital Allowance	3,030	9,207	6,177	7,037	4,007
Fuel	27,473	65,110	37,637	66,633	39,160
Materials and Supplies	19,912	25,823	5,911	27,402	7,490
Deferred Charges	83,318	71,203	(12,115)	77,491	(5,827)
Total Average Rate Base	**1,489,323**	**1,692,567**	**203,244**	**1,802,024**	**312,701**

3.4.2 Other Components of Rate Base

Cash Working Capital Allowance

Cash working capital allowance of $9.2 million in the 2014 Test Year and $7.0 million in the 2015 Test Year, as outlined in Schedule III, page 2 of 2 of the Finance evidence, reflects the average amount of capital provided by investors above and beyond investments in plant and other. Cash working capital allowance is intended to bridge the gap between the time expenditures are made to provide service and the time payment is received for the service.

Fuel Inventory

Fuel in inventory is comprised of a thirteen month average of No. 6 fuel, diesel, and gas turbine fuel. The primary drivers for the increase in average fuel are both price per barrel, and the amount of fuel storage. This resulted in an increase from $27.5 million in the 2007 Test Year to $65.1 million in the 2014 Test Year and $66.6 million in the 2015 Test Year.[15] The average purchase price of No. 6 fuel has increased from $56.71/bbl in

[15] As outlined in Schedule III, page 2 of 2 of the Finance evidence.

the 2007 Test Year to $106.46/bbl in the 2014 Test Year and $90.85/bbl in the 2015 Test Year. These increases are outlined in Schedule V of the Regulated Activities evidence. Higher fuel storage levels are required due to the increase in production requirements from the Holyrood generating station and to ensure there is adequate fuel supply to reliability meet customer demands.

Materials and Supplies

Materials and supplies of $25.8 million in the 2014 Test Year and $27.4 million in the 2015 Test Year, as outlined in Schedule III, page 2 of 2 of the Finance evidence, include consumables, inventory and critical spares that are used by Hydro operations for construction and maintenance of operational assets and equipment.

Deferred Charges

Deferred Charges represent expenses incurred by Hydro that are amortized over a longer period of time, rather than the period in which they were incurred, in order to minimize the impact on ratepayers. Hydro amortizes the costs noted in Table 3.10 for periods ranging from three to 27 years based on amortization criteria approved by the Board.

Table 3.10

Deferred Charges
($millions)

	Dec. 31, 2014 Opening Balance	Additions	Amortization	Dec. 31, 2015 Ending Balance
CDM	6.3	0.7	-	7.0
Hearing Costs	-	1.0	0.3	0.7
Holyrood Blackstart Diesel	3.6	1.6	1.0	4.1
Supply Costs Deferral	10.0	-	2.0	8.0
Extraordinary Repairs	-	1.2	0.2	1.0
Foreign Exchange	58.2	-	2.2	56.0
Total	**78.1**	**4.5**	**5.7**	**76.8**
Current Year Opening	64.3			78.1
Average	**71.2**			**77.5**

Conservation and Demand Management

Pursuant to Board Orders No. P.U 14(2009), No. P.U. 13(2010), No. P.U. 4(2011) and No. P.U. 35(2013), Hydro received approval to defer costs associated with CDM expenditures related to electricity conservation programs for residential, industrial and commercial sectors. Please refer to 3.8.2.

External Regulatory Costs

An estimate of $1.0 million[16] in external regulatory costs is forecasted to be incurred with respect to the current GRA. It is proposed that Hydro defer and amortize these costs over a three-year period commencing in 2015 and that the unamortized balances be included in rate base. Deferring these costs and amortizing over a three year period will ensure Test Year costs are not overstated if rates remain in place beyond the Test Year. Hydro has included $1.0 million of the estimated costs incurred in relation to the 2013 GRA in 2014 and these costs are included in the 2014 Revenue Deficiency.

Holyrood Diesel Units

Pursuant to Order No. P.U 38 (2013), Hydro deferred the lease costs of $3.6 million in the 2014 Test Year and $1.6 million in the 2015 Test Year associated with the 16 MW diesel plant and other necessary infrastructure to ensure black start capability at the Holyrood Thermal Generating Station. Hydro proposes that commencing in 2015, the deferred lease costs be amortized over a five year period and the unamortized balances be included in rate base.

Supply Costs Deferral

Hydro proposed to defer the unanticipated increased fuel, and purchased power supply costs incurred in the first Quarter of 2014 in its Application dated October 8, 2014.

[16] Estimate to be updated prior to conclusion of the GRA.

Hydro proposed in the Application that commencing in 2015, these fuel and purchased power supply costs should be amortized over a five year period and that the unamortized balances be included in rate base.

Extraordinary Repairs

On May 15, 2014, the Board issued its Interim Report in the matter of an investigation and hearing into supply issues and power outages on the Island Interconnected System. The action items included work required to be completed totalling $1.2 million in 2015 relating to air blast circuit breakers and transformers. Hydro recognizes that although there will be an increase in future preventative and corrective maintenance, the full $1.2 million will not be a recurring annual expense. Hydro proposes that the $1.2 million be deferred and amortized over a five year period and that the unamortized balances be included in the rate base. Deferring these costs and amortizing over a five year period rather than including the $1.2 million in 2015 Test Year will ensure Test Year costs are not overstated between GRAs.

Foreign Exchange

Hydro incurred foreign exchange losses related to the issuance of Swiss Franc and Japanese Yen denominated debt in 1975 and 1985, respectively, which were recognized when the debt was repaid in 1997. The Board has accepted the inclusion of realized foreign exchange losses related to long-term debt in rates charged to customers in future periods. Hydro continues to amortize costs associated with foreign exchange losses consistent with this practice.

3.4.3 Capital Structure

Hydro's regulated capital structure for rate making purposes is comprised of net regulated debt[17], regulated equity, and customer-supplied capital, which includes a portion of Hydro's AROs and employee future benefits (EFBs).

The inclusion of AROs and EFBs as customer-supplied capital is based on the nature of the underlying liabilities. With respect to the AROs and EFBs, Hydro recovers funds from ratepayers in advance of those funds being used to settle the liabilities in the future. The amounts are included in the regulated capital structure at zero cost.

As noted in Table 3.11, there are four principal components of Hydro's regulated capital structure, details of which have been forecast for the 2015 Test Year in Schedule I, Page 4 of 11:

- Debt;
- Asset retirement obligations;
- Employee future benefits; and
- Shareholder's equity (retained earnings and contributed capital).

The weighted average cost of capital is derived from the proportionate cost of the components of Hydro's capital structure. Hydro's forecast embedded cost of debt for 2015 is 6.67% and the proposed ROE used in this filing is 8.8%. Details of the computation of Hydro's cost of debt are outlined in Schedule IV, Page 1 of 1 of this evidence. The proposed return on equity is based on the ROE for NP of 8.8% per Order in Council OC2009-063, and Board Order No. P.U. 13(2013). The derivation of Hydro's weighted average cost of capital is presented in Table 3.11.

[17] Net regulated debt is equal to total debt less non-regulated debt less sinking funds.

Table 3.11

Weighted Average Cost of Capital (WACC)			
	2007 Test Year	**2014 Test Year**	**2015 Test Year**
Embedded Cost of Debt	8.26%	7.33%	6.67%
Asset Retirement Obligation	0.00%	0.00%	0.00%
Employee Future Benefits	0.00%	0.00%	0.00%
Equity	4.47%	8.80%	8.80%
WACC	**7.44%**	**7.32%**	**6.82%**

The proportion of debt in the capital structure of Hydro is also key to both the financial stability of the company as well as the rate making process. Debt results in charges of interest and principal against the cash flows of a company. Hence, higher levels of debt impact a company's available cash flows. Providers of debt financing have a priority claim on the assets of the business should the business fail, whereas equity investors only have a residual claim. In addition, the return on an equity investment is subject to potential variability in the profits of a company. Consequently, capital structure targets also play a key role in maintaining a sound financial position.

A summary of Hydro's regulated capital structure for rate making purposes from 2006 to 2015 is presented in Table 3.12. As at December 31, 2013, the proportion of regulated debt in Hydro's regulated capital structure was 69.6%, which represented a significant decrease since December 31, 2006. This decrease is driven largely by the equity contribution of $100 million in 2009. Over the course of 2014 and 2015, regulated debt will increase to 73.2% and 74.8% respectively, as Hydro issues new long-term debt to fund its planned capital spending.

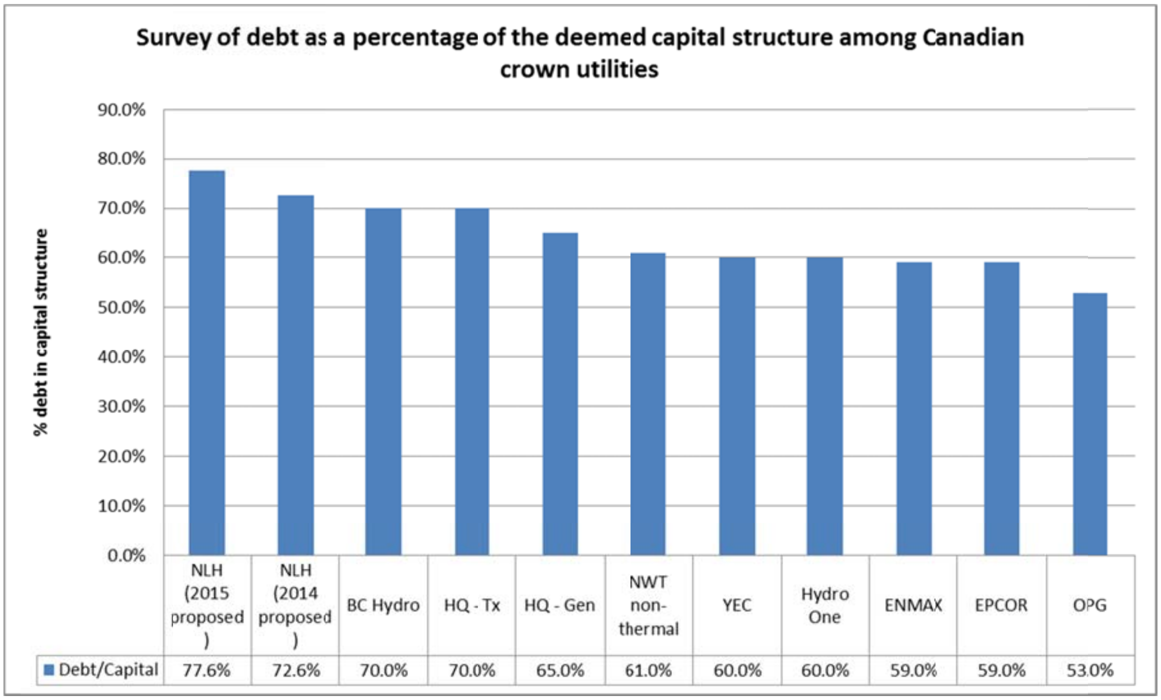
Table 3.12

Newfoundland and Labrador Hydro
Proportion of Debt in Hydro's Regulated Capital Structure
($ millions)

	31-Dec-07	31-Dec-08	31-Dec-09	31-Dec-10	31-Dec-11	31-Dec-12	31-Dec-13	Test Year 31-Dec-14	Test Year 31-Dec-15
Promissory notes	7.1	163.0	-	-	-	52.0	41.0	145.6	-
Long-term debt	1,359.4	1,154.8	1,149.8	1,144.9	1,139.7	1,134.1	1,128.8	1,252.0	1,649.5
Non-regulated debt pool	(40.4)	(18.0)	(3.5)	(5.5)	(5.1)	(7.2)	(8.2)	(8.2)	(8.2)
CF(L)Co Share Purchase debt	(6.0)	-	-	-	-	-	-	-	-
Sinking Funds, net of mark to market adjustment	(132.2)	(148.0)	(164.8)	(182.9)	(201.9)	(221.9)	(243.6)	(189.5)	(207.8)
Total regulated debt	**1,187.9**	**1,151.8**	**981.5**	**956.5**	**932.7**	**957.0**	**918.0**	**1,199.9**	**1,433.5**
Contributed capital (Regulated)	-	-	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Retained earnings	210.9	219.7	236.9	212.6	212.1	231.3	232.0	262.9	296.4
Total regulated equity	**210.9**	**219.7**	**336.9**	**312.6**	**312.1**	**331.3**	**332.0**	**362.9**	**396.4**
Total regulated debt and equity	1,398.8	1,371.5	1,318.4	1,269.1	1,244.8	1,288.3	1,250.0	1,562.8	1,829.9
Employee future benefits, funded	39.8	41.9	44.0	48.3	53.6	56.9	61.6	66.2	72.5
Asset retirement obligations, funded	-	-	-	-	1.6	4.3	7.4	10.4	13.4
Total regulated capital	**1,438.6**	**1,413.4**	**1,362.4**	**1,317.4**	**1,300.0**	**1,349.5**	**1,319.0**	**1,639.4**	**1,915.8**
Regulated debt to total regulated capital	82.5%	81.5%	72.1%	72.6%	71.8%	70.9%	69.6%	73.2%	**74.8%**
Average regulated debt to total regulated capital	***83.1%***	***82.0%***	***76.8%***	***72.4%***	***72.2%***	**71.4%**	***70.3%***	**71.4%**	**74.0%**

For the 2014 and 2015 Test Years, the average percentage of regulated debt in the capital structure is 71.4% and 74.0% respectively, as shown in Table 3.12. While this represents an improvement over historical levels, the percentage of debt in the regulated capital structure is still high relative to other Canadian crown utilities, as shown in Chart 3.3.

Chart 3.3[18]



3.4.4 Forecast Debt

Hydro's regulated debt to total regulated capital ratio is forecasted to improve from 82.5% at the end of 2007 to a projected 73.2% and 74.8% by the end of 2014, and 2015 respectively, as shown in Table 3.12.

Actual regulated debt outstanding at December 31, 2013 was $918.0 million, which still represents a significant decline since December 31, 2007. On September 15, 2014, Hydro raised $200.0 million of new long-term debt by issuing Series AF debentures. Based on the current forecast, which includes proposed capital expenditures in Labrador West, Hydro anticipates raising an additional $400.0 million in 2015, which it will do through a re-opening of the Series AF debentures. If these capital expenditures in Labrador West do not occur, the debt issuance will be less than $400.0 million. As a

[18] Debt percentages are based on available data published for crown-owned utilities.

result of these new financings, regulated debt outstanding is projected to increase to $1,433.5 million by December 31, 2015, as shown in Table 3.12.

3.4.5 Forecast Asset Retirement Obligations

Asset retirement obligations are considered by Hydro to be a zero cost component of its capital structure as shown in Table 3.12. The amount included in capital structure includes the portion of the AROs which is proposed to be recovered from ratepayers (the funded portion) through inclusion in revenue requirement, through both depreciation of the asset retirement cost (ARC), and accretion of the ARO which is recorded as a liability. Further discussion of the treatment of the AROs is included in Section 3.9.3.

The forecasted balance of funded AROs is $10.4 million in 2014 and $13.4 million in 2015, as shown in Schedule 1, Page 11 of 11. No AROs existed in 2007.

3.4.6 Forecast Employee Future Benefits

Employee future benefits (EFBs) are considered by Hydro to comprise part of its capital structure at zero cost as shown in Table 3.12. The amount included in Hydro's capital structure includes the portion of EFBs which have been recovered from customers through inclusion in the revenue requirement through EFB expense. Based on the results of Hydro's 2013 actuarial valuation, the EFB liability, is forecasted to be $66.2 million and $72.5 million in 2014 and 2015 respectively, as shown on Schedule 1, Page 8 of 11.

3.4.7 Forecast Equity

Equity includes past earnings of Hydro and equity contributions to Hydro by its Shareholder, offset by dividends paid to its Shareholder. The forecasted equity of Hydro for 2014 includes $262.9 million[19] of retained earnings and $100.0 million of contributed capital. For 2015, the forecasted equity of Hydro includes $296.4 million[20] of retained earnings and $100.0 million contributed capital.

3.4.8 Hydro's Application

Hydro is proposing approval of the following:

- A 2014 and 2015 average rate base of $1,692.6 million and $1,802.0 million respectively;
- Its forecast capital structure for the 2014 and 2015 Test Years with a weighted average cost of capital of 7.32% and 6.82% respectively;
- Hydro is requesting the Board's approval of a rate of return on average rate base of 7.12% and 6.82% for the 2014 and 2015 Test Years, respectively;
- To include in revenue requirement the amortization of costs associated with the Black Start diesel generating units in Holyrood of $3.6 million in 2014 and $1.6 million in 2015 and that the amortization be based on a five year period commencing in 2015;
- To include in revenue requirement amortization of external regulatory costs associated with the GRA Hearing of $1.0 million over three years commencing in 2015; and
- To defer costs of $1.2 million associated with Extraordinary Repairs, as noted in this Amended Application, with recovery over a five year period.

[19] Net of retained earnings Cost of Service exclusions of $1.0 million for 2014 and $1.3 million for 2015 which primarily relate to depreciation of assets not in service.

[20] Net of retained earnings Cost of Service exclusions of $1.0 million for 2014 and $1.3 million for 2015 which primarily relate to depreciation of assets not in service.

3.5 FINANCIAL POSITION AND PERFORMANCE

3.5.1 Return on Equity

In 2009, under the authority of Section 5.1 of the *Electrical Power Control Act*, *1994*, the Government directed that:

- In calculating the return on rate base, the same rate of return on equity would be set for Hydro as was set for NP;
- Hydro would earn ROE on its entire rate base, including amounts related to rural assets;
- Hydro would be permitted to have a proportion of equity in its capital structure up to a maximum of the same as is approved for NP; and
- These policies would become effective commencing with the first GRA after January 1, 2009.

3.5.2 Equity Contribution

In 2009, the Government, through Nalcor Energy, made a $100 million equity contribution to Hydro. These funds were included in the Government's 2008-2009 Budget[21] and the contribution from the Government was intended to strengthen Hydro's financial position. This action, in combination with a higher rate of return on equity, provides a strong foundation for future financial performance and positions Hydro to be able to finance a greater portion of its capital program with internally generated funds.

[21] *"The Province will also provide a $100 million equity injection that will improve Newfoundland and Labrador Hydro's financial profile by reducing its level of debt. Our equity injection will also bring the Company more in line with similar utilities in Canada in terms of its ratio of debt to equity."* Government of Newfoundland and Labrador Budget Speech, April 29, 2008.

3.5.3 Financial Performance Initiatives

Over the period from 2008 to the present, the Government has undertaken the following initiatives to enhance Hydro's financial position:

- Reduction of required debt guarantee fee payments from Hydro;
- Alterations to power purchase arrangements with respect to Exploits Generation; and
- Additional equity contribution of $100.0 million.

Debt Guarantee Fee Initiative

The debt guarantee fee is an annual fee paid by Hydro in return for the Government's guarantee of its debt obligations. This fee, which has been in effect for approximately 20 years, was previously charged at 1% of Hydro's outstanding debt obligations, and is included in Hydro's revenue requirement and customer rates. In 2008, as a means of temporarily improving Hydro's net income, the Government waived Hydro's requirement to pay the fee while continuing to guarantee Hydro's debt. This waiver continued until 2011 when the Government directed that the fee be reinstated at a market rate.

This direction was based on a market analysis undertaken by one of Hydro's capital market advisors in the fall of 2010 at the request of Hydro, as the last review that assessed the value of the fee was undertaken in 2008 under very different market conditions. The new analysis was based on a comparison of yields on bonds issued by the Province to bonds with similar maturities issued by a group of investment-grade utilities comparable to Hydro. The difference between the yield on the Province's bonds and those of the companies within the comparison set is reflective of the value of the guarantee fee. The analysis supported a debt guarantee fee in the range of 25-50 basis points (bps) per issue, depending on the remaining term to maturity. The reasonableness of this range was confirmed by an additional study undertaken in the

Fall of 2013. The Debt guarantee fee rates in the range of 25-50 basis points will result in significant savings passed on to ratepayers in 2014 and 2015 upon the setting of new electricity rates, as outlined in Table 3.13.

Table 3.13

Newfoundland and Labrador Hydro
Net Income Benefits of Debt Guarantee Fee Waivers and New Debt Guarantee Formula
($ millions)

				Actual				Test Year	
Newfoundland and Labrador Hydro Fiscal Year:	**2007**	**2008**	**2009**	**2010**	**2011**	***2012***	***2013***	***2014***	***2015***
Balances as at December 31 of previous fiscal year:									
Long-term debt	$1,357.4	$1,151.1	$1,146.4	$1,141.6	$1,136.7	*$1,131.5*	*$1,125.9*	*$1,046.6*	*$1,243.9*
Current portion of long-term debt	8.3	208.3	8.4	8.2	8.2	*8.2*	*8.2*	*82.2*	*8.2*
	1,365.7	1,359.4	1,154.8	1,149.8	1,144.9	*1,139.7*	*1,134.1*	*1,128.8*	*1,252.1*
Sinking funds	(117.1)	(151.8)	(163.9)	(179.6)	(208.4)	*(247.0)*	*(263.3)*	*(267.6)*	*(220.5)*
	1,248.6	1,207.6	990.9	970.2	936.5	*892.7*	*870.8*	*861.2*	*1,031.6*
Promissory notes	63.2	7.1	163.1	-	-	*-*	*52.0*	*41.0*	*162.1*
Guaranteed debt outstanding at December 31 of the preceding fiscal year	$1,311.8	$1,214.7	$1,154.0	$ 970.2	$ 936.5	*$ 892.7*	*$ 922.8*	*$ 902.2*	*$1,193.7*
Debt guarantee fee @ 1% under old formula	**$ 13.1**	**$ 12.1**	**$ 11.5**	**$ 9.7**	**$ 9.4**	***$ 8.9***	***$ 9.2***	***$ 9.0***	***$ 11.9***
Actual debt guarantee fee paid/proposed for year[1]	13.1	-	-	-	3.9	*3.7*	*3.7*	*3.7*	*4.4*
Net impact	**$ -**	**$ 12.1**	**$ 11.5**	**$ 9.7**	**$ 5.5**	***$ 5.2***	***$ 5.5***	***$ 5.3***	***$ 7.5***

[1] *Actual fee paid for 2011, 2012, 2013 and 2014 based on the new formula of 0.25% - 0.50% of outstanding debt*

Increase in net income from debt guarantee fee waivers for 2008 - 2010	**33.3**
Increase in net income from new formula for 2011 - 2014	**21.5**
Reduction in 2015 revenue requirement from new formula	**7.5**
Cumulative impact of debt guarantee fee initiatives	**$ 62.3**

The debt guarantee fee in the 2014 Test Year is $3.7 million, which is $5.3 million lower than if it was based on 1% of Hydro's outstanding debt obligations, as was the case when rates were last set in 2007. The debt guarantee fee in the 2015 Test Year is $4.4 million, an estimated reduction of $7.5 million from the rates that were previously in place, the benefit of which will be passed on to ratepayers. The cumulative impact of the debt guarantee fee initiatives to 2015 is $62.3 million.

Power Purchases Initiative

As discussed in Section 2.2.2, in 2008, the Government passed the *Abitibi-Consolidated Rights and Assets Act* which, among other things, expropriated Exploits Generation assets. In 2011, the Government altered the arrangements for power purchases from

Exploits Generation to enable Hydro to purchase the energy at 4¢ per kWh from all plants, including the Exploits generation which previously had supplied the paper mill, without which Hydro would have experienced a net financial loss for the year. In both the 2014 and 2015 Test Years, Exploits Generation is included in Hydro's revenue requirement at 4¢ per kWh. Holyrood fuel requirements and associated costs are forecasted to be less than they would otherwise be without the use of the Exploits Generation.

3.6 FINANCIAL OBJECTIVES AND TARGETS

The *Electrical Power Control Act*, *1994* directs that Hydro achieve and maintain a sound credit rating in the financial markets of the world. Hydro views a sound credit rating as one that achieves an appropriate balance between (a) maintaining the degree of financial stability required to deliver reliable electrical service in a safe manner, and (b) the overall cost of capital passed on to ratepayers. Beginning in 2008, the Government, undertook initiatives to improve Hydro's financial position and financial performance. This is reflected in the rate of return on rate base and capital structure that has been directed, and is proposed in this Application.

In 2009, the Government directed in OC2009-063 that Hydro would be allowed to earn ROE equal to that of NP which is currently 8.8%. This rate represents an increase over Hydro's current ROE of 4.47%, which is one of the lowest in the country compared to other similar utilities. In addition, the Government waived the debt guarantee fee for 2009 and 2010, and adjusted the method used to calculate the fee for 2011 and beyond to more closely reflect the market value of the guarantee.

In order to help improve Hydro's financial position, the Government provided a $100.0 million equity injection to improve the regulated capital structure and improve Hydro's stand alone financial position. The Government has also directed that going forward, Hydro can increase the amount of equity in its regulated capital structure[22], up to a maximum of that approved for NP, which is currently 45%. Currently, Hydro's dividend policy is aimed at maintaining debt at approximately 75%[23] of the regulated capital structure. This represents an improvement over previous years, when the debt to total capital ratio exceeded 80%. Maintenance of a strong financial position and stable financial performance will be critical when Hydro returns to the capital markets.

3.6.1 Target Return on Equity

ROE is a financial ratio determined by the net earnings available for distribution to shareholders after the payment of all expenses, including debt costs. An adequate level of return on equity is important because it allows flexibility to withstand unexpected and adverse economic circumstances that can put pressure on earnings. Therefore, Hydro's ROE target plays a key role in meeting its objective of maintaining a sound financial position.

In 2004, the Board ruled that, as an interim measure, Hydro's approved ROE would be equal to its marginal cost of debt of 5.83%. During the 2006 GRA, a negotiated settlement was reached that based Hydro's ROE on that 2004 methodology. This resulted in Hydro having an ROE target of 4.47% which, as illustrated in Chart 3.4, is the lowest in Canada.

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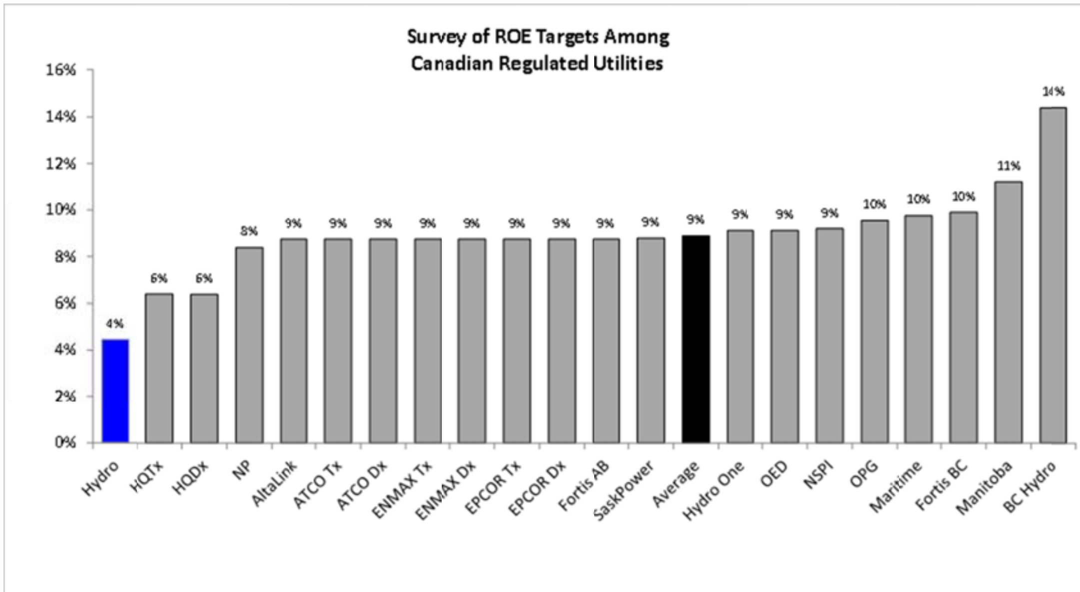
[22] The regulated capital structure referred to here differs from the regulated capital structure for rate making purposes, in that it does not include sources of customer-supplied capital, which is a regulatory concept. This approach is consistent with how external stakeholders (i.e. rating agencies) would assess Hydro's capital structure.

[23] In 2009, Hydro's Board of Directors approved a dividend policy whereby Hydro is to pay, on or before March 31 of each year, a dividend on common shares if the percentage of debt to debt plus equity in the regulated capital structure at the end of the preceding year is less than 75%. The amount of the dividend is to bring that percentage up to 75% based on the end of that previous fiscal year. As the dividend is not paid until March, the December 31 balance sheet for the previous fiscal year will not reflect a debt to debt plus equity ratio of 75%.

Chart 3.4



In its November 2012 rating for Hydro, DBRS expected that an ROE of 8.8% would help improve Hydro's earnings and overall financial profile. Therefore, increasing Hydro's target ROE to NP's level will be an important step toward the objective of achieving and maintaining a sound financial position.

3.6.2 Credit Standing

In its August 2012 Credit Rating Report on Hydro, Dominion Bond Rating Service (DBRS) confirmed ratings on Hydro's long-term debt at "A"[24] and its short-term debt as "R-1 (low)". DBRS pointed out in their commentary that Hydro's ratings continued to be "*a flow through of the rating of the Province of Newfoundland and Labrador (the "Province"), which unconditionally guarantees the Company's debt.*" The unconditional guarantee from the Province remains in place and as such, in its August 2014 Credit

[24] DBRS long-term debt ratings range from a low of D for a company in default, to a high of AAA, which denotes an exceptionally high financial capacity which is unlikely to be adversely affected by future events. Ratings above BBB are considered investment grade ratings. Short-term debt ratings follow a similar trend, ranging from R3 to R1 (high).

Rating Report for Hydro, DBRS confirmed the ratings on Hydro's long-term debt at "A" and its short-term debt as "R-1" (low). There has been no change in the status of the unconditional guarantee from the province.

3.6.3 Target for Allowable Range of Return on Rate Base

Board Order No. P.U. 8(2007) provided Hydro with an allowed return on rate base of 7.44% and established an allowable range of return on rate base of +/- 15 bps. For 2015, Hydro is proposing a return on rate base of 6.82%, which would correspond to an allowable range of 6.67% to 6.97% based on the previously established range. However, given the impact of the measures taken by the Government to improve the capital structure and the new higher return on equity, Hydro is proposing the allowable range of return on rate base be increased to +/-20 bps. This request is supported by a report prepared by Ms. Kathy McShane of Foster and Associates, which is included as Exhibit 6.

3.6.4 Hydro's Application

Hydro is proposing approval of the following:

- An increase in the allowed range of return from +/- 15 basis points (bps) to +/- 20 bps based on changes in the capital structure and the new approach to setting target return on equity.[25]

3.7 INTERCOMPANY CHARGES AND SHARED SERVICES

As a result of the 2007 Energy Plan, a new crown corporation was established to take a lead role in the development of the Province's energy resources.

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[25] Refer to Exhibit 6 for a corresponding report from Foster and Associates supporting this position.

> "*This Energy Corporation will be wholly owned by the Province and will be the parent company of Newfoundland and Labrador Hydro (NLH), Churchill Falls Labrador (CF(L)Co) Corporation, other subsidiaries currently owned by NLH and new entities created to manage the Province's investments in the energy sector. This will provide a structure that permits both regulated and non-regulated activities to exist and grow within separate legal entities.*"[26]

The Corporation was subsequently named Nalcor Energy. Hydro's mandate was expanded by its shareholder in 2005 and since that time new entities have been established. Nalcor assumed most of that expanded mandate and has also entered into new lines of business. Newfoundland and Labrador Hydro is now a 100% owned subsidiary of Nalcor.

3.7.1 Hydro Activities

The activities currently taking place in Hydro include:

1. Operations:
   The generation, transmission and distribution of electricity to serve customers on the Island Interconnected, Labrador Interconnected and Isolated Systems, including L'Anse au Loup.
2. Non-regulated Activities:
   Certain non-regulated activities including the sale of Recall energy to external markets and to non-regulated customers in Labrador West. Detailed descriptions of non-regulated activities can be found in Exhibit 7.

[26] 2007 Energy Plan, Page 14.

3. Corporate Services:
   The provision of services to support the regulated and non-regulated business of Hydro and other lines of business of Nalcor. This includes a range of activities including finance services, information services, supply chain management, human resources services, health and safety, as well as costs associated with the operation of Hydro Place.

3.7.2 Cost Recovery Methodologies

The expansion by Nalcor into lines of business other than electricity has resulted in changes in the organizational structure that has facilitated the sharing of resources among the Nalcor lines of business. The Nalcor companies have adopted cost-based methodologies for intercompany transactions and these transactions include labour charges, administration fees for services provided by Hydro to the other lines of business, as well as certain other costs and cost allocations.

The cost recovery methodologies employed adhere to the following principles:

Cost-based: Intercompany charges among lines of business are cost-based only.

> **Fair and reasonable:** The result of allocations should fairly and reasonably reflect the cost of providing a service. The allocation of a cost should reflect a causal relationship between the provision of a service and the cost.

> **Accurate and traceable:** The allocated charges should reflect the cost of the provision of services among entities with a reasonable degree of accuracy. Labour should be charged using time sheets based on work activity or, where there is cost sharing, the allocators should be a reasonable reflection of the cost driver.

Acceptable in a regulatory context: The methodology should be acceptable under a regulatory framework which demands a certain amount of rigor in development and design, taking into account the fact that results of the methodology may affect large groups of stakeholders, including end consumers of electrical energy in Newfoundland and Labrador.

Consistent with industry standards: The methodology should be consistent with industry standards and practices, where applicable, as well as best practices among Canadian utilities.

All costs charged across the lines of business are governed by the Intercompany Transaction Costing Guidelines attached as Exhibit 8.

3.7.3 Creation of the Nalcor Entity

Shared Services

Nalcor was created to "*permit(s) both regulated and non-regulated activities to exist and grow within separate legal entities*"[27]. Nalcor facilitates the sharing of personnel through a matrix organizational model as well as providing the ability to share costs associated with Hydro's head office facilities. As a result, in 2008, there were 24 positions transferred from regulated Hydro to Nalcor, primarily in the areas of Executive Leadership, Corporate Communications, Internal Audit and Finance, as well as staff associated with non-regulated activities in Hydro such as business development. This has had a positive impact on Hydro as costs are able to be shared among the lines of business. This reduction in costs created a strategic opportunity for Hydro to:

- Expand its engineering and operations workforce; and

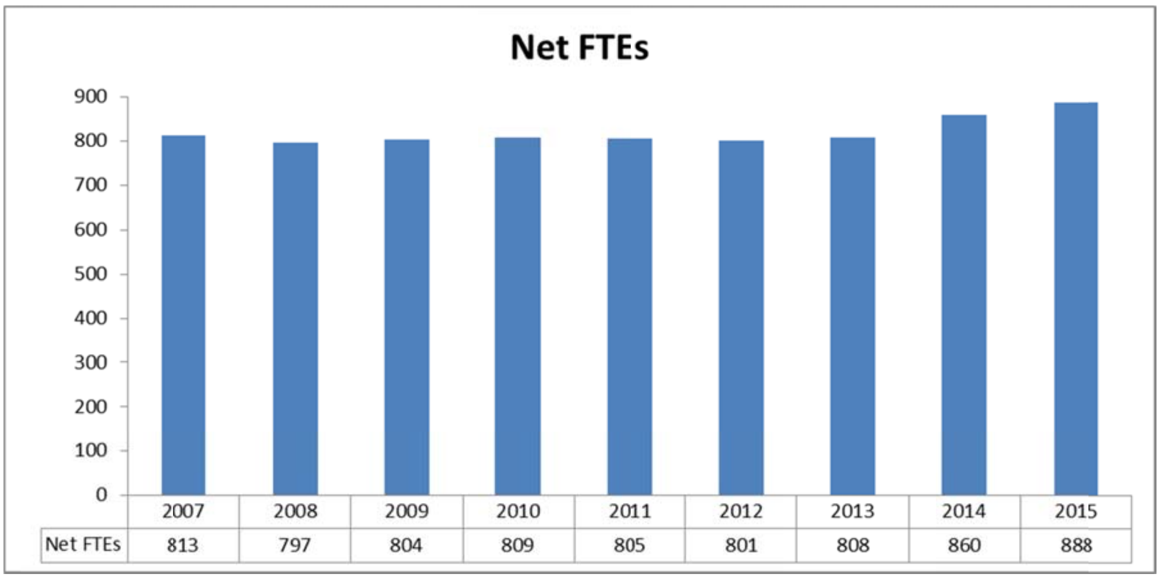
[27] 2007 Energy Plan, Page 14.

- Implement a retention and recruitment initiative, while keeping operating and maintenance costs close to inflationary levels.

Charts 3.5 to 3.7 show net FTE information for regulated Hydro. Net FTEs in this chart represent:

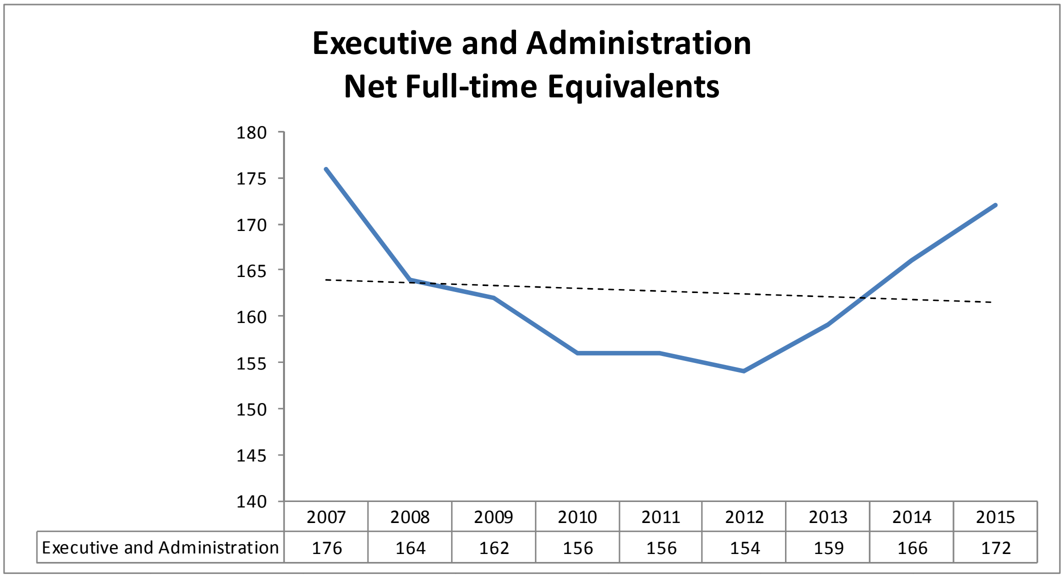
- Hydro employees' time less time charged to other lines of business; plus
- Employees' time in other lines of business who charge time to Hydro.

Chart 3.5[28]



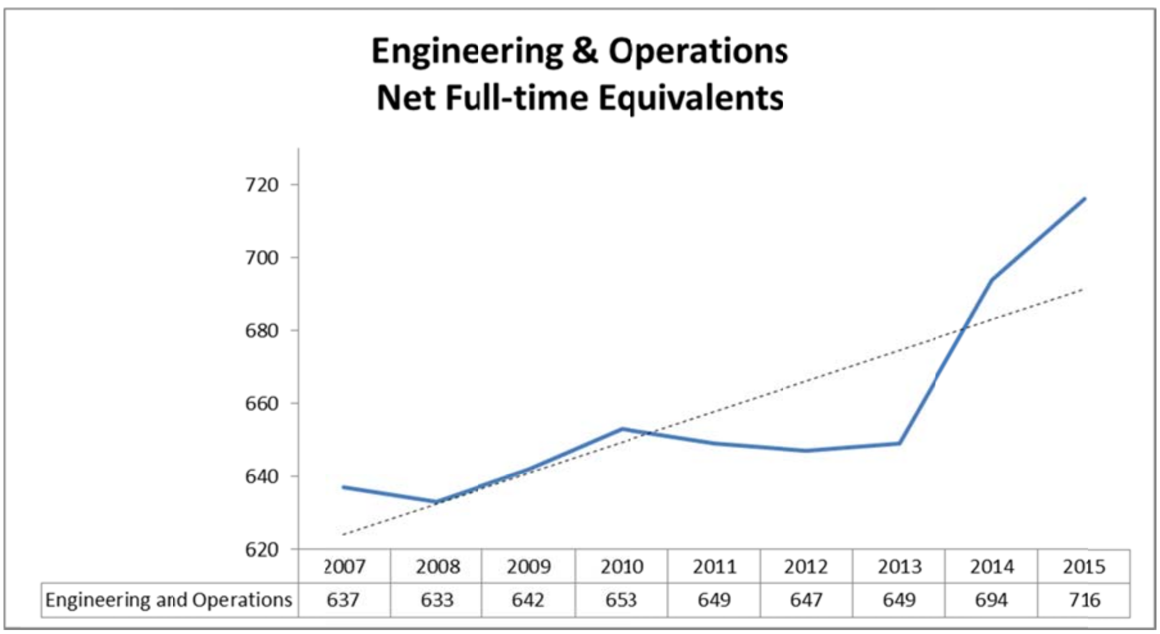
[28] Employees in common service business units are included as Hydro FTEs, however, costs are recovered through the Administration fee. Please refer to Exhibit 7 of this evidence for additional information.

Chart 3.6[29]



	2007	2008	2009	2010	2011	2012	2013	2014	2015
Executive and Administration	176	164	162	156	156	154	159	166	172

Chart 3.7



	2007	2008	2009	2010	2011	2012	2013	2014	2015
Engineering and Operations	637	633	642	653	649	647	649	694	716

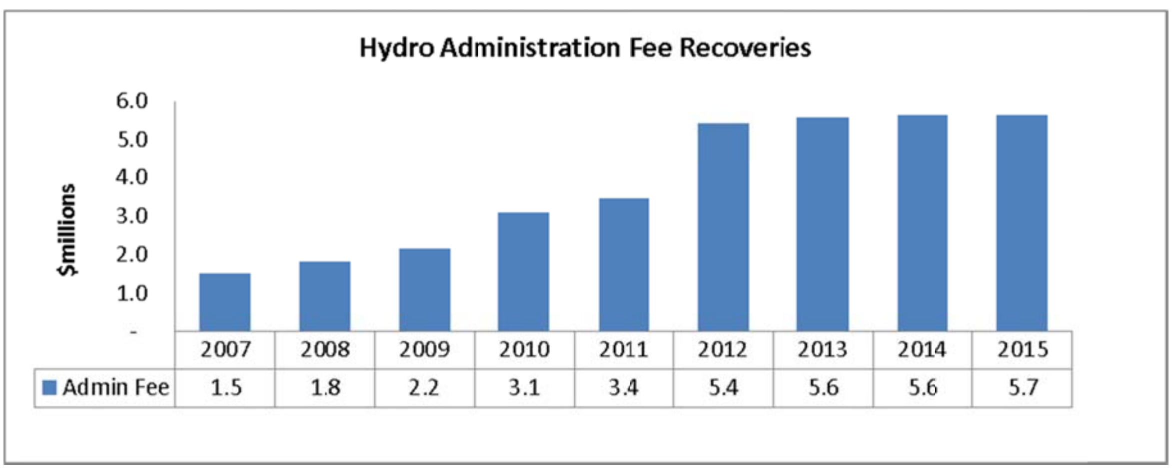
[29] Employees in common service business units are included as Hydro FTEs, however, costs are recovered through the Administration fee. Please refer to Exhibit 7 of this evidence for additional information.

As can be seen from Chart 3.6, Executive and Administration net FTEs in Hydro have decreased over the period 2007 to 2015 from 176 to 172. This is mainly the result of FTEs having been transferred out of Hydro to Nalcor. Chart 3.7 shows that there has been an increase in Engineering and Operations net FTEs over the period 2007 to 2015 from 637 to 716. The sharing of services among the Nalcor entities has resulted in the ability to redeploy Hydro's workforce. Hydro has also hired more of its own engineering staff where possible, rather than engaging external resources.

3.7.4 Administration Fees

Hydro Place is the head office of both Hydro and Nalcor. As a result, Hydro is now able to share common costs of Hydro Place, including interest and depreciation, with other Nalcor entities. These costs are recovered through administration fees that Hydro charges to, and recovers from, Nalcor's other lines of business. Administration fee recoveries are shown in Chart 3.8.

Chart 3.8



	2007	2008	2009	2010	2011	2012	2013	2014	2015
Admin Fee	1.5	1.8	2.2	3.1	3.4	5.4	5.6	5.6	5.7

There are also increased cost recoveries from shared services departments, such as HROE. Additional information regarding the administration fee can be found in the Intercompany Transaction Costing Guidelines in Exhibit 8.

3.7.5 Intercompany Costs – Other

Certain other costs are incurred by Hydro to serve all lines of business. Table 3.14 outlines the types of costs and methods of allocation.

Table 3.14

Intercompany Costs – Other	
Type of Cost	**Allocation**
Advertising expenses administered by Nalcor	Allocated
Audit expenses	Direct billed
Bonus, performance contracts and signing bonuses	Bill rate
Branding costs administered by Nalcor	Not charged
Capital costs of Hydro Place emergency diesel power system	Admin fee
Capital costs of printers and fax machines	Admin fee
Cell phone expenses	Direct billed
Consultant costs associated with building	Admin fee
Corporate memberships	Allocated
Cost of postage machines	Admin fee
Directors expenses	Direct billed
Directors fees	Direct billed
Equipment for fitness centre and cafeteria	Admin fee
Freight and courier expenses	Direct billed
Group insurance – Administration costs	Admin fee
Group insurance – premiums	Direct billed
Heat and light expenses	Admin fee
Insurance expenses	Direct billed or allocated as per industry standard
Local area network (LAN) costs expenses	Admin fee
Long distance expenses	Admin fee
Nalcor annual report and annual general meeting expenses	Allocated across lines of business
Office equipment and maintenance expenses	Admin fee
Operating costs of Hydro Place emergency diesel power system	Not allocated
Postage expenses	Admin fee
Print forms and supplies	Admin fee

Intercompany Costs – Other	
Type of Cost	**Allocation**
Purchase of miscellaneous office furniture	Admin fee
Rewards and recognition expenses	Admin fee
Routers, Multiplex (MUX), Switches acquisition costs	Admin fee
Safety supply expenses	Admin fee
Security system acquisition costs	Admin fee
Security system maintenance expenses	Admin fee
Telephone expenses	Admin fee
Telephone, LAN and wireless network acquisition costs	Admin fee
Treasury related fees	Direct billed
Wellness Program expenses	Admin fee

The allocation methods in Table 3.14 are defined as follows:

Administration fee (Admin fee) – Costs of common service business units, based in Hydro, that provide services to all Nalcor lines of business, are charged to the lines of business through an administration fee. Common service business units' costs include Human Resources, Safety and Health, Information Systems, Hydro Place office space and related costs and telephone and network costs. Further information is located in the Intercompany Transaction Costing Guidelines (Exhibit 8).

Allocated – Certain costs are allocated to lines of business using a causality based factor. For example, costs of the Human Resources department are allocated using FTEs. Further information is outlined in the Intercompany Transaction Costing Guidelines (Exhibit 8).

Bill Rate – Bill rate is the rate charged after a factor is applied to hourly wage rates to cover employee related costs such as fringe benefits, payroll taxes, bonuses and certain travel benefits. The factor is based on average total available working hours. Further information is outlined in the Intercompany Transaction Costing Guidelines in Exhibit 8.

Direct billed – Direct billed refers to costs that are clearly related to a line of business and can be billed directly to that entity (one to one relationship).

Not allocated/charged – Not allocated/charged refers to costs that are specific to one entity only or are not charged to another line of business. For example, Nalcor branding costs are not charged to Hydro and costs associated with the on-site diesel unit in Hydro Place, which is associated with Hydro's Energy Control Centre, are accounted for by Hydro.

3.8 REGULATORY DEFERRAL AND RECOVERY MECHANISMS

Hydro is proposing new deferral and recovery mechanisms for:

- CDM program costs;
- Isolated Systems energy supply cost variances; and
- Energy supply cost variances on the Island Interconnected System other than currently in place for Holyrood fuel.

Hydro will also be proposing to implement a deferred recovery mechanism for fuel cost variances resulting from variances from the Holyrood fuel conversion factor reflected in the 2015 Test Year by the end of 2014.

3.8.1 Background

The Board has approved a number of deferral mechanisms for both Hydro and Newfoundland Power. The Board has approved a deferred recovery approach for CDM program costs for Newfoundland Power and has historically approved that the amortization of external regulatory costs be reflected in Test Year costs.

3.8.2 Proposed Deferral and Recovery Mechanisms

CDM Cost Deferral

As discussed in Section 2.2.3, Hydro and NP have jointly undertaken CDM activities since 2009. Hydro has received approval[30] from the Board to defer its 2009, 2010, 2011, 2012, 2013 and 2014 CDM program expenditures.

Hydro is proposing that CDM expenditures be recovered through a separate recovery mechanism. CDM program expenditures vary based upon circumstances often outside Hydro's control. Hydro Rural CDM costs vary based upon customer uptake and the introduction of new programs. Expenditures on CDM for the Island IC can vary materially by year as they are customized programs with a small customer base.

In the Amended Application, Hydro is proposing a CDM Cost Deferral Account. The proposed deferral account definition is provided as Schedule V to this evidence. The recovery mechanism proposed for CDM costs is outlined in Section 4.11 and in pages 18 to 19 of the Rates schedules. Hydro's proposal for CDM cost deferral is consistent with the approach approved for NP at its 2013/14 GRA.

Isolated Systems Supply Cost Variance Deferral

Over the past several years, diesel fuel and certain power purchase prices have been subject to the same upward pressures as Holyrood fuel costs. Chart 3.9 below illustrates Montreal rack prices for diesel fuel from 2007-2013.

[30] Order No. P.U. 14(2009); Order No. P.U. 13(2010); Order No. P. U. 4(2011); Order No. P.U. 3(2012); and Order No. P.U. 43(2014).

Chart 3.9

Diesel Fuel Price Variability[31]

As shown in Chart 3.9, the year over year average price has varied by more than 50%.[32] Variances of this magnitude relative to the price reflected in customer rates expose Hydro to material risk in recovery of Isolated System supply costs.

Hydro's Isolated System supply cost variances from 2007 to 2013 relative to the 2007 Test Year have ranged from \$0.3 million to approximately \$6 million. For each year since 2007, the price variation has negatively impacted Hydro's financial results.

Table 3.15 below provides an illustration of the cost variation with a 10% change in Isolated System supply cost from the 2015 Test Year forecast.

[31] Data obtained from NRCan – Montreal Rack Prices January 2007 - December 2013
[32] Illustrated Example: 2009 Yearly Average 56.89 cents, 2008 Yearly Average of 88.18 cents.

Table 3.15

Supply Cost Variation Example			
2015 Supply Cost/kWh	**10% Unit Cost Variance**	**kWh Supply**	**Total Cost Variance**
$0.30	$0.03	72,757,503	$2,182,725

Hydro is proposing an Isolated Systems Supply Cost Variation Deferral Account to provide Hydro a reasonable opportunity to recover its supply costs on the Isolated Systems. Hydro is proposing a variance threshold of ±$500,000 prior to any transfer to/from the deferral account. The deferral account provides for recovery of isolated system supply costs outside of this range. An Application to the Board would be required annually for disposition of any accrued balance. The details of the proposed deferral account definition are provided in Schedule VI to this evidence.

Energy Supply Cost Variance Deferral

As discussed in Sections 2 and 3, Hydro has been able, in recent years, to acquire additional power purchases from hydraulic and wind generators. As shown in Section 2, Schedule V, power purchases account for approximately 14% of the 2015 forecast total energy requirements on the Island Interconnected System, while Holyrood production is forecast to account for 22%. There is a material difference between the price of power purchases (a range of 4¢ to 15¢ per kWh) and the 2015 Holyrood fuel cost of 15.37 cents per kWh[33] for No. 6 fuel at Holyrood.

[33] Forecast Average No. 6 Fuel cost per bbl divided by Holyrood conversion factor ($93.32/607 = 15.37¢ per kWh)

Other variances, both quantity and price, in Island Interconnected supply costs result when diesel and/or gas turbine production varies from the Test Year assumption.[34] These sources of generation are not normally called upon to meet normal energy requirements of energy as they are used primarily for system peaking, area supply requirements, or energy requirements in the event of system generation constraints or outages.

Holyrood production remains the marginal supply for energy on the Island Interconnected System, meaning that increases or decreases in power purchases vary the amount of fuel required to be consumed at Holyrood. Variances in the quantity of other sources of supply could cause significant volatility in the amount of fuel burned at Holyrood from year to year.

The magnitude of Hydro's Island Interconnected energy supply costs is such that Hydro also proposes to stabilize its prices. The terms of the various PPAs also provide for variations in the purchase price of power. Other than for the Exploits power purchase, each of the PPA rates has a fixed and variable component. The variable component is escalated annually in accordance with the provisions of each of the contracts, based on the Consumer Price Index. The rate for purchases from Exploits Generation has, to date, been set at 4¢ per kWh.

In the Amended Application, Hydro is proposing an Energy Supply Cost Variance Deferral Account for annual energy supply cost variances on the Island Interconnected System. Mechanisms that permit recovery of energy supply costs by utilities are common in

[34] For example, Hydro incurred $5.5 million additional fuel cost relative to forecast in the first quarter of 2014 for the operation on the Island Interconnected System of Hydro's diesels, gas turbines and Newfoundland Power thermal generation.

Canadian regulatory practice.[35] Hydro is proposing an annual cost variance threshold of ±$500,000 whereby any variance up to ±$500,000 will be borne by Hydro, and amounts in excess of this threshold will be deferred in this account. An Application to the Board would be required annually for approval to dispose of any balance in this account. The proposed deferral account definition is provided as Schedule VII to this evidence.

Holyrood Conversion Factor Deferral

At present, Hydro uses a fuel to energy conversion rate of 630 at Holyrood. In the Amended Application, Hydro is proposing to reduce this factor to 607 as outlined in Section 2.6.1 of this evidence. Hydro is seeking to defer all fuel cost variances that result when the actual conversion factor differs from 607 kWh per barrel. Hydro will submit supplemental evidence outlining the proposed deferral account and recovery method before the end of 2014.

3.8.3 Hydro's Application

Hydro is requesting approval of the following:

- To exclude Hydro's CDM program costs as an expense in the determination of revenue requirement and to approve a CDM Cost Deferral Account;
- An Isolated Systems Supply Cost Variation Deferral Account to provide Hydro a reasonable opportunity to recover its supply costs on the Isolated Systems; and
- An Energy Supply Cost Variance Deferral Account for energy supply cost variances on the Island Interconnected System, other than that currently in place, to recover Holyrood fuel.

[35] Source: Report on Supply Cost Mechanisms filed by Newfoundland Power in 2013/2014 General Rate Application.

3.9 OTHER COST AND ACCOUNTING MATTERS

3.9.1 Accounting Changes

Accounting Reporting Standards

Hydro adopted International Financial Reporting Standards for external reporting purposes in 2014. To remain consistent with Hydro's 2013 GRA filing, Hydro did not change presentation to IFRS for the amended GRA filing. There is no material impact on Hydro's average rate base or revenue requirement from the adoption of IFRS, and therefore no impact on ratepayers.

3.9.2 Employee Future Benefits

Hydro provides a severance payment upon retirement and group life insurance and health care benefits on a cost-shared basis to retired employees. The expected cost of providing these EFBs is accounted for on an accrual basis, and has been actuarially determined using the projected benefit method prorated on service and using management's best estimate of salary escalation, retirement ages of employees, and expected health care costs. Schedule I, Page 8 of 11, shows the details of Hydro's EFB liability and obligation for the period 2007 through 2015.

Prior to 2011, the EFB liability included only the amortized portion of cumulative actuarial gains and losses with the remainder deferred and amortized to income over the expected average remaining service life of the employee group (referred to as the corridor method). To minimize regulatory and external accounting differences due to changes in accounting standards, the Board approved Order No. P.U. 13(2012). Under this Order, Hydro effectively deferred all actuarial gains and losses. Using this methodology for the 2014/2015 Test Years would result in a portion of the expense associated with EFBs being excluded from Hydro's revenue requirement. The cumulative actuarial gains and losses of these EFBs are a significant component of the cost of providing retirement benefits to utility employees, and therefore basic to the public utility's operation. As such, Hydro has included these costs in the proposed 2014/2015 revenue requirement, consistent with the methodology used to establish existing rates.

3.9.3 Asset Retirement Obligations

Asset Retirement Obligations represent legal or constructive obligations associated with the retirement of long-lived assets. Accounting standards require that the estimated present value of the AROs be added to the original cost of the related asset (an Asset Retirement Cost, or "ARC") and an offsetting liability be recognized. Over time, the ARC is depreciated and the ARO increases (or accretes) toward its future value.

Hydro recorded a liability for decommissioning long-lived assets in the 2010 audited financial statements. In fiscal year 2011, the financial reporting of accretion and depreciation expense on AROs commenced. Hydro applied to the Board in May 2012 to include depreciation and accretion expenses in its next GRA for the purposes of recovering the costs from ratepayers through revenue requirement. In Order No. P.U. 29(2012), the Board ordered that Hydro recognize and record asset retirement obligations, and indicated that regulatory treatment of AROs would appropriately be considered within the context of a GRA. In 2012, Hydro continued to record and report, in the audited financial statements, AROs and corresponding expenses in accordance with Canadian GAAP.

Existing AROs

Hydro has recorded AROs for the following:

- <u>Holyrood Dismantling and Cleanup Costs (Holyrood ARO):</u>
  In 2010, planning for the conversion of Holyrood to a synchronous condenser operation was contemplated. This future conversion would require the decommissioning of certain components of the Holyrood facility. The Holyrood ARO was initially recorded in Hydro's 2010 financial statements

using the best information available at that time, and was then updated in Hydro’s 2011 financial statements with revised projections. In 2012, Hydro hired an external firm to prepare a report on the decommissioning of the Holyrood Thermal Generating Station (Exhibit 14) and updated the ARO in the 2012 financial statements based upon the results of the report. The total undiscounted estimated cash flows required to settle the Holyrood ARO as at December 31, 2012 was $32.1 million.

- <u>Transformers Containing Polychlorinated Biphenyls (PCBs) (PCB ARO):</u> Hydro, like other CEA members, has a significant amount of sealed equipment (instrument transformers and bushings) with unknown levels of PCBs. Federal Government PCB Regulations SOR/2008-273, state in Section 16 that the end-of-use date for equipment containing PCBs that are above 500 mg/kg was December 31, 2009. In 2009 Hydro applied for and, in 2010, was granted an extension to 2014 by Environment Canada (EC) to replace sealed equipment that is suspected to contain PCBs above 500 mg/kg. Hydro’s Application document to EC stated that due to the volume of equipment requiring replacement the plan was a “pro forma” plan, and a more realistic plan would be to extend the replacement to 2025. EC subsequently proposed an amendment on June 6, 2013 to the regulations which would increase the deadline from 2014 to 2025 and are accepting comments for 60 days. Hydro has recorded an ARO reflecting the legal obligation to dispose of sealed instrument transformers and bushings expected to contain PCBs.

  The total undiscounted estimated cash flows required to settle the PCB ARO at December 31, 2013 was $1.9 million. Cash payments to settle the obligations began in 2012 and are expected to continue until 2025.

Depreciation costs of $2.3 million and accretion costs of $0.9 million are included in the 2015 Test Year Revenue Requirement for AROs.

3.9.4 Hydro's Application

Hydro is requesting the Board's approval for the following:

- To include actuarial gains and losses associated with Employee Future Benefits of $1.6 million in the 2015 Test Year as part of the revenue requirement; and
- To include depreciation and accretion expenses associated with asset retirement obligations of $3.1 million and $3.2 million for 2014 and 2015 Test Years, respectively in revenue requirement and to include the asset retirement obligations as a component of rate base.

LIST OF SCHEDULES

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Statement of Income and Retained Earnings
($000s)

		Actual							Test year	Test year
		2007	2008	2009	2010	2011	2012	2013	2014	2015
1	**Revenue**									
2	Energy sales	429,794	425,196	425,528	414,774	443,796	453,178	472,785	514,599	659,967
3	Revenue defeciency	-	-	-	-	-	-	-	45,921	-
3	Other revenue	1,983	2,197	2,218	2,287	2,317	2,116	2,343	2,335	2,508
4	**Total revenue**	431,777	427,393	427,746	417,061	446,113	455,294	475,128	562,855	662,475
5										
6	**Expenses**									
7	Operating expenses	97,693	96,694	100,369	96,976	104,564	106,468	111,812	126,068	138,179
8	Other Income and expense	902	2,580	1,267	687	925	5,396	3,634	2,068	4,074
9	Fuels	150,281	149,854	136,933	137,994	131,275	132,003	155,957	201,714	267,820
10	Fuel supply deferral	-	-	-	-	-	-	-	(9,956)	1,991
11	Power purchases	38,606	41,388	46,782	44,244	52,222	56,986	59,379	66,668	63,254
12	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	50,832	55,214	63,792
13	Accretion of asset retirement obligation	-	-	-	-	467	715	911	852	878
14	Interest	103,242	87,610	83,440	86,766	90,844	89,961	92,394	89,723	89,255
15	**Total expenses**	429,066	418,519	410,535	410,457	425,514	438,394	474,919	532,351	629,243
16										
17	**Net income**	2,711	8,874	17,211	6,604	20,599	16,900	209	30,504	33,232
18										
19	**Retained earnings**									
20	Balance at beginning of year	208,147	210,858	219,732	236,943	212,647	212,096	231,174	231,383	261,887
21	Opening adjustment - retained earnings	-	-	-	-	-	2,178	-	-	-
22	Dividends	-	-	-	(30,900)	(21,150)	-	-	-	-
23	**Balance at end of year**	210,858	219,732	236,943	212,647	212,096	231,174	231,383	261,887	295,119

($000s)

		Actual							Test year	Test year
		2007	2008	2009	2010	2011	2012	2013	2014	2015
1	**Assets**									
2	Current assets									
3	Cash and cash equivalents	-	-	10,942	37,760	6,685	2,480	6,726	-	12,113
4	Short-term investments	-	-	20,000	8,992	-	-	-	-	-
5	Accounts receivable	69,114	69,495	65,703	61,678	79,569	80,373	85,383	74,201	72,648
6	Current portion of regulatory assets	17,154	5,000	4,789	3,851	2,762	2,157	2,157	5,193	5,776
7	Inventory	60,925	42,993	49,964	53,390	54,258	51,673	63,974	116,151	109,014
8	Prepaid expenses	841	1,156	1,492	2,322	2,284	2,949	2,742	3,342	3,366
9	Current portion of sinking funds	-	-	-	-	-	-	65,426	-	-
10		148,034	118,644	152,890	167,993	145,558	139,632	226,408	198,887	202,917
11										
12	Property, plant, and equipment	1,352,229	1,354,348	1,364,205	1,386,061	1,410,432	1,440,619	1,463,070	1,673,188	1,889,482
13	Sinking funds	151,765	163,881	179,613	208,381	246,966	263,330	202,184	220,536	238,850
14	Regulatory assets	81,308	74,626	69,324	65,885	63,597	62,824	62,117	72,939	71,074
15										
16	**Total assets**	1,733,336	1,711,499	1,766,032	1,828,320	1,866,553	1,906,405	1,953,779	2,165,550	2,402,323
17										
18	**Liabilities and shareholder equity**									
19	Current liabilities									
	Bank Indebtedness									
20	Promissory notes	8,016	4,557	-	-	-	52,000	41,000	145,564	-
21	Accounts payable and accrued liabilities	65,295	46,212	51,115	65,237	49,341	39,299	66,796	66,914	27,694
22	Accrued interest	30,566	28,667	28,667	28,667	28,667	28,667	28,667	27,468	23,868
23	Current portion of long-term debt	208,315	8,322	8,150	8,150	8,150	8,150	82,150	8,150	8,150
24	Current portion of regulatory liabilities	23,488	22,324	89,814	118,849	137,593	168,985	213,997	185,438	175,525
25	Deferred capital contribution	-	470	165	123	3,497	1,938	702	-	-
26	Due to related parties	182	450	21,441	37,224	49,258	1,873	731	413	687
27	Promissory notes - non-regulated	(33,421)	145,004	(3,531)	(5,521)	(5,118)	(7,217)	(8,187)	(8,187)	(8,187)
28		302,441	256,006	195,821	252,729	271,388	293,695	425,856	425,760	227,737
29										
30	Long-term debt	1,145,198	1,146,414	1,141,618	1,136,755	1,131,542	1,125,901	1,046,658	1,243,892	1,641,394
31	Regulatory liabilities	15,499	31,546	32,788	40,931	33,271	33,174	40,268	11,935	9,022
32	Asset retirement obligations	-	-	-	11,395	19,593	24,031	24,094	24,792	25,526
33	Employee future benefits	39,805	41,881	44,060	48,348	53,556	56,890	61,553	66,213	72,454
34	Contributed capital	-	-	100,000	100,000	100,000	100,000	100,000	100,000	100,000
35	Shareholder's equity / retained earnings	210,858	219,732	236,943	212,647	212,096	231,174	231,383	261,887	295,119
36	Accumulated other comprehensive income	19,535	15,920	14,802	25,515	45,107	41,540	23,967	31,071	31,071
37										
38	**Total liabilities and shareholder's equity**	1,733,336	1,711,499	1,766,032	1,828,320	1,866,553	1,906,405	1,953,779	2,165,550	2,402,323

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Statement of Cash Flows
($000s)

		Actual							Test year	Test year
		2007	2008	2009	2010	2011	2012	2013	2014	2015
1	**Cash provided by (used in)**									
2	**Operating activities**									
3	Net income	2,711	8,874	17,211	6,604	20,599	16,900	209	30,504	33,232
4	Adjusted for items not involving cash flow									
5	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	50,832	55,214	63,792
6	Accretion of long-term debt	675	479	394	426	460	498	540	514	495
7	Accretion of asset retirement obligation	-	-	-	-	467	715	911	852	878
9	Employee future benefits	4,268	2,560	2,179	4,288	5,208	4,521	4,663	4,660	6,241
10	Loss on disposal of property, plant and equipment	902	2,580	1,267	687	925	3,844	2,687	1,230	1,904
11	Other	(92)	-	-	-	-	92	(273)	-	-
12		46,806	54,886	62,795	55,795	72,876	73,435	59,569	92,974	106,542
13	**Changes in non-cash balances**									
14	Accounts receivable	(9,698)	(381)	3,792	4,025	(17,891)	(804)	(5,010)	11,182	1,553
15	Inventory	(15,482)	17,932	(6,971)	(3,426)	(868)	2,585	(12,301)	(52,177)	7,137
16	Prepaid expenses	244	(315)	(336)	(830)	38	(665)	207	(600)	(24)
17	Regulatory assets	49,744	18,836	5,513	4,377	3,377	1,378	707	(13,858)	1,282
18	Regulatory liabilities	(11,382)	14,883	68,732	37,178	11,084	31,295	52,106	(56,892)	(12,826)
19	Accounts payable and accrued liabilities	27,214	(19,083)	4,903	14,122	(15,896)	(10,042)	27,497	118	(39,220)
20	Accrued interest	-	(1,899)	-	-	-	-	-	(1,199)	(3,600)
21	Due to related parties	(3,288)	268	20,991	15,783	12,034	(47,385)	(1,142)	(318)	274
23		84,158	85,127	159,419	127,024	64,754	49,797	121,633	(20,770)	61,118
24	**Financing activities**									
25	Increase (decrease) in long-term debt	12,691	(188,692)	(172)	-	-	-	-	200,000	400,000
26	Increase (decrease) in deferred capital contribution	-	470	(305)	(42)	3,374	(1,559)	(1,236)	(702)	-
27	Sinking Fund Retirement	-	-	-	-	-	-	-	72,219	
28	Long-term debt repayment	-	-	-	-	-	-	-	(72,158)	
29	Increase in contributed capital	-	-	100,000	-	-	-	-	-	-
30	Dividends	-	-	-	(30,900)	(21,150)	-	-	-	-
31	(Decrease) increase in promissory notes - non-regulated	(49,483)	172,911	(148,535)	(1,990)	403	(2,099)	(970)	-	-
32	Increase (decrease) in promissory notes	-	-	-	-	-	52,000	(11,000)	104,564	(145,564)
33	Transfer of employee future benefits to non-regulated	-	(484)	-	-	-	-	-	-	-
34		(36,792)	(15,795)	(49,012)	(32,932)	(17,373)	48,342	(13,206)	303,923	254,436
35	**Investing activities**									
36	Additions to property, plant and equipment	(36,023)	(45,785)	(54,097)	(55,401)	(63,083)	(77,474)	(80,657)	(268,023)	(282,106)
37	Decrease (increase) in short term investments	560	-	(20,000)	11,008	8,992	-	-	-	-
38	Proceeds on disposal of property, plant and equipment	602	693	1,229	463	301	1,200	3,997	1,461	115
39	Settlement of asset retirement obligation	-	-	-	-	-	-		(154)	(144)
40	Increase in sinking funds	(19,592)	(20,781)	(22,040)	(23,344)	(24,666)	(26,070)	(27,521)	(23,163)	(21,306)
41		(54,453)	(65,873)	(94,908)	(67,274)	(78,456)	(102,344)	(104,181)	(289,879)	(303,441)
42										
43	**Net (decrease) increase in cash**	(7,087)	3,459	15,499	26,818	(31,075)	(4,205)	4,246	(6,726)	12,113
44										
45	**Cash position, beginning of year**	(929)	(8,016)	(4,557)	10,942	37,760	6,685	2,480	6,726	-
46										
47	**Cash position, end of year**	(8,016)	(4,557)	10,942	37,760	6,685	2,480	6,726	-	12,113

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Capital Structure
($000s)

		Actual							Test year	Test year
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**Regulated capital structure**									
2	Long-term debt	1,353,513	1,154,736	1,149,768	1,144,905	1,139,692	1,134,051	1,128,808	1,252,042	1,649,544
3	Promissory notes	7,000	163,000	-	-	-	52,000	41,000	145,564	-
4	Promissory notes - related party	88	90	-	-	-	-	-	-	-
5	less: sinking funds	(151,765)	(163,881)	(179,613)	(208,381)	(246,966)	(263,330)	(267,610)	(220,536)	(238,850)
6	add: mark to market of sinking funds	19,535	15,920	14,802	25,515	45,108	41,425	23,967	31,071	31,071
7		1,228,371	1,169,865	984,957	962,039	937,834	964,146	926,165	1,208,141	1,441,765
8	Cost of service exclusions	-	-	-	-	-	-	-	-	-
9	Non-regulated debt pool	(40,421)	(17,996)	(3,531)	(5,521)	(5,118)	(7,217)	(8,187)	(8,187)	(8,187)
10	Net regulated debt	1,187,950	1,151,869	981,426	956,518	932,716	956,929	917,978	1,199,954	1,433,578
11	Asset retirement obligation	-	-	-	11,395	19,593	24,031	24,094	24,792	25,526
12	less: unfunded asset retirement obligation	-	-	-	(11,395)	(17,976)	(19,685)	(16,715)	(14,442)	(12,169) A
13	Employee future benefits	39,805	41,881	44,060	48,348	53,556	56,890	61,553	66,213	72,454
14	Contributed capital	-	-	100,000	100,000	100,000	100,000	100,000	100,000	100,000
15	Retained earnings cost of service exclusions	-	-	-	-	-	113	641	977	1,300
16	Retained earnings	210,858	219,732	236,943	212,647	212,096	231,174	231,383	261,887	295,119
17	**Total**	1,438,613	1,413,482	1,362,429	1,317,513	1,299,985	1,349,452	1,318,934	1,639,381	1,915,808
18										
19	**Regulated capital structure (%)**									
20	Debt	82.5%	81.5%	72.1%	72.6%	71.8%	70.9%	69.6%	73.2%	74.8%
21	Asset retirement obligation	0.0%	0.0%	0.0%	0.0%	0.1%	0.3%	0.6%	0.6%	0.7%
22	Employee future benefits	2.8%	3.0%	3.2%	3.7%	4.1%	4.2%	4.7%	4.0%	3.8%
23	Equity	14.7%	15.5%	24.7%	23.7%	24.0%	24.5%	25.2%	22.1%	20.7%
24	**Total**	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
25										
26	**Regulated average capital structure (%)**									
27	Debt		82.0%	76.8%	72.4%	72.2%	71.4%	70.3%	71.4%	74.0%
28	Asset retirement obligation		0.0%	0.0%	0.0%	0.1%	0.2%	0.4%	0.6%	0.7%
29	Employee future benefits		2.9%	3.1%	3.4%	3.9%	4.2%	4.4%	4.4%	3.9%
30	Equity		15.1%	20.1%	24.2%	23.8%	24.3%	24.9%	23.65%	21.4%
31	**Total**		100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
32										
33	**Weighted average cost of capital (WACC)**									
34	Embedded cost of debt		8.26%	8.26%	8.26%	8.26%	8.26%	8.30%	7.33%	6.67%
35	Asset retirement obligation		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
36	Employee future benefits		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Equity		4.47%	4.47%	4.47%	4.47%	4.47%	4.47%	8.80%	8.80% B
38	**WACC**		7.45%	7.24%	7.06%	7.03%	6.98%	6.94%	7.32%	6.82%

A The asset retirement obligation is not part of capital structure until it has been funded by rate payers. As such, the unfunded amount is removed. The funded amount includes the depreciation and accretion charges that have been recorded in net income.
B Proposed 2015 return on equity based on NP's approved return on equity.

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate of Return on Rate Base
($000s)

		Actual							Test year	Test year
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**Property, plant, and equipment**	1,352,229	1,354,348	1,364,205	1,386,061	1,410,432	1,440,619	1,463,070	1,673,188	1,889,482
2	add: accumulated depreciation	570,225	603,362	632,085	669,742	707,241	88,865	138,317	193,532	203,834
3	add: contributions in aid of construction	96,396	96,143	96,749	97,257	98,054	14,052	15,786	16,550	17,936
5	less: work in progress	(2,535)	(9,456)	(10,579)	(17,002)	(23,736)	(32,948)	(13,822)	(42,950)	(240,977)
6	**Capital assets in service**	2,016,315	2,044,397	2,082,460	2,136,058	2,191,991	1,510,588	1,603,351	1,840,320	1,870,275
7	less: asset retirement obligation	-	-	-	(11,395)	(17,976)	(19,685)	(16,715)	(14,442)	(12,169) A
8	less: contributions in aid of construction	(96,396)	(96,143)	(96,749)	(97,257)	(98,054)	(14,052)	(15,786)	(16,550)	(17,936)
9	less: accumulated depreciation	(570,225)	(603,362)	(632,085)	(669,742)	(707,241)	(88,865)	(138,317)	(193,532)	(203,834)
10	**Capital assets - current year**	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986	1,432,533	1,615,796	1,636,336
11	**Capital assets - previous year**	1,345,766	1,349,694	1,344,892	1,353,626	1,357,664	1,368,720	1,387,986	1,432,533	1,615,796 B
12	Unadjusted capital assets - average	1,347,730	1,347,293	1,349,259	1,355,645	1,363,192	1,378,353	1,410,259	1,524,165	1,626,066
13	less: Average net assets not in use	-	-	-	(777)	(423)	(1,428)	(7,102)	(2,941)	(2,605)
14	**Capital assets - average**	1,347,730	1,347,293	1,349,259	1,354,868	1,362,769	1,376,925	1,403,157	1,521,224	1,623,461
15										
16	Cash working capital allowance	3,496	3,548	2,668	3,092	4,625	7,810	5,875	9,207	7,037
17	Fuel	25,874	34,389	20,817	29,908	33,680	50,308	48,949	65,110	66,633
18	Materials and supplies	21,699	22,561	23,567	24,089	24,096	25,339	25,763	25,823	27,402
19	Deferred charges	84,725	81,996	76,870	71,925	68,048	65,670	64,627	71,203	77,491
20										
21	**Average rate base**	1,483,524	1,489,787	1,473,181	1,483,882	1,493,218	1,526,052	1,548,371	1,692,567	1,802,024
22										
23	Unadjusted return on regulated equity	2,711	8,874	17,211	6,604	20,599	16,900	209	30,504	33,232
24	add: Cost of service exclusions	-	-	-	-	-	113	528	336	323
25	Interest	103,242	87,610	83,440	86,766	90,844	89,961	92,394	89,723	89,255
26	**Return on rate base**	105,953	96,484	100,651	93,370	111,443	106,974	93,131	120,563	122,810
27										
28	**Rate of return on rate base**	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	6.01%	7.12%	6.82%

A Asset retirement obligation costs are not funded through debt or Hydro funds, but are to be fully recovered from rate payers over the life of the asset retirement obligation through depreciation. As such, we remove these costs from rate base.

B 2012 'Capital assets - previous year' value reflects Order No. P.U. 13 (2012).

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Revenue Requirement Analysis
($000s)

		Actual							Test year	Test year
		2007	2008	2009	2010	2011	2012	2013	2014	2015
1	**Revenue requirement**									
2	Energy sales	429,794	425,196	425,528	414,774	443,796	453,178	472,785	514,599	659,967
3	Revenue defeciency	-	-	-	-	-	-	-	45,921	-
4	Other revenue	1,983	2,197	2,218	2,287	2,317	2,116	2,343	2,335	2,508
5	**Total revenue requirement**	431,777	427,393	427,746	417,061	446,113	455,294	475,128	562,855	662,475
6										
7	**Expenses**									
8	Operating expenses	97,693	96,694	100,369	96,976	104,564	106,468	111,812	126,068	138,179
9	Other income and expense	902	2,580	1,267	687	925	5,396	3,634	2,068	4,074
10	Fuels	150,281	149,854	136,933	137,994	131,275	132,003	155,957	201,714	267,820
11	Fuel supply deferral	-	-	-	-	-	-	-	(9,956)	1,991
12	Power purchases	38,606	41,388	46,782	44,244	52,222	56,986	59,379	66,668	63,254
13	Amortization	38,342	40,393	41,744	43,790	45,217	46,865	50,832	55,214	63,792
14	Accretion of asset retirement obligation	-	-	-	-	467	715	911	852	878
15	**Expenses prior to cost of service exclusions**	325,824	330,909	327,095	323,691	334,670	348,433	382,525	442,628	539,988
16	less: Cost of service exclusions	-	-	-	-	-	(113)	(528)	(336)	(323)
17	**Total expenses**	325,824	330,909	327,095	323,691	334,670	348,320	381,997	442,292	539,665
18	**Return on rate base**	105,953	96,484	100,651	93,370	111,443	106,974	93,131	120,563	122,810
19										
20	**Average rate base**	1,483,524	1,489,787	1,473,181	1,483,882	1,493,218	1,526,052	1,548,371	1,692,567	1,802,024
21										
22	**Rate of return on rate base**	7.14%	6.48%	6.83%	6.29%	7.46%	7.01%	6.01%	7.12%	6.82%

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate Stabilization Plan
($000s)

		Actual							Test year	Test year
		2007	2008	2009	2010	2011	2012	2013	2014	2015
1	**Historical rate stabilization plan balances**									
2	Utility	12,053	-	-	-	-	-	-	-	-
3	**Total**	12,053	-	-	-	-	-	-	-	-
4										
5	**Current rate stabilization plan**									
6	Hydraulic	(14,820)	(30,903)	(32,562)	(40,399)	(32,737)	(32,676)	(39,801)	(11,505)	(8,629)
7	Utility	(14,652)	(10,330)	(53,069)	(56,251)	(55,940)	(64,905)	(80,174)	(25,730)	(4,601)
8	Industrial	(8,829)	(11,994)	(36,884)	(62,612)	(81,653)	(104,080)	566	8,347	8,592
9	Segregated Load Variation	-	-	-	-	-	-	(8,200)	(33,095)	(35,351)
10	Utility Surplus	-	-	-	-	-	-	(115,330)	(124,014)	(132,468)
11	Industrial Surplus	-	-	-	-	-	-	(10,858)	(11,031)	(11,783)
12	**Total**	(38,301)	(53,227)	(122,515)	(159,262)	(170,330)	(201,661)	(253,797)	(197,028)	(184,240)
13										
14	**Combined rate stabilization plan balances**	(26,248)	(53,227)	(122,515)	(159,262)	(170,330)	(201,661)	(253,797)	(197,028)	(184,240)
15										
16	**Average fuel cost per barrel**	$ 52.51	$ 71.59	$ 52.51	$ 73.90	$ 91.92	$ 114.80	$ 106.63	$ 109.59	$ 93.32

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Employee Future Benefits
($000s)

		Actual							Test year	Test year
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**Accrued employee future benefits liability**									
2	Balance at beginning of year	35,537	39,805	41,881	44,060	48,348	52,207 A	56,890	61,553	66,213
3	Current service	1,885	1,666	1,143	1,651	2,068	2,875	3,178	3,177	3,177
4	Interest	3,057	3,079	3,197	3,767	4,036	4,137	3,615	3,613	3,613
5	Amortization of actuarial losses	1,215	911	-	676	1,166	- B	-		1,581
6	Amortization of past service costs	20	20	20	20	20	-	-	-	-
7	Transfers	-	(1,456)	(43)	32	-	-	-	-	-
8	Benefits paid	(1,909)	(2,144)	(2,138)	(1,858)	(2,082)	(2,329)	(2,130)	(2,130)	(2,130)
9	**Balance at end of year**	39,805	41,881	44,060	48,348	53,556	56,890	61,553	66,213	72,454
10	Opening adjustment - Other comprensive income (OCI)	-	-	-	-	-	1,349 A	1,349	1,349	1,349
11	Actuarial losses amortized through OCI	-	-	-	-	-	2,264 B	3,972	5,554	5,554
12	Unamortized losses	20,307	702	14,007	20,875	35,630	30,006	21,036	19,454	17,873
13	**Accrued employee future benefits obligation**	60,112	42,583	58,067	69,223	89,186	90,509	87,910	92,570	97,230
14										
15	**Funded employee future benefits balance**									
16	Balance at beginning of year	35,537	39,805	41,881	44,060	48,348	52,207	56,890	61,553	66,213
17	Employee future benefits expense	6,177	5,676	4,360	6,114	7,290	7,012	6,793	6,790	8,371
18	Transfers	-	(1,456)	(43)	32	-	-	-	-	-
19	Benefits paid	(1,909)	(2,144)	(2,138)	(1,858)	(2,082)	(2,329)	(2,130)	(2,130)	(2,130)
20	**Balance at end of year**	39,805	41,881	44,060	48,348	53,556	56,890	61,553	66,213	72,454

A 2012 Balance at beginning of year reflects Order No. P.U. 13 (2012). As a result, $1,349 was relcassed from the opening accrued employee future liability to Other comprehensive income. There was no impact on total Accrued employee future benefits obligation.

B Pursuant to Order No. P.U. 13 (2012), in 2013 Hydro deferred the amortization of actuarial gains and losses of $1,708 (2012 - $2,264).

($000s)

	Actual							Test year	Test year	YOY %
	2007	2008	2009	2010	2011	2012	2013	2014	2015	2007 to 2015
1 **Salaries and benefits**										
2 Salaries and benefits	56,741	58,263	61,933	65,692	68,304	70,901	74,987	81,934	90,476	
3 Employee future benefits	5,861	5,559	4,334	6,098	7,247	6,970	6,790	6,790	8,371	
4 Group insurance	1,459	1,719	2,336	2,052	2,546	2,403	2,372	2,469	2,567	
5 Overtime	6,108	7,580	7,778	8,675	9,462	10,633	12,282	12,207	10,128	
6 Capitalized salaries	(11,258)	(14,600)	(15,959)	(19,456)	(19,736)	(19,051)	(20,185)	(21,944)	(22,654)	
7	58,911	58,521	60,422	63,061	67,823	71,856	76,246	81,456	88,888	
8 Cost recoveries allocation	(577)	(624)	(1,256)	(1,942)	(2,040)	(2,603)	(2,957)	(3,450)	(3,102)	
9	58,334	57,897	59,166	61,119	65,783	69,253	73,289	78,006	85,786	4.94%
10										
11 **System equipment maintenance**										
12 System equipment maintenance	21,416	19,366	19,408	19,167	19,867	19,655	22,005	22,979	26,576	
13 Deferred major extraordinary repairs	2,109	2,916	2,714	2,581	1,643	606	-	-	249	
14	23,525	22,282	22,122	21,748	21,510	20,261	22,005	22,979	26,825	
15 Cost recoveries allocation	(392)	(372)	(614)	(418)	(279)	(739)	(570)	(504)	(465)	
16	23,133	21,910	21,508	21,330	21,231	19,522	21,435	22,475	26,360	1.65%
17										
18 **Other operating expenses**										
19 Office supplies and expenses	2,262	2,182	2,161	2,100	2,307	2,230	2,595	2,629	2,804	
20 Professional services	3,532	4,109	3,278	4,165	6,042	7,324	5,874	12,207	9,161	
21 Insurance	1,703	1,783	1,937	1,960	1,965	2,109	2,422	2,689	2,607	
22 Equipment rentals	1,082	1,493	1,721	1,738	1,636	1,699	1,877	1,877	3,066	
23 Travel	2,942	2,854	2,910	2,755	2,977	2,979	3,338	3,711	3,717	
24 Miscellaneous expenses	3,962	4,389	4,174	4,454	4,614	5,003	5,142	6,345	5,655	
25 Building rental & maintenance	1,234	1,078	1,145	1,170	1,172	1,027	1,186	1,149	1,217	
26 Transportation	1,989	2,186	1,833	1,796	1,836	1,928	2,107	2,450	2,245	
27 Customer costs	285	(29)	3,892	(625)	122	141	76	126	118	
28 Deferred regulatory costs	334	334	334	50	50	-	-	-	333	
29	19,325	20,379	23,385	19,563	22,721	24,440	24,617	33,183	30,923	
30 **Cost recoveries allocation**	(240)	(266)	(458)	(1,362)	(1,662)	(2,518)	(2,812)	(3,658)	(2,261)	
31	19,085	20,113	22,927	18,201	21,059	21,922	21,805	29,525	28,662	5.21%
32										
33 **Total operating expenses before other cost recoveries**	100,552	99,920	103,601	100,650	108,073	110,697	116,529	130,005	140,807	4.30%
34										
35 **Other cost recoveries**	(2,859)	(3,226)	(3,232)	(3,674)	(3,509)	(4,229)	(4,717)	(3,937)	(2,628)	-1.05%
36 **Total operating expenses**	97,693	96,694	100,369	96,976	104,564	106,468	111,812	126,068	138,179	4.43%

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Net Interest
($000s)

		Actual							Test year	Test year
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**Interest**									
2	Long-term debt	101,450	94,051	90,450	90,450	90,450	90,450	90,450	86,288	95,325
3	Interest on rate stabilization plan	1,125	2,746	7,026	10,244	12,237	13,188	17,113	18,162	12,432
4	Accretion of long-term debt	675	479	394	426	460	499	540	514	495
5	Amortization of foreign exchange losses	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157	2,157
6	Debt guarantee fee	13,145	-	-	-	3,874	3,693	3,735	3,683	4,447
7	Other interest	2,398	10,434	(1,885)	(160)	(231)	705	14	1,053	(1,230)
8	Interest on sinking fund	(11,439)	(12,629)	(13,891)	(15,190)	(16,557)	(18,025)	(19,434)	(16,026)	(13,413)
9	Interest capitalized during construction	(6,269)	(9,628)	(811)	(1,161)	(1,546)	(2,706)	(2,181)	(6,108)	(10,958)
10	**Interest**	103,242	87,610	83,440	86,766	90,844	89,961	92,394	89,723	89,255

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Funded Asset Retirement Obligation
($000s)

		Actual							Test year	Test year
		2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**Funded asset retirement obligation:**									
2	Opening	-	-	-	-	-	1,617	4,346	7,380	10,350
3	Accretion	-	-	-	-	468	715	911	852	878
4	Depreciation	-	-	-	-	1,149	2,044	2,274	2,273	2,273
6	Asset retirement obligation disposed	-	-	-	-	-	(30)	(151)	(155)	(144)
7	**Ending**	-	-	-	-	1,617	4,346	7,380	10,350	13,357

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Income Statement at Existing Rates
($000s)

		Test Year 2007	Actual 2007	Existing Rates 2014	Existing Rates 2015
1	**Revenue**				
2	Energy sales	429,058	429,794	514,599	520,329
3	Revenue defeciency	-	-	-	-
4	Other revenue	2,021	1,983	2,335	2,508
5	**Total revenue**	431,079	431,777	516,934	522,837
6					
7	**Expenses**				
8	Operating expenses	93,418	97,693	126,068	135,325
9	Fuels				
10	No. 6 fuel	136,867	107,369	255,841	244,914
11	Rate stabilization plan deferral	-	31,540	(81,878)	(73,978)
13	Diesel and other	11,569	11,372	27,751	22,940
14	Total fuels	148,436	150,281	201,714	193,876
16	Fuel supply deferral	-	-	(9,956)	1,991
17	Power purchases	38,327	38,606	66,668	63,254
19	Amortization	38,825	38,342	55,214	63,792
20	Accretion	-	-	852	878
22	Other Income and expenses	1,366	902	2,068	4,074
23	Interest	102,728	103,242	89,713	94,561
25	**Total expenses**	423,100	429,066	532,341	557,751
26					
28	**Net income before cost of service exclusions**	7,979	2,711	(15,407)	(34,914)
29	less: Assets Not In Service Depreciation	-	-	336	331
31		7,979	2,711	(15,071)	(34,583)
32					
34	Return on regulated equity	7,979	2,711	(15,071)	(34,583)
35	Net interest	102,728	103,242	89,713	94,561
37	**Return on rate base**	110,707	105,953	74,642	59,978
38					
40	**Average rate base**	1,489,323	1,483,524	1,692,607	1,803,149
41					
43	**Rate of return on rate base**	7.44%	7.14%	4.41%	3.33%

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Revenue Requirement Analysis - 2007 vs. 2015 Test Year
($000s)

		Test Year 2007	Actual Year 2007	Test year 2014	Test Year 2015	Variance 2007 Test Year to 2014 Test Year $	Variance 2007 Actual to 2014 Test Year $	Variance 2007 Test year to 2015 Test Year $	Variance 2007 Actual to 2015 Test year $
1	**Revenue requirement**								
2	Energy sales	429,058	429,794	514,599	659,967	85,541	84,805	230,909	230,173
3	Revenue defeciency	-	-	45,921	-	45,921	45,921	-	-
4	Other revenue	2,021	1,983	2,335	2,508	314	352	487	525
5	**Total revenue requirement**	431,079	431,777	562,855	662,475	131,776	131,078	231,396	230,698
6									
7	**Expenses**								
8	Operating expenses								
9	Salaries and fringe benefits	58,457	58,911	81,456	88,888	22,999	22,545	30,431	29,977
10	System equipment maintenance	20,579	23,525	22,979	26,825	2,400	(546)	6,246	3,300
11	Office supplies and expenses	2,106	2,262	2,629	2,804	523	367	698	542
12	Professional services	4,418	3,866	12,207	9,494	7,789	8,341	5,076	5,628
13	Insurance	1,881	1,703	2,689	2,607	808	986	726	904
14	Equipment rentals	1,369	1,082	1,877	3,066	508	795	1,697	1,984
15	Travel	2,332	2,942	3,711	3,717	1,378	768	1,384	774
16	Miscellaneous expenses	4,530	4,247	6,471	5,772	1,941	2,224	1,242	1,525
17	Building rental and maintenance	825	1,234	1,149	1,217	324	(85)	392	(17)
18	Transportation	1,994	1,989	2,450	2,245	456	461	251	256
19	Cost recoveries	(2,199)	(1,389)	(9,623)	(7,069)	(7,424)	(8,234)	(4,870)	(5,680)
20	Allocated to non-regulated customer	(2,874)	(2,679)	(1,926)	(1,387)	948	753	1,487	1,292
21	**Net operating expenses**	93,418	97,693	126,068	138,178	32,650	28,375	44,760	40,485
22	Fuels								
23	No. 6 fuel	136,867	107,369	255,841	244,914	118,974	148,472	108,047	137,545
24	Rate stabilization plan deferral	-	31,540	(81,878)	(34)	(81,878)	(113,418)	(34)	(31,574)
26	Diesel and other	11,569	11,372	27,751	22,940	16,182	16,379	11,371	11,568
27	Total fuels	148,436	150,281	201,714	267,820	53,278	51,433	119,384	117,539
28	Fuel supply deferral	-	-	(9,956)	1,991	(9,956)	(9,956)	1,991	1,991
29	Power Purchases	38,327	38,606	66,668	63,254	28,341	28,062	24,927	24,648
30	Amortization	38,825	38,342	55,214	63,792	16,389	16,872	24,967	25,450
31	Accretion of asset retirement obligation	-	-	852	878	852	852	878	878
32	Other income and xpense	1,366	902	2,068	4,074	702	1,166	2,708	3,172
33	**Expenses before cost of service exclusions**	320,372	325,824	442,628	539,987	122,256	116,804	219,615	214,163
34	less: Cost of service exclusions	-	-	(336)	(323)	(336)	(336)	(323)	(323)
35		320,372	325,824	442,292	539,664	121,920	116,468	219,292	213,840
36									
37	**Return on rate base**	110,707	105,953	120,563	122,811	9,856	14,610	12,104	16,858
38									
39	**Average rate base**	1,489,323	1,483,524	1,692,567	1,802,024				
40									
41	**Rate of return on rate base**	7.44%	7.14%	7.12%	6.82%				

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Rate Base - Existing vs. Proposed
($000s)

		Test Year 2007	Actual 2007	Test Year 2014	Test Year 2015
1	**Capital assets**	2,008,654	2,016,315	1,840,320	1,870,275
2	less: asset retirement obligation costs	-	-	(14,442)	(12,169)
3	less: contributions in aid of construction	(92,250)	(96,396)	(16,550)	(17,936)
4	less: accumulated depreciation	(559,855)	(570,225)	(193,532)	(203,834)
5	**Capital assets - current year**	1,356,549	1,349,694	1,615,796	1,636,336
6	**Capital assets - previous year**	1,354,631	1,345,766	1,432,533	1,615,796
7	Unadjusted Capital assets - average	1,355,590	1,347,730	1,524,165	1,626,066
8	less: Average net assets not in use	-	-	(2,941)	(2,605)
9	**Capital assets - average**	1,355,590	1,347,730	1,521,224	1,623,461
10					
11	Cash working capital allowance	3,030	3,496	9,207	7,037
12	Fuel	27,473	25,874	65,110	66,633
13	Materials and supplies	19,912	21,699	25,823	27,402
14	Deferred charges	83,318	84,725	71,203	77,491
15					
16	**Average rate base**	1,489,323	1,483,524	1,692,567	1,802,024

Newfoundland and Labrador Hydro
Financial Results and Forecasts
Forecast Average Cost of Debt
($ 000s)

	Series	Interest Rate	Year of Issue	Year of Maturity	Actual 2012	Actual 2013	Test year 2014	Test Year 2015
1	Series V	10.50%	1989	2014	125,000	125,000	-	-
2	Series X	10.25%	1992	2017	150,000	150,000	150,000	150,000
3	Series Y	8.40%	1996	2026	300,000	300,000	300,000	300,000
4	Series AB	6.65%	2001	2031	300,000	300,000	300,000	300,000
5	Series AD	5.70%	2003	2033	125,000	125,000	125,000	125,000
6	Series AE	4.30%	2006	2016	225,000	225,000	225,000	225,000
	Series AF	3.60%	2014	2044			200,000	600,000
7	Total debentures				1,225,000	1,225,000	1,300,000	1,700,000
8								
9	Promissory notes				52,000	41,000	145,564	-
10	Less:							
11	Sinking funds				(310,069)	(337,591)	(235,693)	(257,000)
12	Non-regulated debt pool				(7,217)	(8,187)	(8,187)	(8,187)
13	Unamortized debt discount and financing				(2,785)	(2,244)	(1,730)	(1,235)
14								
15	**Total debt**				956,929	917,978	1,199,954	1,433,578
16								
17	**Average debt**					937,454	1,058,966	1,316,766

		Actual 2013	Test year 2014	Test year 2015	Actual 2013	Test year 2014	Test Year 2015
18							
19	**Embedded cost of debt**						
20	Long-term debt	90,450	86,288	95,325			
21	Accretion of long-term debt	540	514	495			
22	Amortization of foreign exchange losses	2,157	2,157	2,157			
23	Debt guarantee fee	3,735	3,683	4,447			
24	Other interest	226	1,053	(1,230)			
25	Interest on sinking fund	(19,302)	(16,026)	(13,413)			
27					77,806	77,669	87,781
28							
29	**Embedded cost of debt**				8.30%	7.33%	6.67%

Conservation and Demand Management (CDM) Cost Deferral Account

The account shall be charged with the costs incurred in implementing the CDM Program Portfolio but shall exclude CDM Program Costs associated with customers on the Labrador Interconnected System.

The costs include the CDM Program Portfolio costs incurred by Hydro for: detailed program development, promotional materials, advertising, pre and post customer installation checks, processing applications and incentives, training of employees and trade allies, and program evaluation costs.

This account shall also be charged the costs for major CDM studies such as comprehensive customer end use surveys and CDM potential studies that cost greater than $100,000.

This account will include Hydro’s program expenditures for 2009 to 2014 which received Board approval for deferral.

Disposition of any Balance in this Account

Balances in the account shall be maintained separately for the Island Interconnected and Other Systems. This account will maintain a linkage of all costs recorded in the account to the year the cost was incurred.

The account balances as at March 31 each year shall be recovered over a period of (7) years using a CDM Cost Recovery Adjustment.

Isolated Systems Supply Cost Variance Deferral Account

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

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

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

Where:

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

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

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

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

Disposition of any Balance in this Account

Hydro shall file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

Energy Supply Cost Variance Deferral Account

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

It will apply to variations in the following supply sources:

- Power purchases from wind generation;
- Power purchases from CBPP cogeneration;
- Power purchases from hydraulic generation;
- Diesel generation; and
- Gas Turbine generation.

Energy Supply costs will be determined by the following formula:

$$(A - B) - C$$

A = Total Actual energy supply costs in the calendar year for the defined supply sources;

B = Total Test Year energy supply costs for the defined supply sources; and

C = Energy supply costs or savings, resulting from the variance, if any, in kWh, based on the cost of generation at the Holyrood Thermal Generating Facility ("Holyrood").

Where:

$$C = D/E \times F$$

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

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

F = Annual kWh variance between Actual consumption and the Test Year forecast for the defined supply sources.

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

Disposition of any Balance in this Account

Hydro shall file an Application with the Board no later than the 1st day of March each year for the disposition of any balance in this account.

SECTION 4: RATES AND REGULATION

SECTION 4: RATES AND REGULATION

4.1 OVERVIEW

Hydro prepares Cost of Service studies for five systems:

- Island Interconnected;
- Island Isolated;
- Labrador Isolated;
- L'Anse au Loup; and
- Labrador Interconnected.

Rates for these customers are grouped into the following classifications:

- Island Interconnected Utility (NP);
- Island Interconnected Industrial Customers;
- Island Interconnected and L'Anse au Loup Rural Customers;
- Island and Labrador Isolated Rural Customers;
  - Non-Government; and
  - Government.
- Labrador Interconnected Rural Customers; and
- Labrador Industrial Customers.

On the Island Interconnected System, Hydro provides electricity service to Newfoundland Power (NP) and five Industrial Customers (IC) including: Corner Brook Pulp and Paper Limited (CBPP); North Atlantic Refining Limited (NARL); Teck Resources Limited (Teck); Vale Newfoundland and Labrador Limited (Vale); and Praxair. Hydro also serves 23,700 Rural Customers at the retail level on the Island Interconnected System.

On the Labrador Interconnected System, Hydro serves 11,600 Rural Customers and serves two IC.[1] On the 21 isolated systems, including the L'Anse au Loup system, Hydro has 4,600 Rural Customers.

The Rates and Regulation evidence will cover:

- Regulatory Outlook;
- Proposed Cost of Service methodology changes;
- Rate Implementation;
- Proposed rates for NP and IC;
- Proposed Rate Stabilization Plan (RSP) Changes;
- Proposed rates for Hydro Rural Customers;
- Proposed Labrador Industrial rates;
- A comparison of 2015 revenues based on both existing and proposed rates; and
- Proposed revision to KPI reporting.

4.2 REGULATORY OUTLOOK

4.2.1 Overview

This section of Hydro's evidence provides an outlook related to the Cost of Service methodology and rate design matters that will be before the Board over the next several years. Most of these matters need to be addressed prior to the implementation of customer rates reflecting the costs of the Labrador-Island Interconnection.[2] The purpose of this outlook is to provide information to the Board and the Parties so that

[1] Under the Labrador Industrial Rates Policy, effective January 1, 2015, the rate charged to Labrador IC on the Labrador Interconnected System for transmission-related costs will be regulated and generation supply to customers will be non-regulated.

[2] The Labrador-Island Interconnection refers to both the purchase of generation from Muskrat Falls through a purchase power agreement and the transmission of power to the Island.

discussions and planning can begin to address these matters on a timely basis. The rate-related matters include:

(i) a review of the embedded Cost of Service methodology;

(ii) the completion of a marginal cost study and rate design review; and

(iii) a review of Hydro's regulatory mechanisms for the recovery of supply costs.

A brief discussion of each item is provided below.

4.2.2 Cost of Service Methodology

The Labrador-Island Interconnection will result in the eventual permanent shutdown of the Holyrood Thermal Generating Station (Holyrood).[3] Upon the in-service of the Labrador-Island Interconnection, payments commence under the Transmission Funding Agreement and Muskrat Falls Power Purchase Agreement ("PPA") which, in large measure, are more stable and predictable. Substituting variable Holyrood fuel costs with these costs will result in a stabilization in the cost of supply on the Island.

The replacement of fuel costs on the Island Interconnected System with transmission costs and predominately predictable purchase costs also generates questions with respect to cost classification and allocation among customer classes. Because of these changes, Hydro believes it is necessary to have a Cost of Service methodology review process completed prior to the inclusion of costs reflecting the Labrador-Island Interconnection in rates.

4.2.3 Marginal Cost Study and Rate Design

The transition from an isolated system to a system connected to the North America grid requires a review of the marginal energy costs and marginal capacity costs for both

[3] Until the 2020-2021 timeframe, Holyrood will function as a fully capable standby facility during the early years of operation of the Muskrat Falls Generating Plant and the Labrador-Island Link between Labrador and Newfoundland.

planning and pricing purposes. Knowledge of system marginal costs that reflect the Labrador-Island Interconnection is required when considering efficiency for rate design.

In 2015, Hydro will complete a marginal cost study reflecting the Labrador-Island Interconnection. The results of the marginal cost study will form a basis for a review of customer rate designs to reflect the new system cost structure.

The current uncertainty in marginal capacity and energy costs upon completion of the Labrador-Island Interconnection is reflected in Hydro's rate proposals in the current GRA. Hydro is proposing to maintain the existing rate designs for NP and Island IC until after the marginal cost study is complete and a rate design review is undertaken. Hydro believes the rate design review should be a process that is consultative among stakeholders and monitored by the Board.

4.2.4 Supply Cost Regulatory Mechanism Review

The primary purpose of the RSP is to stabilize customer rates from monthly variations in Holyrood fuel costs due to price, volume and load variations in a manner to ensure rates reasonably reflect fuel cost changes between Test Years. The Labrador-Island Interconnection will result in the eventual permanent shutdown of the Holyrood plant. The elimination of Holyrood fuel expense will eliminate the need for the RSP as it is currently designed.

Following the conclusion of the GRA, Hydro plans to conduct a review of the requirements of regulatory mechanisms to deal with variability in supply costs. Hydro plans on filing a report to the Board prior to the end of 2016 on its review of regulatory mechanisms to provide for supply cost recovery.

4.3 COST OF SERVICE METHODOLOGY

Hydro is proposing the following methodology changes in its Amended Application:

(i) A revised approach to allocation of the Rural Deficit;

(ii) An energy classification for the cost of purchases of wind generated energy;

(iii) A modification to the calculation of capacity factor for the Holyrood generating facility; and

(iv) The treatment of the cost of new Island Industrial Capacity Assistance Agreements as a production demand-related cost.

4.3.1 Rural Deficit Allocation

Background

The Amended Application proposes a 2.1% average increase to retail customers on the Labrador Interconnected System.[4] This proposed customer rate increase reflects an allocation of the Rural Deficit based upon revenue requirement (the Revised Methodology). The proposed approach differs from the Rural Deficit allocation methodology approved by the Board in 1993 (the Existing Methodology).[5]

The proposed rate increase for Labrador Interconnected Rural Customers of 2.1% would increase to approximately 27.8% if the Existing Methodology was maintained.[6] The proposed rate increase of 2.8% for NP's customers would decrease to approximately 2.1% if the Existing Methodology was maintained. The material rate impact of the

[4] See Hydro pre-filed evidence Table 4.4 of Section 4: Rates and Regulations, page 4.16.

[5] The current basis for allocating the Rural Deficit to customer classes is detailed in the Board's February 1993 Report resulting from the Cost of Service methodology hearing. Page 62 of the Report states that "Mr. Baker has presented in his evidence a method of allocating the deficit on the basis of a mini Cost of Service…The result of this approach is to increase unit costs equally in the two Interconnected Systems." The Board accepted the methodology proposed by Mr. Baker and in Recommendation 23 of the Report it is stated: "The Board recommends the approach illustrated in Exhibit GCB-5 (Appendix 1 of this Report) for the allocation of the Rural Deficit for the purpose of the Cost of Service."

[6] Under the Existing Methodology, approximately 30% of the forecast 2015 Test Year revenue requirement from customers on the Labrador Interconnected System would be attributable to the Rural Deficit. $7.6 million deficit allocation divided by $25.7 million revenue requirement (including the Rural Deficit) equals 30%.

Existing Methodology on the customers on the Labrador Interconnected System has created a concern with respect to the reasonableness of the Rural Deficit allocation methodology.

This is the first GRA since the Existing Methodology was approved in 1993 in which the full impact of the Rural Deficit allocation will be reflected in the rates of customers on the Labrador Interconnected System. Therefore, Hydro believes it is appropriate at this time to review the fairness of the Rural Deficit allocation methodology.[7] This evidence summarizes the fairness assessment.

Fairness Assessment

Table 4.1 summarizes the customer impacts of the Rural Deficit allocation in the 2015 Test Year Cost of Service Study under the Existing Methodology.

Table 4.1

Rural Deficit Comparison - Average Cost per Customer Existing Methodology[8]	
	2015 TY
Labrador Interconnected	$653.15
Newfoundland Power	$216.64
Difference	($436.51)

Table 4.1 shows that the average annual cost of the Rural Deficit per customer under the Existing Methodology is approximately three times higher for customers on the Labrador Interconnected System than for customers of NP. The higher deficit allocation per customer is primarily related to the attributes of the Existing Methodology that

[7] Hydro was requested in Request for Information CA-NLH-166 to comment on the fairness of the Rural Deficit allocation methodology.

[8] Total 2013 Test Year deficit allocated divided by number of customers in the Labrador Interconnected System and number of customers served by Newfoundland Power.

provides for increased deficit allocation to the system with higher average energy usage.[9]

Fairness in rates is commonly assessed based on revenue to cost ratios.[10] Table 4.2 provides the impact of the Rural Deficit allocation on revenue to cost ratios under the Existing Methodology.

Table 4.2

Revenue to Cost Ratios Existing Methodology	
	2015 TY
Labrador Interconnected	1.42
Newfoundland Power	1.12
Difference	0.30

As can be seen from Table 4.2, the Existing Methodology requires retail customers on the Labrador Interconnected System to pay rates that reflect a materially higher revenue to cost ratio than that required of the customers of NP.[11]

[9] Domestic customers on the Labrador Interconnected System have materially higher average usage than customers of NP primarily as a result of a very high saturation of electric heating for customers living in an area of the Province with a very cold climate. The annual normal heating degree days are 7,587 in Wabush and 6,538 in Goose Bay; these compare to 4,730 annual normal heating degree days in St. John's. The average annual Domestic usage for 2013 for customers coded as having electric heating in Labrador West was approximately 35,500 kWh, for Happy Valley-Goose Bay approximately 29,700 kWh and for NP customers approximately 18,350 kWh.

[10] Both Hydro and NP use a range of revenue to cost ratios to determine if a class of service is paying rates that need to be adjusted to better reflect the cost to serve.

[11] For NP customers, the cost of purchases from Hydro comprises approximately 68% of total costs. Therefore, based on the Existing Methodology, the percent impact of the Rural Deficit on the bills of NP's customers under proposed rates is approximately 8% (i.e., 68% times 12% at wholesale basis). This compares to a bill impact under the Existing Methodology of 42% for customers on the Labrador Interconnected System.

Hydro's review concludes that the Existing Methodology results in materially higher billing impacts for customers on the Labrador Interconnected System primarily because they have higher electricity usage as a result of living in an area of the Province where the climate is materially colder. Hydro believes that the Existing Methodology does not provide a reasonable sharing of the Rural Deficit between customers on the Labrador Interconnected System and customers of NP.

Alternate Approaches

At the 1992 Cost of Service Hearing, Hydro proposed that the Rural Deficit be allocated on the basis of revenue requirement. This method effectively maintains the same revenue to cost ratio for both the Labrador Interconnected System and NP. Hydro also considers the use of an allocation based on total number of customers as an option that may be reasonable.

Table 4.3 provides a comparison of the Rural Deficit impact per customer under the current method compared to an allocation based on revenue requirement and an allocation based on the number of customers served.

Table 4.3

Average Annual Cost per Customer Comparison[12]

	Existing Method	**Revenue Requirement Method**	**Number of Customers Method**
Labrador Interconnected	$653.15	$207.60	$235.23
Newfoundland Power	$216.64	$236.46	$235.23
Difference	($436.51)	$28.86	$ –

[12] Total 2015 Test Year deficit allocated divided by number of customers in Labrador Interconnected and number of customers served by Newfoundland Power.

Table 4.3 shows that average customer impacts are more comparable on a revenue requirement allocation basis (i.e., the Revised Methodology) than the Existing Methodology. The use of the number of customers as the allocator eliminates the average cost difference per customer.[13] Hydro believes both of these alternate approaches provide a more reasonable sharing of the Rural Deficit between the customers on the Labrador Interconnected System and the customers of NP.

A Rural Deficit allocation change to either a revenue requirement basis or an allocation based upon the number of customers would reduce the amount of the Rural Deficit to be recovered from the customers on the Labrador Interconnected System and increase the amount to be recovered from the customers of NP.

From a customer impact perspective, use of the Revised Methodology has a material impact on the proposed rate change to Hydro Rural Labrador Interconnected Customers (i.e., from approximately 27.8% to 2.1%). For NP's customers, the impact of the methodology change would result in higher customer rates of approximately 0.7% than would be required under the Existing Methodology.

Intervenor Evidence

The expert reports provided by Mr. James Feehan, Mr. Philip Raphals and Mr. Doug Bowman specifically addressed the Rural Deficit allocation issue and all three experts

[13] The use of the allocation of the Rural Deficit using number of customers may be reasonable for allocation between NP and Labrador Interconnected Customers. However, further allocation by rate class would normally consider customer usage characteristics and be allocated on forecast revenue.

recommended a revised approach be implemented.[14] The concerns expressed by the three experts (all representing separate interests) were generally related to the material higher amount contributed towards the Rural Deficit by the customers on Labrador Interconnected System relative to the customers of NP.

Mr. Feehan does not agree that customers on the Labrador Interconnected System should pay approximately three times what a NP customer pays towards the deficit. Mr. Feehan states "[t]he formula should be replaced by one that ensures a more equal outcome." One of the alternative methods presented for consideration by Mr. Feehan was an equal deficit per customer approach comparable to one of the alternatives evaluated by Hydro.[15]

Mr. Doug Bowman states "..if rural rates continue to be subsidized by NP and Labrador Interconnected customers, I recommend that greater emphasis be placed on the fairness of the allocation methodology, particularly since there is no generally accepted cost of service methodology for dealing with this situation..". Mr. Bowman also concluded "[b]ased on the principles of fairness and minimization of the impact of the price signal, allocation of the deficit on the basis of revenue requirement or number of customers are both preferred over the current allocation methodology."[16]

Mr. Raphals also presented evidence on the Rural Deficit allocation and recommended taking "... a fresh look at the methodology for this allocation, as now proposed by Hydro".[17]

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[14] The evidence of Mr. Feehan was prepared for Miller & Hearn representing the Towns of Labrador City, Wabush, Happy Valley-Goose Bay and North West River. The evidence of Mr. Raphals was prepared on behalf of the Innu Nation. The evidence of Mr. D. Bowman was prepared for the Government appointed Consumer Advocate.

[15] Pre-filed evidence of James Feehan, page 11, lines 12-22.

[16] Pre-filed evidence of Doug Bowman, page 37, lines 8-17.

[17] Pre-filed evidence of Philip Raphals, page 18, lines 3-5.

Mr. Larry Brockman, representing NP, did not address the Rural Deficit allocation methodology in his pre-filed evidence. However, Request for Information PUB-NP-005 asked Mr. Brockman for his "opinion on whether the current methodology continues to be appropriate or whether it should be modified as proposed by a number of intervenors". The request for information also asked Mr. Brockman what alternatives to the current methodology should be considered for approval.

Mr. Brockman's Assessment

Mr. Brockman conducted an assessment of the reasonableness of the methodology based on the change in the Rural Deficit allocation between 1995 and the originally proposed 2013 Test Year. Mr. Brockman did not recommend any change in the allocation methodology and did not present alternatives for consideration. Mr. Brockman's comparison of allocation amounts from 1995 to 2013 Test Year does not provide an evaluation of the fairness of the current Rural Deficit allocation.

Historical Deficit Recovery in Labrador Interconnected Rates

Customers' rates on the Labrador Interconnected System did not reflect recovery of any of the Rural Deficit until September 2002.[18] In 2002, approximately $5.0 million of the Rural Deficit was allocated to the Labrador Interconnected System.[19] However, the impact of the initial allocation of the Rural Deficit to the Labrador Interconnected System was largely offset by the assignment of a revenue credit of $3.7 million from secondary energy sales to CFB Goose Bay (the Secondary Revenue Credit).[20]

The phase-out of the Secondary Revenue Credit as a reduction in the revenue requirement of the Labrador Interconnected System was concluded in 2011 concurrent

[18] There was no rate proceeding to implement the approved Cost of Service methodology for the period 1993 to 2001.

[19] Source: Hydro Compliance Filing to Board Order No. P.U. 7(2002-2003).

[20] The net effect was a revenue to cost ratio of 1.12 for the Labrador Interconnected System. This compared to the 1.18 revenue to cost ratio for NP.

with the phase-in of uniform rates for customers on the Labrador Interconnected System.[21]

This is the first GRA in which (i) uniform rates are in place for customers on the Labrador Interconnected System and (ii) none of the Secondary Revenue Credit is specifically assigned to reduce the revenue requirement for the Labrador Interconnected System. Therefore, Hydro believes it is appropriate at this time to re-evaluate the Rural Deficit allocation methodology and the impact on current customer rates.

Rural Deficit Allocation Summary

The average annual cost of the Rural Deficit per customer under the Existing Methodology is approximately three times higher for customers on the Labrador Interconnected System than for the customers of NP.

An evaluation of the fairness of the Rural Deficit allocation supports a change in the Cost of Service allocation methodology to provide a more reasonable sharing of the Rural Deficit between customers on the Labrador Interconnected System and customers of NP.

Hydro is proposing the Rural Deficit commencing January 1, 2014 be allocated by system based upon revenue requirement. Fairness in rates is commonly assessed based on revenue to cost ratios. The use of revenue requirement as a basis of Rural Deficit allocation results in the revenue to cost ratio in the 2015 Test Year

[21] In Order No. P.U. 7(2002-2003), the Board also ruled that the Secondary Revenue Credit be applied to reduce the Rural Deficit rather than applied as a credit against the cost of serving the Labrador Interconnected System. Because of the potential large customer impacts of making this rate change, the Board required Hydro to propose a plan for implementation at its next rate hearing in combination with a plan to implement uniform rates for Labrador City, Happy Valley-Goose Bay and Wabush. The current General Rate Application is the first hearing before the Board in which the Secondary Revenue Credit is fully credited to the Rural Deficit.

Cost of Service Study for Hydro Rural Labrador Interconnected Customers being equal to the revenue to cost ratio for NP.

4.3.2 Classification of Purchases of Wind Generation

Power purchase costs of wind generation are new to the Test Year Cost of Service Study as the wind farms at St. Lawrence and Fermeuse began commercial operation in fall of 2008 and spring of 2009, respectively. The wind generation on the Island Interconnected System was initially cost-justified on the basis of reduced production at Holyrood. If the energy provided by wind generation had continued to be provided by Holyrood generation, then the energy costs would have been classified as 100% energy-related.

From a system planning perspective, Hydro no longer assumes that wind generation will be available to supply system capacity requirements. Therefore, Hydro is proposing that the purchased power costs related to wind be classified as 100% energy related. This proposal is reflected in the 2015 Test Year Cost of Service Study.[22]

4.3.3 Holyrood Capacity Factor

The Holyrood capacity factor in the 2015 Test Year Cost of Service Study is used to determine how much of Holyrood non-fuel costs are classified as demand-related vs. energy-related. A low capacity factor (e.g., 20%) results in a low percentage (e.g., 20%) of the non-fuel costs being treated as energy-related with the remainder being demand-related.

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[22] Wind purchases were classified in the 2013 Test Year Cost of Service Study included in the Application based upon system load factor consistent with the classification of hydraulic resources. This resulted in 48% of the wind generation purchase costs being demand related and 52% of the costs being energy related.

Table 4.4 provides the Holyrood capacity factors from 2001 to 2013 and forecast for 2014 to 2017 in addition to the average for each five-year period. The approved Cost of Service methodology requires the use of a historical five year period.

Table 4.4

Holyrood Capacity Factor 2001-2017F			
Year	**Capacity Factor**	**5-Year Average**	**Change[23]**
2001	51%	-	-
2002	58%	-	-
2003	48%	-	-
2004	40%	-	-
2005	33%	46%	-
2006	18%	39%	(7%)
2007	31%	34%	(5%)
2008	26%	30%	(4%)
2009	23%	26%	(4%)
2010	20%	24%	(2%)
2011	22%	24%	-
2012	21%	22%	(2%)
2013	23%	22%	-
2014F	34%	24%	2%
2015F	39%	28%	4%
2016F	45%	32%	4%
2017F	45%	37%	5%

The use of the period from 2010 to 2014 would provide a capacity factor of 24%. This is materially lower than the forecast Holyrood capacity factors for the period that rates will be in effect. Therefore, Hydro believes it is reasonable to include the 2015 forecast information in the five-year average when computing the Holyrood capacity factor for Cost of Service classification.

[23] The change represents the year over year difference in the five-year moving average.

Hydro is proposing that the Holyrood capacity factor for the 2015 Test Year Cost of Service Study be set at 28%, a significant reduction from the 41% in the 2007 Test Year Cost of Service Study. This proposal is reflected in the 2015 Test Year Cost of Service Study.[24]

4.3.4 Capacity Assistance Agreements

Section 2.2.6 discusses capacity assistance arrangements with Island IC. The costs of these Capacity Assistance Agreements are similar in manner as the Interruptible "B" contract which was negotiated between Abitibi Stephenville and Hydro and became effective December 1, 1993. The Interruptible "B" cost was treated in the Cost of Service Study as a production demand cost with the costs allocated to each class of service based on a single coincident peak allocator. Hydro is proposing the same treatment for the new capacity assistance agreements and has reflected this proposal in the 2015 Test Year Cost of Service Study.

4.3.5 Hydro's Application

Hydro is proposing the following:

- Rural Deficit, commencing January 1, 2014, be allocated by system based upon revenue requirement;
- Purchased power costs on the Island Interconnected System related to wind be classified as 100% energy-related;
- Holyrood capacity factor for the 2015 Test Year Cost of Service Study be calculated to include the 2015 forecast; and
- Hydro is proposing to treat the cost of capacity assistance agreements as a production demand cost in the 2015 Test Year Cost of Service Study.

[24] The Holyrood capacity factor in the 2007 Test Year Cost of Service Study of 41% was based upon a five year average of 2002 to 2005 Actual and 2006 Forecast.

4.4 RECOVERY OF REVENUE REQUIREMENT

4.4.1 2014 Revenue Deficiency

Section 1.1.3 shows a revenue deficiency of $45.9 million for the 2014 Test Year. The rates proposed in the evidence do not reflect the recovery of the 2014 Revenue Deficiency as they are based upon recovery of 2015 Test Year costs.

There are a number of ways to deal with the recovery of the 2014 Revenue Deficiency. One method would be to recover the deficiency through higher rates to be paid by customers in the future.[25] The customer impact of recovery of the 2014 Revenue Deficiency is material. A three year amortization period to recover $45.9 million requires increased revenue of $15.3 million per year. The $15.3 million represents approximately 2.3% of 2015 forecast customer billings under proposed rates.

Another method of dealing with the 2014 Revenue Deficiency is to utilize a portion of the approximate $100 million forecast 2014 year-end credit balance in the RSP which reflects funds already collected from customers.[26] This approach has the advantage of repaying an historic shortfall by using amounts already collected from customers thus providing a better matching of 2015 proposed rates with 2015 costs.[27]

The RSP credit balance available for disposition must initially be allocated between NP and Island IC to determine the amount available to offset each customer classes'

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

[26] The $100 million reflects the $66 million forecast year-end balance in the hydraulic component (before 25% disposition to the current balance) and $33 million forecast year-end balance in the segregated RSP load variation component. The balance does not include the RSP Surplus directed for disposition by Government.

[27] This approach is similar to the method approved by the Board in the case of Hydro's 2006 GRA in which $20.7 million of the Hydraulic Production Variation RSP balance owing to customers offset current costs owing from customers. Mr. Brockman, NP's rates expert, stated a preference for this approach to shortfall recovery for 2014. See response to SIR-NLH-NP-009 in the Second Interim Rates Application.

allocated portion of the 2014 Revenue Deficiency. The RSP would not be available for the portion of the shortfall attributable to customers on the Labrador Interconnected System, whose rates are not subject to the RSP.[28] Reflecting an amortization of the 2014 Revenue Deficiency would be a reasonable approach for recovery from customers on the Labrador Interconnected System.

In November 2014, Hydro will be filing with the Board a 2014 Test Year Cost of Service Study to provide a basis for calculating the 2014 Revenue Deficiency by system and by class of service. The 2014 Test Year Cost of Service Study will also be accompanied by a detailed proposal of the revenue deficiency amounts to be recovered by class and the amounts that can be offset using the RSP credit balance versus recovery through a rate rider on a prospective basis.

4.4.2 Recovery of 2014 Revenue Deficiency

Hydro proposes the use of the RSP balance, where appropriate, to offset the 2014 Revenue Deficiency. Any portion of the 2014 Revenue Deficiency not recovered through the RSP is proposed to be recovered through future customer rates[29] through a rate rider to become effective at the time of new rate implementation. A rate rider will be proposed for any of the 2014 Revenue Deficiency attributable to customers on the Labrador Interconnected System.

If the Board requires further testing of the 2014 Test Year costs prior to approving recovery of the 2014 Revenue Deficiency, Hydro proposes that the Board approve a 2014 cost deferral to provide Hydro the opportunity to earn a reasonable return in

[28] It is estimated that reflecting a three-year recovery period of the 2014 forecast net income shortfall in a 2015 Cost of Service Study would incrementally increase customer rates by approximately 2%.

[29] In its Amended Application, Hydro has requested that the Board approve upon conclusion of the GRA that the existing rates in effect for 2014, on an interim basis, be made final.

2014. The decision on the recovery approach for the 2014 Revenue Deficiency can be addressed in a subsequent order of the Board following the testing of 2014 costs.

Only the tested revenue requirement for 2014 will be ultimately recovered from customers through rates. Hydro proposes that the 2014 Revenue Deficiency to be recovered from customers will be based upon the difference between 2014 revenue based upon existing rates and the 2014 revenue requirement, as determined by the Board.

4.4.3 2015 Rate Implementation

Awaiting completion of the hearing process to fully test costs prior to beginning recovery of 2015 costs will create a revenue deficiency for 2015 due to delayed rate implementation beyond January 1, 2015. Implementation of interim rates to provide additional revenue to the utility in advance of concluding a GRA is common by regulators in Canada and the United States.[30] From Hydro's perspective, it is in the best interests of both Hydro and its customers to limit the amount of revenue deficiency accumulating for 2015. From a customer's perspective, delayed implementation of the proposed rate increase can result in a higher rate increase at a later date.

Hydro's proposal in Section 4.6 requests that the Board approve new rates for the IC on an interim basis effective January 1, 2015. Hydro believes that the rate implementation proposal is in accordance with the implementation approach directed by Government.

[30] 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. In all these cases, when final rates were approved, the interim rates were determined to be too high and rebates or rate adjustments resulted. There is also a recent decision in Manitoba in which Manitoba Hydro received approval of a customer rate increase on an interim basis.

Delayed implementation beyond January 1, 2015 will result in continuing growth in the forecast $8 million current RSP balance due from the IC at December 31, 2014.

To provide adequate time for NP to implement new rates for its customers, Hydro is proposing the requested 2015 Test Year rates be approved on an interim basis effective February 1, 2015 with the revenue shortfall associated with delayed implementation beyond January 1, 2015 to be deferred for future recovery through a rate rider.

If after testing 2014 and 2015 costs, the Board determines that adjustments to revenue requirement are appropriate, then any excess revenues collected through the interim rates could be applied against any revenue deficiency (i.e., for either 2014 or 2015) approved for recovery by the Board. Hydro's proposed approach to rate implementation limits the growth in revenue deficiency for 2015.

4.4.4 Hydro's Application

- Hydro proposes the use of a portion of the RSP credit balance, where appropriate, to offset the 2014 Revenue Deficiency attributable to the Island Interconnected System. The portion of the 2014 Revenue Deficiency not recovered using the RSP credit balance should be deferred for future recovery through a rate rider[31];
- Hydro is proposing the requested 2015 Test Year rates for Newfoundland Power and Hydro Rural Customers be approved on an interim basis effective February 1, 2015 with the revenue shortfall associated with delayed implementation beyond January 1, 2015 be deferred for future recovery through a rate rider; and

[31] The same rate rider can be used to recover a portion of the 2014 Revenue Deficiency and any revenue deficiency for 2015.

- Hydro is proposing to implement IC rates effective January 1, 2015 on an interim basis.

4.5 RATES FOR NEWFOUNDLAND POWER

4.5.1 Background

Pursuant to Board Order No. P.U. 14(2004), in July 2004 Hydro filed an Application to adjust the former energy-only rate structure charged to NP. The proposed rate structure at that time was an embedded cost-based demand rate, as well as a two-block energy structure, with the second block based on the Holyrood Test Year fuel cost. In Order No. P.U. 44(2004), the Board approved a three-year phase in of the embedded cost-based demand rate, and approved the energy charge rate structure. However, the Board agreed that marginal costs should be considered in the future design of the wholesale rate.[32]

During Hydro's 2006 GRA, a demand rate of $4.00/kW/month was agreed upon by the Parties giving consideration to the system marginal capacity costs at the time. The energy rate structure continued to have the second block priced based on the Holyrood Test Year fuel cost.

4.5.2 Cost Review

Fuel prices have risen materially since the 2007 Test Year was reviewed. Current fuel cost, applied in the same manner as used in the 2003 and 2006 GRAs, would result in a second block rate of approximately 15.37¢ per kWh.[33] This compares to 8.805¢ per kWh in the 2007 Test Year. The average embedded demand cost has increased from $6.68

[32] See page 13 of Order No. P.U. 44(2004).

[33] Energy (Second Block):

Average No. 6 Fuel Cost per Barrel	$93.32
Conversion Factor (kWh per Barrel)	607
Rate (¢/kWh)	15.37

per kW in the 2007 Test Year Cost of Service Study to $10.18 per kW in the 2015 Test Year Cost of Service Study.

Hydro engaged Lummus Consultants International Inc. (Lummus), formerly Shaw Group Consultants International Inc., to provide a recommendation on the NP rate structure, and several other issues, the results of which are contained in the report entitled "Cost of Service Study/Utility and Industrial Rate Design Report", attached as Exhibit 9. The guiding principles of the rate design review included maintaining a second block price signal to reasonable reflect the price of Holyrood fuel, considering the demand rate in light of increased embedded capacity costs, and designing the rates to recover NP's revenue requirement.

There is currently uncertainty with respect to marginal costs of demand and energy on the Island Interconnected System as described in Section 4.2.2. The marginal costs of demand and energy should reflect the impact of the commercial arrangements for the cost of electricity from Muskrat Falls and for the costs of the new transmission infrastructure. As discussed in Section 4.2.3. Hydro is planning to conduct a marginal cost study in 2015 to gain an understanding of marginal costs post 2017.

Table 4.5 summarizes the marginal capacity costs for the next three years prior to the Labrador-Island Interconnection.

Table 4.5

Island Interconnected System Marginal Capacity Costs			
	Annualized Cost of Generation	**Forecast LOLH**	**Marginal Generation Capacity Cost**
Current dollars/kW			
	(a)	(b)	(c) (a)*(b)/Target LOLH[34]
2015	$194	0.73	$51
2016	$198	0.99	$70
2017	$202	1.31	$94
Average			**$71.67 ($5.98 per month)**

4.5.3 Proposed Rate

Hydro is proposing the demand charge be set at $5.50 per kW per month. This price reasonably reflects the marginal capacity costs for the period 2015 to 2017 with the inclusion of the new combustion turbine at Holyrood.[35] The proposed demand charge is also comparable to the marginal capacity costs estimated by NERA beyond 2017 based upon the Labrador Interconnection scenario.[36]

In its Amended Application, Hydro considered both Lummus's recommendations and current estimates of marginal costs. Table 4.6 provides a summary of the rate structure for NP.

[34] Target LOLH = 2.8 hours.
[35] Calculated based upon the methodology outlined in NERA's 2006 marginal cost study documented in the report entitled "*Newfoundland and Labrador Hydro Marginal Costs of Generation and Transmission*".
[36] See response to CA-NLH-033, page 2 of 3.

Table 4.6

Utility Rate Structure[37]				
Component	**Unit**	**2007**	**Proposed**	**Comments**
Demand	$/kW/month	4.00	5.50	2007 rate was negotiated; proposed rate reflects marginal cost estimate.
First Block	GWh/month	250	250	Block size designed to have few, if any, kWh recorded as a load variation in the RSP.
First Block	mills/kWh	32.46	34.11	2007 rate was the fallout rate after demand and second block rates were calculated; proposed rate is designed to recover non-fuel energy costs.
Second Block	mills/kWh	88.05	116.22	2007 rate was the marginal fuel cost per kWh based on Test Year Holyrood fuel cost; proposed rate is designed to send a marginal price signal and recover costs not included in demand or first block rates.

Hydro is also proposing a rate of 29.74 mills per kWh for firming up secondary energy purchased from CBPP and resold to NP as firm energy. The calculation is shown on Schedule 1.6 of the 2015 Cost of Service Study (Exhibit 13).

The proposed Utility rate schedule applicable to NP is found on Pages 1 through 4 of the Rates Schedules section of the Amended Application. The RSP adjustment has been updated to set the fuel rider to zero in accordance with Section D of the RSP rules, shown on Pages 15 to 16 of the Rates Schedules section of this Application.

4.5.4 NP Curtailable Load

Subsequent to Hydro's 2006 GRA, NP, the Consumer Advocate, and Hydro entered into discussions concerning NP's rate structure, and in April 2008 submitted to the Board a

[37] The calculation of NP's rate is provided on Schedule 1.4 of the 2015 Cost of Service Study attached as Exhibit 13 to the Application.

report entitled "Review of Demand Billing to Newfoundland Power", a copy of which is included as Exhibit 11 to this evidence. In the report, Hydro and NP agreed in principle to adjusting the billing demand to reflect available curtailable load.[38] This approach would (i) reflect the demand savings to NP from having curtailable load available, and (ii) ensure NP's customers would only be curtailed when required to meet system requirements.

Lummus's report filed with Hydro's Application recommends that a number of matters should be resolved prior to the curtailable load being reflected as a credit to the billing demand of NP.[39] During the period since Hydro notified the Board of its intention to file an Amended Application, Hydro held discussions with NP on implementing a proposal consistent with the 2008 agreement in principle on the treatment of curtailable load. The objective of the proposed changes is to ensure curtailable load is available to meet system load requirements and is reflected in computing NP's billing demand.

On September 19, 2014, Hydro filed an application for approval of a revised Utility Rate to NP (the "Curtailable Credit Application") to reflect the inclusion of a curtailable load credit in the calculation of billing demand for NP for the 2014-2015 winter season. At the time of filing the Amended Application, the Board has not yet ruled on the Curtailable Credit Application.

Hydro believes the changes proposed in the Curtailable Credit Application should be approved by the Board until a review of the longer-term benefits of interruptible/curtailable load is completed giving consideration to the results of a marginal cost study reflecting the Labrador-Island Interconnection. The proposed approach reflected in the Curtailable Credit Application will ensure efficient use of NP's curtailable load until this review has been completed.

[38] See page 26 of the report entitled "Review of Demand billing to NP, April 2008".

[39] See Section 2.1 of the Lummus report filed with Hydro's Application attached as Exhibit 9.

Hydro's proposal to provide a curtailable credit in computing the billing demand for NP does not impact cost allocation in the 2015 Test Year Cost of Service Study. This is because the forecast maximum native peak provided by NP and included in the Test Year Cost of Service reflects curtailable load being deducted from NP's maximum native load.[40]

4.5.5 NP Generation Credit

Hydro's proposed Utility Rate also includes an update to the NP Generation Credit from 117,930 kW to 119,329 kW based on the revised credit described in Section 2.5.4 of the evidence.

4.5.6 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Demand Charge:

  $5.50 per kW of billing demand per month

- Energy Charge:

First 250,000,000 kilowatt-hours	@ 3.411 ¢ per kWh
All excess kilowatt-hours	@ 11.622 ¢ per kWh

- Firming-up Charge: @ 2.974 ¢ per kWh
- Removal of the fuel rider of 1.526¢ per kWh which was based upon a forecasted fuel price of $105.60/bbl ($Can).

4.6 RATES FOR ISLAND INDUSTRIAL CUSTOMERS

4.6.1 Firm Rates

Rates charged to Island IC for firm power and energy are designed based upon the average embedded costs from the 2015 Test Year Cost of Service. Hydro has calculated

[40] This approach is selected because NP requests customers to curtail to minimize its billing demand on an annual basis.

a firm service rate comprised of a demand charge of $8.38 per kW of billing demand per month and an energy charge of 51.51 mills per kWh plus specifically assigned charges. Table 4.7 provides a comparison of the existing and proposed demand and energy base rates for Island IC.

Table 4.7

Industrial Customer Demand and Energy Charges		
	Existing	**Proposed**
Demand charge ($/kW/month)	$6.68	$8.38
Energy charge (¢ per kWh)	3.676	5.151

Specifically assigned charges recover costs incurred for assets that are in service solely for each Island IC.[41] These costs include operating and maintenance costs, depreciation and return on the specifically assigned assets.[42]

Table 4.8 provides a comparison of the existing and proposed specifically assigned charges by customer.

[41] For the NP rate design, there is no specifically assigned charge as these costs are proposed to be recovered through the first block energy charge.
[42] When a customer has paid a contribution in aid of construction for the specifically assigned assets, the costs reflected in the specifically assigned charge only recover the allocation of operating and maintenance costs for those assets.

Table 4.8

Industrial Customer Specifically Assigned Charges[43]		
	Existing	**Proposed**
CBPP	$347,167	$891,045
NARL	150,976	91,729
Teck	186,169	208,600
Vale[44]	-	499,522
Total	**$684,312**	**$1,690,896**

The material increase in the specifically assigned costs to CBPP is a result of approximately $3.5 million of capital expenditures by Hydro over the period 2007 to 2015 forecast on the frequency converter in place to provide service to CBPP.

4.6.2 Non-firm Rates

The IC contracts currently include a provision for interruptible demand.[45] The standard definition is as follows:[46]

> ***"Interruptible Demand"*** *means, that part of a Customer's Demand which exceeds its Power on Order, which may be interrupted, in whole or in part, at the discretion of Hydro and which is supplied to the Customer in accordance with Clause …*

[43] There are no specifically assigned charges proposed for Praxair as there are no transmission or terminal station assets solely for the provision of service to this customer.

[44] Vale was connected in 2012 and does not currently pay a specifically assigned charge.

[45] Provided the Amount of Power on Order is equal to or greater than 20,000 kW, the amount of Interruptible Demand and Energy available shall be the greater of 10% of the Amount of Power on Order and 5,000 kW. If the Amount of Power on Order is less than 20,000 kW, the Amount of Interruptible Demand and Energy available shall be 25% of the Amount of Power on Order.

[46] The definition is slightly different for Corner Brook Pulp and Paper since there is "Generation Outage Demand". The provision states: **"Interruptible Demand"** means, that part of a Customer's Demand, other than its Generation Outage Demand, which exceeds its Power on Order, which may be interrupted, in whole or in part, at the discretion of Hydro, and which is supplied to the Customer in accordance with Clause 4.01 of the Service Agreement.

The 2015 Test Year Cost of Service Study does not include interruptible demand in determining the peak demand for the IC Class for cost allocation. The interruptible demand reflects the non-firm load requirement in the standard IC contracts. When customers are using interruptible demand, they are generally required to pay for their additional energy requirements based upon the cost of fuel for the thermal generation source providing energy.[47]

For non-firm service, Hydro is proposing to retain the previously approved calculation for the energy charge with an update to the loss factors.[48] The loss factor has been updated to the five-year average Island Interconnected System losses from 2.68% to 3.47%.[49]

Hydro has also updated its wheeling rate from 0.384¢ per kWh to 0.443¢ per kWh for IC to reflect 2015 Test Year costs. There are no customers currently accessing the wheeling rate. However, Hydro is proposing to maintain the rate in the event that it may be required.

4.6.3 Rate Structure Review

The IC rate structure was reviewed after Hydro's 2006 GRA, and a report entitled "Review of Industrial Customers Rate Design" was submitted to the Board in 2008. This report is included in this Application as Exhibit 12. Hydro requested that Lummus include this matter in their review (Exhibit 9) for this proceeding.

[47] Because CBPP runs its generation to maximum capacity at the request of Hydro, CBPP is permitted to exceed its firm demand requirements without paying the non-firm energy price as long as thermal generation is not being operated to meet system energy requirements.
[48] See page 7 of 48 of the proposed Rates Schedules included with the Amended Application.
[49] The 2.68% was based on the five-year period ending in 2005 and the 3.47% is based on the five-year period ending in 2013.

Hydro agrees with the recommendation in the Lummus report (Section 5 of Exhibit 9) to maintain the existing rate design to Island IC at this time. Hydro is proposing to review the Island IC rate design after the proposed marginal cost study is complete and a rate design review is undertaken.

4.6.4 Proposed Rate

Hydro is requesting the Board's approval for the following:

- Demand Charge:
  $8.38 per kW of billing demand per month
- Firm Energy Charge: Base Rate @ 5.151¢ 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

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

4.6.5 Phase-in of Island Industrial Customer Rates

Background

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. 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.[50]

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

In its Second Interim Rate Application, Hydro proposed to implement, on an interim basis, a fuel rider relative to 2007 Test Year fuel costs to move the IC rates closer to an average rate that would be more reflective of the cost of providing service. In Order No. P.U. 39(2014), the Board found that there was "uncertainty as to whether the Application proposals are consistent with the Government direction."[51]

OC2013-089 states that the RSP Surplus is to be used to fund a three-year phase-in of rate increases for Island IC. Stage one of the phase-in occurred in September 2013 with an adjustment to the RSP rider for Teck Resources and the removal of the RSP adjustment for the other IC. The rate impacts of the September 1, 2013 rate change were 22.4% increase for Teck and a 19.1% average increase for the other IC.

Proposed Phase-in of Base Rates

Hydro is proposing 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. IC base rates resulting from the 2015 Test Year Cost of Service Study are proposed to become effective for all IC on January 1, 2015, with an offsetting RSP Surplus Credit Adjustment applied to limit the customer rate impact. The RSP Surplus Credit Adjustment would be reduced for the period September 1, 2015 to August 31, 2016 and eliminated September 1, 2016.

RSP Surplus Credit Adjustment

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. The proposed percentages 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.

[51] See page 15, Order No. P.U. 39(2014).

Effective January 1, 2015, it is proposed that the RSP Surplus Credit Adjustment will be set to 85% of each customer's bill increase resulting from the base rate change. This means that 85% of the customer's monthly bill impact of implementation of new base rates will be recovered from the RSP Surplus. Effective September 1, 2015, the RSP Surplus Credit Adjustment would reduce to 35% and on September 1, 2016, RSP Surplus Credit Adjustment would be set to zero.

Table 4.9 provides the forecast balance in the IC RSP Surplus over the phase-in period.

Table 4.9

Proposed IC RSP Surplus Balance[52]	
Date	**Forecast Balance ($000s)**
January 1, 2015	11,031
August 31, 2015	4,570
August 31, 2016	37

RSP Adjustment Rate Update

The IC RSP Adjustment rate was suspended effective January 1, 2014 in accordance with Board Order P.U. 40(2013) and thus rates were not increased to include the fuel rider to recover the approximate $50 per barrel increased cost of fuel relative to the 2007 Test Year. With no RSP rate recovery in place, there has been a substantial increase in the RSP balance to be recovered from the Island IC primarily resulting from higher fuel costs, increasing from $0.6 million on December 31, 2013 to a forecast of $8.3 million on December 31, 2014.

Implementing a recovery rider effective January 1, 2015 to recover approximately $8.3 million from the IC would result in a rate increase of approximately 27%. This increase excludes the impact of the base rate phase-in as directed by Government. Due to the

[52] Includes financing calculated at Hydro's Test Year WACC.

material customer rate impacts of the balances which are presently accumulating in the IC RSP, Hydro proposes that a further phase-in mechanism be implemented in addition to the base rate phase-in mechanism directed by Government and described previously.

Hydro proposes to recover the year-end 2014 current RSP balance over a two-year period rather than the normal 12-month period to allow a reasonable transition to cost-based rates for the IC. The forecast IC RSP recovery rate effective January 1, 2015 is 0.7¢ per kWh. The RSP rate will be determined based upon actual year-end balances and filed with the Board in early January, 2015.[53]

The Government directive requires the rate increases for Teck be implemented equally to a reasonable degree. The proposed RSP Adjustment rate for Teck has been set to achieve the Government directive giving consideration to customer impacts.

Impact Summary

Tables 4.10 and 4.11 provide the forecast impacts of the base rate phase-in combined with the IC RSP balance recovery for IC.

[53] The two-year amortization of 2014 year-end balance is proposed to be segregated from the activity in the RSP for 2015.

Table 4.10

IC Billings (excluding Teck)
($millions)

	Existing Rates	1-Jan-15	1-Sep-15	1-Sep-16
Base Rates Billing	29.4	41.0	41.0	41.0
RSP Recovery Phase-In	-	4.3	4.3	4.3
Total Revenue and RSP	29.4	45.4	45.4	45.4
RSP Surplus Credit	-	(9.8)	(4.1)	-
Total Billing[1]	29.4	35.5	41.3	45.4
Rate Increase		20.7%	16.3%	9.8%

[1] Calculations are based upon 2015 billing determinants.

Table 4.11

Teck Billings
($millions)

	Existing Rates	1-Jan-15	1-Sep-15	1-Sep-16
Base Rates Billing	1.2	1.6	1.6	N/A
RSP Recovery Phase-In	-	0.1	0.1	-
Total Revenue and RSP	1.2	1.8	1.8	N/A
RSP Surplus Credit	-	(0.3)	(0.1)	-
RSP Teck Adjustment	(0.2)	(0.2)	(0.2)	
Total Billing[1]	1.0	1.2	1.4	N/A
Rate Increase[2]		20.7%	16.3%	N/A

[1] Calculations are based upon 2015 billing determinants.
[2] Teck Resources is forecast to close operations in 2015.

Hydro's proposed implementation of IC rates results in customer rates effective September 1, 2016 reflecting the 2015 Test Year costs. Hydro believes the proposed rate implementation plan is in accordance with the Government directive.

4.6.6 Hydro's Application

Hydro is proposing the following:

- Approval of the proposed base rate set forth in Section 4.6.4; and
- 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. IC base rates resulting from the 2015 Test Year Cost of Service Study are proposed to become effective for all IC January 1, 2015, with an offsetting RSP Surplus Credit Adjustment applied to limit the customer rate impact. The RSP Surplus Credit Adjustment would be reduced for the period September 1, 2015 to August 31, 2016 and eliminated September 1, 2016. Refer to Section 4.6.5.

4.7 RATE STABILIZATION PLAN

4.7.1 Load Variation Component

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. The proposed effective date for the RSP change is September 1, 2013.[54]

The existing methodology provides for the net effects of load variation on costs to be assigned to the customer groups that caused the load variation. The direct assignment approach has been shown to have the potential for rate volatility if customer load requirements are materially different from the forecast Test Year load requirements.

The proposed method will allocate the net cost effect of load variation on a basis consistent with the manner that fuel price variation is currently allocated in the RSP.

[54] 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.

The proposed method is also consistent with the cost allocation effects of changes in load in a Test Year Cost of Service Study.[55]

A number of the expert reports specifically addressed the proposed load variation methodology and recommended the proposed approach be approved if the load variation component is maintained in the RSP.

Mr. Patrick Bowman, the IC expert, states…"if it is desired to retain the provision for the time being while Holyrood remains the incremental source of generation, the load variation allocation approach proposed by Hydro in their June 30, 2013 RSP application should be approved pending a future elimination of the provision once a Labrador infeed is established."[56]

The PUB expert, J.W. Wilson and Associates summarized that…"if load variation costs are to be covered by the RSP, Hydro's proposed allocation of these costs based on customer energy ratios is an equitable allocation method."

Concerns were expressed by the IC and CA experts regarding the elimination of the load variation in its entirety. The opinion of NP's expert, Mr. Brockman, is that the load variation component of the RSP is required until such time as Hydro's tail block energy rates are set equal to the marginal cost of production.[57]

The forecast balance in the RSP load variation component as of December 31, 2014 is approximately a $33 million credit to customers. Per Order P.U. 29(2013), this balance is currently segregated.[58] Hydro is proposing to allocate this balance based on an

[55] See Hydro's RSP report filed June 30, 2006.
[56] Pre-filed evidence of Mr. Patrick Bowman, page 4, lines 33-38.
[57] NP response to PUB-NLH-001 relating to Hydro's 2013 GRA.
[58] Per Order No. P.U. 29(2013), load variation is to be segregated in a separate account within the RSP.

energy ratio allocation which would result in an allocation of approximately $31 million to NP and approximately $2 million to IC. This balance will remain segregated until a further Order of the Board providing for the disposition of the balance.

4.7.2 Hydro's Application

Hydro is proposing the following RSP modifications which are reflected in the RSP Section and/or IC Rates Schedules included in the Rates Schedules Tab:

- 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. The proposed effective date for the RSP change is September 1, 2013;
- Implementation of an RSP Surplus Credit Adjustment described in Section 4.6.5 in which the IC RSP Surplus balance will be used to phase-in base customer rates from January 1, 2015 to August 31, 2016;
- Implementation of an updated Teck Resources RSP Adjustment rate necessary to comply with Government direction to phase-in base rates in three equal annual percentages, to a reasonable degree;
- Recovery of the December 31, 2014 IC RSP balance over a two-year amortization period starting January 1, 2015, as outlined in Section 4.6.5;
- Removal of Section D (2.2), by which the IC RSP Adjustment was suspended effective January 1, 2014; and
- Removal of Section 1.4(b) as there is no further Rural Labrador Interconnected Automatic Rate Adjustment. References to the December 6, 2006 Government directive have also been removed.

4.8 RATES FOR RURAL CUSTOMERS

For rate-setting purposes, there are three distinct groups of Rural Customers:

- Island Interconnected and L'Anse au Loup Systems;
- Island and Labrador Isolated Systems; and

- Labrador Interconnected System.

Rates proposed in this Application for Rural Customers are based upon the policies for rural rates as approved in Order No. P.U. 14(2007) and Government direction. However, Hydro is proposing to apply the same increase to all classes of service on the Labrador Interconnected System with the exception of Street and Area Lighting.[59] The reason for this proposed approach is provided in Section 4.8.9.

Excluding Government departments in isolated diesel areas, rates for Rural Customers on the Island Interconnected, L'Anse au Loup and Isolated Systems, including preferential rate customers, will continue to be based on NP rates.

Rates for Government departments in isolated diesel areas will continue to be based on costs. Rates for Labrador Interconnected Customers are also based on costs.

Hydro is proposing some minor changes in its Rules and Regulations, found on Pages 22 to 35 in the Rates Schedules section of this Application. These changes are:

- Section 1(a)(iii) revised to include the words "and Labrador" in the definition of the word "Board";
- Section 2: Classes of Service, revised to include Island Interconnected L'Anse au Loup class 1.1S – Domestic Seasonal and delete Island Interconnected – L'Anse au Loup class 2.2 General Service; Island and Labrador Diesel Areas revised to include 1.2DS – Domestic Seasonal Diesel – Non-Government; Happy Valley Goose Bay Interconnected Area and Labrador City/Wabush Interconnected Area classes removed; and Labrador Interconnected classes added;

[59] Street and Area Lighting rates will be increased to recover the allocated Cost of Service including the Rural Deficit.

- Section 7(f) amended to agree with Section 7(f) of NP's Rules and Regulations, for consistency between the utilities;
- Section 9(k) revised to change the reference to "Happy Valley Goose Bay, Labrador City and Wabush service areas" to "Labrador Interconnected service area"; and
- Section 10(d) amended to agree with Section 10(d) of NP's Rules and Regulations, for consistency between the utilities.

4.8.1 Island Interconnected and L'Anse au Loup Systems

Hydro's rates for Rural Customers on the Island Interconnected and L'Anse au Loup Systems are the same as the rates charged to NP customers. It is estimated that Hydro's proposed rates for NP will see a flow-through increase for these customers of approximately 2.8%, compared to the existing rates that became effective on July 1, 2014.[60] The Burgeo School rate class rate will also be increased by 2.8%. The 2015 revenue to cost ratio for the Island Interconnected and L'Anse au Loup Rural Customers is projected to be 0.67 and 0.45, respectively.

4.8.2 Isolated Systems

For rate-setting purposes, there are three customer groups in the isolated systems:

(i) Rural Domestic Customers, excluding Government Departments;
(ii) Rural General Service Customers, excluding Government Departments; and
(iii) Government Departments.

Hydro's rates for Rural Domestic Customers, excluding Government departments, are the same as NP's rates for the basic customer charge and first block consumption

[60] These percentages do not include any rate impact for recovery of the 2014 Revenue Deficiency.

(lifeline consumption[61]), but non-lifeline consumption is adjusted by the average rate of change granted to NP.

Rates for Rural General Service Customers on the isolated systems are normally adjusted by the average rate of change approved for the customers of NP. However, in the Amended Application, the proposed rate increases are higher than that resulting from the proposed wholesale rate for NP. This is because the proposed rates for the 2015 Test Year for Domestic and General Service customers on Isolated Diesel Systems reflect the cumulative effect of the 2007 Test Year cost increases and the average retail rate change resulting from the proposed change in the NP wholesale rate.

The non-lifeline portion of the Domestic energy rate[62] and both small and large general service diesel rates[63] were forecast to increase by 15% in 2007 to reflect the increased cost of fuel since the previous GRA. These rate changes were not implemented as the revenue requirement effects of the cost increases reflected in the 2007 Test Year for Domestic and General Service diesel customers have been offset by Government funding. This funding will cease upon new rates being approved upon conclusion of the current GRA. The rate increase of 7.1% for Domestic Diesel customers and approximately 19% for General Service Diesel customers reflect the cumulative rate impact of the deferred 2007 rate increase and the 2015 proposed rate increase.

Government rate classes in isolated systems pay cost-based rates and the 2015 cost recovery level for Government departments remains at 100%.

[61] The lifeline block is designed to provide Domestic Customers with access to electricity at non-discriminatory prices for essential services. Essential services include most electrical appliances and hot water heating, but not electric heat.

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

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

The 2015 revenue to cost ratio for customers on the Island and Labrador Isolated Systems, excluding L'Anse au Loup, is projected to be 0.16 and 0.24 respectively, or a combined revenue to cost ratio of 0.23.

4.8.3 Isolated Rural Domestic Customers – Excluding Government Departments

Isolated Rural Domestic Customers, excluding Government departments, have the same rates as NP customers for the basic customer charge and lifeline block consumption, and rates charged for consumption above the lifeline block are automatically adjusted by the average rate of change granted to NP. Hydro is also proposing rates that are based on these criteria be adjusted for the deferred 2007 rate increase. It is estimated that the rate increase for these customers will be 7.1% compared to the existing rates that became effective on July 1, 2014.

4.8.4 Isolated Rural Domestic Customers – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on the combined costing for both Government and Non-Government Domestic Customers, it is proposed that the rate for Government Departments - Domestic (1.2G) will increase on average by 21.5% compared to the existing rates that became effective on July 1, 2014.

4.8.5 Isolated Rural General Service Customers – Excluding Government Departments

As outlined in Section 16(c) (ii) of the Rules and Regulations for Rural Customers and as approved by the Board in Order No. P.U. 14(2007), rates for Isolated Rural General Service Customers, excluding Government departments, are automatically adjusted by the average rate of change granted to NP from time to time. Hydro is proposing 2015 rates that are based on these criteria, adjusted for the deferred 2007 rate increase. The rate for small General Service Customers will increase on average by 18.5%. The rate for large General Service Customers will increase on average by 19.2%.

4.8.6 Isolated Rural General Service Customers – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on the combined costing for both Government and Non-Government General Service Customers, the rate for small General Service – Government Departments (2.1G) will increase, on average, by 24.7%. The rate for large General Service Government[64] Departments (2.2G) will increase, on average, by 25.4%.

4.8.7 Isolated Rural Street and Area Lighting – Excluding Government Departments

Rates for Isolated Rural Street and Area lighting, excluding Government departments, are the same rates as NP rates for similar service. It is estimated that Hydro's current proposal for NP will see a flow-through increase of approximately 2.8% compared to the rates in effect on July 1, 2014.

4.8.8 Isolated Rural Street and Area Lighting – Government Departments

Government departments are charged rates based on full cost recovery. These rates have not changed since 2007. Based on an allocation of the combined costing for both Government and Non-Government Street and area lighting service, it is proposed that rates will increase on average by 27.5%, compared to the rates in effect on July 1, 2014.

4.8.9 Labrador Interconnected

Table 4.12 provides the revenue to cost ratios for the Hydro Rural classes of service on the Labrador Interconnected System assuming all classes receive the proposed average rate change of 2.1%.

[64] Excludes hospitals and schools as outlined in Order No. P.U. 7(2002-2003), p. 130.

Table 4.12

Revenue to Cost Ratios	
Hydro Rural class	**Revenue to Cost Ratio**[65]
1.1 Domestic	0.89
2.1 General Service 0-10 kW	1.00
2.2 General service 10-100 kW	1.16
2.3 General Service 110-1000 kVA	1.22
2.4 General Service 1000 kVA and Over	1.22
4.1 Street and Area Lighting	0.85

In Order No P.U. 14(2004), the Board approved a five-year plan to implement uniform rates for Labrador Interconnected Customers using the following cost recovery targets:

- Domestic 95%;
- General Service 105% -115%; and
- Street Lighting 100%.

The Cost of Service Study results indicate that Domestic class and Street and Area Lighting class should receive an above average increase and General Service classes 2.2, 2.3 and 2.4 should receive decreases.

Hydro has concerns with proposing a wide range of increases and decreases at this time due to uncertainty with the accuracy of the load research data used in the Cost of Service Study for its Domestic and General Service classes. The load research data is used to allocate demand costs by class. The current class load factor estimates are based upon load research data borrowed from other utilities. The high percentage of system costs classified as demand related (i.e., greater than 60%) on the Labrador

[65] Before Rural Deficit allocation.

Interconnected System creates a potential volatility in class revenue to cost ratios due to difference in class load factor estimates.

Hydro has reliable estimates of class load for the Street and Area Lighting class as a result of knowing the connected load of each lighting type and the timing of system peaks and class peak. Hydro is proposing to increase Street and Area Lighting rates to achieve full cost recovery.

Hydro is proposing equal increases for all classes with the exception of Street and Area Lighting at this time. Hydro will review its load research requirements and present a proposal prior to the next GRA on a class load research study for Labrador Interconnected System.

Based on the 2015 Cost of Service Study, filed as Exhibit 13, Hydro is proposing the following Labrador Interconnected Rural Rates as presented in Table 4.13.

Table 4.13

Labrador Interconnected Rate Change Comparison		
	Current Rates	Proposed Rates
Domestic 1.1		
Basic Customer Charge ($ per month)	7.15	7.29
Energy Charge (¢ per kWh)	3.280	3.341
General Service 2.1		
Basic Customer Charge ($ per month)	10.45	10.65
Energy Charge (¢ per kWh)	5.240	5.339
General Service 2.2		
Demand Charge ($ per kW per month)	2.20	2.24
Energy Charge (¢ per kWh)	2.433	2.480
General Service 2.3		
Demand Charge ($ per kVA per month)	2.00	2.04
Energy Charge (¢ per kWh)	2.103	2.142
General Service 2.4		
Demand Charge ($ per kVA per month)	1.75	1.79
Energy Charge (¢ per kWh)	1.733	1.763
Street Lights		
250W Mercury Vapour ($ per month)	13.50	15.86
100W High Pressure Sodium ($ per month)	10.00	11.75
150W High Pressure Sodium ($ per month)	13.50	15.86
250W High Pressure Sodium ($ per month)	17.80	20.92
400W High Pressure Sodium ($ per month)	23.00	27.03
Wood Poles ($ per month)	3.40	4.00
100W High Pressure Sodium Closed ($ per month)	6.75	7.93
100W High Pressure Sodium ($ per month)	4.10	4.82

Hydro’s 2006 GRA resulted in an Agreement on Labrador Interconnected Rates, wherein there was a rate plan for the Labrador Interconnected Rural Customers so that in years 2008 through 2011, inclusive, rate changes were to be phased in such that by 2011:

(a) Rates would be based on the 2007 Test Year revenue requirement;

(b) Uniform rates would be charged to all Rural Customers on the Labrador Interconnected System; and

(c) The CFB Goose Bay revenue credit would be fully applied to the Rural Deficit.

Rates for the final year of the phased-in implementation were approved by the Board in Order No. P.U. 33(2010).

The proposed rates schedules for 2015 are included in the Rates Schedules Tab of the Application. The average increase proposed for Hydro Rural customers on the Labrador Interconnected System is 2.1%.

4.8.10 Hydro's Application

Hydro is requesting the Board's approval for the following:

- Amending the rules and regulations for service to all Hydro Rural Customers as set out in this section;
- The rates for Isolated Rural Customers - Government as set out in Pages 36 to 39 of the Rates Schedules attached to this Application; and
- The rates for Labrador Interconnected Rural Customers as set out in Pages 40 to 47 of the Rates Schedules attached to this Application.

4.9 LABRADOR INDUSTRIAL RATES

4.9.1 Industrial Rates Policy

In December 2012, the Provincial Government introduced a series of legislative amendments, to establish a new electricity rate policy for Industrial Customers on the Labrador Interconnected System.

While the Board does not have jurisdiction over the establishment of the generation rate for Labrador Industrial Customers, legislation does provide that the transmission component of Labrador Industrial rates be fully regulated by the Board beginning in 2015.[66]

4.9.2 Industrial Transmission Rate Design

Hydro has isolated the Labrador Industrial transmission revenue requirement in accordance with the approved Cost of Service functionalization. The transmission costs were classified as 100% demand related, consistent with the approved classification methodology. The transmission demand-related costs were then allocated between Labrador Industrial Customers and Rural customers based on the approved single coincident peak allocation method.

Table 4.14 presents the breakdown of the allocated costs:

Table 4.14

Calculation of Labrador Industrial Transmission Rate	
Total Labrador Interconnected Transmission Demand Cost ($)[1]	6,378,120
Labrador Industrial Allocation based on CP[2]	63.37%
Allocated Transmission Demand Cost ($)[3]	4,041,656
(Firm) Billing Demand (kW)[4]	270,000
Annual Cost ($ per kW)	14.97
Monthly Rate ($ per kW)	**1.25**

[1] See Exhibit 9, Schedule 2.1E, Page 1 of 2, Line 23, Col 5.
[2] See Exhibit 9, Schedule 3.1E, Page 1 of 2, Line 14, Col 5.
[3] See Exhibit 9, Schedule 3.2E, Page 3 of 4, Line 62, Col 5.
[4] See Exhibit 9, Schedule 1.3.2, Page 3 of 3, Line 8, Col 2, divided by 12.

[66] Section 5.8(2) of the Electrical Power Control Act states: "The *Public Utilities Act* shall not apply to the setting of electricity rates for IC in Labrador other than the transmission components of those rates, which shall be regulated under subsection (1)."

Upon transition of the TwinCo assets to Hydro, Hydro may also be proposing a specifically assigned charge for Labrador IC.

4.9.3 Generation Costs for Labrador Industrial Customers

The generation costs attributable to Labrador IC will continue to be recorded by Hydro as a cost recovery. The revenues associated with these costs are non-regulated, therefore treatment as a cost recovery ensures there is no impact on regulated customers on the Labrador Interconnected System.

4.9.4 Hydro's Application

Hydro is requesting the Board's approval for the following:

- A regulated transmission demand rate for Labrador Industrial Customers, of $1.25 per kW per month, to be implemented on an interim basis effective January 1, 2015.

4.10 REVENUES AND RSP BASED ON EXISTING AND PROPOSED RATES

Table 4.15 summarizes the projected 2015 revenues and RSP charges based on the proposed and existing rates.

1 **Table 4.15**

Comparison of Revenues and RSP at Existing and Proposed Rates				
	Dec 31/14 Existing Rates	**Jan 1/15 Proposed Rates**	**$ Change**	**% Change**
Newfoundland Power				
Firm	$ 415,402,365	$ 525,340,174	$ 109,937,809	
RSP[1]	57,759,975	(32,641,791)	(90,401,766)	
Total Firm NP	$ 473,162,340	$ 492,698,383	$ 19,536,043	4.1%
Island Industrial				
Island Industrial Firm	$ 30,546,755	$ 42,517,934	$ 11,971,179	
Island Industrial Non-Firm	-	-	-	
Island Industrial Total	$ 30,546,755	$ 42,517,934	$ 11,971,179	39.2%
Labrador Industrial				
Transmission	-	$ 4,050,000	$ 4,050,000	
Generation Cost Recovery	2,270,848	1,387,390	(883,458)	
Labrador Industrial Total	$ 2,270,848	$ 5,437,390	$ 3,166,542	139.4%
Canadian Forces Base Goose Bay	$ 932,221	$ 932,221	-	0.0%
Rural Island Interconnected	$ 51,653,313	$ 53,097,023	$ 1,443,710	2.8%
Rural Isolated Systems	9,257,429	10,519,193	1,261,764	13.6%
L'Anse au Loup	2,881,421	2,961,956	80,535	2.8%
Rural Labrador Interconnected				
Domestic	11,150,910	11,359,109	208,199	1.9%
GS 2.1 0 - 10 kW	410,227	417,993	7,766	1.9%
GS 2.2 10 - 100 kW	2,342,225	2,386,562	44,337	1.9%
GS 2.3 110 - 1000 kVA	3,071,096	3,129,052	57,956	1.9%
GS 2.4 Over 1000 kVA	2,806,310	2,860,240	53,930	1.9%
Street & Area Lighting	312,471	367,187	54,716	17.5%
Rural Labrador Interconnected	$ 20,093,239	$ 20,520,143	$ 426,904	2.1%
All Rural Systems Total	$ 83,885,402	$ 87,098,315	$ 3,212,913	3.8%
Grand Total	$ 590,797,566	$ 628,684,243	$ 37,886,677	6.4%
Reconciliation to the Cost of Service, Sch 1.2, Page 1 of 6, Column 2, Line 15				
Revenue from Proposed Rates				$628,684,243
Newfoundland Power RSP				32,641,791
Total				$661,326,034
COS				$661,326,034

[1] The ($90.4 million) change in RSP relates to the NP fuel rider.

4.11 OTHER REGULATORY ITEMS

4.11.1 CDM Cost Recovery Adjustment

Hydro is proposing a number of deferral accounts as outlined in Section 3.8.2 of the evidence, namely the Isolated Systems Cost Variance Deferral Account, the Energy Supply Cost Deferral Variance Account and the CDM Cost Recovery Deferral Account. Hydro will file applications annually for disposition of year-end balances in the Isolated Systems Supply Cost Variance Deferral Account and the Energy Supply Cost Variance Deferral Account.

The CDM Cost Recovery Deferral Account balance is proposed to be recovered using an annual adjustment for each of NP and IC, using a seven-year amortization period, as outlined in Pages 18 to 19 of the Rates Schedules. An illustration of the amortization calculation is provided in Table 4.16.

Table 4.16

CDM Recovery Illustration								
		Amortization ($)						
	CDM Program Spending	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7
Year 1[1]	2,000,000	285,714	285,714	285,714	285,714	285,714	285,714	285,714
Year 2	500,000		71,429	71,429	71,429	71,429	71,429	71,429
Year 3	500,000			71,429	71,429	71,429	71,429	71,429
Year 4	500,000				71,429	71,429	71,429	71,429
Year 5	500,000					71,429	71,429	71,429
Year 6	500,000						71,429	71,429
Year 7	500,000							71,429
Total Amortization		285,714	357,143	428,572	500,001	571,430	642,859	714,288

[1] Includes cumulative balance from 2009 to initial year of amortization.

The methodology presented in Table 4.16 reflects a seven-year recovery of costs over a discrete period rather than a rolling balance approach.

4.11.2 KPI Reporting

The Board, in Order No. P.U. 14(2014), directed Hydro to, among other things, file annually appropriate historic, current and forecast comparisons of reliability, operating, financial and other key targeted outcomes and measures, including KPIs. Hydro complied with this Order by filing KPI reports. Exhibit 2 provides Hydro's 2013 Annual Report on Key Performance Indicators. Commencing with its KPI report for 2004, Hydro noted that its functionally orientated (e.g. generation, transmission) financial KPIs require a Cost of Service Study to allocate costs among systems and functional areas. This is primarily due to the nature of Hydro's TRO department, which serves multiple systems and functions.

Forecast Cost of Service studies are typically prepared by Hydro in support of rate cases, and the significant effort to produce such a study is not part of Hydro's annual budgeting process.

In its 2013 GRA, Hydro requested the Board's approval for altering or amending Order No. P.U. 14(2004) so that functionally oriented KPIs are not required to be provided on forecast basis.

Hydro has given consideration to the pre-filed evidence by Mr. Doug Bowman in which he states that "it is useful for the Parties and the Board to see how Hydro is performing relative to targets, particularly when Hydro's target return on equity is fixed by way of Government directive (see OC2009-063) and that is not clear why there is a problem basing a financial performance target on an older Cost of Service Study provided results relative to the target are recorded in a consistent manner."[67] Hydro is therefore proposing to continue to provide such information in its annual KPI reports based on the most recent Test Year Cost of Service Study.

[67] Pre-filed evidence of Mr. Doug Bowman, pages 38-39.

4.11.3 Hydro's Application

Hydro is proposing the following:

- CDM cost recovery deferral be recovered using an annual adjustment for each of NP and IC, using a seven-year amortization period, as outlined in Pages 18 to 19 of the Rates Schedules; and
- To use the most recent Test Year Cost of Service Study in preparing its annual KPI reports.

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments
Domestic Diesel 1.2G

Dollars Change in Annual Costs	Percentage Change				
	21% to 23%	23% to 25%	25% to 27%	27% to 29%	Total
$ - to $ 2,000	19.23%		3.85%	7.69%	30.77%
$ 2,000 to $ 4,000	46.15%				46.15%
$ 4,000 to $ 6,000	11.54%				11.54%
$ 6,000 to $ 8,000	7.69%				7.69%
$ 8,000 to $ 10,000	3.85%				3.85%
Total:	**88.46%**	**0.00%**	**3.85%**	**7.69%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on 2013 usage patterns and an average of 26 customers.

Rates	Existing	Proposed
Basic Charge ($)	41.03	58.03
kWh Charge (¢)	78.100	94.410

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments
General Service 2.1G

Dollars Change in Annual Costs					Percentage Change 23% to 25%	25% to 27%	27% to 29%	Total
$	-	to	$	1,000	4.35%	8.70%	8.70%	21.74%
$	1,000	to	$	2,000	13.04%	8.70%		21.74%
$	2,000	to	$	3,000	32.61%			32.61%
$	3,000	to	$	4,000	17.39%			17.39%
$	4,000	to	$	4,600	6.52%			6.52%
				Total:	**73.91%**	**17.39%**	**8.70%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on 2013 usage patterns and an average of 46 customers.

Rates	Existing	Proposed
Basic Charge ($)	44.82	62.22
kWh Charge (¢)	69.701	86.288

Newfoundland & Labrador Hydro
Impact of Proposed Rates on Annual Electricity Costs
Government Departments
General Service Diesel 2.2G

	Percentage Change			
Dollars Change in Annual Costs	**21% to 23%**	**23% to 25%**	**25% to 27%**	**Total**
$ 2,000 to $ 10,000	9.09%	45.46%	22.73%	77.27%
$ 10,000 to $ 20,000			18.18%	18.18%
$ 60,000 to $ 66,500			4.55%	4.55%
Total:	**9.09%**	**45.46%**	**45.45%**	**100.00%**

Each number in the body of the table represents the proportion of customers with the combination of percent range at the top and dollar range to the left.

Note: This analysis is based on 2013 usage patterns and an average of 22 customers.

Rates	**Existing**	**Proposed**
Basic Service Charge	66.37	76.64
kWh Charge	49.554	64.094
Demand	53.68	62.25